British Columbia Transmission CORPORATION™

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26 May 2006

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Box 250
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

Re: British Columbia Transmission Corporation
Transmission Revenue Requirement Application

British Columbia Transmission Corporation ("BCTC") hereby submits its Transmission Revenue Requirement Application (the "Application"), filed pursuant to sections 56, 58 and 89 of the *Utilities Commission Act* and section 6 of Special Direction No. 9, to the British Columbia Utilities Commission ("Commission") seeking approval of permanent rates effective April 1, 2006.

BCTC's existing Transmission rates were declared interim effective April 1, 2006 through Commission Order G-34-06 dated March 30, 2006. The Application now seeks to further amend on an interim basis the current interim rates, effective July 1, 2006, to reflect the reduced rates BCTC is seeking on a permanent basis. This interim adjustment will minimize the adjustment that will need to be made once permanent rates are approved, and give customers the benefit of the applied for decrease as early as possible.

Section 14 and Appendix A of the Application, which address BCTC responses to Commission Directives, will be filed at a later date. BCTC notes that certain Commission Directives are addressed in various sections of the Application, and these responses will be included in the Concordance Table provided in Appendix A when it is filed.

BCTC has proposed a review process for the Application which considers the fact that parts of the Application are related to BC Hydro's F2007 and F2008 Revenue Requirement Application, filed on May 25, 2006. This process is consistent with that proposed by BC Hydro in its application and will ensure that related matters are

examined in the most appropriate proceeding and treated consistently in each proceeding. This process is discussed at pages 12 through 14 of the Application.

Should the Commission consider it helpful to the review process, BCTC is prepared to receive and prepare responses to Commission Staff information requests at the earliest possible date, rather than await the closing of intervenor registration and the conclusion of an initial procedural conference.

Sincerely,

Original signed by

Marcel Reghelini
Director, Regulatory Affairs

Copy: Registered Intervenors
BCTC F2006 Revenue Requirement Application

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LIST OF ABBREVIATIONS

	Abbreviation	Definition
1	ABSU	Accenture Business Services for Utilities
2	Act	Utilities Commission Act
3	AMM	Asset Management/Maintenance department
4	AMMRR	Asset Management/Maintenance Revenue Requirement
5	AMP	Asset Management Project
6	APD	Asset Program Definition department
7	APM	Asset Program Management department
8	ARN	Aboriginal Relations and Negotiations business unit at BC Hydro
9	ARO	Asset Retirement Obligation
10	BC Hydro	British Columbia Hydro and Power Authority
11	BCTC	British Columbia Transmission Corporation
12	BCTC RR	BCTC Revenue Requirement
13	BCUC	British Columbia Utilities Commission (or “Commission”)
14	BPA	Bonneville Power Administration
15	CAV	Condition Assessment Value
16	CB	Condition Based maintenance
17	CFO	Chief Financial Officer
18	CFT	Call For Tender by BC Hydro
19	CIAC	Contributions In Aid of Construction
20	CO	Corrective maintenance
21	COMDA	Cost Of Market Deferral Account
22	Commission	British Columbia Utilities Commission (or “BCUC”)
23	CPCN	Certificate of Public Convenience and Necessity
24	DSM	Demand Side Management
25	EAR	Expenditure Authorization Request
26	ELT	Executive Leadership Team
27	EMEDA	Emergency Maintenance Expenditure Deferral Account
28	EMS	Energy Management System
29	EROA	Expected Return On Plan Assets
30	Etag	Energy tagging system
31	FRSR	Future Removal and Site Restoration
32	G&A	General and Administrative (costs)
33	GRTA	Generation Related Transmission Assets
34	GRTL	Generation Related Transmission Lines
35	GRTS	Generation Related Transmission Substations
36	GWEDA	Grid West Expenditures Deferral Account
37	HVDC	High Voltage Direct Current

	Abbreviation	Definition
38	IDC	Interest During Construction
39	IEP	Integrated Electricity Plan for 2006 by BC Hydro
40	kV	kilovolt
41	LMC	Lower Mainland control Centre
42	NCC	Northern Control Centre
43	NITS	Network Integrated Transmission Service
44	NWPP	Northwest Power Pool
45	OAD	Operator / Area Dispatcher
46	OASIS	Open Access Same time Information Service
47	OATI	Open Access Technology International
48	OATT	Open Access Transmission Tariff
49	OEM	Original Equipment Manufacturer
50	OMA	Operations, Maintenance and Administration
51	Owner's RR	BCH Owner's Revenue Requirement
52	PM	Preventive Maintenance
53	PTP	Point-to-Point
54	R&D	Research and Development
55	RCM	Reliability Centred Management
56	RDA	Revenue Deferral Account
57	REDA	Regulatory Expenditures Deferral Account
58	ROE	Return on Equity
59	SCADA	Supervisory Control And Data Acquisition system
60	SCC	System Control Centre
61	SCMP	System Control Modernization Project
62	SD9	Special Direction No. 9, Order in Council No. 1107
63	SDA	Substation Distribution Assets
64	SIC	Southern Interior Control Centre
65	SLA	Service Level Agreement
66	SO	System Operations department
67	SPPA	System Planning and Performance Assessment department
68	TNO	Telecom Network Operations
69	TRR	Transmission Revenue Requirement
70	TSS	Transmission Scheduling System
71	VIC	Vancouver Island Control Centre
72	VITR	Vancouver Island Transmission Reinforcement project
73	WECC	Western Electricity Coordinating Council

GLOSSARY

Term	Definition
BCTC Depreciation Study	Determination of Average Service Lives Applicable to Plant in Service of BCTC as at March 31, 2005.
Debt	The amount obtained by adding revolving borrowings, bonds, notes and debentures, and deducting from that sum the total of related sinking funds, temporary investments and repurchased debt.
Deemed Equity Component	As amended by Order in Council 752, approved and ordered October 19, 2005, Deemed Equity Component means, for BCTC's financial year commencing April 1, 2005, and for all subsequent financial years, 40.7%.
Deemed Equity	For any period, the product obtained by multiplying the Deemed Equity Component by the sum of the Forecast Debt and the Forecast Equity relating to that period.
Equity	The sum of share capital, contributed surplus and retained earnings.
F2005 Actual	Actual results for the fiscal year ending March 31, 2005.
F2006 Approved	Amounts reflected in approved rates for the fiscal year ending March 31, 2006. See also Appendix F for clarification.
F2006 Forecast	11 months actual results plus one month of forecast results for the fiscal year ending March 31, 2006.
F2007 Plan	Proposed amounts for the fiscal year ending March 31, 2007. Approval is not sought at the line item level of detail.
F2008 Plan	Proposed amounts for the fiscal year ending March 31, 2008. Approval is not sought at the line item level of detail.
Forecast Debt	In relation to BCTC, Forecast Debt means, for a period made up of one or more years, the average of the amounts that are forecast to represent the average of BCTC's debt in each of the months of that period.
Forecast Equity	In relation to BCTC, Forecast Debt means, for a period made up of one or more years, the average of the amounts that are forecast to represent the average of BCTC's equity in each of the months of that period.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the *Utilities Commission Act*
[RSBC 1996] Chapter 473;

AND IN THE MATTER OF an application by
British Columbia Transmission Corporation
for an order or orders approving rates
effective April 1, 2006

1.0 APPLICATION

Pursuant to section 58 of the *Utilities Commission Act* (the "*Act*"), British Columbia Transmission Corporation ("BCTC") applies to the British Columbia Utilities Commission (the "Commission") for approval of permanent rates effective April 1, 2006.

Pursuant to Section 89 of the *Act*, BCTC applies to the Commission to have its interim rates amended effective July 1, 2006 to reflect the rates applied for in this Application and that the rates remain interim.

Under section 56 of the *Act*, BCTC applies for approval of depreciation rates.

BCTC also applies under section 6 of Special Direction No. 9 for approval of the clearing of deferral account balances and for continuation of deferral accounts.

Pursuant to section 11.3 of the Master Agreement and section 10.3(a) of the Distribution Operations Service Agreement and section 10.3(a) of the SDA Asset Management Service Agreement, BCTC seeks approval of costs to be incurred by BCTC for provision of services to BC Hydro.

1.1 Contact Information

Communications with respect to this Application should be sent to:

British Columbia Transmission Corporation
PO Box 49260
Suite 1100, Four Bentall Centre
1055 Dunsmuir Street
Vancouver, BC V7X 1V5

Attention: Marcel Reghelini, Director, Regulatory Affairs

Phone: (604) 699-7331
Fax: (604) 699-7537
Email: marcel.reghelini@bctc.com

and

Attention: Gerry Lister, Senior Regulatory Advisor, Regulatory Affairs

Phone: (604) 699-7528
Fax: (604) 699-7537
Email: gerry.lister@bctc.com

1.2 Legal Counsel for the Applicant

BCTC has retained outside legal counsel to support internal resources for the preparation of this Application and any associated proceeding.

Fasken Martineau DuMoulin LLP
Suite 2100
1075 West Georgia Street
Vancouver, BC V6E 3G2

Attention: Peter Feldberg

Phone: (604) 631-3131
Fax: (604) 632-4994
Email: pfeldberg@cgy.fasken.com

1.3 Summary of the Application

For F2007, BCTC applies for a BCTC Revenue Requirement of $70.3 million and an Asset Management/Maintenance Revenue Requirement of $87.3 million. BCTC also files for approval of the BCH Owner's Revenue Requirement ("Owner's RR") of $366.6 million for F2007 and $375.1 million for F2008. The total Transmission Revenue Requirement ("TRR") applied for is $524.2 million for F2007.

The F2007 TRR represents a decrease of $42.2 million, or 7.4 percent, over the Commission-approved revenue requirement for F2006. The changes to the TRR by revenue requirement component are:

(a) $2.2 million (3.0%) decrease to the BCTC Revenue Requirement;

(b) $2.9 million (3.2%) decrease to the Asset Management/Maintenance Revenue Requirement; and

(c) $37.1 million (9.2%) decrease to the Owner's RR.

Forecast Point-to-Point revenues in F2007 show an increase from the F2006 approved forecast by $18.5 million. These changes primarily reflect an increase in short-term rates and an increase in short-term volumes. Short-term rates are a function of the spread between the Alberta and US markets, and the BCTC forecast is an average based on historical rates. As a result of the forecast higher Point-to-Point revenues, the revenue requirement recovered from network rates will be correspondingly less.

BCTC submits that the applied-for rates are just and reasonable.

1.3.1 Approach to the Review of the Application

Both BCTC and BC Hydro have filed revenue requirement applications. In an effort to arrive at a practical solution to coordinating the two proceedings, BCTC and BC Hydro have developed a proposed approach to the review of the two applications. The two companies expect that this approach will:

(a) be consistent with the Master Agreement;

(b) simplify the process of hearing the applications for all stakeholders;

(c) reduce confusion as to what each company is responsible for;

(d) reduce duplication of evidence and process;

(e) ensure consistency between the two proceedings; and

(f) allow related issues to be heard together.

The proposed approach is described below:

(a) BCTC has filed a F2007 TRR Application comprising:

i the BCH Owner's Revenue Requirement ("Owner's RR") for F2007 and F2008;

ii the Asset Management/Maintenance Revenue Requirement for F2007; and

iii the BCTC Revenue Requirement for F2007;

(b) BC Hydro has filed a 2-year (F2007 and F2008) Revenue Requirement Application;

(c) Separate proceedings will be established for each application (the "BCTC proceeding" and the "BC Hydro proceeding"); and

(d) The Asset Management/Maintenance Revenue Requirement and BCTC Revenue Requirement will be determined in the BCTC proceeding. However, for the reasons described below, BCTC will defend the elements of the Owner's RR that BCTC is responsible for in the BCTC proceeding, and BC Hydro will defend the elements that BC Hydro is responsible for in the BC Hydro proceeding.

The respective elements of the BCH Owner's Revenue Requirement are:

<u>BCTC proceeding</u>

(a) Transmission Capital (in-service)

(b) Non-tariff revenues: Generation Related Transmission Assets ("GRTA") and Substation Distribution Assets ("SDA")

<u>BC Hydro proceeding</u>

(a) Allowed return

(b) Finance charges

(c) Corporate Business Sustaining Costs

(d) Depreciation and Depreciation Study

(e) Grants and Taxes

(f) Operations, Maintenance and Administration (i.e., Aboriginal Relations, Properties Management and Asset Retirement Obligation)

(g) Allocated Demand Side Management ("DSM") amortization

(h) Non-tariff revenues: Secondary Revenues and Control Centre Leases

Each element is designated to the appropriate proceeding on the basis of its context and the responsible company. The elements in the BC Hydro proceeding typically involve a corporate-wide cost structure and/or an allocation process among BC Hydro's lines of business. The BCTC items reflect BCTC's responsibility for managing the transmission assets, as well as a cost allocation process with respect to GRTA and SDA revenues.

The two companies recognize that the setting of permanent rates for either company will require Decisions from both proceedings.

1.3.2 Proposed Process

For F2006, BCTC and the stakeholders were successful in achieving a negotiated settlement for the Asset Management/Maintenance and BCTC Revenue Requirements. The settlement was approved by Commission Order G-60-05.

The portion of this Application that BCTC proposes to have heard in the BCTC proceeding addresses the same two components of the TRR as the F2006 Application, plus two elements of the Owner's RR, as described above. BCTC believes that the nature of this portion of the Application, particularly in the context of a modest change in the TRR, makes the BCTC proceeding a suitable candidate for a written process, with the potential for a negotiated settlement. BCTC understands that the remaining elements of the Owner's RR will be heard in the BC Hydro proceeding, which may have a different process (e.g., oral hearing).

Accordingly, BCTC proposes a written public hearing for the BCTC proceeding, and that the process allow for the opportunity to achieve a negotiated settlement if possible.

1.3.3 Structure of the Application

The Application comprises:

Section	Description
1	The Application
2	The regulatory context and framework of the application
3	A corporate outlook
4	A summary of the TRR
5	The BCH Owner's Revenue Requirement
6	The Asset Management/Maintenance Revenue Requirement
7	The BCTC Revenue Requirement
8	A description of the Cost of Service Determination
9	A description and justification of Operations, Maintenance and Administrative expenses
10	A description of the Capital Program status
11	The revenue forecast
12	Deferral accounts
13	Responses to Commission Directives
14	Commission Directives
Appendix A	Concordance Table of Directives from Commission Decisions
Appendix B	BCTC Depreciation Study
Appendix C	Review of Capital Overhead Allocation Methodology – RJ Rudden
Appendix D	Report on General Liability Coverage for BCTC – HW Asset Management
Appendix E	Strategic Research and Development - Active Projects Summary
Appendix F	F2006 Discussion
Appendix G	Pension and Benefits Expense – F2006 / Estimated F2007

1.3.4 Implementation of Approved Rates

As the Decision on this Application will be issued after April 1, 2006, BCTC has requested that current rates be approved as interim effective April 1, 2006. Commission Order No. G-34-06 approved this request. BCTC is requesting that the interim rates be amended effective July 1, 2006 to reflect the rates applied for in this Application and that the rates remain interim. On conclusion of this proceeding, BCTC will implement permanent rates, and make adjustments to prior billing, in accordance with the Commission's Decision on this Application. BCTC recognizes that a Decision on BC Hydro's revenue requirements application will be a prerequisite for setting permanent rates.

1.3.5 Orders Sought

(a) An order under section 58 of the *Utilities Commission Act* approving permanent rates as shown in Table 11-8 column (d) effective April 1, 2006 to recover the BCTC Revenue Requirement for F2007, the Asset Management/Maintenance Revenue Requirement for F2007 and the BCH Owner's Revenue Requirement for F2007 and F2008.

(b) An order under section 89 of the *Utilities Commission Act* amending the interim rates effective July 1, 2006 to the rates shown in Table 11-8 column (d) and that the rates remain interim.

(c) An order under section 56 of the *Utilities Commission Act* approving the depreciation rates listed in column (d) of Tables 5-11 and 7-12 of the Application.

(d) An order under section 6 of Special Direction No. 9 approving the clearing of deferral account balances and the continuation of deferral accounts as described in Section 12 of the Application.

(e) An order approving Substation Distribution Asset Management and Maintenance costs and Distribution Operations Services costs for F2007, to be incurred by BCTC for provision of services to BC Hydro, as shown in Table 7-10 and described in Sections 7.6.2 and 7.6.5 respectively.

2.0 REGULATORY CONTEXT AND FRAMEWORK

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this evidence is to provide the Regulatory context and framework for the revenue requirement application. Specifically, this evidence will address the following:

2.1 BCTC Background

2.2 Transmission Revenue Requirement Components; and

2.3 Responsibilities of BCTC and BC Hydro

2.1 BCTC Background

BCTC is a provincial Crown Corporation that was formed in May 2003 and began operations on August 1, 2003. Under the *Transmission Corporation Act* [SBC 2003] CHAPTER 44, and the Master Agreement, Order in Council No. 1083, Approved and Ordered Nov 20, 2003, with the British Columbia Hydro and Power Authority ("BC Hydro"), BCTC is responsible for operating, managing, and maintaining BC Hydro's transmission system and certain other related assets including transmission facilities connecting generation and distribution substation equipment.

BCTC rates are regulated based on cost of service regulation principles. The Commission determines the just and reasonable cost of the various transmission services provided by BCTC. The costs, so determined, equal the approved revenue requirement that must be recovered under the various transmission service rates charged by BCTC.

In this Application, BCTC seeks approval of revenue requirements for F2007 and F2008 and the establishment of rates for various services under the Open Access Transmission Tariff ("OATT"). The proposed rates produce the required revenues using the forecast volume of the transactions under each rate. The rate for short-term Point-to-Point service reflects an estimate of both the volume and average price for short-term Point-to-Point transactions.

BCTC has many business relationships with the different lines of business within BC Hydro. These business relationships are governed either by the OATT tariffs or by Service Level Agreements. This Application contains evidence that explains the effect of these business relationships on the Transmission Revenue Requirement.

There are three components of the Transmission Revenue Requirement. BCTC has its own revenue requirement and its own rates that are charged to transmission customers (the BCTC Revenue Requirement). BC Hydro's transmission revenue requirement is divided into two components – an Owner's Revenue Requirement and an Asset Management and Maintenance Revenue Requirement. Transmission customers are billed by BCTC for all three components on one bill.

2.2 Transmission Revenue Requirement Components

Sections 4.7, 4.8 and 4.9 of the Master Agreement between BCTC and BC Hydro describe the three Transmission Revenue Requirement components in greater detail. Specifically the Agreement states the following:

4.7 BCH Owner's Revenue Requirement

The BCH Owner's Revenue Requirement will comprise all aspects of BC Hydro's revenue requirement related to its ownership of the Transmission System and management of Transmission Property Rights pertaining to it, including:

(a) costs related to the Transmission System, including debt service, return on equity, depreciation and taxes (or grants in lieu);

(b) general and administrative costs relating to BC Hydro's ownership of the Transmission System and management of the Transmission Property Rights, including:

i Property Services costs, including both BC Hydro internal costs and costs paid to Third Parties incurred in connection with managing and maintaining the Transmission Property Rights;

ii First Nations' Costs (as defined in the Asset Management and Maintenance Agreement) incurred by BC Hydro;

iii Corporate overhead costs, including insurance costs;

iv An allocation of demand side management costs; and

v Regulatory costs.

4.8 BCTC Revenue Requirement

The BCTC Revenue Requirement will comprise the following:

(a) costs related to BCTC's rate base as approved by the Commission from time to time (including control centres and system operations assets), including debt service, return on equity, depreciation and taxes (or grants in lieu);

(b) operations, maintenance and general and administrative costs relating to BCTC's assets and business;

(c) costs of BCTC carrying out its responsibilities under this Agreement and the other Key Agreements (excluding costs included in the Asset Management/Maintenance Revenue Requirement or the BCH Owner's Revenue Requirement); and

(d) all other costs which the Commission determines are properly recoverable in BCTC's rates.

4.9 Asset Management/Maintenance Revenue Requirement

The Asset Management/Maintenance Revenue Requirement will consist of the amount BCTC obtains the approval of the Commission to permit BC Hydro to recover in rates to pay to BCTC under the Asset Management and Maintenance Agreement for costs incurred or to be incurred by BCTC for the purpose of providing the Asset Management and Maintenance Services.

2.3 Responsibilities of BCTC and BC Hydro

Sections 4.11 (a), (b) and (c) of the Master Agreement state:

4.11 Rate Applications

(a) BCTC will be responsible for preparing an umbrella application to the Commission for approval of the BCTC Revenue Requirement, the BCH Owner's Revenue Requirement and the Asset Management/Maintenance Revenue Requirement.

(b) BCTC will provide reasonable notice to BC Hydro of its intention to apply to the Commission for any amendment to the OATT relating to revenue requirements that are recovered through the OATT in order that BC Hydro will be informed as to the proposed timing of such application. BCTC will use commercially reasonable efforts to keep BC Hydro informed about anticipated changes in timing of the application and related regulatory processes.

(c) Upon receiving notice pursuant to paragraph (b) above, BC Hydro will prepare information and material in connection with the BCH Owner's Revenue Requirement for inclusion in BCTC's umbrella application. BC Hydro will have the authority and responsibility for defending the BCH Owner's Revenue Requirement, including filing such evidence and supporting material and calling such witnesses as BC Hydro considers appropriate and engaging its own counsel. The BCH Owner's Revenue Requirement will be based on the Transmission System capital plan provided to BC Hydro by BCTC. BCTC will make commercially reasonable efforts to support and defend any information it has provided to BC Hydro in connection with the capital plan.

This Application and supporting evidence are consistent with the Master Agreement.

3.0 CORPORATE OUTLOOK

PREFILED EVIDENCE OF BRIAN GABEL, VP CORPORATE SERVICES AND CFO

This Corporate Outlook section discusses the primary determinants of the changes in the level of the Transmission Revenue Requirement ("TRR") for F2007 compared to F2006 Approved. These determinants include factors that are unique to the current year and factors that impact TRR in future years. Subsequent sections of the Application provide a more detailed discussion of the changes in costs in the context of each of BCTC's business activities and processes. They also address the efforts taken in each area to ensure that costs are kept low without compromising service quality.

There are four fundamental business considerations that are driving the transmission costs and the TRR.

(a) The need for BCTC to complete the transition to a stand-alone corporate environment.

(b) The need to invest in maintenance and replacement of existing transmission assets, so that reliability and other service standards are maintained.

(c) The need for BCTC to build open and constructive relationships with all stakeholders and meet the current expectations of increased public and regulatory accountability.

(d) The need for significant capital investment to meet future transmission requirements. Meeting the demand for additional capacity will require not only significant planning and capital investment, but will also result in increased operations and maintenance activity when the additional capacity is in service.

In addition to these fundamental business considerations, BCTC's F2007 costs reflect the current inflationary pressures being caused by the competition for labour in the Canadian energy sector, certain accounting changes, staffing needs to address workforce demographics and reductions in cost due to certain process improvements. Prior to discussing the impact of these business considerations and cost factors, Section 3.1 provides a brief overview of the components of the TRR.

3.1 Overview of the Transmission Revenue Requirement

As discussed in Sections 2.2 and 4.1, the Transmission Revenue Requirement ("TRR") consists of the following components.

(a) BCH Owner's Revenue Requirement ("Owner's RR"): The transmission business is assigned its share of depreciation, financing and other costs that are incurred by BC Hydro as a consequence of its ownership of transmission assets.

(b) The Asset Management/Maintenance Revenue Requirement ("AMMRR") consists of costs incurred by BCTC for the purpose of managing and maintaining the transmission assets. These costs are received from customers by BC Hydro and paid to BCTC under the terms of the Master Agreement.

(c) The BCTC Revenue Requirement ("BCTC RR") consists of costs incurred by BCTC for the purpose of fulfilling its obligations as the operator of the transmission system. These costs (net of non-tariff revenues) are recovered through the OATT from all transmission customers.

Table 3-1 shows the relative magnitudes of the three components of the TRR.

Table 3-1. F2007 TRR

	$ millions	**F2007 Plan**
1	**Owner's RR**	
2	BC Hydro Costs	433.4
3	Less Non-Tariff Revenue & Recoveries	(66.8)
4	**Owner's RR (L2 - L3)**	366.6
5	**BCTC RR**	
6	BCTC Costs	189.7
7	Less AMMRR	(87.3)
8	Less Non-Tariff Revenue & Recoveries	(32.1)
9	**BCTC RR (L6 - L7 - L8)**	**70.3**
10	**AMMR (L7)**	**87.3**
11	**TRR (L4 + L9 + L10)**	**524.2**

Notes:

1. Refer to Tables 4-1 and 4-2

2. Line 3 relates to BC Hydro recoveries for GRTA, SDA, Secondary Revenue, and Control Centre Leases

The cost information in Table 3-1 demonstrates that for F2007,

(a) BC Hydro will incur $433.4 million in transmission costs that are to be recovered through transmission charges. $66.8 million of BC Hydro's cost of transmission asset ownership is expected to be recovered through non-tariff revenue and recoveries for Generation Related Transmission Assets, Substation Distribution Assets and Secondary Revenue and Control Centre leases, and the balance of $366.6 is defined to be the Owner's RR.

(b) BCTC will incur $189.7 million in costs that are to be recovered through transmission charges. Of that amount, $32.1 million is recovered from customers through asset management fees and the balance is the AMMRR ($87.3 million), and the BCTC RR ($70.3 million).

Of the total $433.4 million in costs that are incurred by BC Hydro, $313.5 million (72.4%) relates to allowed return, finance charges, and grants and taxes, $102.9 million (23.7%) in costs relates to depreciation and amortization, and $17.0 million (3.9%) relates to Operations Maintenance and Administration ("OMA") and Corporate costs.

BC Hydro's costs and the BC Hydro Revenue Requirement will be reviewed in detail in the BC Hydro proceeding and this information is also summarized in Section 5 of this Application.

Of the total $189.7 million in costs that are incurred directly by BCTC, 86.9% or $164.9 million relates to BCTC's OMA costs as indicated in Table 7-1 of Section 7. Depreciation and amortization account for 7.7% of gross transmission costs. The remaining 5.4% consists of the cost of market, BCTC's allowed return and grants and taxes.

This section provides a summary of the business considerations impacting the costs which are discussed in detail later within this Application. For ease of reference, Table 3-2 shows the OMA functions with their associated costs and cross-references to the section in the Application where each function is discussed in greater detail.

Table 3-2. OMA Expense

	$ millions	Ref.	F2007 Plan
	(a)	(b)	(c)
1	**Asset Management & Maintenance**	Sec.9.3	99.7
2	**Operations:**		
3	System Operations	Sec.9.2.1	32.5
4	System Plng & Performance Assessment	Sec.9.2.2	9.7
5	Market Operations	Sec.9.2.3	3.3
	Operations Total		45.5
6	**General & Administration**	Sec.9.4	29.5
7	**Total OMA Expense**		174.7
8	Capitalized Overhead	Sec.9.5	(9.8)
9	**Net OMA Expense**	Sec.9.1	164.9

3.2 Impact of the Transition to a Stand-Alone Corporate Environment

BCTC was formed in 2003 as a stand-alone entity with a mandate to provide independent, open and non-discriminatory access to BC's electric transmission system, to facilitate private generation investment in BC and to maintain open access to the Western North American wholesale electricity market.

The initial organizational structure of BCTC reflected the previous structure of BC Hydro's transmission operations that were acquired by BCTC. However, because the transmission and non-transmission functions of BC Hydro were not cleanly separable, BCTC did not acquire from BC Hydro all of the resources needed to fulfill its roles, responsibilities and services on a stand-alone basis. In particular, BC Hydro retains capabilities that were previously used jointly by the distribution and transmission functions of BC Hydro, such as Field Services and Engineering. As a result, BCTC is able to fulfill its mandate by using a combination of internal and outsourced resources. Furthermore, it is able to draw on a mix of BC Hydro resources with fees based on service level agreements and independent contractors who charge market-based rates for their services.

BCTC has augmented its acquired resources by entering into outsourcing arrangements with BC Hydro and other suppliers. As a result, a large portion of BCTC's operations and capital activities are currently performed by third parties under contract to BCTC. Major contractors include BC Hydro Field Services

(approximately $100 million per annum), BC Hydro Engineering (approximately $50 million per annum), SNC Lavalin ($40 million over four design-build, turn-key projects) and Accenture Business Services for Utilities (approximately $7 million per annum).

Like other energy sector employers, BCTC is facing a tight labour market for skilled resources. Through its arrangements with BC Hydro, BCTC has the comfort that it can access a supply of skilled labour to complete a large portion of its planned work. BCTC can selectively access the competitive market for skills where BC Hydro is resource-constrained or where opportunities exist to benefit from using competitive service providers.

Even with these outsourcing arrangements in place, it has been necessary for BCTC to build its internal capacity in selected areas of its business. BCTC is forecasting an increase of 21 full-time employees (7.0%) from the levels reflected in the 2006 Revenue Requirement Application (Refer to Table 9.6-1). These headcount additions include employees to perform work that was previously outsourced (6 employees), to address regulatory and stakeholder consultation requirements (5 employees), to address system operations (4 employees), to plan and manage the growing capital plan (2 employees), to provide a transition for forecast retirements (2 employees), and to address administrative, control and governance issues (2 employees).

BCTC has also pursued the mandate that is set out for the Company in the Energy Plan, while at the same time pursuing opportunities for cost efficiencies. BCTC is committed to achieve continuous improvement in providing cost-effective, efficient and reliable transmission service for all transmission customers.

Key accomplishments are:

(a) Developed and implemented computer systems to support BCTC's Asset Management approach. These systems assist engineering staff in the analysis in a consistent manner of asset performance, design of effective maintenance programs, and monitoring and control program execution.

(b) Received approval from the Commission to upgrade the critical operations technology systems and consolidate control centres. The SCMP project will allow

BCTC to replace dated technology, resolve seismic issues at existing control centres, provide a geographically separate backup for the system control centre and for area control centres, and streamline the control and operating infrastructure.

(c) Implemented a new Open Access Transmission Tariff that facilitates opportunities for independent power producers and provides choices for large customers in British Columbia. BCTC has developed new business processes and computer systems to assist BCTC in the effective management of customer service requests in accordance with tariff requirements.

(d) Developed a ten-year $2.7 billion plan for BCTC's transmission system and launched a public consultation process regarding that plan. Received Commission approval and recommendations regarding BCTC's proposed transmission system investments for 2006 and 2007.

(e) Implemented Dynamic Scheduling, which facilitates transmission customer sales to the California Ancillary Services market.

3.3 Impact of the Need to Maintain High Reliability and Other Standards

BCTC maintains high reliability and other service standards in three ways.

(a) The Asset Management/Maintenance group ensures that the transmission assets operated by BCTC are maintained in a manner that minimizes service outages. Cost trends in this area are determined primarily by changes in unit costs (inflationary pressures and productivity enhancements) and reflect growth in the transmission system over time. The discussion of Asset Management/Maintenance in Section 9.3 shows the net effect of inflation and growth in the transmission asset base is forecast to be offset by productivity improvements during 2007; hence total costs associated with planning and maintaining the existing asset base are declining.

(b) The Asset Management/Maintenance group continuously updates and refines its maintenance policies and practices so as to optimize the cost over the service life of all assets. As discussed in Section 3.3.1, the results of the Depreciation Study conducted in F2006 suggests that the average lives of certain transmission

assets are longer than was expected at the time that depreciation rates were most recently set.

(c) The System Planning group ensures that additional assets are in place as necessary on a timely basis to meet future transmission requirements driven by demand growth, new generation capacity, increased interconnection requirements, or other factors. As discussed in Section 3.5, BCTC forecasts significant new investments in new transmission assets in the coming years and continues to plan to meet the expected transmission requirements.

3.3.1 Optimizing the Service Lives of Transmission Assets

The Transmission Depreciation Study (included in the BC Hydro Application) shows that the original cost of the assets currently operated by BCTC was $4.5 billion. The net book value of those assets currently stands at $2.5 billion. The annual cost of these assets as they are depreciated is determined by the life expectancy of the assets under management. The Transmission Depreciation Study has been prepared for BC Hydro in respect of transmission assets. The results of this study will also impact on the depreciation charges that are reflected in the Owner's RR and in transmission rates. The results of the Transmission Depreciation Study show that the expected service life was increased for 74.9% of existing assets. Service lives were shortened for only 4.5% of assets, with the service lives of the remaining 20.6% of assets being unchanged.

The overall impact of the service life extensions indicated by the Transmission Depreciation Study is a reduction in depreciation expense in F2007 by $29.1 million.

3.4 Impact of Increased Regulatory and Stakeholder Expectations

BCTC recognizes the value of regulation and believes that sufficient resources must be committed to the regulatory processes to ensure that stakeholders are able to obtain all relevant information on a timely basis. Effective processes require thorough and understandable evidence, early stakeholder engagement and fully responsive answers to information requests.

To date, BCTC staff has met this standard of disclosure largely through an unsustainable level of overtime effort. BCTC has addressed this challenge through

staff additions in the areas most strained by increasing regulatory and consultation responsibilities in addition to other responsibilities.

BCTC's increasing responsibilities in these areas have directly resulted in the addition of three staff positions in Corporate Services.

(a) Regulatory / Costing Advisor,

(b) Capital Accounting Assistant, and

(c) Senior Regulatory Advisor.

The headcount impact of these additions has been partially offset by the elimination of the Corporate Services position of Financial Service Manager.

The impact of BCTC's increasing regulatory responsibilities is also being felt throughout the organization as an increasing portion of staff time is devoted to activities related to BCTC's regulatory and consultation accountabilities. BCTC is responsible for the applications that are required to gain Commission approval for BCTC's capital plans and transmission projects. Experience has clearly demonstrated that extensive public processes can be anticipated for the overall capital plans pertaining to the transmission system.

All stakeholders expect BCTC to be able to manage its regulatory and public affairs in a professional manner. The resources that are engaged throughout the public processes are not limited to BCTC's regulatory department but extend through much of the organization in order to have subject matter experts prepare evidence, respond to information requests, prepare for the hearing and be cross-examined.

For example, during F2006 BCTC had ten major regulatory processes:

(a) F2006 Revenue Requirements

(b) VITR, with over 2000 Information Requests

(c) Canal Plant Support Agreement

(d) Network Economy Historical Review

(e) Business Practice Review

(f) OATT Compliance filing

(g) Permanent approval of Dynamic Scheduling

(h) Approval of a new Loss Compensation Service

(i) Approval of the Generation Plant and Operating Obligations Agreement

(j) NEB NERC Reliability Compliance Review.

BCTC anticipates the regulatory workload will continue to increase due to the forecast high level of capital expenditures in the next few years. BCTC resources will have to keep pace with the related demands that have to be met in all areas in order for BCTC to accommodate the anticipated requirement for additional transmission capacity.

3.4.1 Building Open and Constructive Relationships with Stakeholders

BCTC's commitment to build open and constructive relationships with stakeholders goes beyond its activities within formal regulatory processes. For example, as a reflection of its commitment to improving relations with aboriginal communities, BCTC has established a new position, Manager, Aboriginal Relations, reporting to BCTC's General Counsel (Refer to Section 9.4).

Furthermore, BCTC recognizes that staff throughout the organization will have to invest more time in developing relationships with stakeholders so that consultations on BCTC's plans and proposals are productive. Working more closely with stakeholders is a necessary step in enabling BCTC to fulfill its mandate within the current regulatory and market environment. The commitments to stakeholders that are driving staff additions at BCTC include:

(a) Building in stakeholder considerations early in BCTC's planning, and engaging all stakeholders early as part of BCTC's consultation activities;

(b) Participating actively in municipal government forums to develop positive relationships with community representatives and to understand their needs;

(c) Sustaining a positive, open and cooperative relationship with the Commission and intervenor groups; and

(d) Continuing BCTC's public planning process with respect to the capital plan.

These commitments are contributing to the staff additions in areas such as Major Projects (two additions: one Director, Major Projects and one Project Manager, where both positions are driven by an increase in the number of projects as well as the increased need for stakeholder relationships) and Customer and Strategy Development (three additions: two Community/Stakeholder Relations Managers and one Business Development Manager).

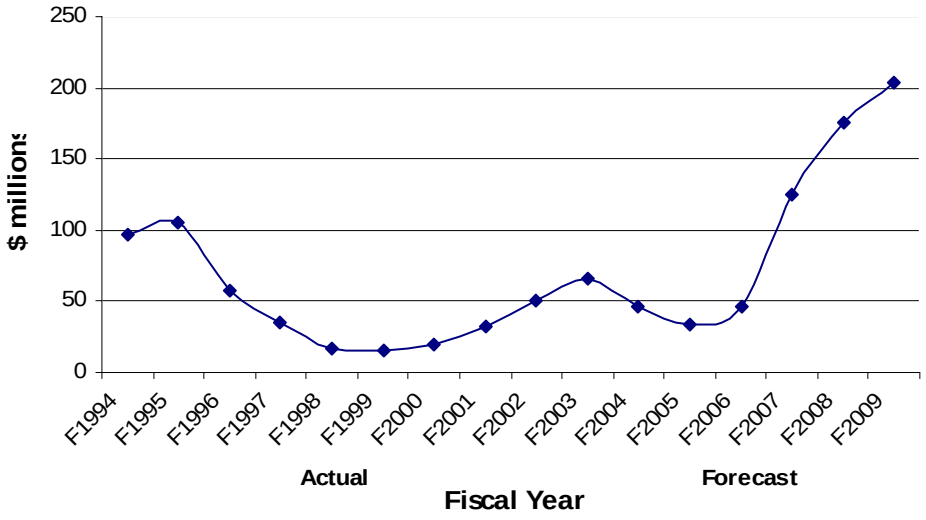
3.5 Impact of the Requirement for New Transmission Assets

Capital expenditures on the transmission assets fall into two major categories: sustaining capital and growth capital. Although the requirement for sustaining capital is fairly stable, growth capital goes through cycles that reflect the lumpiness of the capacity expansions required to meet load growth and to integrate new generation capacity. As Table 3-3 and Figure 3-1 show, the growth-related capital requirements for the transmission assets are expected to increase in the coming years as compared to the last decade.

Table 3-3. Transmission Capital Expenditures Forecast

	$ millions	F2006 Approved	F2006 Forecast	F2007 Forecast	F2008 Forecast
	(a)	(b)	(c)	(d)	(e)
	Transmission Assets Owned by BC Hydro				
1	Sustaining Capital	95.4	92.4	84.7	85.4
2	Growth Capital	73.1	42.4	124.7	175.7
3	Contributions In Aid of Construction	(15.0)	(10.2)	(3.0)	(3.0)
4	**Total Transmission Assets Owned by BC Hydro**	**153.5**	**124.6**	**206.4**	**258.1**
5	**Assets Owned by BCTC**	**49.2**	**24.7**	**65.4**	**67.0**
6	**Total Transmission System Capital Expenditures**	**202.7**	**149.3**	**271.8**	**325.1**

Figure 3-1[1]. Historic and Future Growth Transmission Capital



Given the anticipated increase in growth capital, an important consideration in optimizing the organization is ensuring that BCTC has the necessary resources in place to manage the expected growth in the transmission system over the next few years. The staffing issues associated with the increasing growth capital requirements are particularly urgent at this time because the BCTC workforce is aging. As a result, the trend to increased staff turnover will be accentuated in the coming years with the retirement of key skilled staff. This expected turnover will drive an increase in costs to recruit, train and retain the skill sets required for BCTC manage its responsibilities.

For this reason, BCTC has adopted a number of objectives related to ensuring that sufficient skilled resources are in place in the coming years. Specifically, BCTC is undertaking initiatives to:

(a) Identify and fill critical capacity gaps within the organization;

(b) Implement succession plans and establish the development planning process;

[1] On Figure 3-1, the Growth Transmission Capital for years F1994 to F2003 has been estimated, as the Sustaining Capital and Growth Capital were not recorded separately for those years.

(c) Review BCTC's employment offering (both financial and non-financial rewards for working at BCTC) in terms of the total cost and effectiveness of attracting and retaining high performing employees;

(d) Continue to enhance the performance management system so that rewards are clearly linked to results;

(e) Secure the right skills for BCTC to achieve its objectives and implement and provide for succession and establish the development planning process through effective recruitment, retention, development and succession planning;

(f) Continue to enhance the performance management system so that rewards are clearly linked to results;

(g) Continue BCTC training programs;

(h) Implement succession plans and establish the development planning process; and

(i) Establish the employee recruitment function within BCTC through insourcing at a cost saving.

3.6 Other Factors Affecting BCTC's Costs and the TRR

In addition to the fundamental business considerations discussed above, the F2007 TRR has been affected by several one-time accounting changes, general inflationary pressures and BCTC's commitment to continually improve its environmental and safety management performance.

3.6.1 General Inflationary Pressures

As with any organization, many cost categories are subject to inflationary pressures, including:

(a) Wages, salaries and benefits (refer to Section 9.6),

(b) Service level agreements with BC Hydro, such as Engineering and Field Services, and

(c) BCTC outsourced business functions such as computer desktop support, financial and operating system sustainment, payroll, audit, accounts receivable and payable and purchasing.

BCTC strives to reduce the impact of these inflationary pressures where possible, and the planning and budgeting process at BCTC is designed to address this and other cost pressures. This planning process occurs on an annual basis and involves senior levels of the organization including the Board of Directors. The specific planning and budgeting process is more completely discussed in Section 9.1.5. Over the longer term, the costs pressures for BCTC will remain.

3.6.2 Environmental and Safety Management

BCTC is committed to continually improve its environmental and safety management performance. Additional resources are required for BCTC to meet its commitment through initiatives such as:

(a) Implement oil containment program – minimization of transformer oil spillages,

(b) Continue SF6 (sulfur hexafluoride) tracking and leak minimization program,

(c) Implement error management program for control centre operators,

(d) Rollout Multiple Employer Workplace Agreement, and

(e) Improve Control Centre/Field staff communications.

The cost to implement these initiatives is estimated at approximately $100,000.

3.6.3 Organizational Streamlining

Offsetting these upward pressures on costs are reductions in the TRR that have been achieved through BCTC's on-going efforts to reduced maintenance costs by adopting improved maintenance processes and revised standards. Embedded in the TRR for F2007 are BCTC efforts over the past year to revisit and refocus internal processes, including:

(a) Asset planning approach

(b) Human resource strategy to address:

i Skill sets required for new responsibilities (as set out above);

ii Aging workforce (increased training and personnel development required);

iii Trend to increased staff turnover rates (caused by expanded responsibilities and workload as well as general trends in the economy) addressed through retention strategies and accommodation (increased training and recruiting); and

iv The competitive (tight) market for skilled employees.

(c) Sourcing/outsourcing model and strategy. For example, BCTC has:

i insourced its employee recruitment function, providing cost savings and performance improvements;

ii added a Manager, Aboriginal Relations to augment services provided by BC Hydro;

iii outsourced its payroll to a new service provider, Ceridian;

iv outsourced the internal audit function by establishing annual audit plans which are then conducted by a third party auditor; and

v implemented a financial modelling and reporting tool to better enable consistent and accurate budgeting and reporting, both for internal business purposes and for meeting regulatory requirements.

(d) Business planning cycle and review process to address items from the Capital Plan into the Planning Process.

BCTC has formal quarterly forecast requirements to the provincial government and to its Board of Directors; it annually prepares a strategic plan for submission to government and prepares submissions to the Commission for Revenue Requirement, Capital Plan and Certificates of Public Convenience and Necessity. To

facilitate the forecasts supporting these submissions, BCTC undertook the development of a financial model that integrates the financial elements pertaining to revenue, OMA, capital planning and forecasting, cash flow analysis and revenue requirement determination. The financial model, while in its initial implementation stage, has been designed to meet the following objectives:

(a) Efficiently model the BCTC and Transmission Business financial forecasts and combine to produce consolidated transmission impacts and results.

(b) Produce financial reports in a consistent format and in-line with BCTC's Oracle account and project structure.

(c) Model rate impacts and revenue requirements in support of management scenarios analysis and regulatory application filings including the production of schedules.

(d) Effectively integrate the more detailed annual planning processes for revenue, OMA and capital.

By linking the various aspects of the financial forecasting process BCTC is able to streamline the preparation of its forecasts by reducing staff time to manually produce schedules and alter spreadsheets; build a broader knowledge in the corporation of the forecasting requirements and processes, provide faster turnaround time for assumption or scenario changes and permit drill-through from top level summary results to detailed supporting schedules.

BCTC is therefore meeting its immediate obligations by redeploying staff where possible and outsourcing when necessary. Only where it is clear that there will be on-going demands that cannot be met with BCTC's existing resources is staff added. Staff additions for F2007 are being driven by BCTC's responsibility for:

(a) Maintaining reliability in the face of increasing demand on the transmission system and escalating resistance to projects with (perceived or real) local impacts;

(b) Managing increasing scope, complexity, and volume of project studies;

(c) Managing increasing scope, complexity, and volume of capital projects;

(d) Accommodating increased regulatory accountability (environmental, Commission, etc.);

(e) Achieving the performance standards built into the various Service Level Agreements ("SLA"s) that have been signed with BC Hydro; and

(f) Implementing OMA process review.

The changes in BCTC's organizational structure since the F2006 Revenue Requirement Application are described in Section 9.6. These changes were made to provide an appropriate focus on key areas and to recognize increasing workload.

(a) System Operations and Asset Management, which previously reported to a Senior Vice-President, has been reorganized into three groups that now report directly to the President and CEO.

i System Operations reports to a Vice-President

ii System Planning and Asset Management reports to a Director

iii Major Projects reports to a Director

(b) In addition, some of the departments within the Customer Strategy and Development group were reduced from four departments to two.

i The Communications and Stakeholder Relations departments were combined to form Communications and Stakeholder Relations, reporting to a Director.

ii The Strategy and Investment Analysis departments were combined to form Strategy and Policy, reporting to a Director.

3.7 Conclusion

Four fundamental business considerations are driving the current and near-term trends in BCTC's costs:

(a) BCTC is still making the transition to the new corporate and electricity market environment so it can achieve its mandate to provide independent, open and non-discriminatory access to BC's electric transmission system, to facilitate private generation investment in BC and to maintain access to the Western North American wholesale electricity market.

(b) BCTC is committed to maintaining high reliability and other service standards while meeting future transmission requirements prudently, efficiently and cost effectively.

(c) BCTC is committed to meeting the expectations of increased public and regulatory accountability and is adapting its processes and procedures in order to build open and constructive relationships with all stakeholders.

(d) BCTC is preparing to meet the increasing transmission requirements and associated capital investments that are expected in the coming years.

These are discussed throughout this application. BCTC is working to address and mitigate the upward pressure on costs.

This F2007 Revenue Requirement Application requests approval of a BCTC RR of $70.3 million and an AMMRR of $87.3 million. BCTC also requests approval of the Owner's RR of $366.6 million for F2007 and $375.1 million for F2008. The total requested F2007 TRR is $524.2 million which is 7.4% less than the F2006 TRR.

4.0 SUMMARY OF TRANSMISSION REVENUE REQUIREMENT

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to provide an overview of the Transmission Revenue Requirement ("TRR"). Specifically, the section will address the following:

(a) the relationship between the TRR and its component revenue requirements; and

(b) a summary of the total TRR.

4.1 Relationship Between TRR Components

The relationship between the TRR, its component revenue requirements, and the costs comprising the component revenue requirements is shown in Figures 4-1 and 4-2. Figure 4-1 shows a summary of the BCH Owner's Revenue Requirement in green (also showing the BCH Transmission costs and BCH Service Provider costs), and the components of BCTC Total Costs Incurred in blue. Figure 4-2 uses the same colour system, and shows the components of the BCH Owner's Revenue Requirement in green, and a summary of BCTC Total Costs Incurred in blue. Both figures show Non-Tariff Revenue and Recoveries in red.

The largest component of the TRR is the $366.6 million BCH Owner's Revenue Requirement ("Owner's RR"). The costs contributing to the Owner's RR are BC Hydro costs related to the ownership of the transmission assets. These costs, which total $433.4 million, are primarily Asset-Related costs (Depreciation, Grants and Taxes, Financing Charges and Allowed Return). Offsetting these costs in the Owner's RR are Non-Tariff Revenues and Recoveries of $66.8 million. Refer to Table 5-1 in Section 5 for a breakdown by major cost component.

The next largest component of the TRR is the $87.3 million Asset Management/Maintenance Revenue Requirement ("AMMRR"). The AMMRR includes gross costs totaling $104.4 million for maintenance work performed on the transmission assets in accordance with the Asset Management and Maintenance Agreement. In addition to using BCTC's own resources, a significant portion of the work is performed by BC Hydro services providers (e.g., Field Services and Engineering Services) under Service Level Agreements ("SLAs") and by other contractors, at the direction of BCTC. BC Hydro SLA costs are depicted on

Figure 4-1 by the green BCH Service Provider box and arrow. Offsetting these costs in the AMMRR are Non-Tariff Revenues and Recoveries of $17.1 million, depicted on Figure 4-1 in red. Refer to Table 6-1 for details by major cost component.

The third revenue requirement component is the $70.3 million BCTC Revenue Requirement ("BCTC RR"). BCTC costs, net of Asset Management and Maintenance costs, total $85.3 million and relate primarily to the provision of transmission services under the Open Access Transmission Tariff ("OATT") and the operation of the transmission system. BCTC work is performed by BCTC's own resources as well as service providers including BC Hydro, ABSU and other consultants and contractors. Offsetting these costs in the BCTC RR are Non-Tariff Revenues and Recoveries of $15.0 million. Refer to Table 7-1 for details by major cost component.

4.2 Transmission Revenue Requirement Summary

At its current approved rates BCTC forecasts that it will receive more revenue in F2007 than the forecast revenue requirement. For F2007, BCTC proposes a rate reduction of $42.2 million or 7.4% from current rates. Table 4-1 summarizes the total TRR for F2007 ("F2007 Plan") with a comparison to the approved revenue requirement for F2006 ("F2006 Approved").

Table 4-1. Transmission Revenue Requirement Summary[2]

	$ millions	Ref.	F2006 Approved	F2007 Plan	$ Change	% Change
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Transmission Revenue Requirement**					
2	BCH Owner's	T5-1	403.7	366.6	(37.1)	-9.2%
3	Asset Management & Maintenance	T6-1	90.2	87.3	(2.9)	-3.2%
4	BCTC	T7-1	72.5	70.3	(2.2)	-3.0%
5						
6	**Total Transmission Revenue Requirement**		**566.4**	**524.2**	**(42.2)**	**-7.4%**

A more detailed summary of the TRR is provided in Table 4-2.

[2] See Appendix F regarding "F2006 Approved" column.

Table 4-2. Detailed Transmission Revenue Requirement Summary[3]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	***BCTC***					
2	OMA	Sec.9	160.2	166.2	155.8	164.9
3	Allowed Return	Sec.7.2	3.4	3.6	13.3	2.9
4	Finance Charges	Sec.7.2	1.5	0.5	1.1	0.2
5	Cost of Market	Sec.7.3	0.6	5.8	4.7	6.8
6	Depreciation & Amortization	Sec.7.4	17.3	21.5	20.1	14.6
7	Grants & Taxes	Sec.7.5	0.3	0.3	0.3	0.3
8	**BCTC Total Cost**		**183.3**	**197.9**	**195.3**	**189.7**
9	Less Non-OATT Revenue and Recoveries	Sec.7.6	(33.2)	(35.2)	(36.7)	(32.1)
10	**BCTC Transmission Revenue Requirement**	L8+L9	**150.1**	**162.7**	**158.5**	**157.6**
11	***BC Hydro***					
12	OMA	Sec.5.1	4.1	4.8	7.0	5.8
13	Allowed Net Income	Sec.5.2	101.6	115.9	140.7	102.6
14	Finance Charges	Sec.5.2	116.8	133.3	116.5	123.2
15	Depreciation & Amortization	Sec.5.3	130.8	134.4	125.2	99.3
16	DSM	Sec.5.4	2.3	3.6	3.0	3.6
17	Grants & Taxes	Sec.5.5	87.9	90.5	87.9	87.7
18	Corporate Business Sustaining Costs	Sec.5.6	15.4	14.7	16.8	11.2
19	**BC Hydro Total Cost**		**458.9**	**497.3**	**497.1**	**433.4**
20	Less Non-OATT Revenue and Recoveries	Sec.5.7	(92.2)	(93.6)	(93.5)	(66.8)
21	**BC Hydro Transmission Revenue Requirement**	L19+L20	**366.7**	**403.7**	**403.6**	**366.6**
22	**Total Cost**	L8+L19	**642.2**	**695.2**	**692.3**	**623.1**
23	Less Non-OATT Revenue and Recoveries	L9+L20	(125.4)	(128.8)	(130.2)	(98.9)
24	**Total Transmission Revenue Requirement**		**516.8**	**566.3**	**562.1**	**524.2**

The net reduction in TRR is primarily the result of:

(a) Reduced depreciation expense reflecting proposed new depreciation rates for transmission assets as set out in the Depreciation Study conducted in F2006 (This study is filed as evidence in the BC Hydro Revenue Requirement Application);

(b) Reduced finance charges and allowed return in the BCH Owner's Revenue Requirement as a result of lower allocations by BC Hydro to transmission (See Section 5.2);

[3] See Appendix F regarding "F2006 Approved" column.

(c) Reduced maintenance costs from improved maintenance processes and revised standards (See Section 9.3); and

(d) Increased capitalization of overhead expenses based on the Capital Overhead Allocation study resulting in a reduction to Operations, Maintenance and Administration costs ("OMA") reflecting the capitalization of a greater proportion of OMA costs (See Section 9.5).

partially offset by:

(e) Increased costs related to the addition of resources within BCTC to manage a large capital program and other workload (e.g., to undertake BC Hydro Call-For-Tender studies), to respond to regulatory requirements and to undertake public consultation respecting all business activities; and

(f) Increased costs reflecting the net effect of the transfer of Substation Distribution Assets from transmission to distribution within BC Hydro. (See Section 5.7.2)

The following sections explain these changes in more detail.

Section 5 – BCH Owner's Revenue Requirement

Section 6 – Asset Management/Maintenance Revenue Requirement

Section 7 – BCTC Revenue Requirement

Figure 4-1. Components of BCTC Total Costs Incurred (in millions)

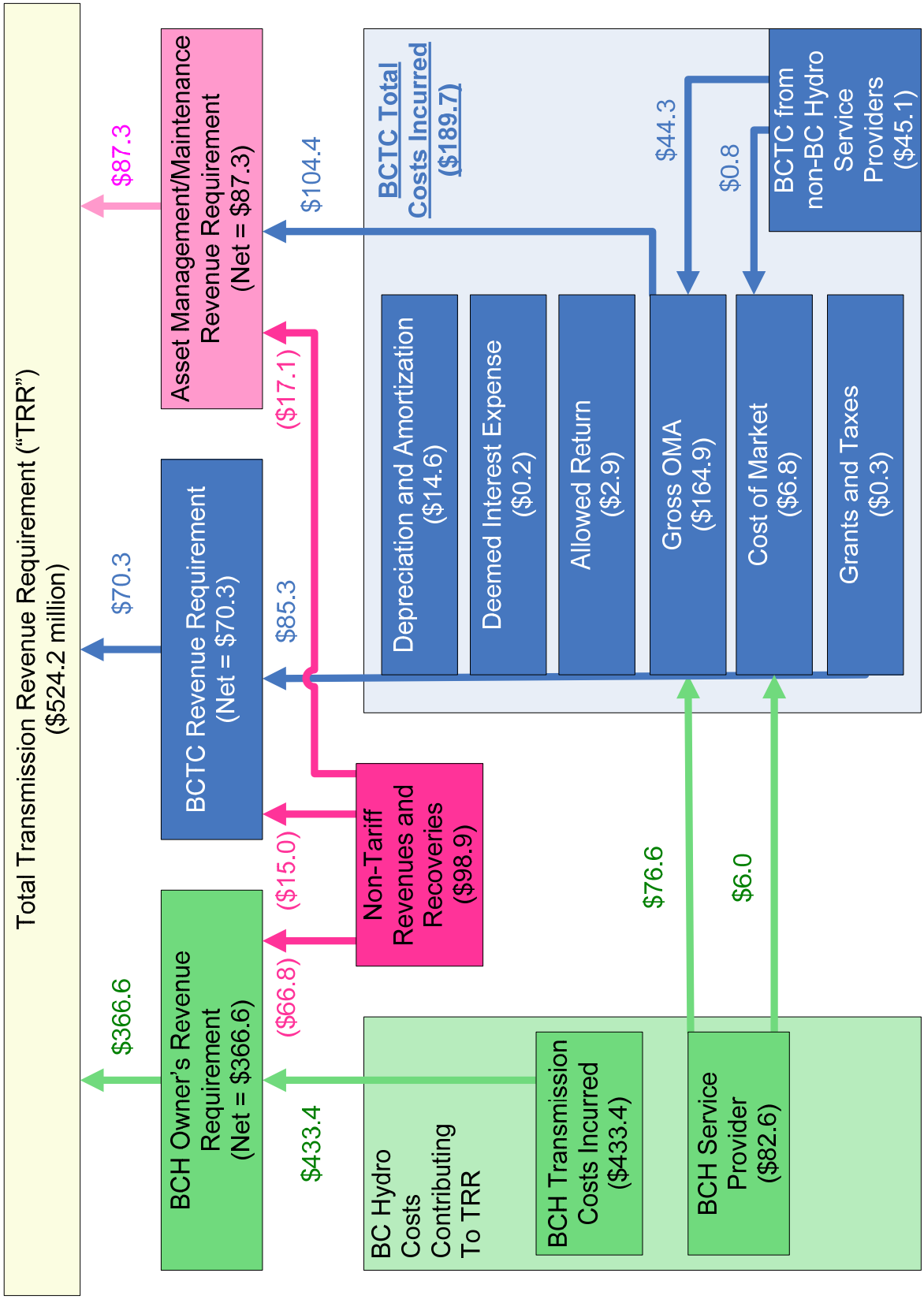
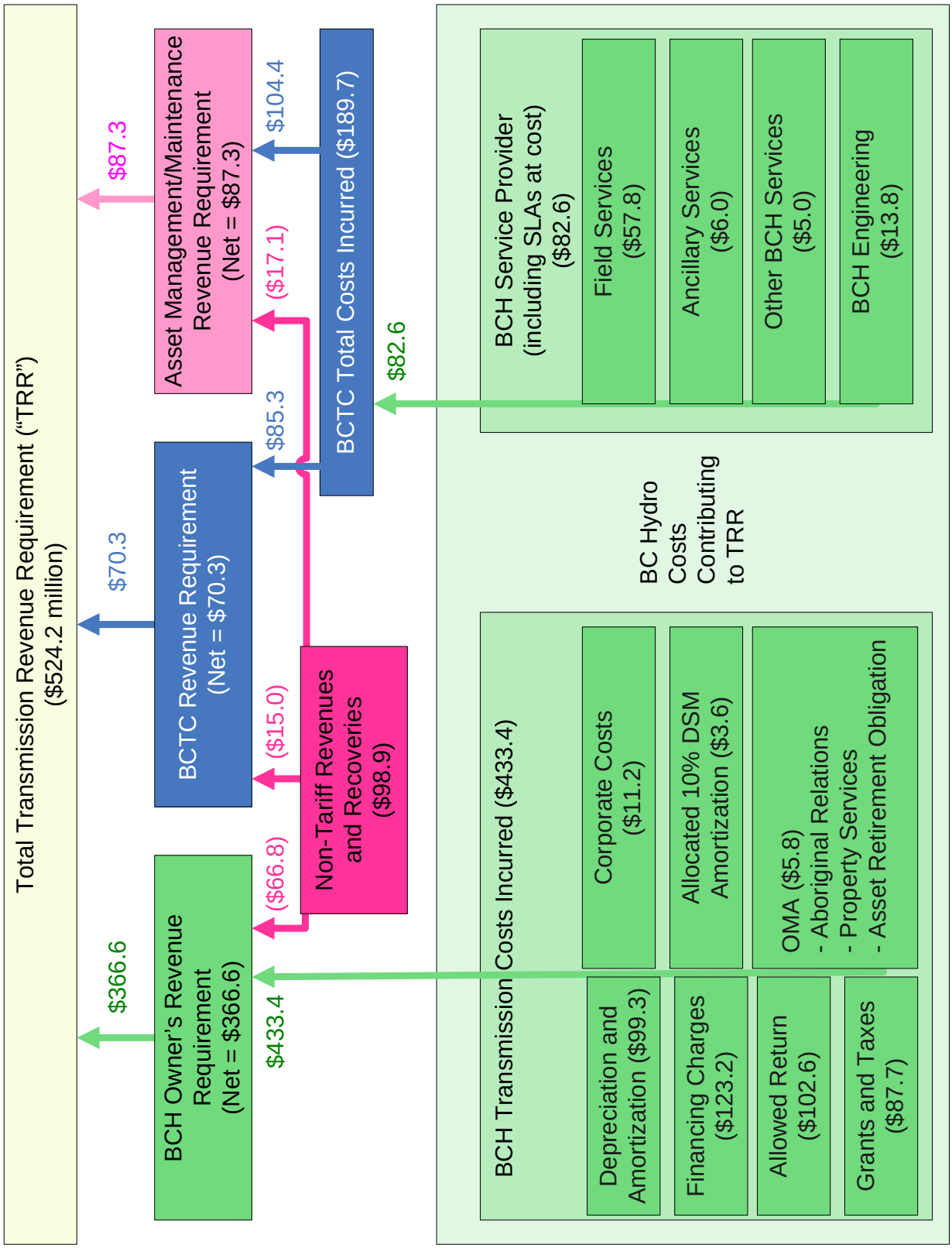


Figure 4-2. Components of BC Hydro Costs (in millions)



5.0 BCH OWNER'S REVENUE REQUIREMENT

The purpose of this section is to describe the BCH Owner's Revenue Requirement ("Owner's RR"). Specifically, this section addresses the elements of the Owner's RR, with the exception of Capital Assets in-service, which will be addressed in Sections 10.1 and 10.2. As described in Section 1.2.1 of the Application, BCTC and BC Hydro propose that the elements described in this section be reviewed in detail in the BC Hydro proceeding, with the exception of non-tariff revenues associated with GRTAs and SDAs, which the companies propose be considered in the BCTC proceeding.

BC Hydro owns the transmission system and receives the Owner's RR. Pursuant to the Master Agreement, the Owner's RR is included in this umbrella TRR Application. The application for the Owner's RR is for F2007 and F2008. The Owner's RR reflects the costs related to BC Hydro's ownership of the transmission system and management of transmission property rights as stated in section 4.7 of the Master Agreement which is shown in Section 2.2 of the Application.

Table 5-1 shows the cost components of the Owner's RR. In Table 5-1 certain of the F2005 actual costs have been restated. This restatement reclassifies certain costs incurred by BC Hydro as BCTC costs in a manner that is consistent with how these costs are accounted for effective April 1, 2005 (Phase 2). This reclassification of costs enables more meaningful cost comparisons over the years shown.

Table 5-1. BCH Owner's Revenue Requirement Cost Components[4]

$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan	F2008 Plan
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Transmission Cost						
Net Income / Allowed Return	Sec.5.2	101.6	116.0	140.7	102.6	105.9
Finance Charges	Sec.5.2	116.8	133.3	116.5	123.2	125.6
Operating, Maintenance & Admin.	Sec.5.1	4.1	4.8	7.0	5.8	5.8
Corporate Costs	Sec.5.6	15.4	14.7	16.8	11.2	10.8
Depreciation & Amortization	Sec.5.3	130.8	134.4	125.3	99.3	100.8
DSM	Sec.5.4	2.3	3.6	2.8	3.6	3.9
Grants & Taxes	Sec.5.5	87.9	90.5	87.9	87.7	89.2
Total Transmission Cost		**458.9**	**497.3**	**497.0**	**433.4**	**442.0**
Less Non-Tariffed Revenues and Recoveries						
Generation Related Transmission Assets	Sec.5.7.1	(32.6)	(33.1)	(33.2)	(37.9)	(37.9)
Substation Distribution Assets	Sec.5.7.2	(55.6)	(56.5)	(56.5)	(25.3)	(25.4)
Secondary Revenues	Sec.5.7.3	(3.8)	(3.8)	(3.6)	(3.4)	(3.4)
Control Centre Leases	Sec.5.7.4	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Total Non-Tariffed Revenue and Recoveries	T5-10	**(92.2)**	**(93.6)**	**(93.5)**	**(66.8)**	**(66.9)**
BCH Owner's Revenue Requirement	T4-1	**366.7**	**403.7**	**403.5**	**366.6**	**375.1**

Note 1: For comparative purposes Operations, Maintenance & Admin. Expenses and recoveries for Generation Related Transmission Assets and Substation Distribution Assets for F2005 Actual have been restated to reflect BCTC's Phase 2 operations that became effective April 1, 2005.

The F2007 Owner's RR is $37.1 million, or 9.2%, lower than the F2006 Approved, and the F2008 Owner's RR is $28.6 million, or 7.1%, lower than the F2006 Approved, primarily as a result of the following:

(a) Lower allocated finance charges and allowed Return on Equity ("ROE"). The changes in BC Hydro's allocation of finance charges and ROE to Transmission are discussed in BC Hydro's application.

(b) Lower depreciation and amortization expense as a result of:

i the extension of service lives and lower depreciation rates for many transmission assets based on a new depreciation study;

[4] See Appendix F regarding "F2006 Approved" column.

ii the transfer of approximately $150 million in substation distribution and other assets in F2005 from Transmission to Distribution within BC Hydro which reduces Transmission depreciation expense by $10 million; and

iii partially offset by an increase related to the addition of new assets in F2006 and F2007.

The changes in depreciation and amortization expense for transmission assets are discussed further in BC Hydro's application.

(c) Non-Tariff Revenues are $26.8 million lower in F2007 than the F2006 Approved primarily due to the transfer of Substation Distribution Assets from Transmission to Distribution. This decrease is partially offset by an increase in the recovery of asset related expenses for Generation Related Transmission Assets. The F2008 Non-Tariff Revenues are $0.1 million higher than F2007 reflecting the increase in finance charges and Allowed ROE in F2008. Non-Tariff Revenues are more fully discussed in Section 5.7.

5.1 Operations, Maintenance and Administration

The Owner's RR includes OMA expenses that pertain to the ownership of the transmission assets and management of transmission property rights. Table 5-2 details these costs.

Table 5-2. BC Hydro Transmission Operations, Maintenance and Administration Expenses[5]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	First Nations Community Services Fund		-	0.5	0.5	1.1	1.1
2	Aboriginal Relations and Negotiations		0.5	0.5	0.5	0.5	0.5
3	Properties & Rights Management		2.7	2.8	3.4	3.1	3.1
4	Asset Retirement Obligation		0.9	1.0	1.0	1.1	1.1
5	Grid West Loan Receivable Write-off		-	-	1.6	-	-
6							
7	**Total TLoB OMA**	Table 5-1	**4.1**	**4.8**	**7.0**	**5.8**	**5.8**

Each of these OMA components is summarized below and explained in BC Hydro's application.

[5] See Appendix F regarding "F2006 Approved" column.

5.1.1 First Nations Community Development Fund

Treasury Board approved a grant program, implemented in 2001, for all First Nations with transmission and distribution facilities on reserve land. The program is called the "First Nations Community Development Fund" and $1.1 million is allocated to Transmission.

5.1.2 Aboriginal Relations and Negotiations

BC Hydro's Aboriginal Relations and Negotiations ("ARN") business unit provides policy and strategic direction to BC Hydro and BCTC regarding relationships with First Nations. ARN leads consultation and negotiations related to the planning, operations and growth of the transmission system. ARN's activities are described in detail in BC Hydro's application.

5.1.3 Property and Rights Management

BC Hydro's Properties business unit provides professional advice, policy oversight and technical services to BC Hydro and BCTC regarding electric system property and real estate matters. The group delivers acquisition and management services for transmission property interests. The Properties business unit's activities are described in detail in BC Hydro's application.

BC Hydro establishes Transmission Property policies and procedures in consultation with BCTC and in response to BCTC requirements, and obtains and holds transmission property rights. Transmission properties work plans and budgets, $3.1 million for F2007 and F2008, are developed and agreed on by both BC Hydro and BCTC. Variances are reviewed and managed together by both parties regularly.

5.1.4 Asset Retirement Obligation

The accretion expense relating to the Asset Retirement Obligation associated with the future removal cost of submarine cables between the Lower Mainland and Vancouver Island remains the same as described in BC Hydro's F2005 and F2006 revenue requirement application.

5.1.5 Provision for Grid West Loan Receivable

BC Hydro participated in funding the development of Grid West commencing in F2002, with loans advanced to F2004. In F2006, BC Hydro made a provision of $1.6 million due to the uncertainty of collecting these loan advances. This provision has no impact on the F2007 revenue requirement.

5.2 Allowed Return and Finance Charges

BC Hydro determines its allowed return and finance charges on a consolidated basis and then allocates the consolidated allowed return and finance charges to the Generation and Distribution lines of business and to Transmission in proportion to their average asset bases relative to the total BC Hydro average asset base. The calculation of the transmission portion of asset base is set out in BC Hydro's application.

5.2.1 Allowed Return

BC Hydro calculates its allowed ROE in accordance with Heritage Special Direction No. HC2 to the British Columbia Utilities Commission. BC Hydro's allowed rate of return is calculated as 13.13% for F2007, and discussed in BC Hydro's application. A return of 13.13% is assumed for F2008.

5.2.2 Finance Charges

BC Hydro's finance charges are mainly impacted by changes in long term debt balances to fund capital expenditures and changes in interest rates. These factors are discussed in BC Hydro's application.

5.3 Depreciation and Amortization Expense

5.3.1 Overview

Depreciation expense includes the annual write-off of the original investment cost of transmission assets (except for land and property rights) on a straight-line basis over the expected useful life of the assets. Depreciation expense also includes depreciation on the Asset Retirement Obligation ("ARO") assets, gains or losses on disposal and the costs of abandoned or indefinitely deferred projects. Consistent with the Commission's decision on the BC Hydro F2005 and F2006 Revenue Requirement application (Order G-96-04, Decision page 164), forecast dismantling

cost is funded by the Provision for Future Removal and Site Restoration costs ("FRSR") and is not included in Depreciation Expense.

Offsetting depreciation expense is the annual amortization of Customer Contributions in Aid of Construction ("CIAC") for transmission assets. CIAC are amounts paid by customers toward the capital cost of assets for the extension of transmission services, interconnection to the transmission system and other customer requested capital work. CIAC are amortized over the expected useful life of the related assets.

Depreciation rates are established based on the expected useful life of the assets and applied on a straight line basis to the original cost of the assets. BC Hydro engaged Gannett Fleming to perform an independent depreciation study of its transmission assets. The Transmission Depreciation Study is included with BC Hydro's application. The impact of the depreciation study is reflected in the F2007 and F2008 depreciation forecasts.

Under section 56 of the *Utilities Commission Act*, approval is requested for the new depreciation rates, as shown in column (d) of Table 5-11 (located at the end of Section 5).

The depreciation forecasts for F2007 and F2008 are based on the forecast F2006 depreciation expense, adjusted for the new depreciation rates, the new assets to be placed in service and asset retirements in F2007 and F2008. A similar approach is used for forecasting the amortization of CIAC for F2007 and F2008. Table 5-3 below shows the depreciation expense for F2005 to F2008.

Table 5-3. Depreciation and Amortization Expense[6]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Depreciation Expense	Sec.5.3.2	129.6	133.5	123.9	98.7	100.0
2	Depreciation of ARO Assets	Sec.5.3.3	1.3	1.6	0.7	0.7	0.7
3	Contribution in aid amortization	Sec.5.3.4	(3.7)	(3.9)	(3.9)	(3.7)	(3.7)
4	Loss (gain) on asset	Sec.5.3.5	3.5	3.2	4.6	3.6	3.9
5	Asset Dismantling Costs		0.7	3.6	4.7	4.9	5.0
6	Less: Transfer to Provision for FRSR		(0.7)	(3.6)	(4.7)	(4.9)	(5.0)
7							
8	**Total Depreciation and Amortization**	Table 5-1	**130.7**	**134.4**	**125.4**	**99.3**	**100.8**

[6] See Appendix F regarding "F2006 Approved" column.

5.3.2 Depreciation Expense

Transmission capital expenditures have been increasing over the last several years to meet customer demand and to replace assets reaching end of life. New capital asset additions contribute to higher depreciation expense which is partially offset by the cessation of depreciation on retired assets. Table 5-4 shows the continuity schedule of capital assets in service from F2005 to F2008.

Table 5-4. Transmission Continuity Schedules for Fixed Assets, Accumulated Depreciation and Net Book Value[7]

$ millions	Ref.	F2005 Actual	F2006 Forecast	F2007 Plan	F2008 Plan
(a)	(b)	(c)	(d)	(e)	(f)
Fixed Asset Cost					
Opening balance		4,814	4,577	4,625	4,785
Additions		147	128	198	171
Retirements		(50)	(39)	(35)	(7)
NBV of asset disposals			(2)	(4)	(4)
Transfers		(333)	(39)		
Ending balance		**4,577**	**4,625**	**4,785**	**4,945**
Accumulated Depreciation					
Opening balance		2,287	2,181	2,268	2,336
Depreciation		125	127	103	105
Retirements		(32)	(39)	(35)	(7)
Transfers		(199)	(2)		
Ending balance		**2,181**	**2,268**	**2,336**	**2,433**
Net Book Value		2,397	2,358	2,449	2,512

A more detailed discussion on capital projects forecast to be completed in F2006 to F2008 is included in Section 10 of the Application. Table 5-5 shows the depreciation expense associated with transmission capital assets in service for F2007 and F2008.

[7] See Appendix F regarding "F2006 Approved" column.

Table 5-5. Depreciation Expense[8]

	$ millions	Ref.	F2006 Approved	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)	(e)
1	On capital assets in service in F2006			124.6	122.6
2	On new capital assets in service			3.2	9.2
3	Impact of Depreciation Study			(29.1)	(31.8)
4					
5	**Depreciation Expense**	T5-3, L1	**133.5**	**98.7**	**100.0**

Depreciation expense for F2007 and F2008 is forecast to be lower than F2006 Approved for the following reasons:

(a) The decline in depreciation expense on assets in service as compared to F2006 reflects asset retirements totaling $34.5 million and $7.4 million in F2007 and F2008 respectively. Retired assets are assets that have reached the end of their economic life and are fully depreciated. The depreciation reduction is determined by applying a composite rate of depreciation against the total original cost of the assets retired. The effect is to reduce depreciation expense $1.8 million and $3.2 million for F2007 and F2008 respectively.

(b) Depreciation is forecast to increase as capital projects totaling $197.6 million and $171.2 million are forecast to be placed in service and become used and useful in F2007 and F2008 respectively. For the forecast period, projects are assumed to be placed in service mid-year and 50% of the depreciation, calculated using revised rates, is included in the depreciation forecast.

(c) Based on the results of the Transmission Depreciation Study, the average service life of transmission assets will be extended by 8 years from 45 years to 53 years and station assets by 8 years from 22 years to 30 years. The net impact is a reduction of $29.1 million and $31.8 million in depreciation expense in F2007 and F2008, respectively. This reduction contributes to lower transmission rates for customers. For F2007, the depreciation impact is net of a one-time write-off of $3.4 million for those assets that would have been in service beyond the revised

[8] See Appendix F regarding "F2006 Approved" column.

service lives. The $3.4 million represents the net book value at March 31, 2006 that will be written off in F2007.

The method used in estimating service life includes analysis of actual experience and forecast future use.

The impact of the Transmission Depreciation Study is shown in Table 5-6.

Table 5-6. Transmission Depreciation Study Impact

	Current Rates		F2007 & F2008 Revised Rates	
$ millions	**In Years**	**% Rates**	**In Years**	**% Rates**
(a)	(c)	(d)	(e)	(f)
Asset Class				
Transmission	45	2.2%	53	1.9%
Transformation	22	4.5%	30	3.3%
Computers	9	11.5%	9	10.7%

5.3.3 Depreciation on Asset Retirement Obligation ("ARO") Asset

Effective April 1, 2004, BC Hydro set up a provision for the future removal and site restoration costs for submarine cables 1L17 and 1L18 that are forecast to be retired in F2009 and F2018, respectively. The retirement date of 1L17 reflects the in-service date of the proposed Vancouver Island Transmission Reinforcement ("VITR") project in October 2008. The forecast depreciation and accretion expense for F2006 has been reduced to reflect the financial impact of extending the retirement date of 1L18 to F2018 from F2009.

5.3.4 Contributions in Aid of Construction ("CIAC") Amortization

CIAC is amortized over the service life of the related assets and reduces depreciation expense. Customer contributions for F2007 and F2008 are estimated at $3 million per year. Table 5-7 shows the CIAC continuity schedule and amortization for F2005 to F2008.

Table 5-7. CIAC Amortization

	$ millions	Ref.	F2005 Actual	F2006 Forecast	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	**CIAC Amortization**					
2	Opening balance, net of amortization		83.0	88.9	95.2	94.5
3	- additions		11.8	10.2	3.0	3.0
4	- retirements		(2.2)	-	-	-
5	- amortization		(3.7)	(3.9)	(3.7)	(3.7)
6						
7	**Closing balance, net of amortization**		**88.9**	**95.2**	**94.5**	**93.7**

5.3.5 Gains or Losses on Disposal and Costs of Abandoned or Indefinitely Deferred Projects

Gains or Losses on Disposal and Costs of Abandoned or Indefinitely Deferred Projects include proceeds less the net book value of the disposed assets, project write-offs and asset write-offs. Disposal of capital assets occurs by sale, loss, retirement prior to end of service life, abandonment or destruction. The disposal of an asset generally results in the receipt of salvage proceeds and costs for dismantling and disposing of the asset.

The forecasts for F2007 and F2008 shown in Table 5.8 are estimated by averaging the actual losses recorded during the previous three years.

Table 5-8. Gains or Losses on Disposal and Costs of Abandoned or Indefinitely Deferred Projects

	$ millions	Ref.	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)
1	F2004		2.7	
2	F2005		3.5	3.5
3	F2006		4.6	4.6
4	F2007			3.6
5				
6	**Average**	T5-3, L4	**3.6**	**3.9**

5.4 Demand Side Management ("DSM")

The Owner's RR includes the amortization of a portion of DSM investments made by BC Hydro. The portion of DSM amortization allocated to Transmission is 10% in

accordance with the Decision on BC Hydro Wholesale Transmission Services, April 23, 1998, page 29, issued with Commission Order G-43-98.

5.5 Grants and Taxes

For transmission circuits and all assessable station assets, BC Hydro pays school taxes based on assessed values and provincial school tax rates. BC Hydro also pays "grants-in-lieu" of municipal/rural/regional district taxes. For fee-owned land along transmission corridors and at station sites, and for any buildings at station sites, the grant-in-lieu is based on the assessed value of the land and buildings. Table 5-9 summarizes the annual grants and taxes paid by BC Hydro for its transmission assets.

Table 5-9. Grants and Taxes[9]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Grants and Taxes**						
2	**School Taxes**		64.4	66.3	63.5	61.9	62.9
3	**General Grants**		8.3	8.4	8.9	9.4	9.5
4	**1% Revenue Grant**		15.4	15.8	15.5	16.4	16.8
5	**Less: Assigned to BCTC**		(0.3)				
6							
7	**Total**	Table 5-1	**87.9**	**90.5**	**87.9**	**87.7**	**89.2**

5.6 Corporate Costs

BC Hydro's corporate costs are either charged directly to the BC Hydro lines of business and Transmission, or allocated using allocation factors. The charge and allocation methodologies and a summary of Transmission's portion of these costs are provided in BC Hydro's application.

5.7 BC Hydro Non-Tariff Revenues and Recoveries

BC Hydro recovers costs from external parties for non-transmission use of transmission assets. These revenues and cost recoveries are outside the transmission tariff and are not recovered from the TRR. Table 5-10 shows these non-tariff revenues and recoveries.

[9] See Appendix F regarding "F2006 Approved" column.

Table 5-10. BC Hydro Non-Tariff Revenues and Recoveries[10]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan	F2008 Plan
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Generation Related Transmission Assets	Table 5-1	32.6	33.1	33.2	37.9	37.9
2	Substation Distribution Assets	Table 5-1	55.6	56.5	56.5	25.3	25.4
3	Secondary Revenues	Table 5-1	3.8	3.8	3.6	3.4	3.4
4	Control Centre Leases	Table 5-1	0.2	0.2	0.2	0.2	0.2
5							
6	**Total Non-Tariffed Revenues and Recoveries**	Table 5-1	**92.2**	**93.6**	**93.5**	**66.8**	**66.9**

Non-tariff revenues and recoveries are $26.8 million lower in the F2007 Plan relative to the F2006 approved level. The reduction primarily relates to the transfer of the Substation Distribution Assets from Transmission to Distribution partially offset by higher costs for Generation Related Transmission Assets.

Sections 5.7.1 and 5.7.2 discuss the GRTA and SDA revenues and recoveries. Sections 5.7.3 and 5.7.4 provide brief descriptions of secondary revenues and revenues from control centre leases as these items are included in BC Hydro's application.

5.7.1 Generation Related Transmission Assets

Transmission assets include transmission circuits and substation assets required to connect generation resources to the integrated transmission grid. In the Commission's Decision on Wholesale Transmission Services, April 23, 1998, Section 2.1 pages 5 to 18, issued with Commission Order G-43-98; the Commission determined that transmission users would not receive enough benefit from Generation Related Transmission Assets ("GRTA") to warrant having some of these costs allocated to them and directed that 100% of GRTAs be functionalized to generation.

Subsequently, as part of its April 30, 2003 Heritage Contract filing regarding the Heritage Payment Obligation, BC Hydro proposed the amount in respect of BC Hydro's GRTA be fixed at $43.3 million. Appendix F, Section D "GRTA Cost Component of Forecast Heritage Payment Obligation" of the filing states:

[10] See Appendix F regarding "F2006 Approved" column.

> "BC Hydro proposes to include in the Heritage Payment Obligation an amount in respect of BC Hydro's Generation Related Transmission Assets (GRTA)...That amount is $43.3 million."

> "BC Hydro proposes that the GRTA amount be fixed at the proposed amount for the duration of the Heritage Contract and that it not be associated with any specific set of assets, regardless of what BC Hydro assets eventually come under the operational control of the BC Transmission Corporation....."

In its Report and Recommendations issued October 17, 2003, the Commission made the following recommendation:

> Recommendation #27
>
> That the determination of Generation Related Transmission Assets ("GRTAs") for the BC Hydro Wholesale Transmission Service rates, be accepted for the purposes of the BCTC tariff filing to be made pursuant to section 4(1) of the TCA, and that functionalization of GRTAs otherwise continue to be within the jurisdiction of the Commission.

The fixed annual charge of $43.3 million includes both BCTC maintenance costs (discussed in Section 7.6) and BC Hydro ownership costs (Allowed Return, Finance Charges, Depreciation and Amortization, Grants and Taxes and Corporate Business Sustaining Costs), shown in Table 5-19 on line 2. To determine the Transmission charge, the GRTA maintenance charges from BCTC (Table 7-1, line 19) are deducted from the total fixed fee amount of $43.3 million to determine the amount to be recovered by Transmission from Generation. Although the annual amount is fixed at $43.3 million, BCTC continues to review the cost of service associated with GRTAs and estimates the total cost to be $41.5 million for F2007. The difference between the forecast cost of $41.5 million and the agreed fixed amount of $43.3 million only affects the internal transfer of cost between Transmission and Generation.

5.7.2 Substation Distribution Assets ("SDAs")

Prior to F2007, Transmission assets included all substation assets in the following categories:

(a) 100% Transmission Substations; and

(b) Combined Transmission and Distribution Substations.

Combined Substations include transformation assets relating to transmission and distribution as well as equipment common to both such as buildings, HVAC, fences and gravel, etc. As part of the SLA negotiations, BCTC and BC Hydro undertook a review of the substation assets and as a result approximately $150 million (net book value) in combined substation assets, i.e. assets used solely in the provision of distribution service (below 60kV), were transferred from Transmission to Distribution. This transfer leaves Transmission with substation assets for transmission and common and consequently results in a more precise allocation of costs between Transmission and Distribution. The charge for SDAs shown in Table 5-18 only relates to common station asset-related expenses in the Combined Substations. The result of this asset transfer decreases SDA non-tariff revenue by $31.2 million as shown in Table 5-18. The assignment of costs related to the common station assets is covered by the Transmission – Distribution Interface Agreement between BC Hydro and BCTC. This cost assignment is more fully discussed in Section 8.0, Cost of Service Determination.

5.7.3 Secondary Revenues

Secondary revenues are received from external parties for non-electric use of transmission assets, e.g., facility rentals and cellular equipment sites.

5.7.4 Control Centre Leases

The control centre lease revenue relates to operating leases between BC Hydro and BCTC for the area control centres located on Vancouver Island and in Prince George.

Table 5-11. Transmission Depreciation Rates

Profile ID	Description	Old Rates	New Rates
(a)	(b)	(c)	(d)
55401	Buswork and Station Conductor	2.5%	1.7%
25101	Structure - Steel Support	2.0%	1.5%
25202	Pole Structures	2.9%	2.0%
25203	Towers	2.0%	1.5%

	Profile ID	Description	Old Rates	New Rates
	(a)	(b)	(c)	(d)
5	56001	Insulators	2.5%	1.8%
6	68302	Radio - Microwave - Digital	14.3%	5.0%
7	68402	Multiplex Device - Digital	14.3%	5.0%
8	52106	Transformer - Power - Composite Pool	3.0%	2.2%
9	52103	Transformer - Power > 100 MVA	3.3%	2.5%
10	52401	Transformer - Oil / 69 kV and Above	3.3%	2.5%
11	52404	Transformer - Current, Encaps	2.9%	2.2%
12	52405	Transformer - Current, Composite Pool	2.5%	2.0%
13	52504	Transformer, Voltage, Encaps	2.9%	2.2%
14	54601	Circuit Switcher	5.0%	3.3%
15	55101	Overhead Conductor > 60 kV	2.0%	1.7%
16	58101	VAR Compensator - Static	3.3%	2.5%
17	59301	Storage Batteries, Bank	10.0%	5.0%
18	65101	Fault Locating and Reporting	10.0%	5.0%
19	67005	Oil Spill Containment	4.0%	2.9%
20	68202	Terminal Unit - Remote	10.0%	5.0%
21	52102	Transformer - Auto / Bulk System	2.7%	2.2%
22	25102	Structure, Support, Wood	4.0%	3.3%
23	52303	Reactor - Composite Pool	2.9%	2.5%
24	52406	Comb CT and VT Transformer	2.9%	2.5%
25	54102	Breakers - Gas (Sf6) 12/25 kV	4.0%	3.3%
26	55303	Cable - Submarine > 60 kV	2.5%	2.2%
27	59201	Charger System, Battery	6.7%	5.0%
28	68303	Microwave, Conversion Only	6.7%	5.0%
29	68601	Protection Tone System	6.7%	5.0%
30	68602	Digital Teleprotection System	6.7%	5.0%
31	68801	Fibre Optic System	6.7%	5.0%
32	70001	Cable, Entrance Protection	6.7%	5.0%
33	75201	Tanks, Steel, Air/Fuel	4.0%	3.3%
34	68201	Control Center - Master Equipment	10.0%	8.3%
35	52301	Reactor - Oil	3.3%	4.0%
36	53201	Capacitor - Series	2.9%	3.3%
37	54103	Breakers - Bulk/Mon Oil/Air Blast	2.9%	3.3%
38	54203	Disconnect - 3 Phase - 12/25 kV	2.5%	2.9%
39	54204	Disconnect - 3 Phase - 69-230 kV	2.5%	2.9%
40	54205	Disconnect - 3 Phase - 500 kV	2.5%	2.9%
41	22006	Equipment Shelter	5.0%	10.0%
42	25301	Foundations	2.0%	2.5%

	Profile ID	Description	Old Rates	New Rates
	(a)	(b)	(c)	(d)
43	52402	Transformer - Gas / Sf6 / 69 kV and Above	2.0%	2.5%
44	53101	Capacitor – Shunt	2.5%	3.3%
45	68203	Integrated Control/Data (ICDA)	6.7%	20.0%
46	68401	Multiplex Device, Analog	6.7%	20.0%
47	75103	Piping, Stainless Steel	2.0%	2.5%
48	42201	Resistor - Load Breaking	2.5%	4.0%
49	54104	Breakers - Gas (Sf6) 69 to 500 kV	2.5%	4.0%
50	51002	Condenser - Synchronous, Static	1.7%	2.5%
51	12301	Pad, Helicopter	2.0%	4.0%
52	11901	Yard Surfacing	2.9%	2.9%
53	12001	Trail, Caterpillar	2.0%	2.0%
54	12402	Landscaping	4.0%	4.0%
55	21102	Erosion Donut and/or Bank	4.0%	4.0%
56	21103	Debris/Avalanche Deflector	4.0%	4.0%
57	25401	Trenches and Ducts	2.0%	2.0%
58	25502	Ductbanks > 60kV	2.0%	2.0%
59	52302	Reactor - Dry Type	2.5%	2.5%
60	52403	Oil, < 69 kV	2.9%	2.9%
61	52501	Transformer, Voltage, Capacitor	2.9%	2.9%
62	52502	Transformer, Voltage, Oil-Fill	2.5%	2.5%
63	52503	Transformer, Voltage, Gas-Fill	2.0%	2.0%
64	52505	Transformer, Volt, Comp. Pool	2.5%	2.5%
65	53202	Metal Oxide Varister (MOV)	2.9%	2.9%
66	53301	Capacitor - Coupling	2.9%	2.9%
67	54105	Breakers - Composite Pool	3.3%	3.3%
68	54201	Use Individual Disconnect Caus	2.5%	2.5%
69	55103	Line Disconnect Switches	4.0%	4.0%
70	55302	Cable - Underground > 60 kV	2.5%	2.5%
71	55501	Grounding Systems	2.5%	2.5%
72	57001	Surge Arrestor	3.3%	3.3%
73	58001	Converter	3.3%	3.3%
74	58002	Inverter	3.3%	3.3%
75	58201	Resistor, Anode Damping	4.0%	4.0%
76	61001	Fencing	4.0%	4.0%
77	65001	Panels/Cubicles, P&C	5.0%	5.0%
78	68001	Carrier System, Power Line	6.7%	6.7%
79	68101	Antennae and Waveguide, Microwave	5.0%	5.0%
80	68503	Radio Equipment, Protection	4.0%	4.0%

	Profile ID	Description	Old Rates	New Rates
	(a)	(b)	(c)	(d)
81	68701	Wave Trap / Line Trap	5.0%	5.0%
82	70102	Accelerometers	5.0%	5.0%
83	70103	Seismic Monitoring Equipment	5.0%	5.0%
84	73001	Cooling System – Air	4.0%	4.0%
85	75101	Drier, Air	4.0%	4.0%
86	75202	Tank, Fibreglass, Dbl Bottom, Fuel	3.3%	3.3%
87	75204	Tanks - Concrete	3.3%	3.3%
88	82510	Railcars	2.9%	2.9%
89	89001	Intangible/Franchise/Consent	10.0%	10.0%
90	89501	Animal Preventative Equipment	5.0%	5.0%

6.0 ASSET MANAGEMENT/MAINTENANCE REVENUE REQUIREMENT

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to provide a description of the Asset Management/Maintenance Revenue Requirement ("AMMRR").

BCTC manages and maintains the transmission system owned by BC Hydro, and began charging an Asset Management and Maintenance fee to BC Hydro effective April 1, 2005. The fee is in accordance with the Asset Management and Maintenance Agreement, and is used to establish the AMMRR. BC Hydro recovers the AMMRR in rates and pays BCTC under the Asset Management and Maintenance Agreement for these services.

In this Asset Management and Maintenance function, BCTC:

(a) Establishes asset management strategies, policies, processes and practices;

(b) Establishes and maintains capital replacement programs and carries out required capital upgrades and additions funded by BC Hydro;

(c) Monitors and assesses the remaining useful life of assets forming part of the transmission system and identifies significant operating capacity limitations or other constraints and develops appropriate replacement or refurbishment programs for such assets;

(d) Develops, implements and evaluates maintenance plans and programs;

(e) Carries out vegetation control in respect of the transmission system;

(f) Maintains and inspects the transmission system;

(g) Undertakes corrective maintenance and emergency repairs of the transmission system;

(h) Measures and analyzes asset management results, including the results of capital investment and maintenance plans and programs;

(i) Develops and implements new plans to address any deficiencies identified from the measurement and analysis of asset management and maintenance results;

(j) Monitors, evaluates and where appropriate, implements technological advancements and improvements;

(k) Manages equipment inventories, including systems spares, which BC Hydro will own; and

(l) Manages contracts with Third Parties that relate to the management and maintenance of the transmission system.

Table 6-1 identifies the cost components of the AMMRR for F2006 Approved and F2007 Plan. Only OMA expenses are included in the AMMRR; there is no allocation of asset related expenses from BCTC. There is no charge associated with this revenue requirement for F2005 as this charge was established at the beginning of BCTC's Phase 2 operations commencing April 1, 2005.

BCTC's Asset Management and Maintenance groups also provide services for two non-tariff related services: Generation Related Transmission Assets and Substation Distribution Assets. These services are described in Section 5.7.

Table 6-1. Asset Management / Maintenance Revenue Requirement

$ millions	Ref.	F2006 Approved	F2007 Plan	$ Change	% Change
(a)	(b)	(c)	(d)	(e)	(f)
Gross Asset Management & Maintenance Cost	T7-1	111.3	104.4	(6.9)	-6.2%
Less Non-Tariffed Revenues					
Generation Related Transmission Assets	T7-1, Sec.7.6.1	(10.2)	(5.4)	4.8	-47.1%
Substation Distribution Assets	T7-1, Sec.7.6.2	(10.9)	(11.7)	(0.8)	7.3%
Total AMM Revenue Requirement	T4-1	90.2	87.3	(2.9)	-3.2%

The F2007 Asset Management and Maintenance Revenue Requirement shown in Table 6-1 is $87.3 million, which is $2.9 million, or 3.2%, lower than the F2006 Approved AMMRR. The decrease results from improved maintenance practices; a discontinued program for High Voltage Direct Current ("HVDC") transformer

refurbishment; increased capitalized overhead and a reduced allocation of administrative costs. The cost decreases are partially offset by additional resources required to address an increased project management focus on an expanding capital plan and increases in BC Hydro service provider costs. Section 9.3 of the Application provides detailed descriptions of BCTC's Asset Management and Maintenance programs.

7.0 BCTC REVENUE REQUIREMENT

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to provide an overview of the BCTC Revenue Requirement ("BCTC RR"). Specifically, the section summarizes the BCTC RR and describes the elements that comprise the BCTC RR.

The BCTC RR encompasses the entire scope of BCTC's responsibilities including system operations, provision of transmission services under BCTC's OATT tariff and the planning and management of the transmission system. As shown in Table 7-1, the F2007 BCTC RR of $70.3 million is $2.2 million or 3.0% less than the F2006 Approved amount.

Table 7-1. BCTC Revenue Requirement[11]

$ millions	Ref.	F2006 Approved	F2007 Plan	$ Change	% Change
(a)	(b)	(c)	(d)	(e)	(f)
BCTC Revenue Requirement					
Operations	Sec.9.2	43.1	45.5	2.4	5.6%
Maintenance	Sec.9.3	102.2	99.7	(2.5)	-2.4%
General and Administration	Sec.9.4	20.9	19.7	(1.2)	-5.7%
Operating, Maintenance and Administration Costs		**166.2**	**164.9**	**(1.3)**	**-0.8%**
Depreciation and Amortization	Sec.7.4	21.5	14.6	(6.9)	-32.2%
Grants and Taxes	Sec.7.5	0.3	0.3	-	0.0%
Deemed Interest	Sec.7.2.2	0.5	0.2	(0.3)	-60.0%
Cost of Market	Sec.7.3	5.8	6.8	1.0	17.2%
Allowed Return on Deemed Equity	Sec.7.2.3	3.6	2.9	(0.7)	-19.4%
Gross Transmission Costs		**197.9**	**189.7**	**(8.2)**	**-4.2%**
Asset Management Fees from BCHydro					
Transmission Assets	Sec.6	(90.2)	(87.3)	2.9	-3.2%
Substation Distribution Assets	Sec.7.6.2	(10.9)	(11.7)	(0.8)	7.3%
Generation Related Transmission Assets	Sec.7.6.1	(10.2)	(5.4)	4.8	-47.1%
Asset Management Fees from BCHydro		**(111.3)**	**(104.4)**	**6.9**	**-6.2%**
Gross BCTC Revenue Requirement		**86.6**	**85.3**	**(1.3)**	**-1.5%**
Non-Tariff Revenues	Sec.7.6, T7-10, L3-6	(14.1)	(15.0)	(0.9)	6.1%
BCTC Transmission Revenue Requirement		**72.5**	**70.3**	**(2.2)**	**-3.0%**

Operating, Maintenance and Administration ("OMA") expense is reduced for F2007 as a result of improvements to maintenance processes and standards, and vegetation maintenance cycles for specific transmission circuits. OMA is also reduced by the higher Capital Overhead allocation resulting from the Capital Overhead Study. These OMA reductions are partially offset by an increase in the size of the organization in response to the need to manage a large capital program and other workload (e.g., to undertake BC Hydro Call-For-Tender studies), respond to regulatory requirements and undertake public consultation respecting all business

[11] See Appendix F regarding "F2006 Approved" column.

activities. These additional resources will allow BCTC to fulfill its responsibilities effectively. The increase in Operations cost is largely a result of higher labour costs, increased WECC fees and the inclusion of SCMP Project OMA.

Other cost reductions include lower depreciation and amortization expense as a result of assets reaching end of life and revised depreciation rates, a lower allowed return reflecting a high level of temporary investment at year end, and lower finance charges.

7.1 Operating, Maintenance and Administration Expense

OMA is the largest element of the BCTC RR, and is discussed in detail in Section 9 of the Application.

7.2 Cost of Capital

Included in the BCTC RR the cost of capital comprising the cost of debt and an allowed return on equity, based on a deemed capital structure.

7.2.1 Deemed Capital Structure

Special Direction No. 9, Order in Council No. 1107, Approved and Ordered November 27, 2003 ("SD 9") sets out the mechanism for determining BCTC's deemed capital structure. SD 9 defines the debt and equity components as follows:

> "equity" means the sum of share capital, contributed surplus and retained earnings;
>
> "debt" means the amount obtained by adding revolving borrowings, bonds, notes and debentures, and deducting from that sum the total of related sinking funds, temporary investments and repurchased debt;
>
> "forecast debt", in relation to the transmission corporation, means, for a period made up of one or more years, the average of the amounts that are forecast to represent the average of the transmission corporation's debt in each of the months of that period;
>
> "forecast equity", in relation to the transmission corporation, means, for a period made up of one or more years, the average of the amounts that are

forecast to represent the average of the transmission corporation's equity in each of the months of that period;

"deemed equity" means, for any period, the product obtained by multiplying the deemed equity component by the sum of the forecast debt and the forecast equity relating to that period; and

As amended by Order in Council 752, approved and ordered October 19, 2005, "deemed equity component" means, for the transmission corporation's financial year commencing April 1, 2005, and for all subsequent financial years, 40.7%.

Table 7-2. BCTC Capital Structure[12]

	$ millions	F2006 Approved	31.Mar.06 Forecast	2006 April	May	June	July	Aug	Sep	Oct	Nov	Dec	2007 Jan	Feb	Mar	F2007 Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Short term borrowings	18.5	-	-	-	-	-	-	-	-	-	-	1.0	7.5	10.0	1.5
2	Debenture	31.3	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1
3	Capital Lease	7.1	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.9	6.9	6.9	6.9	6.9	6.9	7.0
4		56.8	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.0	37.0	37.0	38.0	44.5	47.0	38.6
5	Less: Temporary Investment	(16.7)	(40.5)	(37.7)	(51.6)	(48.7)	(45.8)	(41.7)	(16.8)	(14.3)	(9.6)	(5.9)	(1.1)	(1.3)	(1.1)	(23.0)
6	Less: Sinking Fund	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Forecast Debt**	**40.1**	**(3.4)**	**(0.6)**	**(14.5)**	**(11.6)**	**(8.7)**	**(4.6)**	**20.3**	**22.7**	**27.4**	**31.1**	**36.9**	**43.2**	**45.9**	**15.6**
8																
9	Common Shares	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
10	Retained Earnings	5.9	16.8	17.1	17.3	17.6	17.8	18.1	18.3	18.6	18.8	19.1	19.3	19.6	19.8	18.4
11	**Forecast Equity**	**25.9**	**36.8**	**37.1**	**37.3**	**37.6**	**37.8**	**38.1**	**38.3**	**38.6**	**38.8**	**39.1**	**39.3**	**39.6**	**39.8**	**38.4**
12																
13	**Total Forecast Debt and Equity**	**65.9**	**33.4**	**36.5**	**22.8**	**26.0**	**29.1**	**33.5**	**58.6**	**61.2**	**66.2**	**70.2**	**76.2**	**82.7**	**85.7**	**54.1**
14																
15																
16	Deemed Debt Component at 59.3%	39.1														32.1
17	Deemed Equity Component at 40.7%	26.8														22.0
18		65.9														54.1
19	Allowed Return (%)	13.51%														13.13%
20	Allowed Return ($ millions)	3.6														**2.9**

7.2.2 Cost of Debt

Deemed debt is not a defined term in SD 9. BCTC has defined deemed debt as:

(1- Deemed Equity Component) x (the sum of Forecast Average Debt and Forecast Equity)

Deemed debt is multiplied by the effective interest rate to calculate deemed cost of debt. Deemed cost of debt, net of Interest During Construction ("IDC"), is a cost

[12] See Appendix F regarding "F2006 Approved" column.

recovery item in the BCTC RR calculation. Funds used during the construction of projects are accumulated, and interest expense (IDC) is calculated on the balance. As each asset goes into service, the accumulated funds, plus IDC, are placed in capital and depreciated. Therefore, IDC is not recovered as part of cost of debt in the revenue requirement calculation and must be subtracted from deemed cost of debt.

Table 7-3. Deemed Cost of Debt[13]

	$ millions	F2006 Approved	F2007 Plan
	(a)	(b)	(c)
1	Deemed Debt	39.1	32.1
2	Effective Interest Rate	4.7%	4.9%
3	Deemed Cost of Debt	1.8	1.6
4			
5	Less: Interest During Construction (IDC)	(1.3)	(1.4)
6	Deemed Cost of Debt, net of IDC	0.5	0.2

The effective interest rate is the weighted average cost of actual debt, including capital leases. Interest earned on Deferral Account balances is excluded from this calculation as BCTC is required to pay interest upon clearing of deferral accounts. Table 7-4 shows the effective interest rates for F2006 Approved and F2007 Plan.

Table 7-4. Effective Interest Rates[14]

	$ millions	F2006 Approved	F2007 Plan
	(a)	(b)	(c)
1	- Short term borrowings	18.5	1.5
2	- Debentures	31.3	30.1
3	- Capital Leases	7.1	7.0
4	Average Borrowing	56.8	38.6
5			
6	Cost of Debt		
7	- Short-term borrowings @ 4.3%		0.1
8	- Debentures @ 4.3%		1.3
9	- Capital leases @ 7.7%		0.5
10	Total		1.9
11			
12	Effective Interest Rate	4.7%	4.9%

[13] See Appendix F regarding "F2006 Approved" column.
[14] See Appendix F regarding "F2006 Approved" column.

7.2.3 Allowed Return on Equity

Under SD 9, in regulating and fixing rates for BCTC, the Commission must ensure that those rates allow BCTC to collect sufficient revenue in each financial year to generate:

> an annual rate of return on deemed equity that is equal to the annual rate of return that is allowed by the commission on [BC Hydro's] equity as that term is defined in Special Direction HC2.

Special Direction HC2, Section 4, in part, requires that:

> Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to (d) achieve an annual rate of return on equity equal to the pre-tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*.

Section 7 of HC2 relates to deferral accounts.

In Commission Order G-14-06, dated March 2, 2006, the Commission established a rate of return on common equity of 8.80 percent for 2006 for a low-risk benchmark utility. Adjusting for the effective income tax rate for Terasen Gas, the pre-tax rate of return is estimated to be 13.13 percent, as calculated by BC Hydro, and will be subject to approval by the Commission when BC Hydro files for approval.

The application of these provisions and the calculation of BCTC's allowed return for F2007 are set out below.

Table 7-5. Allowed Return on Equity [15]

	$ millions	F2006 Approved	F2007 Plan
	(a)	(b)	(c)
1	Deemed Equity	26.8	22.0
2	Allowed Rate of Return	13.51%	13.13%
3	Allowed Return on Equity	3.6	2.9

7.3 Cost of Market

Cost of Market expenses support OATT services. These costs reflect:

(a) Charges incurred for the purchase of Ancillary Services for OATT customers that do not self-supply ("Ancillary Services"); and

(b) Congestion management expenses including the purchase of operating reserves, transmission locational credits, unscheduled flow mitigation, and operating agreements between control areas. These costs are incurred to maximize transmission capacity and provide additional transmission uptake opportunities. BCTC only incurs congestion management expenses if it believes incremental transmission revenues will offset these costs. Congestion management payments are currently made to Boston Bar Limited Partnership, WECC, AESO, and other members of NWPP ("Congestion Management").

Cost of Market expenses are shown in the Table 7-6, and are recovered through the OATT Tariff.

[15] See Appendix F regarding "F2006 Approved" column.

Table 7-6. Cost of Market Expenses[16]

	$ millions	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)
1	Ancillary Services (RS 04-09)	3.1	4.8	3.6	6.0
2	NWPP Reserve Deliveries or Receipts	-	-	-	-
3	Congestion Management	0.8	1.0	0.9	0.8
4	**Total Cost of Market**	**3.9**	**5.8**	**4.5**	**6.8**

The decrease in Ancillary Services costs from F2006 Approved to F2006 Forecast is predominately driven by lower transmission volumes resulting in reduced requirement for Loss Compensation Service. The increase in Ancillary Services costs from F2006 Approved to F2007 Plan is predominately driven by changes to Tariff Rate Schedule 04 – Reactive Supply and Voltage Control.

Rate Schedule 09 (Loss Compensation Transmission Service) generates the most revenue of all of the Ancillary Services. As mentioned in the Ancillary Services evidence (Section 11.2.3), Rate Schedule 09 is driven by the actual MWh volume of customers' transactions. Thus, increased volumes generate higher revenue to offset the higher cost and vice versa.

7.4 Depreciation and Amortization Expense

7.4.1 Overview

BCTC's assets comprise control and communication equipment, computer hardware and software, land and buildings (including those under capital leases), and furniture and equipment. Most of the assets were acquired, at net book value, from BC Hydro in F2004 as part of the establishment of BCTC.

Depreciation expense includes the annual write-off of the original investment cost of BCTC's capital assets over the expected useful life of the assets. Depreciation expense also includes depreciation on an Asset Retirement Obligation ("ARO") asset and an accelerated write-off on the existing control centre assets. Depreciation rates

[16] See Appendix F regarding "F2006 Approved" column.

are established based on the expected useful life of the assets and applied on a straight line basis to the original cost of the assets.

In F2006, BCTC commissioned an independent depreciation study on BCTC's assets. Gannett Fleming was engaged to perform the study based on its extensive experience in asset service life analysis for electric utilities. The study determined the average service lives to be used in the determination of depreciation rates and amounts for rate making purposes. The BCTC Depreciation Study is filed as Appendix B. The impact of the depreciation study is reflected in the F2007 Depreciation forecast.

Under section 56 of the *Utilities Commission Act*, approval is requested for the new depreciation rates, as shown in column (d) of Table 7-12 (located at the end of Section 7).

7.4.2 Depreciation Expense

The Depreciation expense forecast for F2007 is determined based on forecast F2006 depreciation expense, adjusted for new assets to be placed in service and asset retirements in F2007. Table 7-7 shows depreciation expense for F2005 to F2007.

Table 7-7. Depreciation Expense[17]

	$ millions	**F2005 Actual**	**F2006 Approved**	**F2006 Forecast**	**F2007 Plan**
	(a)	(b)	(c)	(d)	(e)
1	Depreciation of existing assets	17.3	13.6	14.0	10.6
2	Depreciation of planned additions		1.4	2.2	1.1
3	Accelerated depreciation of existing control centre assets		6.5	3.4	3.4
4	Impact of Depreciation Study				(0.5)
5	**Closing balance, net of amortization**	**17.3**	**21.5**	**19.6**	**14.6**

Included in the F2007 depreciation forecast is $3.4 million related to the accelerated write-off of the existing control center assets starting in F2006. With the approval to

[17] See Appendix F regarding "F2006 Approved" column.

proceed with SCMP, the service life of the existing control center assets and the associated ARO asset (decommissioning and dismantling costs for the System Control Centre) has been reduced to ensure these assets are fully depreciated by October 2008, to align with the revised forecast SCMP in-service date. The original in-service date was forecast to be April 2008.

Compared to F2006 Approved, total depreciation and amortization is forecast to decrease in F2007 by $6.9 million due to the following factors:

(a) Computer software and hardware assets reaching their end of life during F2006 or F2007, contributing a $6.8 million reduction in depreciation. The majority of the decrease relates to four assets that are fully depreciated in F2006, all with lives of 3 years. These four projects are the Scheduling System, Dispatch and Compliance Monitoring, Settlements and Billing System and Transmission Scheduling System Software.

(b) The estimated accelerated depreciation on existing control center assets is reduced by $3.1 million due to the change in SCMP in-service date from April 2008 to October 2008 and refinements to the depreciation calculation from the declining balance to the straight line method of amortization;

(c) The net impact of the depreciation study is a $0.5 million reduction in depreciation expense

Partially offset by the following factors:

(d) About $1.1 million in higher depreciation relating to new assets forecast to be complete and placed in service in F2007. The forecast is based on projects being placed in service mid-year and 50% of the depreciation, calculated using revised rates, is included the depreciation forecast in F2007. Projects in progress at year end are forecast to be in service July 1, 2007. Evidence on completed capital projects and depreciation impacts is provided in Section 7 of this application.

(e) About $2.4 million in higher depreciation on existing assets and F2006 assets placed in service due to actual depreciation exceeding F2006 Approved.

Compared to F2006 Forecast, depreciation expense on existing assets are forecast to decline by $5.0 million in F2007 as a significant portion of BCTC's computer software and hardware reach end of life. It is forecast that $16.7 million assets will be retired in F2006 and F2007. New capital asset additions contribute to higher depreciation expense. Table 7-8 following shows the continuity schedule of capital assets in service from F2005 to F2008.

Table 7-8. BCTC Asset Continuity Schedules and Net Book Value

	$ millions	**F2005 Actual**	**F2006 Forecast**	**F2007 Plan**
	(a)	(b)	(c)	(d)
	Asset Costs			
1	Opening Balance	62.1	72.6	73.9
2	Additions	10.6	17.4	12.0
3	Retirements	(0.1)	(16.1)	(0.6)
4	Ending Balance	72.6	73.9	85.3
	Accumulated Depreciation			
5	Opening Balance	5.0	21.9	25.9
6	Additions	16.9	19.6	14.6
7	Retirements	-	(16.1)	(0.6)
8	Ending Balance	21.9	25.4	39.9
	Net Book Value of Fixed Assets			
9	Ending Balance	50.7	48.5	45.4

More detail on capital projects forecast to be completed in F2006 – F2007 is included in Section 10 of the Application.

7.4.3 Depreciation Study

Based on the results of the BCTC Depreciation Study – Determination of Average Service Lives Applicable to Plant in Service of British Columbia Transmission Corporation as at March 31, 2005 ("BCTC Depreciation Study"), the average service life of computer software will be extended from 4 years to 7 years whereas computer hardware life will be reduced from 7 years to 5 years. The net impact is a reduction of $0.5 million in depreciation expense in F2007 which contributes to lower transmission rates for customers.

The method used in estimating service life includes analysis of actual experience and forecast future use. The service life of those assets at the existing five control

centers which are being replaced under the SCMP projects is not affected as these assets are being subjected to accelerated depreciation.

Table 7-9. BCTC Depreciation Study Impact on Depreciation Rates by Asset Class

		F2007 - Current Rates		F2007 - Revised Rates	
	Asset Class	**In years**	**% Rate**	**In years**	**% Rate**
1	Computer Hardware	5.6	17.8%	4.9	20.5%
2	Computer Software	4.0	25.0%	6.4	15.6%
3	Furniture and Equipment	20.0	5.0%	14.9	6.7%
4	Buildings/Leases	40.0	2.5%	34.1	2.9%
5	Communications Equipment	10.0	10.0%	12.0	8.3%

7.4.4 Depreciation on Asset Retirement Obligation ("ARO") Asset

Effective April 1, 2004, BCTC adopted the CICA Handbook section 3110 on Asset Retirement Obligations and set up a provision for the decommissioning and dismantling cost for System Control Center building on leased land from Simon Fraser University. The retirement date is October 2008 to coincide with the in service date of SCMP project.

7.5 Grants and Taxes

By regulation, BCTC is subject to section 34 of the *Hydro and Power Authority Act* in respect of property taxes. Accordingly, BCTC is assessed school taxes and pays grants in lieu of municipal or similar taxes on its property. During F2006 and F2007, BCTC will pay school taxes and grants in lieu of taxes for its existing System Control Centre and for the land on which the new System Control Centre will be constructed. (BCTC will capitalize grants and taxes paid on SCMP and begin amortizing them once the project is in-service in October 2008.) BCTC also reimburses BC Hydro for taxes and grants in lieu paid by BC Hydro on the Area Control Centre facilities under the terms of the various lease agreements. BCTC will pay school taxes and grants in lieu of $0.3 million in F2006 and will pay an estimated $0.3 million in F2007.

7.6 BCTC Non-Tariff Revenues

BCTC performs activities and incurs costs related to non-transmission aspects of BCTC's operations. These activities include the management and maintenance of non-transmission assets; generation control; distribution operations; and

maintenance of the microwave system as it applies to data and voice use. The BCTC Revenue Requirement excludes these costs. Cost recovery occurs outside of the transmission tariff. Table 7-10 reflects the non-tariff revenues collected by BCTC.

Table 7-10. BCTC Non-Tariff Revenues and Recoveries[18]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	Generation Related Transmission Asset Mgmt & Mtc	Sec.7.6.1	10.7	10.2	10.1	5.4
2	Substation Distribution Asset Mgmt & Mtc	Sec.7.6.2	11.6	10.9	11.4	11.7
3	Fortis General Wheeling Agreement	Sec.7.6.3	3.8	3.8	3.8	3.8
4	Generation Control Services	Sec.7.6.4	1.0	1.0	1.0	1.0
5	Distribution Operations Services	Sec.7.6.5	2.6	6.8	6.8	7.4
6	Other Recoveries - BCTC	Sec.7.6.6	3.4	2.5	3.6	2.8
7						
8	**Total Non-Tariffed Revenues and Recoveries**		**33.2**	**35.2**	**36.7**	**32.1**

Non-tariff revenues and recoveries are $3.1 million lower in the F2007 Plan relative to the F2006 approved level. Changes in non-tariff revenues and recoveries are driven by the following:

(a) lower maintenance for Generation Related Transmission Assets as a result of vegetation maintenance cycles, the capitalization of major overhauls on gas insulated switchgear extending the life of the assets for up to 25 years and maintenance process improvements; and

(b) lower other recoveries relating to telecom maintenance of the microwave system associated with non-transmission voice and data use.

(c) higher labour costs for Distribution Operations Services reflecting completed union contract negotiations; and

[18] See Appendix F regarding “F2006 Approved” column.

(d) higher asset SDA management costs primarily due to reduced capital overhead allocation.

Brief descriptions of each revenue category follow.

7.6.1 Generation Related Transmission Asset Management and Maintenance

As noted in section 5.7.1, BC Hydro pays an annual fee to BCTC to cover the costs associated with the asset program planning and maintenance of generation related transmission assets. These assets consist of specific transmission lines and substations determined by the Commission in its Decision on Wholesale Transmission Services dated April 23, 1998 to be generation related and required to connect generation to the integrated transmission grid. The decline in GRTA Revenue is a result of lower maintenance for GRTAs as a result of vegetation maintenance cycles, the capitalization of major overhauls on gas insulated switchgear (extending the life of the assets for up to 25 years) and maintenance process improvements.

7.6.2 Substation Distribution Asset ("SDA") Management and Maintenance

BCTC is responsible for the planning, maintenance and management of 100% Transmission and Combined Transmission and Distribution Substations. BCTC manages the maintenance programs for SDAs on behalf of BC Hydro Distribution. The charge from BCTC to BC Hydro for SDAs includes direct maintenance costs for SDAs and an allocation for common equipment, fixed fee costs relating to asset management and indirect corporate and capital overhead allocation. The annual charge for this service has increased by $0.8 million from the approved F2006 level of $10.9 million to $11.7 million in F2007. This increase reflects lower capitalized overhead costs and increased maintenance costs resulting from the negotiated work program for F2007.

7.6.3 Fortis General Wheeling Agreement

The revenue collected from Fortis is in accordance with the General Wheeling Agreement dated October 15, 1986, as amended pursuant to the General Wheeling Amendment Agreement (2002) dated Dec 13, 2002 and the General Wheeling Amending Agreement (2004) dated April 5, 2004 between BC Hydro and Fortis BC Inc. These agreements were assigned to BCTC in 2005 pursuant to Commission

Order G-34-05. The charges for the wheeling of electricity from Point of Supply to the Lambert, Okanagan Point of Interconnection and Princeton are set out in BCTC Transmission Tariff Rate Schedule 21.

7.6.4 Generation Control Services

Generation Control Services are covered by a Service Level Agreement between BCTC and BC Hydro. Services provided by BCTC include generation control, water conveyance, alarm monitoring, notification and reporting services, data services and SCADA system services. The demarcation point for this service is the high side of the step-up transformer out to the generating unit. The annual charge for this service is charged on a fixed fee basis.

7.6.5 Distribution Operations Services

BCTC area control centres provide services to BC Hydro for both the Downstream Distribution System and the Substation Distribution Assets ("SDAs"). Services provided to BC Hydro have two major service components; inside the substation fence downstream of the high side of the step down transformer called the SDAs (prior to F2006, activities associated with this service component were collected through the transmission tariff); and outside the substation fence called the Downstream Distribution System. In addition, BC Hydro Distribution has requested that BCTC manage the activities of Field and Engineering Services in relation to SDAs and the Downstream Distribution System.

The annual charge for this service has increased by $0.6 million from the approved F2006 level of $6.8 million to $ 7.4 million in F2007. This increase is primarily caused by increased labour costs (negotiated labour contracts and pension cost increases).

The following services are provided:

(a) On a 24 hours, 7 days per week basis:

- i person-in-charge duties, including issuing Safety Protection Guarantees and Permits, maintaining real-time mimic displays, managing Power System Safety Protection procedures, issuing switching orders and managing plant alteration processes;

ii managing field crews carrying out switching operations for system optimization and equipment protection purposes, including managing costs, budgets, quantity and quality of such switching operations;

iii real-time monitoring and reporting of events and requested near real-time information to BC Hydro;

iv response to unplanned outages, including responsibility for dispatching field crews and restoration of service to BC Hydro customers with respect to the Substation Distribution Assets (but not the Downstream Distribution System) and, in large scale outages involving feeder facilities, coordinating the restoration activities for the Downstream Distribution System;

v in the event of unplanned outages, coordinating repairs to Substation Distribution Assets with the party responsible for maintaining and managing the Substation Distribution Assets; and

vi initiating response to incidents which may affect the safety or operation of the Substation Distribution Assets, including dispatching field crews.

(b) Supplying required operating drawings to the BCTC control centres and to BC Hydro for the Distribution System and mimic display maintenance;

(c) Outage scheduling for Substation Distribution Assets and the Downstream Distribution System including collecting, analysing, prioritizing and approving outages, coordinating commissioning of new plant into service, coordinating plant alterations and commissioning notices to energize, and managing field crews to implement requested services;

(d) Operating Order administration;

(e) Developing Operating Orders pertaining exclusively to the Distribution System on a system-wide basis;

(f) Operational planning including contingency planning and interim load balancing and transfers as required; and

(g) Other services as requested by BC Hydro, including providing studies, analyses and reports (including studies defining and assessing the impacts on the Distribution System of different operating scenarios), project management for service/process improvements and providing expert operator advice into distribution planning processes.

7.6.6 Other Recoveries – BCTC

Table 7-11 provides detail of the other recoveries collected by BCTC. The increase in other recoveries from F2006 Approved to F2007 Plan reflects higher investment income partially offset by lower recovery for the use of the telecommunications system for voice and data. The level of recovery is determined in reference to market price and the anticipated reduction is supported by a study currently being conducted by BC Hydro Engineering.

Table 7-11. Other Recoveries – BCTC

	$ millions	**F2005 Actual**	**F2006 Approved**	**F2006 Forecast**	**F2007 Plan**
	(a)	(b)	(c)	(d)	(e)
1	Generation Control Services to other Customers	0.1	0.1	0.1	0.1
2	Engineering Services	0.8	0.8	0.8	0.8
3	Telecom service	1.1	1.6	1.6	1.1
4	Investment Income	1.4	-	1.1	0.8
5	**Total BCTC Other Recoveries**	**3.4**	**2.5**	**3.6**	**2.8**

7.6.6.1 Generation Control Services to External Customers

Similar to the services provided to BC Hydro (described in Section 7.6.4), BCTC also provides generation control services to generators other than BC Hydro through third party contracts.

7.6.6.2 Engineering Services

BCTC manages a very large capital portfolio of Transmission projects along with its own capital projects. BCTC staff charge directly to Transmission capital projects if:

(a) the employee working on the capital project is back-filled by temporary staff or a contractor;

(b) the employee is required to work overtime on a capital project; or

(c) the employee is working more than 40% of their time in a given month on a specific capital project.

BCTC bills these engineering costs directly to BC Hydro.

7.6.6.3 Investment Income

Investment income reflects the interest earned on BCTC's temporary investments and cash balances.

7.6.6.4 Telecom Service for Non-Transmission use of the Microwave System:

BCTC maintains BC Hydro's microwave system and recovers costs from BC Hydro and 3rd parties for voice and data use of the microwave system. This charge is expected to decrease as the excess bandwidth shrinks in response to increased transmission use of the microwave system.

Table 7-12. BCTC Depreciation Rates

	Profile ID	Description	Old Rates	New Rates
	(a)	(b)	(c)	(d)
1	C22005	Building	2.2%	2.2%
2	C22202	Tenant Improvement	10.0%	10.0%
3	C48003	Generator, composite pool	2.9%	2.9%
4	C59001	Power supply, uninterruptable	6.7%	6.7%
5	C59301	Storage batteries, bank	10.0%	6.7%
6	C61101	Alarm systems	4.0%	6.7%
7	C65101	Fault locating and reporting	10.0%	10.0%
8	C68201	Control center master equip	10.0%	8.3%
9	C68202	Terminal unit, slave	10.0%	8.3%
10	C68302	radio microwave, digital	14.3%	10.0%
11	C68501	Radio systems, UHF	14.3%	14.3%
12	C68901	Telephone equip, PAX	10.0%	6.7%
13	C70001	Cable, entrance protection	6.7%	6.7%
14	C75202	Tank, fibreglass	3.3%	3.3%
15	C75204	tank, concrete	3.3%	3.3%
16	C80101	computer hardware, micro	33.3%	33.3%
17	C80102	computer hardware, mini	14.3%	20.0%
18	C80103	computer hardware, I/O	20.0%	20.0%

	Profile ID	Description	Old Rates	New Rates
	(a)	(b)	(c)	(d)
19	C80104	computer, h/ware, comp pool	25.0%	25.0%
20	C80105	Laptops	50.0%	33.3%
21	C80204	storage device disk,tape	14.3%	20.0%
22	C80208	printer, mainframe, laser	10.0%	20.0%
23	C80401	simulator training	20.0%	20.0%
24	C80502	routers	14.3%	20.0%
25	C80503	switches	14.3%	20.0%
26	C80504	servers	25.0%	20.0%
27	C80505	servers	33.3%	20.0%
28	C80508	misc network equip	25.0%	20.0%
29	C80302	software, mainframe	10.0%	10.0%
30	C80303	software, midrange	33.3%	33.3%
31	C80304	PC software	100.0%	33.3%
32	C80305	software, midrange, upgrade	50.0%	50.0%
33	C80306	network software	25.0%	14.3%
34	C85001	furniture and equip	5.0%	6.7%
35	C85002	office equipment	20.0%	20.0%

8.0 COST OF SERVICE ALLOCATION

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The purpose of this evidence section is to describe the cost of service allocation used in the development of the Transmission Revenue Requirement ("TRR").

All BCTC and BC Hydro Transmission ("Transmission") costs are recovered through the TRR, Service Level Agreement charges or non-tariff revenues. The cost of service allocation is the process for assigning costs to these three recovery mechanisms. Specifically, costs are allocated to the three TRR Components, three Service Level Agreements and two non-tariff revenues, as shown below.

(a) TRR Components

- i BCH Owner's Revenue Requirement ("Owner's RR")
- ii Asset Management / Maintenance Revenue Requirement ("AMMRR")
- iii BCTC Revenue Requirement ("BCTC RR")

(b) Service Level Agreements

- i Substation Distribution Assets
- ii Distribution Operations
- iii Generation Control

(c) Non-Tariff Revenues

- i Generation Related Transmission Assets
- ii Substation Distribution Asset ("SDA") allocation of Common Station Assets

The costs assigned by the cost of service allocation come from two sources, BC Hydro Transmission costs and BCTC costs:

(a) BC Hydro Transmission costs:

i. Asset Related Expenses;

ii. Operations, Maintenance and Administrative costs related to the transmission system;

iii. Corporate costs, and

iv. Demand Side Management costs;

(b) BCTC Costs:

i. Asset Related Expenses;

ii. Operations, Maintenance and Administrative costs related to the control and operation of the transmission system, asset management and maintenance and indirect costs relating to corporate governance and services; and

iii. Cost of Market expenses pertaining to the purchase of ancillary services and congestion management.

A variety of methods are used for assigning the various categories of costs, including direct assignment and allocation on the basis of relative asset base size, types of assets, activity types and levels, and management estimates.

Section 8.1 describes the allocation of Transmission costs and Section 8.2 describes the allocation of BCTC costs.

8.1 Transmission Cost Allocations

Transmission costs are assigned to the following transmission services:

(a) the Owner's RR;

(b) Common Station Assets and associated costs as related to Substation Distribution Assets ("Common for SDA"); and

(c) Generation Related Transmission Assets ("GRTA") – comprising Lines and Substations ("GRTL" and "GRTS")

Table 8-1 summarizes the results of the cost assignment for Transmission.

Table 8-1. Summary of Transmission Costs Assigned to Transmission Services

	$ millions	Functionalization of F2007 Expenses for BC Hydro Transmission						Basis of Assignment
					BCH GRTA			
		Total	Common for SDA	Owner's RR	Total	Lines	Subs	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Allowed Return	102.6	4.3	90.6	7.7	5.3	2.4	Asset Base net of Work in Progress
2	Finance Charges	123.2	5.2	108.8	9.2	6.4	2.8	Asset Base net of Work in Progress
3	OMA	5.8	-	5.8	-	-	-	Direct assignment
4	Corporate Costs	11.2	1.5	9.0	0.7	0.4	0.3	Direct maintenance cost
5	Depreciation & Amortization	99.3	5.6	87.2	6.6	3.6	3.0	F2005 actual
6	DSM	3.6	-	3.6	-	-	-	Direct assignment
7	Grants & Taxes	87.7	8.7	67.0	12.0	10.1	1.9	Direct Assignment & Allocation
8	Total BCH Transmission	433.4	25.3	372.0	36.1	25.7	10.4	

	$ millions	Functionalization of F2008 Expenses for BC Hydro Transmission						Basis of Assignment
					BCH GRTA			
		Total	Common for SDA	Owner's RR	Total	Lines	Subs	
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
10	Allowed Return	105.9	4.4	93.6	7.9	5.5	2.4	Asset Base net of Work in Progress
11	Finance Charges	125.6	5.3	111.0	9.3	6.5	2.9	Asset Base net of Work in Progress
12	OMA	5.8	-	5.8	-	-	-	Direct assignment
13	Corporate Costs	10.8	1.4	8.8	0.6	0.4	0.2	Direct maintenance cost
14	Depreciation & Amortization	100.8	5.6	88.5	6.7	3.6	3.1	F2005 actual
15	DSM	3.9	-	3.9	-	-	-	Direct assignment
16	Grants & Taxes	89.2	8.7	68.3	12.2	10.3	1.9	Direct Assignment & Allocation
17	Total BCH Transmission	442.0	25.4	379.9	36.7	26.3	10.5	

The allocation methodology for each cost category is described in the following sections.

8.1.1 Transmission Expenses

Transmission incurs expenses that include Allowed Return, Finance Charges, OMA, Corporate Costs, Depreciation and Amortization, Demand Side Management ("DSM") and Grants and Taxes.

8.1.1.1 Finance Charges and Allowed Return

Both Finance Charges and Allowed Return are related to the Transmission asset base. BC Hydro allocates its consolidated Finance Charges and Allowed Return to each of Transmission and its lines of business on the basis of average asset base as described in Section 5.2. Accordingly, BCTC has allocated these costs on the same basis of relative asset base size. Net of Work in Process, the percentages of asset base are:

(a) Common for SDA 4.2%

(b) Owner's RR 88.3%

(c) GRTA – Lines 5.2%

(d) GRTA – Substations 2.3%

The resulting allocations of Finance Charges and Allowed Return are shown in Table 8-1, lines 1 and 2 for F2007 and lines 10 and 11 for F2008.

8.1.1.2 Operations, Maintenance and Administration

Transmission expenses that pertain to the ownership of the transmission assets and property rights are directly assigned to the Owner's RR, as shown in Table 8-1 lines 3 and 12 for F2007 and F2008 respectively.

8.1.1.3 Corporate Costs

Corporate costs are allocated to Transmission by BC Hydro on the basis of Transmission's use of Field Services and Engineering Services. Accordingly, the allocation of Transmission's portion of these costs to the transmission services

reflects the use of these service providers and is based on the direct expenses for maintenance of lines and vegetation and stations by each of the transmission services. The breakdown of the GRTA allocation to GRTL and GRTS corresponds to the relative sizes of the direct expenses for maintenance of lines and vegetation and stations. Table 8-2 provides the allocation factors for each transmission service, and the resulting allocations are shown in Table 8-1 lines 4 and 17 for F2007 and F2008 respectively.

Table 8-2. Allocation Factors for Corporate Costs

	$ millions	**SDA**	**GRTA**	**Owners RR**	**Total**
	(a)	(b)	(c)	(d)	(e)
1	Lines & Vegetation	-	3.1	38.1	41.2
2	Stations	10.4	1.5	25.1	37.0
3	Safety & Environment	0.2	0.1	1.3	1.5
4					
5	**Total Corporate Costs**	**10.6**	**4.7**	**64.5**	**79.8**
6		13.3%	5.9%	80.8%	100.0%
7	**GRTL**		4.0%		
8	**GRTS**		1.9%		

8.1.1.4 Depreciation and Amortization

BC Hydro books depreciation expense at an asset level. For the F2007 and F2008 Plans, however, depreciation expense is not calculated at this level of detail, so depreciation expense for the Plan years is allocated. Amortization expense (related to Contributions in Aid of Construction) is directly assigned to the Owner's RR.

To allocate depreciation expense, BCTC groups existing assets by facility and then groups the facilities by transmission service (i.e., Common for SDA, Owner's RR and GRTA). Applying actual depreciation expense for F2005 to these asset groups, the allocation factors for F2007 and F2008 are calculated.

Table 8-3 summarizes the Transmission depreciation assignment factors for GRTL, GRTS, Common Stations and Other Transmission. The next step is to split Common Stations into SDA (Common for SDA) and non-SDA. The split of Common Stations is based on a station-by-station analysis which allocates common assets in the same

proportion as Transmission and SDA assets for each station. The non-SDA amount is combined with Other Transmission to become the Owner's RR allocation.

Table 8-3. Depreciation by Asset Category

$ millions	F2005 Actual Depreciation	% of Total
Actual Depreciation	129.9	
Less depreciation for SDA transfer	(10.0)	
Total Depreciation excluding SDA	119.9	
GRTL	4.7	4.0%
GRTS	4.1	3.4%
Common Stations	11.7	9.7%
Other Transmission	99.4	82.9%
	119.9	100.0%

The resulting allocation factors for Depreciation expense are:

(a) Common for SDA 5.6%

(b) Owner's RR 87.0%

(c) GRTA – Lines 4.0%

(d) GRTA – Substations 3.4%

The resulting allocations of Depreciation and Amortization expense are shown in Table 8-1, line 5 for F2007 and line 14 for F2008.

8.1.1.5 Demand Side Management

The Transmission asset base includes an assignment of the unamortized DSM investments made by Distribution. The portion of the unamortized DSM assigned to Transmission is 10%, in accordance with Commission Decision on BC Hydro Wholesale Transmission Services, April 23, 1998, page 29. The amortization expense related to Transmission's portion of the DSM investment is directly assigned to the Owner's RR. The amounts assigned are shown in Table 8-1 lines 6 and 15 for F2007 and F2008 respectively.

Section 5.4 includes further discussion on DSM.

8.1.1.6 Grants and Taxes

A forecast of grants and taxes payable by Transmission is provided by the BC Hydro Property Services Department. The forecast is split into the following categories:

(a) Substations;

(b) Total Transmission Lines;

(c) GRTS; and

(d) Miscellaneous.

The forecast for Total Transmission Lines is allocated proportionally to GRTL and Other Transmission Lines on the basis of the preceding year's actual grants and taxes, as provided by BC Hydro Property Services. Since grants and taxes forecast for substations relate to the entire substation, i.e., Transmission, SDA and Common substation assets, the assignment of grants and taxes to Common for SDA also includes the portion for SDA assets. The allocation is based on the relative size of Transmission and SDA assets, calculated on a station-by-station basis. The amounts assigned are shown in Table 8-1 lines 7 and 16 for F2007 and F2008 respectively.

8.2 BCTC Cost Allocations

Through either direct assignment or on an allocation basis, BCTC costs are assigned to the following transmission services:

(a) the BCTC RR;

(b) the AMMRR;

(c) Distribution Operations;

(d) Generation Control;

(e) SDA (including allocation of common assets); and

(f) GRTA.

Table 8-4 summarizes the results of the cost assignment for BCTC.

Table 8-4. Summary of BCTC Costs Assigned to Transmission Services

		Functionalization of F2007 Expenses for BCTC									
							BCH GRTA				
	$ millions	Total	SDA incl Common	BCTC Dist Ops	BCTC Gen Control	AMMRR	Total	Lines	Subs	BCTC	Basis of Assignment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Allowed Return on Deemed Equity	2.9	-	-	-	-	-	-	-	2.9	Direct assignment
2	Deemed Interest	0.2	-	-	-	-	-	-	-	0.2	Direct assignment
3	OMA	164.9	11.7	7.4	1.0	87.3	5.4	3.7	1.7	52.2	Direct Assignment & Allocation
4	Cost of Market	6.8	-	-	-	-	-	-	-	6.8	Direct assignment
5	Depreciation & Amortization	14.6	-	-	-	-	-	-	-	14.6	Direct assignment
6	Grants & Taxes	0.3	-	-	-	-	-	-	-	0.3	Direct assignment
7	**Total BCTC**	**189.7**	**11.7**	**7.4**	**1.0**	**87.3**	**5.4**	**3.7**	**1.7**	**77.0**	

8.2.1 BCTC Expenses

With the exception of OMA, all BCTC expenses are assigned to the BCTC RR. BCTC's expenses include Allowed Return on Deemed Equity, Deemed Interest, OMA, Cost of Market, Depreciation and Amortization, and Grants and Taxes. Allowed Return on Deemed Equity, Deemed Interest, Depreciation and Amortization, and Grants and Taxes all relate to BCTC's assets and are assigned 100% to the BCTC RR. Cost of Market is assigned 100% to the BCTC RR as this cost element relates to BCTC's provision of transmission service under the OATT.

8.2.1.1 OMA

The allocation of OMA to the various transmission services is discussed in this section. In order to determine the appropriate allocations, BCTC analyses OMA in three broad categories:

(a) System Planning and Asset Management;

(b) System Operations; and

(c) General and Administration.

8.2.1.1.1 System Planning and Asset Management

System Planning and Asset Management is responsible for

(a) maintenance of transmission lines, vegetation and substations;

(b) safety and environment;

(c) research and development;

(d) system planning and performance assessment; and

(e) asset program definition and management.

Direct maintenance costs for BCTC's three maintenance departments (Transmission Lines, Vegetation and Substations) are directly assigned to the transmission services on the basis of the planned maintenance expenses for F2007. Safety and environment expenses are allocated proportionally to the allocation of direct maintenance costs.

Research and development ("R&D") programs support both AMMRR and BCTC RR activities. Based an analysis of the R&D programs, 13% of the program costs are assigned to the BCTC RR and 87% is assigned to the AMMRR.

BCTC's system planning and performance assessment ("SPPA") group is responsible for operational, regional and bulk transmission planning. This group is also responsible for planning and management of the growth capital program. Based on these responsibilities, costs for SPPA are directly assigned to the BCTC RR.

The management and planning of the direct maintenance programs and the sustaining capital program is the responsibility of the Asset Program Definition and Asset Program Management departments ("APD/APM"). Certain specific costs from these two departments are directly assigned, including Emergency Maintenance costs, sustainment costs for Passport, EGIS and PeopleSoft, and the Fire Prevention Program. All other costs for these two departments are allocated for F2007 based on an analysis of activities undertaken in F2006.

Costs associated with the overall management of System Planning and Asset Management activities are allocated to transmission services proportionately to the allocations of APD/APM, SPPA and R&D.

8.2.1.1.2 System Operations

BCTC's System Operations group is responsible for:

(a) the control and operation of the transmission system;

(b) the provision of distribution services to DLoB; and

(c) generation control services to GLoB and an external customer.

Based on management interviews, Area Control Centre activities associated with each of the transmission services were identified along with estimates of time spent on these activities. Area Control Centre costs are allocated to the transmission services in proportion to this activity analysis.

The other departments in the System Operations group; System Control Centre, Telecom Network Operations, EMS Technology and Training, all support transmission system operation and control and are therefore directly assigned to the BCTC RR.

Costs associated with the overall management of System Operations are allocated in proportion to the combined allocations of the Area Control Centres and assignment of the other System Operations departments.

8.2.1.1.3 General and Administration

General and Administration costs are initially allocated by department to AMMRR and BCTC RR on the basis of activities undertaken as determined through interviews with managers. For departments determined to be 100% AMMRR or 100% BCTC RR, the allocation process is complete.

For those departments not totally allocated to either BCTC RR or AMMRR, these percentages form the first step of the allocation. The second step is the allocation of the initially estimated costs associated with AMMRR to transmission services in proportion to the combined allocation of APD/APM costs, R&D costs and the costs

associated with the overall management of System Planning and Asset Management, as described above. The initially estimated costs associated with

General and Administrative are allocated on the same basis to SDA (including allocation of common assets), AMMRR, GRTA and BCTC RR. General and Administrative costs are not assigned to Distribution Operations or Generation Control as these services are considered to be incremental, with BCTC able to provide the services because of the transmission control and dispatch infrastructure.

Capital Overhead is assigned to transmission services on the basis of the forecasted capital expenditures for F2007. Capital overhead associated with Sustaining Capital is assigned to SDA (including allocation of common assets), AMMRR and GRTL. Growth and BCTC Capital are assigned to BCTC RR. This assignment of costs is consistent with the planning, management and execution of the capital program.

9.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION EXPENSES

9.1 OMA Overview

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to provide an overview of BCTC's OMA included in the BCTC Revenue Requirement ("BCTC RR") or allocated to the AMM Revenue Requirement ("AMMRR"). The cost of internal and external resources used in the operation of BCTC's business processes and activities are classified as Operations, Maintenance and General and Administration Expenses ("OMA").

To the extent that these processes and activities pertain to capital plans and projects, a Capital Overhead amount is allocated. The Capital Overhead amount reduces the OMA costs to be recovered through rates.

The F2006 Settlement Agreement in Amendment No. 7 in Appendix 1 to Commission Order G-60-05 states in part that,

> BCTC will report on its study of appropriate capitalized overhead allocations at its next revenue requirement application.

BCTC undertook a Capital Overhead Study in support of this F2007 Revenue Requirement Application. This Study is addressed in Section 9.5 and attached as Appendix C.

BCTC's total OMA expenses are shown in Table 9.1-1.

Table 9.1-1. Operations, Maintenance and Administration Expenses[19]

$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
(a)	(b)	(c)	(d)	(e)	(f)
BCTC OMA					
Operations	Sec.9.2	38.9	43.1	39.0	45.5
Maintenance	Sec.9.3	101.3	102.2	97.5	99.7
General & Administration	Sec.9.4	24.4	27.4	25.8	29.5
Gross BCTC OMA		164.6	172.7	162.3	174.7
Less: Capital Overhead	Sec.9.5	(4.4)	(6.5)	(6.5)	(9.8)
BCTC Total OMA		160.2	166.2	155.8	164.9

Certain OMA costs that were incurred by BC Hydro during Phase 1 of BCTC's formation (December 1, 2003 to March 31, 2005) have been reclassified as BCTC costs for comparative purposes. These costs are primarily those relating to BC Hydro Field and Engineering Services for asset maintenance. The F2006 Forecast column in Table 9.1-1 reflects expenses before transfer to the Regulatory, Emergency Maintenance and Grid West deferral accounts.

BCTC is facing continued cost pressures with increasing business demands, a tight labour market and general cost inflation. Active redeployment of resources to address business priorities and prudent cost management enables BCTC to maintain OMA expenditures within a reasonable range. Compared to F2006 Approved Plan, the main changes in F2007 OMA are as follows:

(a) Higher Operations expense due to:

- i increased labour costs including pension, $1.6 million;
- ii System Control Modernization Project OMA, $1.1 million;
- iii higher fees from the Western Electricity Coordinating Counsel ("WECC"), $0.4 million;
- iv higher technology costs, $0.4 million; and
- v other cost increases of $0.4 million.

[19] See Appendix F regarding "F2006 Approved" column.

These increases are partially offset by the elimination of $1.5 million in Grid West Funding.

(b) Lower Maintenance expense due to:

i maintenance cost reductions of $4.9 million, reflecting improved asset management and efficiency improvements, and

ii other cost reductions of $0.2 million;

iii offset by labour cost increases of $2.0 million which includes the new Major Projects department; and

iv $0.6 million impact of the higher billing rates from BC Hydro Service Providers.

(c) Higher General and Administration expense due to:

i higher labour cost associated with increased headcount, the transfer in of the Business Improvement department and salary/wage escalation, $1.6 million;

ii consulting costs for regional transmission and business development strategies (non-Grid West), $0.7 million;

iii additional premise costs $0.4 million;

iv capital project OMA, $0.3 million; and

v other cost increases of $0.1 million;

vi the higher costs above are offset by the elimination of funding for key agreement implementation, $1.0 million.

(d) The increase in capital overhead allocation reduces OMA by $3.3 million and is further discussed in Section 9.5.

9.1.1 BCTC Business Processes

The following sections describe the major functional areas and their responsibilities.

9.1.1.1 System Operations

Responsible for developing and implementing plans, strategies, policies and processes for the operation and control of the generation, transmission, distribution and telecommunication systems managed by BCTC. This group also manages the System Control Modernization Project designed to improve process efficiency and effectiveness through the amalgamation of the existing six operational locations into one control centre (with a backup centre) and the replacement of the outdated Energy Management System ("EMS") with a new system able to address the requirements of a changing energy market. The responsibilities of System Operations are further discussed in Section 9.2.1.

9.1.1.2 System Planning and Performance Assessment

Responsible for the long-term capacity plans to ensure the transmission system meets customer needs in a reliable and effective way. The responsibilities of System Planning and Performance Assessment are further discussed in Section 9.2.2.

9.1.1.3 Market Operations

Responsible for Generator and Load Interconnection Services, Wholesale Transmission Services including transmission prescheduling, settlements and billing, revenue reporting and forecasting, and Tariff design, Tariff implementation and Tariff administration. The responsibilities of Market Operations are further discussed in Section 9.2.3.

9.1.1.4 Asset Management/Maintenance

Responsible for the management and maintenance of the $2.5 billion BC Hydro transmission assets under BCTC management as well as the Capital Planning Process for Sustaining Capital. Cost recovery for these activities occurs through:

(a) the Asset Management/Maintenance Revenue Requirement discussed in Section 6;

(b) a service level agreement for substation distribution asset services, discussed in Section 5.7.2; and

(c) for the management of generation related transmission assets, collected through a cost allocation process as a result of a Commission directive and further defined in the Heritage contract as discussed in Section 5.7.1.

This group is responsible for the maintenance and sustaining capital programs for stations, lines and vegetation. The responsibilities of Asset Management/Maintenance are further discussed in Section 9.3.

9.1.1.5 General and Administrative Functions

Business functions and processes that support BCTC's day-to-day operations, including:

(a) Executive leadership that sets the strategic direction and leads the corporation in achieving its goals and objectives.

(b) Legal services, including the Corporate Secretary, that develop and lead the corporate governance framework, and ensure proper functioning of the Board and its Committees. Legal Services also act as Chief Compliance Officer for Standards of Conduct.

(c) Customer and Strategy Development that develops and facilitates the strategic planning process for the corporation including assessing BCTC's strategic position, and developing the strategic plan, business plans and capital asset investment plans.

(d) Human resources that develops and implements the human resource and performance management strategy and processes to ensure BCTC has a highly skilled high performance workforce.

(e) Purchasing services and facilities functions that manage the company's procurement and sourcing activities, contracts and agreements and facilities.

(f) Financial management of the company including all aspects of fiscal strategy and policy, financial processes and controls, and management of financial systems.

(g) Rates and regulatory processes that plan, develop and submit regulatory applications to meet BCTC's business objectives and enable open-access transmission service.

(h) Communications strategies and issues management involving all aspects of BCTC's business.

The responsibilities of the General and Administrative group are discussed further in Section 9.4.

9.1.2 Transition to New Corporate Environment

At the organizational level, a number of adjustments were made since the F2006 Revenue Requirement Application. With retirement and other changes at the executive management team level, BCTC refined the organizational structure to provide a better balance of responsibilities and improve focus for system operations, asset management, capital planning and project execution. Organizational changes are discussed in Section 9.6.

9.1.3 Maintaining Reliability

BCTC's processes and activities are designed and implemented to enable the organization to maintain reliability. The core processes and activities are:

(a) Operate, control and monitor more than 18,000 kilometers of transmission circuits and associated substations, over 20 generating plants, over 56,000 kilometers of distribution circuits, and a province-wide telecommunications network;

(b) Plan, design and execute transmission projects to meet load growth and generation interconnection; and

(c) Plan, design and execute maintenance and sustaining capital programs/projects to sustain the service capability of the existing transmission system.

9.1.4 Increased Accountability and Demand

BCTC recognizes the growing demand on its transmission system and the need to respond more effectively to regulatory and public expectations. BCTC has identified the following challenges:

(a) resource gaps in capital planning and project execution, regulatory and community/stakeholder relations;

(b) System Control Modernization Project transition; and

(c) Anticipated employee retirements.

While BCTC is able to meet some requirements through redeployment of the F2006 planned headcount of 329, a number of new positions have been identified. In total, 23 new roles have been identified, of which 2 were met through reassignment of existing headcount. The increase of 21 headcount from 329 to 350 is necessary for BCTC to respond to its business requirements as described previously. Table 9.1-2 identifies the business areas and the number of new positions created to address BCTC's growing demands on resources.

Table 9.1-2. Business Areas and Resource Additions

	Business Area	Headcount
1	Capital planning and project execution	8
2	Community / Stakeholder Relations and Regulatory	4
3	SCMP Transition Project Resources	5
4	Anticipated Retirement	2
5	Asset Management	2
6	Business Development	1
7	Repatriate HR Recruitment from ABSU	1
8	**New Positions Added**	**23**
9	Less: Existing Positions eliminated	-2
10	**Net Increase in Headcount**	**21**

9.1.5 Planning and Budgeting Process

BCTC initiated the F2007 planning and budgeting process in October 2005. Budget Guidelines for OMA were issued to management setting out the budgeting assumptions and requirements. The key budgeting assumptions were:

(a) 3% inflation factor to account for labour cost increases;

(b) Additional funding provided for headcount increases (see the discussion in Section 9.6 on Compensation); and

(c) Absorb 2% general inflation on non-labour costs with productivity improvement.

Budget and headcount targets were issued for each department to facilitate detailed work program budgeting. Business priorities reflect alignment with corporate strategies and objectives. The review process for F2007 OMA budget included:

(a) Each Executive Leadership Team ("ELT") member reviewed the department budgets with the managers, established priorities and made trade-off decisions to stay within the funding target for the Division. To the extent there are new work programs or initiatives requiring additional funding, a business justification was prepared to support funding requests.

(b) BCTC's Chief Financial Officer ("CFO") and Controller reviewed each Division budget with the responsible ELT member to ensure the OMA funding is appropriate for the level of work requirements.

(c) The President reviewed the OMA Plan with all the ELT members and established the final OMA budget that was submitted to the Board of Directors for review and approval.

(d) The F2007 OMA Plan including headcount was reviewed and approved by the Board of Directors in December 2005.

A more in-depth discussion of OMA expense and Capital Overhead is contained in the following sections:

9.2 Operations

9.3 Asset Management and Maintenance

9.4 General and Administration

9.5 Capital Overhead Allocation

9.6 Compensation

9.7 Insurance

9.2 Operations

The purpose of this section is to provide an overview of the function of BCTC Operations and to explain the operations costs included in OMA. BCTC Operations is discussed under its component parts in several subsections in this Application:

9.2.1 System Operations – Prefiled Evidence of Martin Huang

9.2.2 System Planning and Performance Assessment – Prefiled Evidence of Paul Choudhury

9.2.3 Market Operations – Prefiled Evidence of Janet Fraser

The following Table 9.2-1 is an OMA cost summary of BCTC Operations. Column (b) provides a reference to the subsection of this Application where these costs and activities are discussed:

Table 9.2-1. BCTC Operations OMA[20]

	$ millions	**Ref.**	**F2005 Actual**	**F2006 Approved**	**F2006 Forecast**	**F2007 Plan**
	(a)	(b)	(c)	(d)	(e)	(f)
1	**BCTC Operations OMA**					
2	System Operations	Sec.9.2.1	24.2	28.7	25.0	28.5
3	System Planning & Performance Assessment	Sec.9.2.2	7.5	9.1	7.6	9.4
4	Market Operations	Sec.9.2.3	2.7	2.7	2.9	3.2
5	Corporate Assignment:					
6	Technology	Sec.9.2.1.6	2.7	2.6	2.6	3.0
7	Labour Concessions & Pension	Sec.9.2.1.7	1.8	-	0.9	1.4
8						
9	**Total BCTC Operations**		**38.9**	**43.1**	**39.0**	**45.5**

[20] See Appendix F regarding "F2006 Approved" column.

9.2.1 System Operations

PREFILED EVIDENCE OF MARTIN HUANG, VICE PRESIDENT, SYSTEMS OPERATIONS

The purpose of this section is to provide an overview of the function and cost of System Operations ("SO") within BCTC Operations and within the electric system in British Columbia and its coordination with neighbouring utilities, and to provide an overview of SO's primary activities.

SO is responsible for the safe, reliable and efficient operation of the Transmission system and has certain operating responsibilities for the generation and distribution systems.

9.2.1.1 Summary of SO Costs

A summary of the Operations, Maintenance and Administrative expenses for each of the components of System Operations costs is set out in Table 9.2-2 following.

Table 9.2-2. System Operations OMA[21]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	System Operations, Office of the VP	Sec.9.2.1.4	-	0.5	0.3	2.6
2	System Operations and Asset Management		1.2	-	-	-
3	Real Time Operations	Sec.9.2.1.5	22.5	26.6	23.8	24.8
4	Operations Initiatives	Sec.9.2.1.8	0.5	1.6	0.9	1.1

The revenue from non-tariff services offset the overall costs of the BCTC Revenue Requirement. These revenues are shown in Table 9.2-3 following. (Refer also to Section 7).

[21] See Appendix F regarding "F2006 Approved" column.

Table 9.2-3. Real Time Operations Revenues[22]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	**BCTC Real Time Operations Revenue**					
2	Distribution Operations	Sec.7.6.4	2.6	6.8	6.8	7.4
3	Generation Control	Sec.7.6.5	1.0	1.0	1.0	1.0
4						
5	**Total**		**3.7**	**7.8**	**7.8**	**8.4**

9.2.1.2 Summary of SO Functions

The SO department at BCTC is comprised of two functional groups: Real Time Operations and System Control Modernization Project ("SCMP"), plus other activities.

9.2.1.2.1 Real Time Operations

Real Time Operations is central to the SO function. This activity consists of the real-time controlling and monitoring of more than 18,000 kilometers of transmission circuits and associated substations, over 20 generating plants, over 56,000 kilometers of distribution circuits, and a province-wide telecommunications network.

Real Time Operations also includes Energy Management System Support which supports and maintains the computer systems used for controlling and monitoring the electric transmission system.

9.2.1.2.2 System Control Modernization Project

SCMP is a $133 million project consisting of the construction of two new control centers, the consolidation of the six existing control centers into these new facilities, replacement of the Energy Management System used for monitoring and controlling the electric system, and various telecommunication upgrades. The British Columbia Utilities Commission issued a Certificate of Public Convenience and Necessity to BCTC for SCMP on February 14, 2005. The estimated in-service date for SCMP is October 2008. SCMP is discussed in more detail in Section 9.2.1.8.

[22] See Appendix F regarding "F2006 Approved" column.

9.2.1.2.3 Other Activities

In addition to the two functional groups, System Operations is also responsible for representing BCTC at various external electric system reliability organizations such as the North American Electric Reliability Council, the Western Electricity Coordinating Council ("WECC"), and the Northwest Power Pool ("NWPP"). These activities and associated costs are included in the Office of the VP (Section 9.2.1.4).

9.2.1.3 Business Considerations

System Operations staff levels have not increased since the creation of a stand-alone function within BC Hydro and the establishment of the Wholesale Transmission market in 1997, with the exception of two additional staff required to manage activities related to implementing SCMP.

In preparation for the implementation of SCMP, System Operations has also been engaged in a change management process that encompasses virtually all staff and systems and technologies used by SO. This process involves a number of activities including:

(a) Standardization of work process across control centres to ensure that all controls centres are using standardized methods that are consistent with the best practices that will be adopted in the consolidated control centres.

(b) The design of the future consolidated SO organization, the design of the more effective and efficient workflow in the consolidated control centers, and training of personnel to ensure that the transition to the consolidated and modernized SCMP control centres will proceed smoothly. The increased work load involved in preparing staff for SCMP is transitory and has therefore been accommodated within the existing staff complement or through the use of external consultants where appropriate.

Implementation of SCMP is expected to have a positive impact in terms of BCTC's ability to maintain a reliable transmission system while meeting future transmission requirements, lowering costs and meeting service quality standards.

9.2.1.4 System Operations, Office of the VP

The Vice-President of System Operations provides executive leadership for the safe, reliable and efficient operation of the electric system managed by BCTC, and executive sponsorship for the System Control Modernization Project.

BCTC's transmission system is part of a large interconnected electric system in western Canada, western United States and Northern Mexico known as the Western Interconnection. The Western Electricity Coordinating Council ("WECC", www.wecc.biz), a regional council of the North American Electric Reliability Council ("NERC", www.nerc.com), is an organization that promotes a reliable electric power system in the Western Interconnection, supports efficient competitive power markets, assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members. BCTC is an active member in WECC participating in its forums for Western Interconnection electric system reliability strategies, policies, and standard development and compliance monitoring activities. BCTC also participates in transmission market business practices development and implementations. These activities will enhance Western Interconnection system reliability and transmission access from BC to other electricity markets in the Interconnection.

BCTC is also an active member of the Northwest Power Pool ("NWPP", www.nwpp.org). NWPP serves as a forum in the electrical industry for reliability and operational adequacy issues in the Pacific Northwest. NWPP promotes cooperation among its members to achieve reliable operation of the electrical power system, coordinate power system planning, and assist in transmission planning in the Northwest Interconnected Area. In addition, the NWPP Operating Reserve Sharing program provides significant economic benefits to all its members while meeting all associated reliability standards.

The membership dues for WECC and NWPP are based on operating cost allocation amongst their members as stipulated in their by-laws, mostly based on the proportional electricity consumption in the member's service area. BCTC's dues for WECC and NWPP for F2007 are estimated to be $1.8 million and $0.2 million respectively.

9.2.1.5 Real Time Operations

Real Time Operations includes the Office of the Manager of Real Time Operations, five control centres, as well as Telecom Network Operations ("TNO"), an Operator Training Program and an Energy Management System Support function. The five control centres are:

(a) System Control Centre ("SCC")

(b) Lower Mainland Control Centre ("LMC")

(c) Southern Interior Control Centre ("SIC")

(d) Vancouver Island Control Centre ("VIC")

(e) Northern Control Centre ("NCC")

The OMA cost of Real Time Operation is shown in Table 9.2-5. NCC and SIC are shown together as Interior Operations Control in the table following.

Table 9.2-4. Real Time Operations OMA[23]

$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
(a)		(b)	(c)	(d)	(e)
BCTC Real Time Operations OMA					
Real Time Operations		3.1	5.5	4.2	4.1
System Control		6.0	5.7	5.7	5.7
Lower Mainland Control		4.1	4.3	4.1	4.4
Interior Operations Control		3.1	3.3	3.1	3.3
Vancouver Island Control		2.2	2.2	2.0	2.1
EMS Technology		2.2	2.2	2.5	2.3
Telecontrol Network Operations		1.3	1.8	1.5	1.8
Operator Training		0.5	1.1	0.7	1.1
Total	**T9.2-2**	**22.5**	**26.1**	**23.8**	**24.8**

Each part of Real Time Operations is discussed separately in the following sections.

9.2.1.5.1 Office of the Manager of Real Time Operations

The office of the Manager of Real Time Operations is located in the BCTC Corporate head office. It consists of the Manager of Real Time Operations, Manager of System Operation Process, Manager of Distribution Operation Process, and a Distribution

[23] See Appendix F regarding "F2006 Approved" column.

Engineer. The primary responsibility is to direct the operations and the standardization of work process of all BCTC control centers across the province.

9.2.1.5.2 System Control Centre

The SCC is located in Burnaby, and is responsible for maintaining the overall reliability of the transmission grid in the province. SCC manages interchange on the interconnections with neighbouring electric systems in Alberta and United States, balances the electricity demand and generation on a second-by-second basis, and facilitates the real time (next hour) wholesale transmission market. SCC is also responsible for coordinating system-wide restoration following major system outages.

SCC operates a Generation Console, a Transmission Console, a Real Time Scheduling Console and a Shift Supervision Console on a 7x24 (7 days a week, 24 hours a day) basis with 19 System Power Dispatchers and 8 System Operations Supervisors on rotating shifts. SCC has 6 other staff that provide management and administration functions, operations, and technical support.

9.2.1.5.3 Regional Control Centres

The Regional Control Centres are responsible for the safe, reliable and efficient operation of the integrated electric system in their respective regions of the province. The regional activities in the control center include monitoring and controlling of transmission, generation and distribution systems, safety-related duties for transmission and distribution involving issuing work permits to field personnel, maintenance outage coordination and system or equipment restoration following an electric system disturbance.

9.2.1.5.3.1 Lower Mainland Control Centre (Vancouver)

The LMC in Vancouver operates a Transmission and Generation Operating Console on a 7x24 schedule, two Substation Operating Consoles on a 5x8 (5 days a week, 8 hours a day) schedule, one Distribution Operating Console on a 7x24 schedule, plus three other Distribution Operating Consoles on 5x8 or 5x12 schedules. There are also two dayshift outage scheduling positions, one for Transmission/Substation planned outages and one for Distribution planned outages. The Operating Staff

consists of 26 Operator Area Dispatchers on rotating shifts, an Operations Engineer, an Operations Manager, two Office Administration staff and the LMC Manager.

9.2.1.5.3.2 Vancouver Island Control Centre (Duncan)

The VIC in Duncan operates a Transmission and Generation Console and a Distribution Console on a 7x24 schedule, plus one outage scheduler on a 5x8 schedule and an additional Distribution Console also on a 5x8 schedule. VIC is staffed with 13 Operator Area Dispatchers, one office administrator and one VIC Manager.

9.2.1.5.3.3 Southern Interior Control Centre (Vernon)

The SIC in Vernon operates a transmission console, a generation console and a distribution console. The regular complement of staff at SIC consists of one Operations Engineer who also provides technical support for VIC and NCC, one Chief Dispatcher and 11 Operator Area Dispatchers.

9.2.1.5.3.4 Northern Control Centre (Prince George)

The NCC in Prince George operates a transmission console and a distribution console. Staffing at NCC consists of one manager who is also responsible for SIC, one Chief Dispatcher, 7 Operator Area Dispatchers and one support staff providing administrative supports for both SIC and NCC.

9.2.1.5.3.5 Telecom Network Operations (Burnaby)

Telecom Network Operations ("TNO") is located in Burnaby, and is responsible for the safe, reliable, and efficient operation of the province-wide Microwave Radio and Fibre Telecommunications Network with over 500 Network Elements (Digital Telecom Equipment) located at more than 100 sites (mountain top repeaters, substations, generating stations and offices) across the province. The primary purpose of the Telecommunications Network is to provide high-speed communication circuits that enable protective relaying systems for equipment protection and electric system reliability. The high speed communication is essential to provide secure and dependable high-speed fault clearing for the transmission grid for equipment protection and to meet the reliability criteria set by the WECC.

A second and significant role of the telecommunications system is to provide control and monitoring of substations and generating stations on the electric system. This enables the control centres to dispatch generation, restore service when faults occur on the power system and provide normal monitoring and controlling of equipment for maintenance and operating purposes.

TNO operates a 7x24 Console, with 8 Telecommunications Network Controllers, one Manager, and one administrative staff. In addition, 2 Telecommunications Network Controllers provide 5x8 outage co-ordination, fault resolution, operations, and technical support.

9.2.1.5.4 Operator Training

The Manager, Operator Training is directly responsible for overall program development and management of the Operator/Area Dispatcher ("OAD") apprenticeship program. This 30 month apprenticeship program ensures there are adequate qualified graduates available to meet operator succession needs for all control centers. There are currently 10 apprentices in the program. The number of apprentices required is determined annually reflecting anticipated retirements and attritions in the organization. The Operator Training Manager also works closely with Control Centre Managers for the development and delivery of training programs for the operators in all control centers.

9.2.1.5.5 Energy Management System Support

The activities in Energy Management System Support primarily include computer hardware and software maintenance and support for systems used in monitoring and control of the electric system. These systems and applications are known as Energy Management System ("EMS") and Supervisory Control and Data Acquisition Systems ("SCADA").

The SCADA system allows operators to acquire data and control power system equipment remotely from the control centers. EMS includes SCADA as well as additional advanced computer applications assisting the System Power Dispatchers in balancing electricity demand and supply in real time, controlling the electricity flowing into or out of BC as scheduled, and conducting electric network analysis to ensure the transmission grid is operated reliably. All of these systems combined

allow an operator to see, study/analyze conditions and control the power system, and thus allows operators to make real time operational decisions. The Energy Management System Support group in Real Time Operations, with 14 professional engineers and an administrative position, supports and maintains the EMS/SCADA systems. Some EMS/SCADA hardware supports are provided by BC Hydro Field Services under a service contract.

9.2.1.6 Corporate Assignment – Technology

System Operations is charged with a corporate assignment of technology. This is discussed in Section 9.4.1.2.

9.2.1.7 Corporate Assignment – Labour Concessions and Pension

System Operations is charged with a corporate assignment of labour concessions and pension. This is discussed in Section 9.4.1.2.

9.2.1.8 Operations Initiatives

The Operations Initiatives in F2005 Actual reflect Grid West actual spending. Operations Initiatives in F2006 Approved reflect Grid West at $1.5 million and SCMP at $0.1 million. Operations Initiatives in F2006 Forecast reflects Grid West, and F2007 Plan reflects SCMP.

SCMP is primarily a capital project with about 97% of its total costs for the construction of the two new control centers, the acquisition and implementation of a new Energy Management System used for the monitoring and controlling of the electric system, and other infrastructure. The remaining 3% of the total costs are one-time operational costs associated with SCMP. These include organizational transition related work such as the organization design and work process design for the consolidated control centers, the development and implementation of the transition plan, and relocation assistance for impacted employees. The budgeted amount for the SCMP operating costs for F2007 is $1.1 million, to cover the activities described above.

9.2.1.9 Other Services

System Operations also provides Generation Control Services to BC Hydro Generation and Columbia Power Corporation, and Distribution Operations Services

to BC Hydro Distribution through its control center operations. Refer to Table 9.2.3 and Section 7.

9.2.2 System Planning and Performance Assessment

PRE-FILED EVIDENCE OF PAUL CHOUDHURY, MANAGER, SYSTEM PLANNING AND PERFORMANCE ASSESSMENT

The purpose of this section is to provide an overview of the role of System Planning and Performance Assessment ("SPPA") within the electric system in British Columbia and provide an overview of SPPA's primary activities.

SPPA is responsible for planning capital investments to meet load growth, transmission service requests and generator interconnections, and to ensure a safe, reliable and economic electrical transmission system for the Province of British Columbia. SPPA is also responsible for ensuring that procedures are in place to ensure reliable operation of the existing system, and development of innovative solutions to mitigate transmission constraints.

9.2.2.1 Summary of SPPA Costs

This section provides a summary of the Operations, Maintenance and Administrative costs for SPPA activities and addresses each of the components of SPPA costs set out in Table 9.2-5 following.

Table 9.2-5. System Planning and Performance Assessment OMA[24]

$ millions	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
(a)	(b)	(c)	(d)	(e)
Transmission System Planning	4.5	4.3	3.3	3.3
Regional System Planning	-	-	-	3.0
Performance Planning	1.8	3.6	3.1	2.0
SPPA Management & Administration	1.2	1.2	1.2	1.1
Total BCTC SPPA	**7.5**	**9.1**	**7.6**	**9.4**

Overall, there is an increase of approximately $0.3 million in SPPA costs from F2006 Approved to F2007 Plan. The following comments apply to the components of SPPA costs:

[24] See Appendix F regarding "F2006 Approved" column

(a) Labour costs reflect headcount and are projected to increase by approximately $0.2 million to cover the addition of two Planning Engineers.

(b) BCH/Engineering Services costs reflect the outside engineering services provided by BC Hydro and/or external engineering service providers. A description of these services is found in each of the sections related to the three SPPA departments.

(c) Business Expenses consist primarily of hardware and software licences other than ABS expenses, as well as travel expenses including meeting and conference costs.

(d) ABS Services consist primarily of computer end user and infrastructure support on a per-user and per-device basis.

(e) Outside services consists of advertising, communications, and outside consultants other than engineering consultants.

Table 9.2-6. System Planning and Performance Assessment Headcount[25]

	SPPA Headcount	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
		(a)	(b)	(c)	(d)
1	Transmission System Planning[26]	14	14	17[27]	14
2	Regional System Planning[28]	0	0	0	11
3	Performance Planning[29]	18	20	19[30]	14
4	Management and Administration	6	5	5	4[31]
5	**Total SPPA Headcount**	**38**	**39**	**43**	**43**[32]

Responsibilities common to the three groups include:

(a) Applying reliability techniques to planning and operations.

(b) Training of control centre staff.

[25] See Appendix F regarding "F2006 Approved" column.
[26] Formerly known as System Planning (Lower Mainland/Vancouver Island).
[27] Increase of 5 for 2 Engineering Trainees, 1 IPP coordinator, and 2 Senior Engineers in mid-year.
[28] Regional System Planning was created in the fourth quarter of F2006.
[29] Formerly known as System Planning (North and South Interior).
[30] Reduction from 20 to 19 due to transfer of one Engineer to Market Operations.
[31] Reduction from 5 to 4 due to transfer of one Managerial position to Regional System Planning.
[32] F2007 Plan reflects the SPPA reorganization, with no change in Headcount.

(c) Studying the interconnection of Independent Power Producers.

(d) Preparing submissions to the Commission including CPCN applications and Transmission Capital Plan applications.

(e) Responding to directives from the Commission.

(f) Presenting information about the transmission system in public forums.

Demands on SPPA resources are increasing in all of these areas, particularly the first four areas identified above.

9.2.2.2 Summary of SPPA Functions

The SPPA department at BCTC is comprised of three planning groups:

9.2.2.2.1 Transmission System Planning

Transmission System Planning is responsible for the long-term planning of the integrated transmission system, including interties to adjoining utilities.

9.2.2.2.2 Regional System Planning

Regional System Planning is responsible for the long-term planning of the regional system, including substation and transformation facilities at the points of delivery to customers.

9.2.2.2.3 Performance Planning

Performance Planning is responsible for short-term planning of the existing integrated transmission system, ensuring reliability, determining operational limits and solving operational problems.

9.2.2.3 Business Considerations

SPPA is preparing to meet the expanding transmission requirements that are anticipated over the coming years. As part of these expanding requirements, BCTC is currently experiencing more activity in its role as transmission provider to IPPs, and is studying more requests for Point-to-Point Transmission service. SPPA currently has a queue of 35 Long-Term Firm Wholesale Transmission service requests, of which 21 are in the Study state, and 14 are in the Received state. This

includes additional requests for interconnections to other utilities in other jurisdictions, such as Alaska. BC Hydro is issuing Calls For Tender ("CFT") more frequently, and these CFTs are more fully subscribed and translate into an increased workload for BCTC, particularly within SPPA. The F2006 CFT has resulted in the need to prepare approximately 70 preliminary generator interconnection studies in a three-month period. In addition, there are seven other generator interconnection studies proceeding outside of the CFT.

The number of load interconnection studies for BC Hydro has also been increasing with the growth of the provincial economy. In some cases, these studies trigger additional work as the existing capability of the system is used up and new reinforcements are required or planned reinforcements are advanced. In F2006, seven such studies were completed by SPPA staff. These studies are paid by the customer requesting interconnection.

SPPA is adapting its processes and procedures to meet current accountability expectations and to build open and constructive relationships with stakeholders. SPPA is becoming more involved with consultation and regulatory processes associated with transmission projects including responding to Information Requests, preparing for hearings, providing workshops and preparing evidence. This requires additional time for staff involvement and additional staff training. An example of a recent transmission project is the Vancouver Island Transmission Reinforcement ("VITR") project. SPPA staff members were key contributors in answering many of the approximately 2000 information requests on the VITR CPCN application. In addition to VITR, SPPA is involved in several other projects that are currently in a preliminary review stage. These projects will need additional staffing when they develop to the advanced review stages.

BCTC is committed to maintaining a reliable transmission system while meeting future transmission requirements, lowering costs and meeting expectations for service quality. Due to the increased volume of projects, SPPA is spending an increasing amount of time on reliability assessments, and providing advice to ensure that future corrective actions are optimized and cost-effective.

The present staffing of SPPA is not adequate to deal with the existing and anticipated future volume of work. BC Hydro calls for new generation have become annual events, and there have been more participants on each subsequent call. SPPA is responsible for an increased number of IPP studies and new transmission interconnections. All of these matters have created additional work.

Since August 2005, one Senior Engineer has retired, and one Senior Engineer and one Engineer have left BCTC to pursue careers with other utilities. The Senior Engineer positions have been filled through new staff hires, however, two Senior Engineer vacancies remain unfilled due to a tight labour market and difficulties in attracting experienced engineers to Vancouver.

A demographic analysis of staff in SPPA performed in April 2005 provided the following information:

(a) Six senior employees could potentially retire at any time based on their previous employment with BC Hydro.

(b) Four senior employees were eligible to retire. Three indicated their intent to retire within two years and one has since retired. Experience has shown that employees are likely to retire once they meet the eligibility requirements that are a combination of age plus years of service.

With these impending retirements, it is imperative that new staff are hired and trained quickly. Depending on the level of experience of the newly hired staff, it can take up to two years to become an effective Planning Engineer. These new staff members will be ready to replace some of the staff retirements expected to occur in the next two to three years.

9.2.3 Market Operations

PRE-FILED EVIDENCE OF JANET FRASER, MANAGER, MARKET OPERATIONS

The purpose of this section is to provide an overview of the role of Market Operations within the electric system in British Columbia and provide an overview of the primary activities of Market Operations.

9.2.3.1 Summary of Costs

Table 9.2-7. Market Operations Expenditures[33] ($ millions)

	$ millions	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)
1	Market Operations	2.7	2.7	2.9	3.2

9.2.3.2 Summary of Functions

Market Operations is responsible for Tariff design, implementation and administration, Generator and Load Interconnection Services, and Wholesale Transmission Services including transmission prescheduling, settlements and billing, revenue reporting and forecasting. Key business expenses include travel expenses for customer visits and consultation, and attendance at industry conferences and meetings. Membership dues, licenses and other fees include professional association fees, Open Access Same time Information Service (“OASIS”) and Energy tagging system (“Etag”) application services (contractually provided by Open Access Technology International (“OATI”)), annual Lodestar licence fee, and other miscellaneous software licenses (including Cognos). Communication fees are the OASIS and Etag communication links with OATI.

Support systems for Market Operations include the Transmission Scheduling System (“TSS”), Lodestar (customer billing system), and data warehouse (customer reporting software). Accenture Business Services for Utilities (“ABSU”) provides application support (including system availability, reliability and "break/fix" support) for TSS and

[33] See Appendix F regarding “F2006 Approved” column.

Lodestar. ABSU also provides infrastructure support and storage services for TSS, Lodestar and data warehouse.

The change between F2006 and F2007 is due to increased expenses for customer and stakeholder consultation, and application software support fees.

9.2.3.3 Business Considerations

BCTC's Open Access Transmission Tariff ("OATT") was approved by the Commission in June 2005. The implementation program for the new OATT includes system and process changes that went into effect on March 1, 2006 as well as further tariff design review and the development of improved reporting processes. A number of activities included in the implementation program are planned to occur in F2007. These include, but are not limited to, further tariff design review, additional system and process enhancements and improved reporting processes.

BCTC is committed to providing excellent customer service in its delivery of products and services to customers. Market Operations has aligned its organizational structure to provide efficient and effective customer contact. A significant effort in F2007 will be to make continued improvements in systems, processes and reporting to better serve customers and promote open and transparent access to the transmission system. Increased customer and stakeholder consultation to enable BCTC to better meet the needs of the customer began in F2006 and will continue in F2007.

Market Operations Expenditures are expected to continue as they have in past years, with no significant changes forecast for F2007.

9.3 Asset Management/Maintenance

PRE-FILED EVIDENCE OF LARRY HAFFNER, MANAGER, ASSET PROGRAM DEFINITION

The purpose of this section is to provide an overview of the function of the Asset Management/Maintenance ("AMM") department, including primary activities and costs of the department.

9.3.1 Summary of AMM Costs

This section provides a summary of BCTC's Asset Management/Maintenance costs. Each of the components of Asset Management/Maintenance costs are set out in Table 9.3-1 following.

Table 9.3-1. Asset Management/Maintenance Costs

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	Office of System Planning & Asset Mgmt	Sec.9.3.2.5	-	1.3	1.4	2.6
2	Asset Program Definition	Sec.9.3.2.1	90.1	90.9	88.5	87.0
3	Asset Program Management	Sec.9.3.2.2	3.6	4.2	3.4	4.0
4	Office of Major Projects	Sec.9.3.2.6	-	-	-	0.9
5	Research and Development	Sec.9.3.2.3	1.5	1.7	1.6	1.7
6	Initiatives - EGIS*		1.2	-	-	-
7	Initiatives - HVDC		0.2	0.5	-	-
8	Initiatives - Asset Baseline Study		0.9	-	-	-
9	Initiatives - Emergency Maintenance	Sec.9.3.2.4	1.6	2.0	0.7	2.0
10						
11	**Costs Assigned from General & Administration:**					
12	Business Improvement	Sec.9.3.2.7	0.8	0.7	0.8	0.4
13	Technology	Sec.9.3.2.8	0.9	0.9	0.8	0.7
14	Corp Assignment of Labour Concessions & Pension	Sec.9.3.2.9	0.5	-	0.3	0.4
15						
16	**Total BCTC AMM**		**101.3**	**102.2**	**97.5**	**99.7**

*EGIS = Enterprise Geographic Information System

AMM costs have decreased from F2006 Approved of $102.2 million to a F2007 Plan of $99.7 million, partly due to the following:

(a) Certain AMM OMA costs moved to Capital; and

(b) analytical prioritization tools:

i Stations inspection and ranking program – Manufacturer's recommendations help in setting inspection timing, but every station operates on a different duty cycle. This program is designed to prioritize the inspection for each station so costs are optimized over the life of the assets.

ii Reliability Centred Maintenance ("RCM") – RCM is the practice of maintaining equipment on the basis of the logical application of reliability data and expert knowledge of the equipment, i.e. a systems approach. RCM is similar to the Stations inspection program, with a more general application and a similar result of optimizing costs over the life of the assets.

iii Prioritized Condition Based Maintenance ("CBM") – CBM is an equipment maintenance strategy based on measuring the condition of equipment to assess whether it will fail during some future period, and then taking appropriate action to avoid the consequences of that failure. CBM optimizes costs over the life of the equipment.

9.3.2 Summary of AMM Functions

AMM is focused on sustaining the delivery of transmission services. This responsibility includes both planning and implementation functions.

AMM is comprised of two main functional groups: Asset Program Definition and Asset Program Management. Asset Program Definition is responsible for developing the AMM strategies, developing technical standards and work programs, and is responsible for the budget to implement AMM programs. Asset Program Definition is also responsible for planning the maintenance of the BC Hydro Transmission Assets. Asset Program Management is responsible for overseeing the execution of AMM programs.

AMM also includes the Offices of System Planning and Major Projects, Research and Development and certain initiatives, as described below.

9.3.2.1 Asset Program Definition

The Asset Program Definition ("APD") function defines and implements maintenance and sustainment investment strategies to optimize transmission system lifecycle costs and asset performance. This requires an understanding of asset performance, asset condition, risk, strategic sourcing options, and business support systems. The objective is to develop asset strategies for each asset equipment class so ongoing maintenance and sustaining capital expenditures will be at sustainable levels over time. This process results in a long-term (two to ten years) asset maintain/sustain investment plan and a budget that is based on applying these strategies to actual assets.

The APD function also:

(a) develops system engineering and asset maintenance standards;

(b) develops and prepares replacement strategies and maintenance policies;

(c) develops a prioritized budget for upcoming and long term maintenance and sustainment work;

(d) develops and implements procurement and inventory strategies; and

(e) builds and manages relationships with key vendors.

The budget for these activities resides with APD, which is accountable for the expenditures. Once these programs have been defined, APD undertakes their execution and implementation.

9.3.2.2 Asset Program Management

Asset Program Management ("APM") executes and manages the maintenance work plans for Stations, Transmission and Vegetation as well as the capital work plan consisting of projects from the sustaining and growth capital portfolios developed and sponsored by APD and System Planning and Performance Assessment ("SPPA"). The APM department ensures that work is done to standard, on time and on budget. As part of its commitment to continuous improvement, APM also provides feedback to APD and SPPA on ways to improve strategies and standards.

Asset Program Management is specifically responsible for:

(a) Program management, including scope finalization, schedule development, cost estimate development, and quality assurance for capital and maintenance projects and programs;

(b) Development of project management standards, acceptance and commissioning requirements, and project plans;

(c) Development of procurement strategies, negotiating, contracting, and managing for design/engineering/construction work and the procurement of asset related services;

(d) Management of service provider relationships;

(e) Securing asset-related information and documentation (e.g. equipment specifications, manuals, and warranties);

(f) Implementing a quality assurance review upon project completion; and

(g) Asset commissioning and ongoing maintenance and performance monitoring.

9.3.2.3 Research and Development

The R&D Program includes the funding and management of future-oriented technology activities. These activities are focused on the discovery and application of new knowledge that will improve BCTC's planning, operation and asset management performance. It is anticipated these activities will provide benefits to customers through reliable service at low cost.

Approximately 80 to 90 projects are conducted concurrently, with expenditures extending over one, two or multiple years. F2007 expenditures are budgeted at $1.7 million, which is the same budget as prior years F2006 and F2005. BCTC's R&D expenditures are leveraged through co-funding with other utilities, research organizations and manufacturers. Projects are conducted by Powertech Labs Inc., BC Hydro service providers, manufacturers, contractors, universities and research consortia such as the Electric Power Research Institute, Canadian Electricity Association Technologies Inc. and Power Systems Engineering Research Center.

The active projects, many of which are multi-year projects, are summarized in Appendix F and total $4,411,000 with expenditures to date of $3,145,900.

In consultation with BCTC department representatives, projects are developed to provide new technologies and to gain experience with externally developed technologies that are pre-commercial or newly commercial. Further, the R&D Program provides support to the BCTC departments to incorporate R&D results into company operations and realize the full benefits of the initial R&D investment. Current focus areas of the R&D Program are:

(a) Improved transmission system reliability and security

(b) Increased capacity and use of existing assets

(c) Transmission loss reduction

(d) Asset management and life extension

(e) Equipment condition assessment

(f) Cost reduction and revenue enhancement.

The expected and actual benefits are included in a project-tracking database at three key stages of the lifecycle of each project:

(a) R&D Project Initiation – Value measures are identified and estimated.

(b) R&D Project Completion – R&D results are reviewed, value is estimated, and recommendations are provided on the best way to incorporate the results in company operations.

(c) R&D Implementation in company operations – Benefits are quantified based on actual operating experience.

Since April 2005, the R&D Program has used an improved approach to the selection of projects. This approach targeted a long-term benefit-to-cost ratio of greater than 2.0, along with measurable improvements to reliability, environmental performance and safety performance. In support of this goal, a new process was implemented in

Fiscal 2006 to evaluate the benefit-to-cost ratio and expected value of each new project undertaken by the R&D Program (assuming the R&D project results in a successful outcome and the project is implemented). The benefit-to-cost ratios are included in Appendix F for the active projects evaluated since early 2006 and it is noted that of 14 projects, the benefit-to-cost ratio has a range of 1.6 to 12, with a weighted average of 5.6. This indicates the R&D projects are cost-effective. Over time, as more projects are evaluated, an overall benefit to cost ratio will be developed for the R&D Program as a whole.

9.3.2.4 Initiatives – Emergency Maintenance

Part of the OMA maintenance program is related to performance of CO maintenance. This work is any unplanned repairs or replacements of defective or damaged transmission system facilities. As this work is unplanned, it is not specifically identified in the annual work plan. However, it is essential to provide for this work in the annual budget to deal with urgent issues as they arise throughout the year. Typically, this addresses emergency responses due to imminent or actual failures.

Unexpected maintenance expenditures historically have averaged $2.0 million per year. For F2006, besides the miscellaneous unexpected maintenance issues that arise every year, this funding will be allocated towards response and repairs including repairs to a failed cable stop joint on circuit 2L64 at Cambie and 49th Avenue in Vancouver.

9.3.2.5 Office of System Planning and Asset Management

The Office of the Director of System Planning and Asset Management includes the cost of senior management employees who provide direction to System Planning and Asset Management.

9.3.2.6 Office of Major Projects

The newly-formed Office of Major Projects includes the cost of senior management employees who provide management and direction for major projects in various stages of development. These projects currently include the Vancouver Island Transmission Reinforcement (“VITR”) and the System Control Modernization Project (“SCMP”), among others.

9.3.2.7 Business Improvement

The Business Improvement function, which now reports to the VP of Corporate Services and CFO, provides an independent assessment of BCTC's asset management function against external benchmarks. This function ensures that asset information is accurately retained and that data collection process standards are maintained. It also determines Asset Health, and measures and analyzes asset data, statistical trends, and risk models. Proper analysis and accurate prediction of asset performance leads to better performance measurement and early identification of asset management issues and also establishing target funding levels for sustaining the assets.

9.3.2.8 Technology

Technology expenditures related to AMM include systems to facilitate asset tracking and work management, inventory management, cost and contract management, and ongoing evaluation and performance management.

A number of technology improvements and acquisitions have been made to assist AMM in obtaining their objectives. The technologies are developed to obtain one view for all asset information and are collectively referenced as the Asset Management Project ("AMP").

9.3.2.9 Corporate Assignment

BCTC incorporates a Corporate Assignment of Labour Concessions and Pension to the Asset Management/Maintenance department. This Corporate Assignment reflects those costs which are considered to be most efficiently managed at the corporate level rather than managed by individual department managers. Additional information is provided in Section 9.4.3.

9.3.3 Business Considerations

BCTC continues to refine its corporate structure to improve delivery of electrical transmission services. The demands of regulatory processes have resulted in increases in workload with preparation of evidence, responses to information requests, and other related activities. As a result, the AMM departments have been reorganized and personnel are adapting to the new and changing environment.

AMM is committed to maintaining a reliable transmission system while meeting future transmission requirements, lowering costs and meeting service quality expectations. AMM is particularly focused on identifying prudent expenditures during individual asset lifecycles to achieve the lowest long-term costs. AMM is also preparing to meet the escalating transmission requirements that are anticipated over the coming years, and the associated impact on AMM programs.

AMM's objective in its maintenance strategies is to maintain asset condition and reliability at the lowest cost in a safe and environmentally responsible manner. Using sophisticated decision-making tools, AMM seeks to maintain the health of the asset through monitoring, repair, refurbishment or replacement, as appropriate to minimize the lifecycle costs of the asset.

AMM's asset management strategy is driven by an obligation to provide customers with a reliable transmission system. Maintenance costs are driven by industry-acknowledged Reliability Centered Maintenance ("RCM") philosophies to ensure that only high-value work is initiated at the right time to meet requirements for transmission system reliability.

9.3.4 Asset Management Processes and Programs

9.3.4.1 Asset Management Processes.

9.3.4.1.1 Asset Lifecycle Planning

In Asset Lifecycle Planning, asset requirements are determined and implemented by balancing financial, reliability, and environmental factors. The asset management process results in plans and strategies to ensure that individual assets continue to operate at their designed level of service, for as long as possible, at the lowest long-term cost. This process considers the initial planning and design of the transmission system and includes ongoing evaluation of asset performance, asset condition, maintenance costs, and operating costs. Plans are developed for managing the maintenance and replacement of components in each asset equipment class to ensure that the required levels of service are achieved while minimizing lifecycle costs. Different criteria apply to each asset equipment class based on criticality, performance history, and Original Equipment Manufacture ("OEM") support, to optimize either a repair strategy or a replace strategy. Regulatory and statutory

requirements, customer expectations of reliability and power quality all influence individual asset equipment class maintenance and sustainment strategies.

A key focus of asset planning is reinvestment in the transmission system to ensure that it is able to meet current and future needs. The asset lifecycle management process and sustaining capital investment plan addresses the maintenance and eventual replacement of assets whose performance does not meet system requirements or standards, or that are demonstrated to have reached the end of their useful life.

The lifecycle planning process is also influenced by the way in which the transmission system is operated. These operating choices are made to meet customer and inter-utility requirements for power quality and system reliability, and in response to emergencies. This includes identifying the needs and risks associated with reliability and capacity. Contingency plans are prepared to mitigate the system consequences of unanticipated asset failures.

9.3.4.1.2 Transmission System Maintenance Prioritization

The majority of Preventive Maintenance ("PM") work is planned and scheduled work performed on a time-cycle basis. Included are a variety of inspections and condition assessments, such as general overviews, detailed inspections, infrared inspections, foundation inspections, and special inspections as required. The frequency of each type of inspection is dictated by the circuit criticality, due diligence, age and component condition in accordance with BCTC Maintenance Standards. This category of work also includes specific sampling and testing programs that verify asset condition and track deterioration of specific key components. Examples are the 'wood pole test and treat' program and the 'overhead lines component sampling' program.

The majority of Condition Based Maintenance ("CB") work is annually planned repairs or replacements of defective or damaged transmission system facilities. This work is driven by, and the result of, the prioritization of the damage or defects identified in PM inspections and Condition Assessment Value activities (as described following). Typical CB work for overhead lines include repairs or restoration to civil installations, access facilities, conductors, tower foundations, insulators, switches

and wood pole structure components. For cable systems, it includes specialized submarine cable inspections, and repairs or restoration to cables, alarm systems, pumping systems, ducts, and oil reservoirs. An important component of CB maintenance is engineering, including specialized geotechnical hazard reviews, design studies, property referral tasks, development and improvement of design and maintenance standards, and the maintenance of essential records and drawings related to the transmission system.

The remainder of the OMA maintenance program is related to performance of Corrective Maintenance ("CO") maintenance. This work consists of any unplanned repairs or replacements of defective or damaged transmission system facilities. As this work is unplanned, it is not specifically identified in the annual work plan. However, it is essential to provide for this work in the annual budget to deal with urgent issues as they arise throughout the year. Typically, this addresses emergency responses due to imminent or actual failures.

CB work is prioritized by considering the component Condition Assessment Value ("CAV"), the importance of the component to the structural integrity, due diligence (in accordance with the BCTC risk matrix) and the circuit criticality. Every circuit of the Transmission system has been assigned a criticality (impact) rating in accordance with BCTC Maintenance Standards. Guidelines for structural integrity and due diligence are also provided in BCTC Maintenance Standards. Each of these four considerations is put into an RCM type of decision tree in accordance with BCTC Maintenance Standards. The result of this decision tree analysis determines whether the work will be done within days, months, next fiscal year, or will be monitored on a regular basis in future years. Those CB work items that are identified as needing attention within days or months are incorporated into the OMA work plan for the fiscal year.

In addition to the prioritized CB work that is derived from PM inspections in the previous year, there are additional unplanned CB work items that routinely arise throughout the year. The urgency of these work items is assessed in the same manner. While this process ensures that only the most critical work items are addressed in any fiscal year, it can occasionally result in more work than the OMA budget will allow. In this case, all attempts are made to defer discretionary work

within the particular work plan, or the need is evaluated and assessed across all other department work plans to ensure highest priority work is performed for the entire budget.

9.3.4.2 Transmission Asset Maintenance Progress and Activities

This section provides a description of maintenance programs and activities by asset group: stations, transmission circuits and transmission corridor vegetation management. Maintenance activities include monitoring, inspection, condition assessment, preventive action, and corrective action. They also include environmental programs associated with all assets and vegetation management programs used to maintain stations, transmission corridors, and substations.

9.3.4.2.1 Transmission System Stations

The Stations program covers station apparatus, protection and control and telecommunications.

BC Hydro's electric system consists of 287 stations throughout the province and over 375 transmission lines interconnecting these stations. Station apparatus (equipment) consists of switchgear, circuit breakers, transformers, support structures, buswork, high voltage direct current ("HVDC") converters, reactive support equipment, fencing, land, and buildings.

9.3.4.2.1.1 Stations Apparatus

Station apparatus is maintained to minimize the life cycle cost of the equipment. Stations are maintained in three major categories, one for transmission components, one for Substation Distribution Assets ("SDA") which is not addressed in this Application, and one for common equipment supporting both transmission and SDA equipment in a joint facility. Station apparatus is maintained to sustain existing reliability, safety and environmental standards at lowest costs. In addition, stations are maintained to a standard of zero tolerance for preventable outages. Each preventable incident is reviewed in detail to ensure similar incidents do not occur in the future.

Maintenance standards are reviewed on a regular basis to ensure that optimal work is being performed to maintain the assets in an effective manner. BCTC Asset

Management is continuously looking for opportunities to lower costs on these reviews.

9.3.4.2.1.2 Protection and Control

The protection and control assets comprise all protective relaying and control systems at the transmission stations. The installed value of protection and control related equipment is approximately $500 million. These assets protect the energized transmission equipment from being damaged or destroyed from unplanned electrical events. They also help ensure system stability and electrical service reliability during disturbances, ensure electrical safety for the public and personnel, and assist in the control of energy flows throughout the electrical grid.

Annual protection and control OMA spending is directed at the performance of periodic condition assessment of this equipment. These assessments form the basis for decisions with respect to required maintenance/repair/replacement actions. Planned maintenance intervals and procedures are established by specific protection and control equipment policies and standards, which are documented and reviewed as the asset technology changes. The maintenance procedures are designed to preserve transmission system and equipment service reliability, while minimizing protection and control system and equipment outages, and consequential customer interruptions. Again, these standards are reviewed regularly to ensure only high value work is being performed.

Approximately 80 per cent of the annual protection and control OMA costs are spent on preventive/corrective/condition-based maintenance. The balance typically covers technical support to develop, review, and revise protection and control asset maintenance policies and standards, as required. The majority of protection and control maintenance initiatives involve managing ageing equipment to provide acceptable performance levels until this equipment is replaced at end-of-life.

9.3.4.2.1.3 Telecommunications

BCTC has an extensive private telecommunications network to facilitate the power system protection, control, operations, and business requirements.

9.3.4.2.2 Transmission System Circuits

The BCTC overhead transmission network has a total of 18,000 km of lines with a current replacement value of approximately $6 billion. These circuits include 22,000 steel structures and 75,000 wood pole structures. The network transmission lines are generally in good condition, but a significant proportion are well into middle age and require increasing investment in maintenance and sustaining capital to maintain reliability and to extend life. Approximately 40 per cent of the 500 kV steel tower grid (the original 'Peace' transmission lines) is 35 to 40 years old. Most of the balance of the 500 kV grid is 25 to 30 years old (the original 'Mica' transmission lines).

Spacer damper replacement and grillage foundation refurbishment have begun on the 500 kV Peace system. As well, a major corrosion protection program has been started to address rusted lattice steel towers.

The 230 kV steel tower lines in the Fraser Valley are of similar construction and are approximately 10 years older than the Peace lines. In the past few years these lines have had most of the spacers replaced, and they are currently undergoing major repairs to the grillage foundations.

Due to decommissioning of Forest Service roads, higher environmental standards, and increasing regulatory pressures, the costs of maintaining access roads to inspect and maintain transmission lines and manage vegetation growth is rising, and will continue to rise for the foreseeable future.

The transmission circuit maintenance program is based on scheduled inspections of all circuits. These inspections provide condition assessment and defect information, which is the basis for both the short-term and long-term maintenance programs. The inspections also focus on public safety and right-of-way encroachments. All structures are inspected at least once a year and the more important structures may be inspected up to six times per year. The total transmission circuit maintenance costs are allocated approximately as follows:

(a) corrective work, 67 per cent;

(b) preventive work (inspections and assessment), 25 per cent; and

(c) roads and access, 8 per cent.

The continuing approach is to shift funds from corrective maintenance programs to preventive maintenance.

9.3.4.2.3 Transmission Corridor Vegetation Management

Vegetation management is required to ensure public and worker safety and system reliability. The goal is to manage vegetation at the least possible cost and in a socially and environmentally responsible manner. The overhead transmission lines cover over 75,000 hectares of land in rights-of-way. Roughly 65 million stems of vegetation are removed per year, equivalent to 570 trees per line km.

Maintenance costs are expensed in the year that they are made, as maintenance activity or repair does not significantly increase the asset life beyond its initial design.

9.4 General and Administration

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to provide an overview of the corporate processes and activities undertaken by BCTC in ensuring its operations, asset management and maintenance, capital planning and construction activities are carried out prudently, efficiently and effectively. These corporate processes and activities are categorized as General and Administration ("G&A") costs and include corporate governance, corporate management, Policy and Strategy Development, Communications and Stakeholder Relations, Supply Chain, Information Technology, Business Improvement, Finance, Regulatory, Legal and Human Resources. Also included in this category are certain corporate costs and capital overhead allocation.

9.4.1 Summary of G&A Costs

Table 9.4-1 following summarizes the general and administrative costs for F2007 and comparative figures for F2006 before transfer of balance to the Regulatory Deferral Account.

Table 9.4-1. General and Administration Costs [34]

	$ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	**General and Administration Costs**					
2	**Corporate Governance**					
3	Office of the President and CEO	Sec.9.4.3.1	0.6	0.7	1.1	0.8
4	Strategy and Planning	Sec.9.4.3.2	1.7	1.7	2.2	2.5
5						
6	**Subtotal - Corporate Governance**		**2.3**	**2.4**	**3.3**	**3.3**
7						
8	**Corporate Services**					
9	CFO/Finance	Sec.9.4.3.3	6.7	7.0	8.0	7.9
10	Legal	Sec.9.4.3.4	2.6	4.2	3.1	4.1
11	Supply Chain	Sec.9.4.3.5	2.9	3.3	3.1	3.9
12	Regulatory	Sec.9.4.3.6	3.6	3.3	1.4	3.3
13	Communication/Stakeholder Relations	Sec.9.4.3.7	1.6	2.1	1.7	2.3
14	Information Technology	Sec.9.4.3.8	3.6	3.5	3.4	3.7
15	Human Resources	Sec.9.4.3.9	2.6	2.6	2.9	2.6
16						
17	**Subtotal - Corporate Services**		**23.6**	**26.0**	**23.6**	**27.8**
18						
19	**Corporate Costs**	Sec.9.4.4				
20	Employee benefits, concessions &		3.1	-	0.7	2.4
21	BC Hydro Amortization & Loadings			1.5	0.6	1.5
22	Initiatives - Key Agreement		1.0	1.0	4.3	-
23	Other		0.2	-	-	0.4
24						
25	**Subtotal - Corporate Costs**		**4.3**	**2.5**	**5.6**	**4.3**
26						
27	**Gross General and Administration Costs**		**30.2**	**30.9**	**32.5**	**35.4**
28						
29	Less: Capital Overhead		(4.4)	(6.5)	(6.5)	(9.8)
30						
31	**Total General and Administration before Assignment**		**25.8**	**24.4**	**26.0**	**25.6**
32						
33	Less: Assignment of:	Sec.9.4.2.2				
34	Employee benefits, concessions & pension to Asset Management & Maintenance and Operations		(2.3)	-	(1.2)	(1.8)
35	Technology to Asset Management & Maintenance and Operations		(3.6)	(3.5)	(3.4)	(3.7)
36	Business Improvement to Asset Management & Maintenance		-	-	(0.8)	(0.4)
37						
38	**General and Administration Costs**	T7-1	**19.9**	**20.9**	**20.6**	**19.7**

9.4.2 Summary of G&A Functions

General and Administration costs comprise two major components:

[34] See Appendix F regarding "F2006 Approved" column.

(a) Corporate services, governance and management costs – These are costs pertaining to processes and activities for the oversight and strategic management of BCTC business operations, as well as enterprise-wide processes and activities provided to business users within BCTC and its service provider communities. Focus is on the delivery of effective and efficient services to the Corporation, with a governance aspect including policy setting, controls and compliance monitoring. These costs include the Office of the President and CEO, Strategy and Policy Development. Communications and Stakeholders Relations, Supply Chain, Information Technology, Business Improvement, Finance, Regulatory, Legal, Corporate Secretary and Board, and Human Resources.

(b) Corporate costs and recovery – These are common costs and recoveries that are managed at the corporate level. These include costs relating to employee time banks and pension costs which have not been allocated to the various departments, and capital overhead and one-time initiatives.

The key cost drivers for corporate processes and activities are as follows:

(a) External environment including shareholder, customer, public and other stakeholder expectations;

(b) Level of business activities such as strategic initiatives, maintenance programs, capital projects and regulatory schedules; and

(c) General economy and labour market factors.

9.4.2.1 Gross G&A F2007 Plan Compared to F2006 Approved - $4.5 Million Increase

The increase of $4.5 million in Gross G&A cost is primarily due to the following:

(a) Labour cost increases, $1.6 million due to the transfer in of Business Improvement, salary and wage adjustments and headcount additions to address growing business demands;

(b) Reclassification of $2.4 million in certain employee benefit and concession costs from all the departments to a corporate cost center to facilitate the accounting and management of these costs;

(c) Provision of $0.3 million for capital projects that have OMA expenditures as part of their program;

(d) Increasing focus on developing policies and strategies for enabling transmission expansion and improving coordinating with neighbouring utilities contributed to $0.6 million increase in Strategy and Policy Development;

(e) Higher facilities cost, $0.4 million for increased office space to accommodate additional employees; and

(f) Other cost increases of $0.2 million.

These increases are partially offset by removal of the $1.0 million Key Agreement Funding for the cost of designing and implementing the Master Agreements and Service Level Agreements.

9.4.2.2 Cost Assignment from G&A to Operations and Asset Management/ Maintenance

Certain G&A costs have been assigned to Operations and Asset Management/Maintenance. These costs include:

(a) Employee benefit and concession costs to appropriately reflect the labour cost in each department.

(b) Information Technology costs are split between Asset Management/Maintenance, 20%, and Operations, 80%. The main focus of this group relates to the sustainment and security associated with the control and dispatch systems used by BCTC's Control Centres and Market Operations. As well this group supports the system requirements associated with Asset Management/Maintenance.

(c) Prior to F2007 Business Improvement costs were assigned 100% to Asset Management/Maintenance reflecting the focus of the department on asset performance and quality assurance. Beginning in F2007 Business Improvement costs are partially assigned to G&A, 30%, to reflect the work activities relating to risk management. The balance, 70%, is assigned to Asset Management/Maintenance, reflecting work associated with capital planning

process improvements, participation in Service Level Agreement continuous improvement and benchmarking.

9.4.3 Corporate Governance and Corporate Services

9.4.3.1 Office of the President and CEO

Office of the President and CEO includes the costs of the Chief Executive Officer and one support staff. The President's role is to provide executive oversight to ensure that BCTC is carrying out its responsibilities prudently and effectively. The costs associated with the President's office are for labour and travel costs that are required to carry out the President's mandate.

9.4.3.2 Policy and Strategy Development

Customer and strategy development includes costs associated with strategy and policy, business development, and communications and stakeholder relations. The strategy and policy function includes responsibility for BCTC's strategic and business planning activities, for identifying and analysing strategic and policy issues impacting BCTC and for developing the strategic plan as well as the service plan for approval by the Executive Leadership Team and the Board.

9.4.3.3 CFO and Finance

CFO and Finance supports BCTC's business and operational requirements through the provision of treasury and pension, internal audit, business improvement, insurance and all financial planning, budgeting, accounting and reporting processes. The Office of the Chief Financial Officer is also included in this group. The VP of Corporate Services and CFO is responsible for "CFO and Finance Costs" described following, and also for Regulatory (Section 9.4.3.6) and Information Technology (Section 9.4.3.8).

9.4.3.4 Legal

General Counsel provides leadership and advice to the Chief Executive Officer, Board of Directors and Executive Leadership Team on corporate governance and strategic, commercial and other legal issues. General Counsel is also closely engaged in both day-to-day business activities and strategic endeavours, working as part of broader corporate teams and as a particular resource on legal matters.

Included in Legal is the addition of the Manager, Aboriginal Relations. The Manager, Aboriginal Relations is responsible for spearheading the building of mutually beneficial business relationships between BCTC and Aboriginal Peoples and ensuring that BCTC is in compliance with BC Hydro's Aboriginal Relations policies and procedures, in carrying out BCTC's mandate to plan, construct, operate and maintain the transmission system.

9.4.3.5 Supply Chain

Supply chain manages three activities: Outsourcing, Procurement and Contract management, and Facilities. Outsourcing involves overseeing and facilitating a results oriented relationship with BCTC's external service providers. These include BC Hydro Field Services and Engineering Services divisions, Accenture Business Services, Ceridian (Payroll Services) and IBM (Oracle Financial Systems sustainment). Procurement and Contract Management activities cover the acquisition process of goods and services (including materials, services, and construction) and facilitate purchasing and contract requisitions. Facilities cover planning and support in all areas of facilities management and office services. Support is provided to all BCTC sites including: BCTC's five control centres, Telecom Network Operations at BC Hydro's Edmonds location in Burnaby and Bentall Centre in Vancouver.

Purchasing costs increased in F2006 over F2005 due to BCTC assuming direct procurement responsibility for managing its own contractors as well as procurement relating to Transmission assets owned by BC Hydro. In F2005 these costs were incurred as part of Transmission in BC Hydro.

Premise costs increased from F2005 to F2006 to accommodate additional headcount and related work space requirements. To meet these requirements, BCTC has leased an additional 8,343 square feet of space at Bentall effective July 1, 2005. The additional premise cost of $0.4 million is reflected in the F2007 Plan.

9.4.3.6 Regulatory

Regulatory Affairs is responsible for BCTC's rates and regulatory strategy and provides advice and assistance internally on a regulatory issues and filings. This department also maintains relationships with regulators, intervenors and other regulatory stakeholders.

9.4.3.7 Communication/Stakeholder Relations

Communications and stakeholder relations provide communication and consultation with governments, stakeholders, and community and other interested groups on BCTC's operations, projects and plans for the future.

Communications provides a full range of tactical and business-focused communication services to assist BCTC in achieving its vision of becoming a world-class transmission organization. Areas of responsibility for Communications and Stakeholder Relations include Issues Management, Community Relations, Government Affairs, Media Relations, Outreach Programs, Employee Communications, Advertising, Corporate Events, Research, Writing and Editing, and Design and Print Production.

9.4.3.8 Information Technology

The Technology department develops and executes an integrated technology strategy and operational plan. To ensure appropriate governance and accountability structure is in place over the development, maintenance and operation of the IT systems, the department directs technology capital planning and provides technology governance, policies and procedures, architecture framework, performance criteria, and ensures the security, inter-operability and effective performance of critical systems. To ensure efficient deployment of IT resources, the Technology staff provides support in the design, implementation, delivery and performance of all technology at BCTC through the following functional areas: Technology Operations; Architecture; Project Planning and Implementation; and IT Strategy.

9.4.3.9 Human Resources

The Human Resource function provides strategy and support in all areas of human resources. The range of services include: employee relations; labour relations; workforce planning and development; compensation; pensions and benefits; performance management; leadership development; succession planning; employee health policies and programs, and recruitment.

9.4.4 Corporate Costs

Corporate costs reflect those costs which are considered to be most efficiently managed at the corporate level rather than managed by the individual department managers.

Costs managed at the corporate level include $2.4 million in time bank and vacation benefits that have not been allocated to the various departments in F2007 as in F2006. This reflects an internal accounting change where the costs are now budgeted in the corporate department to facilitate better management of those costs. In F2006 these costs were distributed to the individual departments to improve individual department visibility for the total department labour cost. However, because time bank and vacation benefits accrue on a periodic rather than monthly basis, it was inefficient and impractical to have individual managers review and forecast these costs because data is not readily available to them. BCTC also found that it was difficult to distribute the costs to the individual departments and that it was efficient and practical to manage the time bank and vacation benefits centrally in the corporate cost centre. This change is consistent with F2005 when the time bank and vacation benefits were centralized.

With the BCTC capital plan approved by the Commission, $0.3 million has been included in General and Administrative expenses to fund the OMA portion of two capital projects: hardware support and infrastructure sustainment for the Single Point of Failure Project once it is placed into service and preliminary study costs for the Security Compliance Project to meet NERC Critical Infrastructure Protection standards. These projects are included in BCTC's capital plan. The OMA portion are costs relating to hardware vendor support, sustainment support, vendor licensing, and preliminary study costs, all which cannot be capitalized as part of the related capital projects.

In F2007 there is a reduction of $1.0 million in Key Agreement Implementation reflecting the completion of various projects to implement the new OATT tariff, Service Level Agreement reporting requirements and BCTC's financial system.

BC Hydro loadings and prepayment costs reflect two components: BC Hydro Service Asset Corporation ("SAC") costs and BC Hydro asset loadings costs. The annual

cost for the loadings and prepayment costs is $1.5 million. Plans prior to F2007 reflected these costs in the monthly charges from ABSU for services to each BCTC department.

BCTC, under agreement with BC Hydro SAC paid its share of the asset investment made subsequent to March 31, 2004. This asset utilization fee is amortized over the useful life of the related assets. In F2007 $0.5 million is included for the asset amortization. BCTC paid to BC Hydro SAC in March 2005, an initial asset utilization fee, $6.7 million, an amount based on an agreed allocated share (baseline) of the net book value of the SAC assets used by BCTC as at March 31, 2004. This utilization fee or SAC asset loading has been recorded by BCTC as long-term prepaid expense to be amortized to expense over the asset utilization period. The amortization amount for F2007 is $1.0 million, with the majority of this cost relating to sustainment of BC Hydro's People Soft financial system.

Capital overhead has increased from $6.5 million in F2006 to $9.8 million in F2007. For an explanation of capital overhead costs, see Section 9.5.

9.5 Capitalized Overhead

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

9.5.1 Introduction

The purpose of this section is to present BCTC's methodology and results for capitalizing an appropriate amount of its Operations, Maintenance, and Administration ("OMA") expenses. BCTC conducted a Capitalized Overhead Study to ensure an appropriate amount of OMA cost is capitalized in light of the higher capital expenditure levels, and also in response to the F2006 Settlement Agreement, Amendment No. 5 in Appendix 1 to Commission Order G-60-05 that states,

> BCTC will report on its study of appropriate capitalized overhead allocations at its next revenue requirement application.

The Review of Capital Overhead Allocation Methodology by RJ Rudden is attached as Appendix D.

Overhead capitalization results in the allocation of some OMA expenses incurred in the current year to the cost of capital projects. These capitalized costs will be recovered through future rates as the associated assets are depreciated and the interest on their financing cost is paid. BCTC's capital plan is significant, and about 255 projects with $324 million in expenditures, including Substation Distribution Assets, are forecast for F2007. A portion of BCTC's OMA activities are directed toward or support capital projects, so it is both reasonable and appropriate to include some of these expenses as part of the capitalized cost of new BC Hydro Transmission assets and BCTC's own assets.

This section first covers the purpose of overhead capitalization and the applicable regulatory and accounting guidance. Next, the process and activities involved in developing a capital project at BCTC are described, and BCTC's criteria for categorizing expenses as capital-related vs. OMA are explained. The findings of BCTC's recent Capitalized Overhead Study, along with RJ Rudden's review of that study, are then summarized. (RJ Rudden's Review of Capital Overhead Allocation Methodology is attached as Appendix D.) Finally, the overhead capitalization rate is calculated for BC Hydro Transmission, BC Hydro Substation Distribution and BCTC

projects. The rate will be used to apply overhead to the direct capital costs of each project in the F2007 capital program. The Overhead Capitalization Rate must be recalculated for each fiscal year.

9.5.2 Purpose of Overhead Capitalization

The rationale behind capitalizing certain overhead costs lies fundamentally in the accounting principle that expense recognition should track with the realization of related benefits. Expenses that have a causal relationship with capital projects and that create multi-period benefits over the useful life of the assets should be recognized over those periods, i.e. they should be capitalized.

Capitalization of construction-related overhead expenses also follows the principle of rate equity. If current period expenditures create benefits for customers over a number of periods, it would not be equitable for current period customers to bear all the costs. For example, a new transmission substation may create benefits for customers for a long period, perhaps 30 to 50 years. Rather than impose a large burden on current customers to pay for all of the substation project costs in the current period, the costs are capitalized and recovered over a period more consistent with the useful life of the assets. This principle applies to all costs of a substation, whether they are direct charges or allocated overhead expenses. The allocated overhead expenses are required to plan the capital projects and support the personnel directly involved in executing the projects.

The Canadian Institute of Chartered Accountants ("CICA") gives the following guidance in CICA 3061.20:

> The cost of an item of property, plant, and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction and development activity.

BCTC's accounting policy states that expenditures on support service activities which cannot be readily identified with a particular project, but are attributable to the acquisition or construction activities, should be accounted for as capitalized overhead.

A more complete discussion of applicable accounting principles is provided in the RJ Rudden Report in Appendix D.

9.5.3 Distinction Between Capital Costs and OMA Expenses

The first issue that must be addressed in the process of allocating overhead costs to capital is the distinction between capital costs and OMA expenses. At BCTC, like other utilities, the major portion of the costs of capital projects is direct costs. Labor and materials costs are charged directly to an established capital project. Most of the BCTC projects receiving large amounts of direct charges are large projects that consume a considerable portion of the time of specific individuals. Tracking the time and materials for these large projects is administratively feasible.

By definition, none of these directly charged costs become part of the OMA cost pool considered for allocation to capital. There are two types of OMA costs that are considered to be capital-related:

(a) The first type comprises costs of planning and engineering that are not directly charged to projects because such direct charging would not be administratively feasible. Tracking time spent on a multitude of smaller projects is burdensome and not highly accurate. Instead, these costs are allocated across the total capital program through the capitalized overhead mechanism.

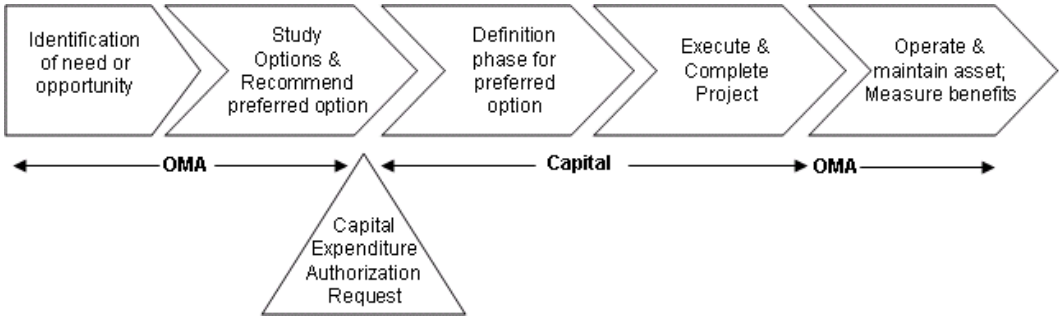
(b) The second type includes all those General and Administrative ("G&A") costs that are necessary to support the planning and execution of capital projects, e.g., human resources, senior management, information technology, facilities, employee benefits, etc. Without incurring these G&A costs, BCTC would not have the capability to execute its capital program. A portion of corporate G&A costs are allocated to capital, as described following and in RJ Rudden's Report in Appendix D.

One of the areas in which accounting principles and Commission rules allow some discretion to utilities on capital cost classification is the definition of what overhead costs are "<u>directly attributable</u> to the construction and development activity," (from CICA 3061.20 above; emphasis added). The planning and execution of capital projects by BCTC involves a sequence of activities, ranging from high-level strategic planning to long-range system planning to specific project planning and analysis.

BCTC's project planning cycle starts with the identification of a specific need or opportunity followed by an analysis of alternatives and recommended solutions. Once the need and recommended alternative are confirmed, a Transmission Capital Expenditure Authorization Request is prepared to support the capital funding for definition and execution phases of the project. Costs for general planning activities preceding the project definition are treated as OMA (rather than direct capital expenses), and become part of the first overhead pool listed above. That is, pre-project planning is treated as a set of activities generally supporting the capital program.

The following graphic illustrates the series of planning-related activities, and the dividing line at BCTC between OMA and capital.

Figure 9.6-1. OMA and Capital Costs for Planning-Related Activities



Thus, BCTC's policy ties the start of direct charging for a capital project to a readily ascertainable event, i.e. the submission of an Expenditure Authorization Request ("EAR").

9.5.4 Overhead Expenses for Allocation Between OMA and Capital

BCTC applied the above accounting policy to separate its direct charged capital expenses from its OMA expenses. It then determined which OMA expenses were appropriate to include in the pool of overhead costs for possible allocation to capital projects.

(a) OMA costs related solely to operations and maintenance of the transmission system and other assets were not included in the overhead cost pool. O&M costs that have no relation to the capital program are current period expenses, and are not capitalized.

(b) BCTC also excluded direct charged service expenses (billable labour).

As a result BCTC has a total of $47.3 million in OMA costs that are considered overhead, and are eligible for allocation to capital. Table 9.5-1 indicates the costs considered for capital overhead allocation.

Table 9.5-1. Costs for Capital Overhead Allocation[35]

$ millions	Ref.	F2007 Plan
(a)	(b)	(c)
Capital Overhead		
Labour (excl HR)		43.6
Computer Desktop Support Costs		2.1
Rent (Bentall and Control Centres)		2.1
Furniture & Other Equip, Office Supplies, Printing, Telephone, Communications		1.1
HR costs including labour, rent		2.7
Other Costs		1.9
Total Capital Overhead		53.5
Less billable labour costs		(6.2)
Costs for Capital Overhead Allocation		**47.3**
Total OMA		164.9
Costs for Capital Overhead Allocation as a percent of total OMA		28.7%

9.5.5 Overhead Expenses Allocated to Capital

As described in detail in the RJ Rudden Report in Appendix D, BCTC conducted a detailed study in January 2006, to determine what proportion of eligible OMA expenses to allocate to capital. To summarize, BCTC interviewed each department manager in the relevant functions, and gathered information on the proportion of labour effort[36] that was expended on capital projects. This information was used to allocate labour costs and labour-related costs (desktop support, rent, etc.) between OMA and capital. The costs of senior and department managers were allocated between OMA and capital based on the department activities they manage. These

[35] See Appendix F regarding "F2006 Approved" column.
[36] Excluding labour directly charged to capital projects.

cost allocation principles are accepted practice in the utility industry and other industries.

When the allocation percentages by department – as developed by the BCTC capital overhead allocation study - were applied to forecasted F2007 overhead expenses, the result was to allocate to capital $9.8 million of F2007 overheads.

BCTC retained the engineering and consulting firm of RJ Rudden to perform an independent review of BCTC's capital overhead allocation methodology. RJ Rudden has significant experience with such allocation methodologies, including a very similar current engagement with Hydro One Networks Inc. in Ontario.

RJ Rudden concluded that the methodology used by BCTC for allocating overhead expenses between capital and indirect and G&A was reasonable and appropriate. See page 34 of Appendix D for RJ Rudden's conclusions.

9.5.6 Overhead Capitalization Rate

As described in Section 9.5.1, the capital program managed by BCTC for F2007 comprises a forecast total of about $324 million in capital expenditures. These capital expenditures include BC Hydro transmission projects, the portion of BC Hydro substation distribution assets projects for BC Hydro's Distribution Line of Business, and BCTC's own capital projects (primarily relating to control centres and information technology).

It is difficult to compare BCTC's overhead capitalization rate directly to those of peer utilities, due to differences in accounting policies, character of capital programs, etc. Nonetheless, BCTC's overhead capitalization rate appears to be modestly lower than many of its peers. This is probably due to the large volume of capital expenditures in relation to its planning and engineering costs. Another explanatory factor is BC Hydro's practice of including certain overheads in the direct costs of its capital projects.[37] This increases the divisor in the overhead capitalization rate calculation (i.e. the total volume of capital expenditures), while not increasing the numerator (i.e. BCTC's capitalized overheads). Thus, only BCTC's overheads are reflected in the capitalization rate that is applied to BCTC and BC Hydro projects.

[37] The costs of BC Hydro's Engineering Services and Field Services organizations are included in the loaded labour billing rates that are charged directly to its capital projects.

The development of BCTC's overhead capitalization rate is summarized in Table 9.5-2 following. The rate is calculated by dividing the total F2007 overhead that is allocated to capital ($9.8 million from Section 9.5.5 preceding) into the total F2007 capital expenditures managed by BCTC ($323.9 million). The result is an overhead capitalization rate of 3.03 percent.

Table 9.5-2. BCTC Overhead Capitalization Rate[38]

$ millions	F2007
OMA Overhead Expenses	46.5
Overheads Allocated to Capital	9.8
Direct Capital Expenditures (Note 1)	323.9
Overhead Capitalization Rate	3.03%

Note 1: Direct capital expenditures exclude recurring capital, interest during construction and capital overhead.

After reviewing the accumulated evidence and expert opinions, BCTC adopted the results of its capital overhead allocation study, and began applying the indicated overhead capitalization rate to active capital projects, as of April 1, 2006. As noted earlier, the Overhead Capitalization Rate must be recalculated for each subsequent fiscal year.

[38] See Appendix F regarding "F2006 Approved" column.

9.6 Staffing, Compensation and Benefits

PREFILED EVIDENCE OF BRIAN DEMERSE, DIRECTOR, HUMAN RESOURCES

The purpose of this section is to provide an overview of the compensation practices of BCTC. This section addresses the following:

(a) An overview of BCTC's staffing;

(b) An overview of BCTC's compensation strategy and related comparison of wages and salaries to market; and

(c) An outline of employee health and pension benefits.

9.6.1 Staffing

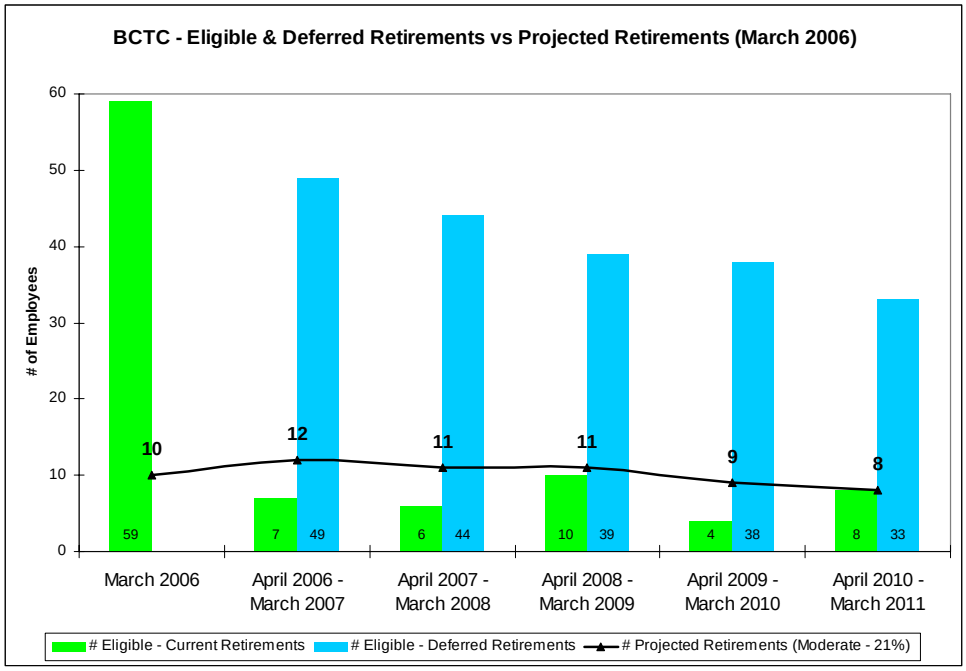
9.6.1.1 Overview

BCTC's employee workforce consists of 146 union and 203 management and professional employees. The average age of BCTC's workforce is 46 years and the average length of service is 13.5 years. According to a recent Canadian Electrical Association study[39], the average age in the Canadian electricity industry is 44 years and the average tenure with the current employer is 16 years.

Voluntary attrition at BCTC during F2006 was 6.3% based on an average headcount of 317. The F2006 voluntary attrition of 20 consists of 18 voluntary resignations and 2 retirements. Based on expected increased levels of retirement (see Figure 9.6-2 following) and continued levels of voluntary resignations, BCTC is forecasting voluntary attrition levels at 7% to 9%, or about 30 employees per year, for the next five years or more. BCTC anticipates that the recruitment of new employees will be an on-going challenge, but manageable at the forecasted attrition levels.

[39] "Keeping Future Bright" 2004 Canadian Electricity Human Resources Sector Study

Figure 9.6-2. Retirements



9.6.1.2 Organizational Changes

At the organizational level, a number of adjustments were made since the F2006 Revenue Requirement Application. With retirement and other changes at the executive management team level, BCTC refined the organizational structure to provide a better balance of responsibilities and improve focus for system operations, asset management, capital planning and project execution.

The major organizational changes are as follows:

(a) System Operations and Asset Management, previously under a Senior Vice-President, is now split into three groups:

i System Operations is responsible for the real time operations of the transmission system and the System Control Modernization Project;

ii System Planning and Asset Management is responsible for planning transmission expansion and sustainment to meet customer load and to maintain the existing transmission assets to provide safe and reliable transmission services in a cost-effective manner; and

iii Major Projects is responsible for ensuring major transmission projects, such as the Vancouver Island Reinforcement Project, are executed successfully.

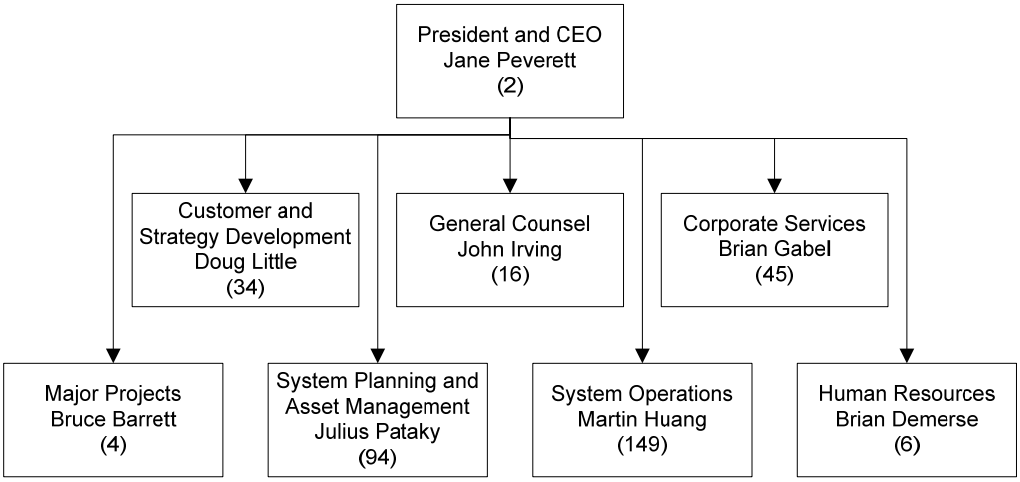
(b) The planning and strategy group has been refocused to Customer Strategy and Development with a mandate to proactively seek ways to enhance electricity industry activity on B.C.'s transmission system and to address customer and stakeholder needs. Four departments were combined into two departments. The Communications department and Stakeholder Relations department were combined to form Communications and Stakeholder Relations. The Strategy department and Investment Analysis department were combined to form Strategy and Business Planning. The Market Operations department was transferred from System Operations and a new department, Regional Market Policy, was established to provide focus on the relationship between Alberta, B.C. and the Pacific Northwest, regarding tariff and interconnection policy design and future energy policy.

(c) The focus of Procurement, previously reporting to the VP Corporate Services and CFO, has been expanded to encompass the Supply Chain including strategic sourcing and major outsourcing contracts. A large portion of BCTC's operating and capital activities are performed by third parties under long-term contracts and the effective management of these service providers is critical to BCTC's success. This function reports to the VP and General Counsel.

(d) The Chief Technology Officer, who previously reported to the VP Planning and Strategy, now reports to the VP Corporate Services and Chief Financial Officer.

The following Figure 9.6-3 provides the BCTC Organization Chart, with headcount information shown in brackets.

Figure 9.6-3. BCTC Organization Chart



9.6.1.3 Attraction and Retention of Staff

BCTC relies on a small, highly-skilled workforce within an increasingly competitive external labour market. Given this situation, creating a workplace culture which fosters commitment to the organization is seen as imperative in terms of both attracting and retaining employees who are enabled, engaged and positioned for success. To measure progress BCTC has adopted a productive engagement measure which is based on surveying employee perceptions on four underlying drivers - employee alignment and capability, available resources and employee motivation. The F2006 Employee productive engagement survey confirmed BCTC's overall score at 3.35 of 5. This is substantially the same score achieved in F2005, and below the targeted improvement set for the year and the WorkCanada 2004/2005 median score of 3.43. BCTC's F2006 results reflect employee feedback that, while employee alignment (knowing the goals of the organization and their expected contribution) has improved relative to the F2005 result, there are increased concerns about resources to address the workload and the impact on capability of the loss of skills due to attrition. The combined impact of the resource issues along with declining confidence of the equity of BCTC's compensation levels in the market place also resulted in a slight decline in motivation.

BCTC remains committed to improving this situation and will continue to focus on the following:

(a) An on-going program of town hall meetings with all employees to review progress on key corporate objectives, to develop understanding of the business model and to provide a forum for discussion on challenges facing the organization.

(b) With over 40% of the organization impacted by the System Control Modernization Project the project plan has emphasized employee consultation and the consideration of the impact on employees in decision making. This broad-based input improves the decision-making and is an investment in building employee commitment to the success of the project.

(c) Performance management processes will continue to stress improvement in objective setting, measurement and providing on-going feedback. The union employee gainsharing program will be reviewed for improvement in the line-of-sight of the measures.

(d) In response to BCTC's demographics, workforce planning is an ongoing process and includes succession planning for key leadership roles and other critical positions in the organization. This work has impacted decisions regarding organizational design, the rotation of key management personnel to build employee capability, developmental assignments and the introduction of new skills into the organization.

(e) Because of its strategic importance, the recruitment function was brought in-house in F2006. An on-line applicant tracking system was implemented in F2006, and a renewed emphasis has been placed on co-op student hiring, campus recruitment and, in some cases, national advertising (for electrical engineers and project managers). During F2007 work will continue building on the BCTC employment brand messaging and on the roll-out of a leadership competency model to inform both recruitment and development processes.

(f) Training and development will receive additional attention in F2007, with increasing focus particularly on the training and mentoring in engineering disciplines. This increased emphasis is needed as the experience level of new hires is shifting from a historical pattern of recruiting individuals who have had several years of transmission-specific electric industry experience, to a greater

number of new employees coming directly from engineering schools or related industries.

9.6.1.4 Budgeted Headcount

BCTC's budgeted headcount for F2007 is 350 full-time equivalents. This is an increase of 21 full-time equivalents from the F2006 Plan. The increase was necessary to address the resource gaps associated with approved strategic initiatives, infrastructure planning and capital projects to meet the growing electricity needs of the Province.

Table 9.6-1. F2007 Headcount Additions

Division		Detail	Total
Major Projects			
1	Project Manager	1	
2	Director, Major Projects	1	
3	Major Projects Additions Subtotal		2
General Counsel			
4	Manager, Aboriginal Relations	1	
5	General Counsel Additions Subtotal		1
System Planning and Asset Management			
6	Coordinator of Occupational Safety and Health	1	
7	Capital Planning Process Manager	1	
8	Technical Writer	1	
9	IPP System Planner	1	
10	Engineer-in-Training	2	
11	Planner	2	
12	SPPA Additions Subtotal		8
Corporate Services			
13	Regulatory / Costing advisor	1	
14	Capital Accounting Assistant	1	
15	Senior Regulatory Advisor	1	
16	Eliminated Financial Service Manager	(1)	
17	Corporate Services Additions Subtotal		2
Customer and Strategy Development			
18	Community/Stakeholder Relations Manager	2	
19	Business Development Manager	1	
20	Customer and SD Additions Subtotal		3
System Operations			
21	Apprentice Operator / Area Dispatcher	3	
22	Control Centre Work Process Expert	1	
23	Administrative Support Assistant	1	
24	Eliminated System Operations Supervisor	(1)	
25	System Operations Additions Subtotal		4
Human Resources			
26	Human Resources Recruiter	1	
27	Human Resources Additions Subtotal		1
BCTC Additions Total			**21**

The cost impact of these 21 additional positions is discussed in Section 9.1.

9.6.2 Compensation

9.6.2.1 Compensation Overview

BCTC's compensation strategy is aimed at attracting, retaining and rewarding a high performing workforce who share BCTC values and whose results contribute to our success. The salary and wage policy is to maintain BCTC's average actual salaries and wages at the median position in the Canadian Electric utility market. Differences in individual salaries, above or below the average actual salary, result from individual performance. Union affiliated employee wages and salaries are determined by collective bargaining.

9.6.2.2 Executive – Cash Compensation

Executive salary ranges were established on start-up in August 2003 based on a combination of the terms of employment of former BC Hydro executives transferred to BCTC and a market review which anchored the salary scales relative to similar positions within the Canadian electricity market. Since start-up, executive recruitment has been undertaken for 8 positions, half of which have resulted in external hiring. This recruiting experience has underscored that executive salary scales are lagging behind market comparators. The executive salary scales will be reviewed in F2007, however no special budget provision has been made to accommodate adjustments.

9.6.2.3 Executive – Performance Pay

In consultation with the Board of Directors, the Human Resources Committee of the Board establishes an annual performance plan for the President and CEO. The plan consists of the key corporate objectives as detailed in the BCTC Service Plan and other individual objectives established by the Board. The CEO establishes individual performance plans for each of the executives. At year-end, the HR Committee and the Chair review actual results to the CEO's performance plan objectives and recommends an award to the Board for approval. Similarly the CEO reviews each executive's results and submits a recommendation on their awards to the HR Committee for approval. Actual awards can vary from zero to two times the appropriate target based on overall corporate performance and individual results. The budget for F2007 executive performance pay has been set based on 1.5 times target.

9.6.2.4 M&P Employee – Cash Compensation

9.6.2.4.1 Salary Scales and Market Comparisons

M&P jobs are ranked into nine job groupings based on internal equity considerations, and each job group is assigned a salary range on the M&P salary scale. The salary scales are constructed such that the midpoint of each salary scale is referenced to the median of the market as established by a comparison of benchmark jobs to actual market salaries. To ensure salary scales remain competitive, the market comparison is undertaken each year. The market used for comparison purposes is the Canadian utilities industry as measured by annual surveys conducted by Towers Perrin. BCTC's M&P salary scales were adjusted to market effective June 2005, which was the first adjustment to the salary scales since June 2002.

9.6.2.4.2 Salary Progression Within Salary Scales

M&P employee salaries are reviewed annually to determine individual salary increases, called salary progression, within the assigned salary range. Individual salary progression awards are determined by the employee's performance review, the position of their salary on the appropriate salary scale and the available salary progression budget. The overall budget for salary progression is based on a number of considerations, but primarily the policy of managing the average of actual salaries to the midpoint of the salary scale (market median).

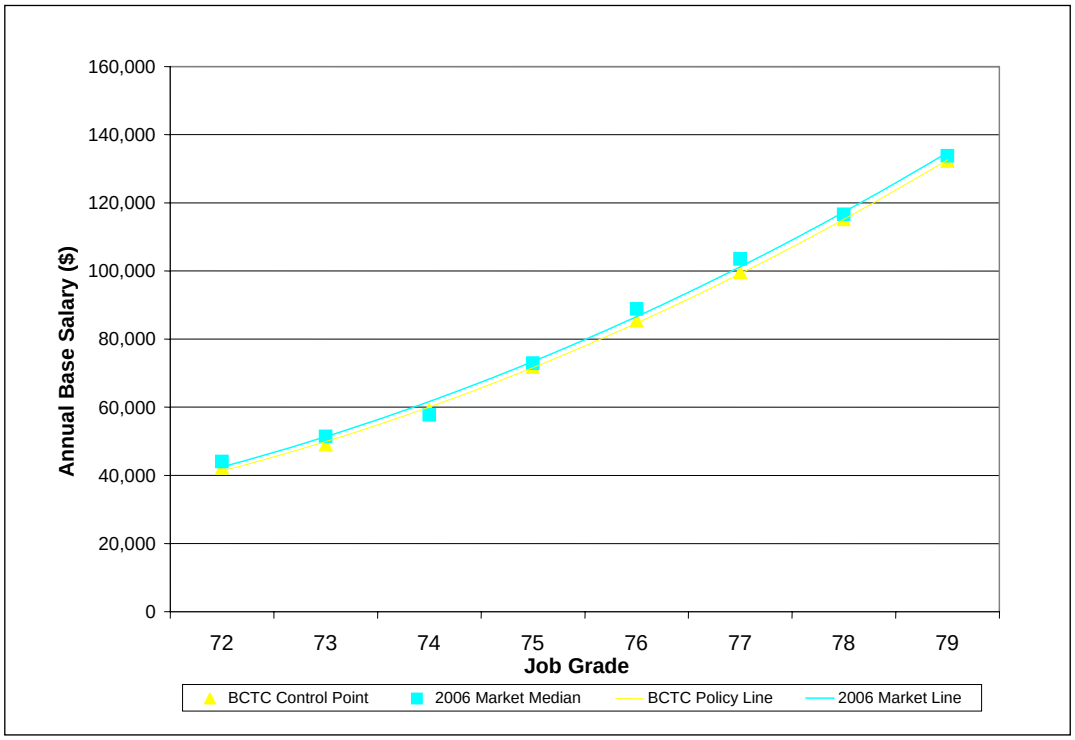
9.6.2.5 M&P Employee – F2007 Salary Range Adjustments and Salary Progression Budget

A comparison of M&P salary scales control points to market salaries for comparable positions throughout the M&P salary scales is provided in Figure 9.6-4 below. This comparison is based on Towers Perrin's Power Services Industry survey. The comparison illustrates that the current BCTC salary scale midpoints are expected to fall slightly behind the median of the market in 2006. This analysis suggests that M&P salary scales will need to be adjusted by about 2% in F2007 to maintain the salary scale mid-points at the targeted market position. It should be noted the suggested adjustment is to salary ranges, and while it is a factor in determining the salary progression budget, scale changes in themselves do not result in individual employee salary increases.

Since the market data was collected, there have been an increasing number of sources indicating that the market adjustments are escalating above the initial forecasts, primarily due to an increasing competitive labour market, particularly in Western Canada, for many of the skills employed by BCTC.

Given the suggested scale adjustment, the expected reduction in actual salaries due to attrition through the year (because less experienced people will be replacing incumbents) and a retention factor in view of the increased market pressure, 3.75% of M&P salaries ($600,000) is allocated for salary progression in F2007. Overall it is expected this level of adjustment will maintain BCTC average actual salaries at or near the M&P salary scale midpoints.

Figure 9.6-4. M&P Market Analysis



9.6.2.6 M&P Employee – Performance Pay

In addition to monthly salaries, M&P employees also participate in a performance pay program which is designed to reward employees for the achievement of annual performance objectives.

Annual performance pay awards are individually determined based on a combination of individual results relative to annual performance objectives set out in an annual Performance Plan. The target award varies depending upon the level of the employee in the organization, and range from 7.5% to 15% of annual base salary. Individual performance objectives are set by the employee's manager based on a cascading of corporate objectives throughout the company. Actual awards can range from 0 to 2 times target for superior results.

9.6.2.7 Oversight of Compensation Changes and Performance Pay

On recommendation from management, the Human Resources Committee of the Board approves salary scale adjustments, the annual salary progression budget and overall disbursement of performance awards. In addition to the BCTC approvals, changes to exempt employee compensation plans and collective agreement terms with union affiliated employees are also subject to approval by the Ministry of Finance.

9.6.2.8 Union Employee – Wages and Salaries

Union affiliated employee wage rates and salaries are also managed in relation to the median of the Canadian utilities industry. The market comparison for the IBEW unit (98 employees) determined that the increases negotiated for F2006 will maintain BCTC's union affiliated employees' salaries and hourly rates at the median of the comparison market. A updated 2006 comparison has not been conducted for COPE affiliated employees (48), however based on prior comparisons it is expected the updated data would demonstrate COPE salaries are at or near the median of the market for comparable positions.

Table 9.6-2. IBEW Wage Benchmarking

	Position	Median Market Rate	BCTC Rate[40]	Market Position
1	Power Dispatcher	$40.05	$39.87	-0.5%
2	Operator/Area Dispatcher	$35.18	$34.67	-1.4%
3	Telecommunications Network Controller	$37.08	$38.05	2.6%

[40] BCTC's rates prior to 1 April 2006 wage adjustments.

9.6.2.9 Union Affiliated Employees – F2007 Compensation

Labour negotiations for the collective agreements with both COPE 378 and IBEW 258 were undertaken using a mutual interest approach. This resulted in a constructive review of the collective agreements inherited from the predecessor organization, and mutual gains based on changing the terms to better fit work requirements relevant to work at BCTC. The new collective agreements run from 1 April 2005 to 31 March 2007.

Wage and salary adjustments provided for in these settlements were based on a combination of the Public Sector Bargaining Mandate issued by the Public Sector Employer's Council (for the first year of the agreements), market comparisons and a sharing of productivity and other benefits from operational improvements resulting from changes to Agreement provisions.

Negotiated wage and salary adjustments within the 1 April 2005 to 31 March 2007 Collective Agreements are as follows:

Table 9.6-3. Union Affiliated Employees

Union	Effective date	Public Sector Mandate	Other mutual gains	Total increase
IBEW	1 April 2005	1.5%	0.5%	2.0%
	31 March 2006		1.5%	1.5%
COPE	1 April 2005	1.5%	0.5%	2.0%
	1 April 2006		1.0%	1.0%

A portion of the first year and all of the second year wage and salary adjustments were tied to productivity improvements and other mutual gains resulting from agreed changes to collective agreement provisions. In addition to specified second year adjustments listed above, both collective agreements also provide a re-opener provision for salaries and wages in the event an additional across the board amount is provided by the 2006 Public Sector Bargaining Mandate which at that time was under development by the Ministry of Finance.

Following the announcement of the 2006 Public Sector Bargaining Mandate, BCTC and COPE agreed to re-open the collective agreement in order to negotiate an extension to 31 March 2010. This extended agreement resulted in increased 1 April

2006 salary adjustments which range from 2.3 to 2.6% (inclusive of previously negotiated increase). Similar discussions were also held with the IBEW, and it was decided not to extend the agreement at this time, and instead to remain committed to bargaining prior to the expiry of the current agreement on 31 March 2007. In making this decision both parties recognized the important work underway associated with the Control Centre Modernization Project and the need to complete this work. However, as a result of the approved 2006 Public Sector Mandate the wage re-opener provision in current IBEW agreement resulted in the planned 31 March 2006 wage increase being adjusted to 3.5% (inclusive of previously negotiated increase).

9.6.2.10 Union Affiliated Employees – Gainsharing

Union affiliated employees participate in a negotiated gainsharing program. Under this program, three key corporate measures are used to determine a common gainsharing award that is paid to all members in the bargaining unit. The maximum award payable in F2007 for F2006 results is 4% of base wages / salary. In F2005 each union affiliated employee received 4%. A similar provision is made within the F2007 budget.

9.6.2.11 Employee Health Benefits

In addition to cash compensation, non-union employees are also provided with various other employee benefits. Unionized employees are provided health benefits in accordance with their collective agreements and are generally similar to the benefits provided to M&P employees. The M&P employees' health benefit plan is a flexible benefit arrangement whereby the employer provides a standard benefit credit that employees use to elect benefit coverage to suit their circumstance. Employees may elect higher or lower levels of coverage for basic plans or additional optional plans resulting in a cost or savings to the employee. The health benefit provisions have remained unchanged since BCTC assumed the terms and conditions of employees transferred from the predecessor organization.

Benefit costs for all employee groups have increased by 12.79% or $211,000 based on comparing the F2006 forecast actual to F2007 budget. This increase is due to the increased headcount, increased administrative fees by benefit providers and inflationary increases in benefit costs.

9.6.2.12 BCTC Pension Plan

The Company provides a defined benefit registered pension plan to all employees. Pension benefits are based on years of membership service and highest five-year average pension eligible earnings. Employees make basic and indexing contributions to the plan funds based on a percentage of current pension eligible earnings. Annual cost-of-living increases are provided to pensioners to the extent that funds are available in the indexing fund. The Company contributes amounts as prescribed by an independent actuary towards the cost of providing basic benefits under the plan.

In addition, the Company provides a supplementary pension arrangement that provides additional pension benefits to employees to the extent that their benefits under the registered pension plan are constrained by the maximum pension limits under the *Income Tax Act*.

The Company provides post-retirement benefits other than pensions including medical, extended health and life insurance coverage for retirees who have at least ten years of service and qualify to receive pension benefits.

Although there has been no enhancement to the employee benefit plans, pension expense in F2007, based on CICA Handbook, is expected to increase by $1.1 million from F2006 plan:

Table 9.6. Pension and Benefits Expense ($000s)

		F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
		(a)	(b)	(c)	(d)
1	Registered Pension Plan	$1,955	$2,088	$1,930	$2,168
2	Special Termination Provision		243	110	215
3	Non-Registered Pension Plans	153	196	276	586
4	Post Retirement Benefit Plan	749	899	899	1,086
5	**Totals**	**$2,857**	**$3,426**	**$3,215**	**$4,055**

The increase in F2006 plan pension expense from F2005 is primarily attributable to the decrease in the discount rate assumption as recommended by actuaries from 6.0% to 5.4% and increase in interest cost for non-registered pension plan and post

retirement benefit plan which are both unfunded arrangements. For unfunded arrangements, the increase is due to higher interest on the actuarial liability.

The Company's Pension Plan received an asset transfer from the BC Hydro Pension Plan on April 29, 2005 in relation to the 151 employees who elected transfer their accrued pension as at August 1, 2003 from the BC Hydro Pension plan to the Company's Pension Plan. As a result of the asset transfer, the F2006 pension expense forecast for basic benefits under the registered pension plan has decreased from F2006 plan since the expected return on the plan assets (7.0%) is greater than the interest cost on the liabilities (6.0%). The F2006 forecast for non-registered pension plan cost has increased due to higher interest cost and granting of special termination benefits.

The increase in F2007 pension expense is primarily attributable to the decrease in the discount rate assumption from 6.0% to 5.25% (a lower discount rate results in higher actuarial liabilities and current service costs for each of the plans) and lower Expected Return On plan Assets ("EROA") assumption from 7.0% to 6.5% in F2007. The F2007 pension expense has been prepared by Mercer Human Resource Consulting, and a copy of their letter is included as Appendix G: F2007 Pension Expense.

9.7 Insurance

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this evidence section is to provide an overview of the role of insurance within the electric transmission system in British Columbia, provide an overview of the primary insurance activities at BCTC, and comply with the terms of the F2006 Negotiated Settlement of BCTC's Revenue Requirement.

BCTC agreed to review its general liability insurance as part of the terms of the F2006 Negotiated Settlement of BCTC's Revenue Requirement. The F2006 Settlement Agreement in Amendment No. 10 of Appendix 1 to Order G-60-05 states that,

> BCTC shall review its general liability insurance coverage for F2007, including consideration of optimal coverage levels and self-insurance possibilities, and report on the results of that review in its next revenue requirements application.

This evidence section provides BCTC's response. BCTC engaged an independent consultant, H-W Asset Management Inc., to review and report on the existing general liability insurance coverage, and this report is included as Appendix D.

A summary of HW Asset Management's observations is as follows:

(a) BCTC's general liability coverage may not be sufficient to cover high impact, low probability events such as a sawmill destruction by a forest fire caused by BCTC.

(b) BCTC has more general liability coverage than the average Canadian utility. It is appropriate for BCTC to have more general liability coverage, since BCTC faces unusual exposures because of the physical environment in which it operates.

(c) BCTC's level of self-insured retention (deductible) of $0.5 million is reasonable, compared with BCTC's peers.

(d) BCTC should investigate a risk-sharing arrangement with the Provincial government.

(e) BCTC pays reasonable premiums for the insurance coverage in place.

BCTC faces a wide range of risks in the course of operations, maintenance, and management of the transmission system. Many of these risks can be managed either by implementing systems, standards and procedures such as safety and environmental, or by purchasing insurance. These measures reduce risk; however, they do not eliminate risk. BCTC, in conjunction with a broker, acquires appropriate insurance coverage from the underwriting market at the lowest cost. This ensures that the organization and its stakeholders are protected from the financial impact of these risks in a fiscally responsible manner.

9.7.1 Existing Program

The current BCTC insurance program consists of ten policies placed with various underwriters. Insurance is purchased on an annual basis through a fee-for-service broker. BCTC has renewed the existing policies to April 1, 2007. The renewal terms were based on the comprehensive assessment of the appropriate coverage levels for various insurance policies and is consistent with the response to the F2006 Settlement Agreement.

The insurance program covers the risks to the corporation such as property damage and liability from the day-to-day operations excluding construction. BCTC purchases construction project insurance on a case-by-case basis and those costs are capitalized in the total cost of the project.

Table 9.7-1. Summary of Coverage and Premiums

	Coverage Category	Annual Premium
1	Property Damage	$190,853
2	Liability	1,034,290
3	Other Liability	87,625
4	Directors and Officers Liability	170,000
5	**Total Cost of Coverage**	**$1,482,768**

9.7.1.1 Coverage Details

Each policy coverage category is listed and discussed below:

9.7.1.1.1 Property Damage

Property damage insurance covers the loss or damage to BCTC property, including equipment. The coverage provides for the cost of replacement for property and equipment and any extra expenses incurred by BCTC to continue operations following a loss event.

This insurance covers losses up to $100 million with a deductible of $0.5 million and an aggregate deductible limit of $1 million. The insurance applies to the existing control centres and the corporate office. BCTC bears the risk for losses up to the deductible and the underwriter pays for losses above the deductible up to the policy limit. The $0.5 million deductible represents approximately ten percent of the expected annual equity return at the current level. The aggregate limit reduces the deductible to zero if annual losses exceed $1 million.

9.7.1.1.2 Liability

These policies provide coverage for damage to third parties caused by BCTC. A liability may result from property or casualty damage caused by right of way maintenance, or types of liability associated with the operation of the system or BCTC facilities.

This insurance covers losses up to $300 million with a deductible of $0.5 million and an aggregate limit of $2 million. The aggregate limit reduces the deductible to $0.2 million if annual losses exceed $2 million.

9.7.1.1.3 Other Liability

Covers losses or damage to BCTC or others caused by employee crime, fiduciary duties such as a trustee of the pension plan and claims related to employment such as wrongful dismissal.

9.7.1.1.4 Directors' and Officers' Liability

Covers directors and officers of BCTC for losses for actual or alleged wrongful acts committed within the scope of their duties, and for which they are not already indemnified by BCTC. Where BCTC provides an indemnity, this insurance reimburses BCTC for amounts paid to directors and officers under the indemnity.

9.7.1.2 Indemnity and Coverage

BCTC's management determines insurance requirements after reviewing all of the risks faced by the organization, discussing the cost and availability of insurance coverage with brokers and the recommendation of consultants on the availability of other risk mitigation strategies. These other strategies include legislative protection, regulatory options and indemnities provided by others. For example, from commencement of operations on August 1, 2003 until April 1, 2005, BCTC was indemnified by BC Hydro for liability to third parties which exceeded $50 million. Accordingly, until April 1, 2005, BCTC did not require third party liability coverage for more than $50 million.

In accordance with the terms of the Key Agreements, specifically the Master Agreement, the BC Hydro indemnity terminated April 1, 2005. In advance of this deadline, BCTC conducted an analysis of a realistic worst-case loss scenario and concluded that the expected loss would require excess liability coverage of $200 million above the existing $50 million limit. A subsequent analysis by HW Asset Management notes a potential for losses of $300 million.

9.7.2 Management

BCTC initially extended its existing policies for 3 months to April 1, 2006 to:

(a) Accommodate any recommendations in H-W Asset Management's report that BCTC's management determines to be in the interests of the customers and its shareholder, and

(b) Allow the policy coverage to coincide with BCTC's fiscal year.

BCTC has renewed its insurance applications based on recommendations in H-W Asset Management's report for a one-year period from April 1, 2006 to April 1, 2007. One of H-W Asset Management's recommendations was to consider obtaining liability coverage for a higher limit; in the 2006/2007 renewal, BCTC increased its excess liability coverage from $250 million to $300 million.

BCTC is continuing to pursue a risk-sharing arrangement with the Provincial government.

9.7.2.1 Analysis of Risk

HW Asset Management's report indicates potential losses of up to $300 million. In the analysis, it was determined that significant damage to third parties may result from BCTC operation, maintenance and management of the Transmission System. The loss to third parties includes both property loss and disability.

9.7.2.2 Analysis of Coverage Levels

Alternate coverage limits in $50 million increments were investigated, and the data are presented in the following table. The premium cost for $300 million coverage is determined to be reasonable on a premium cost per unit of coverage compared to the coverage levels for a lesser amount of coverage.

Table 9.7-2. Alternate Coverage Limits

	Coverage Limits ($ million)	Estimated Premium ($) (based on 2004)	Estimated Premium per Coverage Limits ($ million)
1	$ 50	$426,738	$8,500
2	$100	$626,738	$6,300
3	$150	$726,738	$4,800
4	$200	$840,106	$4,200
5	$250	$896,790	$3,600
6	$300	$979,290	$3,300

Appendix D contains the report on General Liability Coverage for BCTC by HW Asset Management, an independent consultant. This appendix reviews and reports on the existing general liability insurance coverage.

10.0 CAPITAL PROGRAM STATUS (CAPITAL PLANT IN-SERVICE)

10.1 Growth Capital

PREFILED EVIDENCE OF PAUL CHOUDHURY, MANAGER, SYSTEM PLANNING AND PERFORMANCE ASSESSMENT

The purpose of this section is to present the Growth Capital projects forecast to go into service during F2006, F2007 and F2008 based on BCTC's most recent Capital Plan, to be used for the purpose of setting F2007 and F2008 rates through the BCH Owner's Revenue Requirement.

Table 10-1 shows Growth Projects that are forecast to have assets go into service during F2006, F2007 or F2008. Some of the listed projects also have assets that went into service prior to F2006 or are forecast to have assets go into service after F2008. The forecast of in-service additions reflects work-in-process at the beginning of F2006, and at the end of each year shown, including at the end of F2008. Most of these projects have been presented to the Commission through Capital Plans or CPCN Applications and approved. A small number of projects were applied for through the F2007 Capital Plan Update and are awaiting Commission determination. F2008 projects will appear in the F2008 Capital Plan that BCTC expects to file in November 2006.

Table 10-1. Forecast In-Service Additions and Depreciation – Growth ($'000)

		Approved Project Total (Incl SDA)	Forecast							Depn Rate	Forecast Depreciation (Note 1)		
			Project Total		In-Service Additions (Excl SDA)								
	Project Description		Incl SDA	Excl SDA	Prior Years	F2006	F2007	F2008	Beyond F2008		F2006	F2007	F2008
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Prior Year in-serviced projects with trailing costs in F2006												
1	Kennedy - New Transformer T5 (138/25kV)		769	769	624	145				3.3%	2	5	5
2	Transmission connection to Husky Oil Substation		235	235	177	58				1.9%	1	1	1
3	Burnaby Incinerator Plant - IPP Connection	961	1,020	1,020	1,012	8	1			1.9%	0	0	0
4	Executive House Hydro IPP	1,791	1,038	1,038	844	194				3.3%	3	6	6
5	Meridian - 230 kV Mechanically Switched Capacitors	3,893	2,774	2,774	2,655	119				3.3%	2	4	4
6	Rutherford Creek Power - IPP Connection	1,216	1,224	1,224	1,171	53				3.3%	1	2	2
7	CBK - RAS/Autovar for 5L91/98 Contingency	91	103	103	88	16				3.3%	0	1	1
8	GVWD Capilano Pumping PLant 69 kV Connection Proje	1,103	1,410	1,410	1,400	10				1.9%	0	0	0
9	Pingston Creek IPP - 66 kV Interconnection	14,058	14,062	14,062	14,056	6				1.9%	0	0	0
	Projects forecast to go into service during F2006												
10	PFMS Transformer Data Book		300	300		300				3.3%	5	10	10
11	Long Beach Sub - Mobile Transformer Connection		196	180		180				3.3%	3	6	6
12	RAS - Provision Unidentified Additions - F2006 and F200	1,000	750	750		250	500			3.3%	4	17	25
13	Mission Substation - Monitoring equipment	371	193	193		193				3.3%	3	6	6
14	Mission - Equipment Upgrade	478	464	464		464				3.3%	8	15	15
15	Meridian - SVC Station Land Purchase	160	157	157		157				3.3%	3	5	5
16	Area Planning Definition Work	300	300	300		300				3.3%	5	10	10
17	60L300 (Soda Creek to Mount Polley) Line Upgrade	164	198	198		198				1.9%	2	4	4
18	Vaseux Terminal Station Interconnection	11,448	9,520	9,520		9,519	2				150	299	300
19	Upper Mamquam Hydro IPP	2,581	1,764	1,764		1,764				1.9%	17	34	34
20	Prince George Pulp & Paper Interconnection	684	645	645		645				3.3%	11	21	21
21	Power Swing Disturbance Monitopring - GMS, REV, and	659	272	272		272				3.3%	4	9	9
22	Pender Harbour - 138/25 kV Transformer Replacement	4,068	2,570	1,028		1,028				3.3%	17	34	34
23	NTL - T1/T2 O/L Trip RAS	217	112	112		112				3.3%	2	4	4
24	Douglas Street - 138/25 kV Transformer	3,580	3,286	329		329				3.3%	5	11	11
25	China Creek Hydro IPP	375	206	144		131	13			3.3%	2	5	5
26	5L81/82 - RAS Tripping of BC_AB Ties	266	215	215		215				3.3%	4	7	7
27	5L76/79 Gen Shed RAS, Direct Transfer Trips, and 5L92	2,050	2,675	2,675		2,675				3.3%	44	88	88
28	5L51/52 - DTT 5L61 RAS	353	208	208		208				3.3%	3	7	7
29	2L293/112 - O/L RAS Triggering NLY PS Runback Sche	136	160	160		160				3.3%	3	5	5
30	ACK 5RX4 neutral RX and SA addition for 5L91 Single P		574	574		553	21			3.3%	9	19	19
	Projects forecast to go into service during F2007												
31	Whistler Village Reinforcement - Function Junction Subs	13,655	15,200	9,272			8,662	610		3.3%		143	296
32	Squamish - 69/25 kV Transformer	2,568	2,639	528			528			3.3%		9	17
33	Maple Ridge Area Capacity Increase - Haney Substation	14,238	13,946	8,786			8,156	630		3.3%		135	280
34	Mainwaring - 230/12 kV Transformer (T2) Replacement	5,338	5,137	103			103			3.3%		2	3
35	Langley Area System Reinforcement - Harvie Road Subs	28,289	27,100	21,951			20,777	1,175				314	645
36	Fox Creek Substation - Fort St John area Reinforcement	17,986	26,419	21,135			19,372	1,764				238	498
37	Como Lake - 25 kV Feeder Section Addition	6,690	6,616	1,985			1,985			3.3%		33	66
38	Cheekye - 69/25 kV Transformer and Feeder Position	2,674	2,601	130			130			3.3%		2	4
39	Cambie - 230/25 kV Transformer	7,222	7,383	1,255			1,255			3.3%		21	41
40	Annacis - add 69/12 kV transformer and upgrade LV equ	6,102	3,354	335			335			3.3%		6	11
41	Mt. Pleasant - Land for future substation	26,319	534	374			374			3.3%		6	12
42	KMO Islanding RAS	398	412	412			412			3.3%		7	14
43	Future IPP Connections		3,000	3,000			1,000	2,000		3.3%		17	66
44	Terasen TMPSE Project		34,584	34,238			34,225	14				558	1,115
45	Spences Bridge - 12/25 kV Conversion and Station Upgr		2,047	102			102			3.3%		2	3
46	Porteau Station Expansion		3,553	1,066			1,061	5		3.3%		18	35
47	Golden - 69 kV Capacitor Bank Addition		1,810	1,810			1,810			3.3%		30	60
48	Brilliant Expansion (BRX) Remrdial Action Scheme		345	345			345			3.3%		6	11
49	Athalmer - 69 kV Bus Tie and Disconnect Switch Additio		581	523			523			3.3%		9	17
	Note (1) - Each year's forecast depreciation expense reflects the total in-service addition beginning from F2006.												

		Approved Project Total (Incl SDA)	Forecast							Depn Rate	Forecast Depreciation (Note 1)		
			Project Total		In-Service Additions (Excl SDA)								
	Project Description		Incl SDA	Excl SDA	Prior Years	F2006	F2007	F2008	Beyond F2008		F2006	F2007	F2008
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Projects forecast to go into service during F2008												
50	RAS - Provision for Unidentified Additions - Future		500	500				500		3.3%			8
51	GMS Generation Shedding Modifications - Stage 2		1,600	1,600				1,600		3.3%			26
52	60L350 - Williston to Canreed 3rd 69kV line		1,122	1,122				1,122					18
53	Seventy Mile House - 69/25 kV Transformer Replacemer	1,205	1,732	173				173		3.3%			3
54	Rainbow Substation Reconfiguration	1,437	1,437	1,437				1,411	26	3.3%			23
55	Mission and Matsqui Area Supply	43,205	40,788	33,446				33,446					528
56	60L43/44 - Undergrounding	2,000	1,891	1,891				1,891		1.9%			18
57	Selkirk - 500 kV 123 MVAr Shunt Reactor	6,103	5,514	5,514				5,514		3.3%			91
58	Forest Kerr IPP	27,541	29,655	29,655				29,655		3.3%			489
59	Murrin Fault Level Reduction - 230/12 kV Murrin Transfo		8,076	485				485		3.3%			8
60	**Total**			**226,000**	**22,026**	**20,262**	**101,694**	**81,994**	**26**		**313**	**2,186**	**5,053**
61	Less CIA					-10,171	-3,000	-3,000		2.5%	-127	-292	-367
62	**Net Total**					**10,091**	**98,694**	**78,994**			**186**	**1,894**	**4,686**

Note (1) - Each year's forecast depreciation expense reflects the total in-service addition beginning from F2006.

10.2 Sustaining Capital

PREFILED EVIDENCE OF LARRY HAFFNER, MANAGER, ASSET PROGRAM DEFINITION

The purpose of this section is to present the Sustaining Capital programs forecast to go into service during F2006, F2007 and F2008 based on BCTC's most recent Capital Plan, to be used for the purpose of setting F2007 and F2008 rates through the BCH Owner's Revenue Requirement.

Table 10-2 shows Sustaining Capital programs that are forecast to have assets go into service during F2006, F2007 or F2008. The F2006 and F2007 numbers reflect BCTC's Capital Plan Update filing of January 23, 2006, currently under consideration by the Commission. The F2008 forecast is based on the F2006 to F2015 Capital Plan, adjusted to reflect Order G-91-05 and the Update filing. The forecast of in-service additions reflects work-in-process at the beginning of F2006, and at the end of each year shown, including at the end of F2008.

Table 10-2. Forecast In-Service Additions and Depreciation – Sustaining ($'000)

		Forecast In-Service Additions			Forecast Depreciation (Note 1)		
	Sustaining Capital Programs	**F2006**	**F2007**	**F2008**	**F2006**	**F2007**	**F2008**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
1	**Asset Management Support Systems**	750	750	700	40	120	198
2	**Cables**	9,124	8,932	1,910	87	258	361
3	**Overhead Lines**	31,677	30,130	29,500	301	888	1,455
4	**P&C**	8,557	14,730	11,970	141	525	966
5	**ROW Sustainment**	3,646	3,000	4,125	38	108	183
6	**Stations**	29,125	29,792	32,985	481	1,453	2,489
7	**Telecom**	25,278	8,560	8,046	1,264	2,956	3,786
8	**Total**	108,156	95,895	89,236	2,352	6,309	9,437

Note (1) - Each year's forecast depreciation expense reflects the total in-service addition beginning from F2006.

10.3 BCTC Capital

PREFILED EVIDENCE OF EBRAHIM VAAHEDI, CHIEF TECHNOLOGY OFFICER

The purpose of this section is to present the BCTC Capital programs forecast to go into service during F2006 and F2007 based on BCTC's most recent Capital Plan, to be used for the purpose of setting F2007 rates through the BCTC Revenue Requirement.

Table 10-3 shows BCTC Capital Programs that are forecast to have assets go into service during F2006 or F2007. The F2006 and F2007 numbers reflect Commission Order G-91-05 which directed a reduction of $2.4 million in aggregate expenditures over the two years. The forecast of in-service additions reflects work-in-process at the beginning of F2006, and at the end of F2006 and F2007.

Table 10-3. Forecast In-Service Additions and Depreciation – BCTC ($'000)

	Forecast In-Service Additions		Forecast Depreciation (Note 1)	
BCTC	**F2006**	**F2007**	**F2006**	**F2007**
(a)	**(b)**	**(c)**	**(d)**	**(e)**
Business Support Systems	12,697	2,342	1,084	2,367
Control Center Technologies	931	2,941	39	199
Facilities Management	1,558	250	75	161
Information Technologies	2,198	1,398	198	523
Total	17,384	6,931	1,396	3,251

Note (1) - Each year's forecast depreciation expense reflects the total in-service addition beginning from F2006.

11.0 REVENUE FORECAST AND RATE DETERMINATION

11.1 Revenue Forecast (PTP and Ancillary Services)

PREFILED EVIDENCE OF JANET FRASER, MANAGER, MARKET OPERATIONS

The purpose of this section is to provide a description of the revenue forecast process. The components of the forecast include:

(a) Network Integrated Transmission Service,

(b) Long-Term and Short-Term Point to Point ("PTP") Volumes and Prices,

(c) Ancillary Services, and

(d) Congestion Management Cost.

Specifically, this section will address items b) and c). Item a) is addressed in Section 11.2 and item d) is addressed in Section 7.3.

11.1.1 Point to Point Revenues

BCTC provides Long-Term Firm, Short-Term Firm and Non-Firm PTP Transmission Service. Long-Term Firm transmission service is sold in yearly service increments. Short-Term transmission service is sold in hourly, daily, weekly, and monthly service increments.

11.1.1.1 Volume Forecast Methodology

The forecast for Long-Term PTP Firm volume is based on confirmed transmission contracts. Long-Term Firm contracts contain yearly rollover rights which allow the service to be extended. For forecast purposes BCTC assumes that the rollover rights in all Long-Term contracts are exercised. Long-term contracts that are converted to Short-Term uses under BCTC's business practices are treated as Short-Term Transmission for the time that they are converted. BCTC forecasts the amount of additional revenue from Long-Term Conversion in F2007 to be $6.0 million. This is based on historical billed activity.

The forecast for Short-Term PTP volume is largely based on historical activity and customer forecast discussions. Customer forecast information is compared to

transmission scheduling activity and historical billed activity to determine forecast volume. Outage plans, system upgrades, and changing market conditions may also impact the short-term forecast.

11.1.1.2 Pricing Methodology

The Long-Term PTP rate is discussed in Section 11.2.2.

11.1.1.2.1 Short-Term Transmission Service

For the F2006 Annual Plan, BCTC forecast an average rate for all Short-Term transmission service based on billed historical activity. For F2007, short-term prices for firm and non-firm service have been segregated and forecast based on an average historical rate for each service.

11.1.1.2.2 Point to Point Revenue Forecast

Table 11-1. Revenue Table [41]

	Type of Service *$ millions*	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	Long-Term Firm PTP		29.8	32.5	24.6	32.0
2	Long-Term Firm PTP Conversion			-		(6.0)
3	Long-Term Deferral Fee		2.2	2.1		-
4	Short-Term Firm PTP		9.0	3.5	25.2	22.4
5	Short-Term Non Firm PTP		10.4	14.6	20.3	22.7
6	**Total PTP Revenue ($ millions)**		**51.4**	**52.7**	**70.1**	**71.2**
7	**Volumes in MWh**					
8	Long-Term Firm PTP		5,187,409	5,615,160	4,189,502	6,053,160
9	Long-Term Firm PTP Conversion			-		(1,131,837)
10	Short-Term Firm PTP		1,686,756	1,347,275	4,591,866	3,813,367
11	Short-Term Non-Firm PTP		4,601,090	5,521,788	6,340,677	6,961,315
12	**Total PTP Volume (MWh)**		**11,475,255**	**12,484,224**	**15,122,045**	**15,696,005**
13	**$/MWh**					
14	Long-Term Firm PTP	L1*1000000 / L8	5.745	5.788	5.872	5.292
15	Long-Term Firm PTP Conversion	L2*1000000 / L9				5.292
16	Short-Term Firm PTP	L4*1000000 / L10	5.336	2.598	5.488	5.878
17	Short-Term Non-Firm PTP	L4*1000000 / L11	2.260	2.644	3.202	3.260

Point-to-Point revenue is forecast to increase by $18.5 million in F2007 compared to F2006. This net increase is comprised of the following:

[41] See Appendix F regarding “F2006 Approved” column.

(a) Long-Term Firm contract decrease of $6.4 million in F2007 compared to F2006 due to the conversion of Long-Term contracts to Short-Term Firm PTP products combined with lower Long-Term rates.

(b) Long-Term Deferral Fee decrease of $2.1 million in F2007 compared to F2006. A significant Long-Term Firm PTP transmission contract was deferred for F2006.

(c) Short-Term Firm PTP increase of $18.9 million in F2007 compared to F2006 due to a combination of higher rates and volumes based on historical billed activity and customer forecast discussions.

(d) Non-Firm PTP increase of $8.1 million due to a combination of higher rates and volumes based on historical billed activity and customer discussions.

11.1.2 Ancillary Services Revenue

Ancillary services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. They include Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Operating Reserves, and Loss Compensation.

The Scheduling, System Control and Dispatch Service forecast is based on all transactions that require these services, including long term PTP, short term PTP, and Network Integration Transmission Service at approved tariff rates. The balance of the Ancillary Services forecast is based on historical billed activity.

Table 11-2. Ancillary Services Forecast[42]

	Type of Service $ millions	Ref.	F2005 Actual	F2006 Approved	F2006 Forecast	F2007 Plan
	(a)	(b)	(c)	(d)	(e)	(f)
1	Scheduling, System Control and Dispatch Service		2.3	4.0	6.4	3.3
2	Other Ancillary Services		3.1	4.8	3.6	6.0
3	**Total Ancillary Services**		**5.4**	**8.8**	**10.0**	**9.3**
4	**Volumes in MWh**					
5	Scheduling Fee Volume			6,869,064	10,932,543	28,804,825
6	**$/MWh**					
7	Scheduling Fee	T11-7		0.582	0.582	0.115

Ancillary Services revenue increased $0.5 million from F2007 to F2006 based on historical billed activity and changes to prescribed Tariff rates.

Scheduling and Dispatch revenue is forecast to decrease by $0.7 million due to cost reductions. These cost reductions reflect productivity improvements through system automation associated with the scheduling and settlements and billing processes and better management of system sustainment activities. The change reflects net labour cost reductions of $0.3 million and reduced system sustainment costs of $0.4 million.

[42] See Appendix F regarding “F2006 Approved” column.

11.2 Rate Determination

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to provide a description of the determination of rates. The three components of the TRR (the Owners RR, the AMMRR and the BCTC RR) are collected under the Open Access Transmission Tariff ("OATT") through:

(a) Network Integrated Transmission Service;

(b) Long-Term and Short-Term Point-to-Point Services;

(c) Ancillary Services; and

(d) Engineering Studies.

Specifically, this section will address the calculation of rates for items a, b and c. Item d, Engineering Studies revenues, is based on cost recovery.

11.2.1 Network Integrated Transmission Service ("NITS")

NITS charges collect the largest amount of the TRR. The NITS charge equals the transmission revenue requirement less the revenues from Point-to-Point and Ancillary Services as illustrated in the following equation:

NITS = TRR - (Point-to-Point Revenue + Ancillary Services Revenue + Engineering Studies Revenue)

The decrease in the TRR in F2007 compared to the approved levels for F2006, combined with the increase in forecasted Point-to-Point revenue, reduces the revenue requirement recovery from the Network Customer. The Network TRR recovery from domestic customers (the NITS charge) is reduced by $61.1 million or 12.1% for F2007. Table 11-3 provides the calculation of the NITS charge. For further explanation of the change in the Transmission Revenue Requirement refer to Section 4 through Section 7, and for Point-to-Point revenues refer to Section 11.1.

Table 11-3. F2007 Plan - NITS Determination[43]

	$ millions	Ref.	F2006 Approved	F2007 Plan	$ Change	% Change
	(a)	(b)	(c)	(d)	(e)	(f)
1	Total Transmission Expenses	T4-2	695.2	623.1	(72.1)	-10.4%
2	Less non-tariffed Revenues and Recoveries	T4-2, Sec.5.7, Sec.7.6	(128.9)	(98.9)	30.0	-23.3%
3						
4	**Transmission Revenue Requirement**	T4-1	566.3	524.2	(42.1)	-7.4%
5						
6	**Less Point-to-Point & Ancillary Service Revenues**					
7	Long Term Point-to-Point Revenue	T11-1	(34.6)	(26.1)	8.5	-24.6%
8	Short Term Point-to-Point Revenue	T11-1	(18.1)	(45.1)	(27.0)	149.2%
9	Subtotal - Point-to-Point		(52.7)	(71.2)	(18.5)	35.1%
10						
11	Ancillary Services - Scheduling & Dispatch Revenue	T11-2	(4.0)	(3.3)	0.7	-17.3%
12	Ancillary Services - Other Revenue	T11-2	(4.8)	(6.0)	(1.2)	25.0%
13	Subtotal - Ancillary Services		(8.8)	(9.3)	(0.5)	5.8%
14						
15	Engineering Studies Revenue		(0.3)	(0.3)	0.0	0.0%
16	**Network Transmission Revenue Requirement**		**504.5**	**443.4**	**(61.1)**	**-12.1%**

Aside from the determination of the NITS charge there is also a need to split the revenue between BC Hydro and BCTC. Table 11-4 provides the split of the NITS revenue between the two companies, based on the TRR components.

[43] See Appendix F regarding "F2006 Approved" column.

Table 11-4. F2007 TRR and NITS Split Between BC Hydro and BCTC[44]

	$ millions	Ref.	BCH Owners & AMMA	BCTC	Total
	(a)	(b)	(c)	(d)	(e)
1	OMA	Sec.5.1 & 9	5.8	164.9	170.7
2	AMMA Fee to BCTC	Sec.6	87.3	-	87.3
3	Cost of Market	Sec.7.3	-	6.8	6.8
4	Allocated BC Hydro Corporate Sustaining Costs	Sec.5.6	11.2	-	11.2
5	Allowed Return on Equity	Sec.5.2 & 7.2	102.6	2.9	105.5
6	Asset Related Expenses	Sec.5 & 7	313.8	15.1	328.9
7					
8	**Gross Transmission Costs**		**520.7**	**189.7**	**710.4**
9					
10	**Less Non-Tariffed Revenues**				
11	Asset Management Fee from BC Hydro	Sec.6	-	(87.3)	(87.3)
12	Other Non-Tariffed Revenue	Sec.5.7 & 7.6	(66.8)	(32.1)	(98.9)
13					
14	**Total Non-Tariffed Revenues**		**(66.8)**	**(119.4)**	**(186.2)**
15					
16	**Transmission Revenue Requirement**		**453.9**	**70.3**	**524.2**
17					
18	Less Point-to-Point Revenue	T11-5	(62.8)	(8.4)	(71.2)
19	Less Engineering Studies Revenue	T11-3	-	(0.3)	(0.3)
20	Less Ancillary Services - Scheduling & Dispatch Revenue	T11-3	-	(3.3)	(3.3)
21	Less Ancillary Services - Other Revenue	T11-3	-	(6.0)	(6.0)
22					
23	**Network TRR ($ millions)**		**391.1**	**52.3**	**443.4**
24	**F2006 Approved Network TRR**		**447.0**	**57.5**	**504.5**

11.2.2 Point-to-Point

Table 11-5 provides the detail of how the Point-to-Point revenue is split between BCTC and BC Hydro (refer to Table 11-4, line 18).

[44] See Appendix F regarding "F2006 Approved" column.

Table 11-5. Point-to-Point Revenue Split Between BC Hydro and BCTC[45]

	$ millions	Ref.	F2006 Approved	F2007 Plan
	(a)	(b)	(c)	(d)
1	**Total Forecast Point-to-Point Revenue**	T11-3	52.7	71.2
2				
3	BCH Owners RR	T11-6	493.7	453.9
4	BCTC RR less Engineering Studies and Ancillary Services Revenue	T11-6	63.5	60.7
5	**Total Net Transmission RR**		**557.2**	**514.6**
6	**Point-to-Point Revenue assigned**			
7	**on the basis of a prorata share**			
8	**between BCH and BCTC:**			
9	BC Hydro Portion of Total Net Transmission RR	(L3 / L5)	**88.6%**	**88.2%**
10	BCTC Portion of Total Net Transmission RR	(L4 / L5)	**11.4%**	**11.8%**
11				
12	Point-to-Point revenue assigned to BC Hydro	(L1 X L10)	46.7	62.8
13	Point-to-Point revenue assigned to BCTC	(L1 X L11)	6.0	8.4
14	**Total Forecast Point-to-Point Revenue**		**52.7**	**71.2**

Point-to-Point service is provided on a Short-Term or Long-Term contract basis. Short-Term Point-to-Point service rates are cost-of-service based, and discounted in accordance with a formula as discussed in Section 11.1. The Long-Term Point-to-Point rates are set using the following formula:

Long-Term Point-to-Point Rate = (TRR - Ancillary Services Revenue - Engineering Studies Revenue) / Maximum Capacity Supply

Table 11-6 shows the calculation of the Long-Term Firm Point-to-Point rate. In setting the Long-Term Firm Point-to-Point rate, BCTC uses BC Hydro's maximum capacity supply as reported in BC Hydro's 2006 Integrated Electricity Plan ("IEP").

[45] See Appendix F regarding "F2006 Approved" column.

Table 11-6. Long-Term Point-to-Point Determination

	$ millions	Ref.	BCH Owners & AMMA	BCTC	Total
	(a)	(b)	(c)	(d)	(e)
1	Transmission Revenue Requirement	T11-4	453.9	70.3	524.2
2	Less Engineering Studies Revenue	T11-4	-	(0.3)	(0.3)
3	Less Ancillary Services - Scheduling & Dispatch Revenue	T11-4	-	(3.3)	(3.3)
4	Less Ancillary Services - Other Revenue	T11-4	-	(6.0)	(6.0)
5	**Net Transmission Revenue Requirement**		**453.9**	**60.7**	**514.6**
6	**Maximum Capacity Supply (MW)** Note 1		11,100	11,100	11,100
7	**Annual Billing Determinants**	L6 X 12 X 1000	133,200,000	133,200,000	133,200,000
8	**Long Term Point-to-Point Rate**	L5 X 1000000 / L7 = $/kW month	**$3.407**	**$0.456**	**$3.863**

11.2.3 Ancillary Services

With the exception of the ancillary service for Scheduling and Dispatch, BCTC purchases ancillary services on behalf of its customers, primarily from BC Hydro. These services are charged to BCTC on the basis of BC Hydro's Interconnected Operations Services tariff and these charges are passed on to customers on a flow-through basis. The annual revenue of $6.0 million has a corresponding cost reflected in Cost of Market, as noted in Section 7.3.

The Scheduling and Dispatch rate is a volume-driven rate, calculated as the total cost for Scheduling and Dispatch divided by the total volume forecast.

Table 11-7. Scheduling and Dispatch Rate Determination

		MW.h	S&D Cost ($)	S&D Rate $/MW.h
	(a)	(b)	(c)	(d)
1				(c) / (b)
2	**Scheduling & Dispatch Rates**			
3	**F2007**	28,804,825	3,300,000	$0.115
4	**F2006**	6,869,064	4,000,000	$0.582

11.2.4 Proposed Rates

BCTC proposes rates to be effective April 1, 2006 as summarized in the following Table 11-8.

Table 11-8. Proposed Rates

	Rate Schedule	Rate Class	Existing Rate	Proposed Rate	Ref.
	(a)	(b)	(c)	(d)	(f)
1	**RS 00**	**Network Integrated Transmission Services monthly rate**	$ 42,041,667	$ 36,950,000	T11-4, Col (e), L23 / 12
2	**RS 01**	**Long & Short Term Point-to-Point Transmission Service**			
3		Minimum Price - /kW	$0	$0	
4		Maximum Price			
5		Monthly - /kW of Reserved Capacity per mo.	4.220	3.863	T11-6, Col (e), L8
6		Yearly - /kW of Reserved Capacity per year	50.655	46.356	L5 X 12
7		Weekly - /kW of Reserved Capacity per week	0.974	0.891	L6 / 52
8		Daily - /kW of Reserved Capacity per day	0.139	0.127	L7 / 7
9		Hourly - /kW of Reserved Capacity per hour	0.0058	0.0053	L8 / 24
10	**RS 02**	**Non-firm Point-to-Point Transmission Service**			
11		Minimum Price - /kW	$0	$0	
12		Maximum Price:			
13		Monthly - /kW of Reserved Capacity per mo.	4.220	3.863	T11-6, Col (e), L8
14		Weekly - /kW of Reserved Capacity per week	0.974	0.891	L19 / 52
15		Daily - /kW of Reserved Capacity per day	0.139	0.127	L14 / 7
16		Hourly - /kW of Reserved Capacity per hour	0.0058	0.0053	L15 / 24
17	**RS 03**	**Scheduling & Dispatch Transmission Service**			
18		per MW of Reserved Capacity per hour	0.582	0.115	T11-7, Col (d), L3

12.0 APPROVED DEFERRAL ACCOUNTS

PREFILED EVIDENCE OF ELIZABETH HONG, CONTROLLER

The purpose of this section is to:

(a) describe BCTC's approved deferral accounts,

(b) report on the accumulated forecast balances recorded in these deferral accounts,

(c) describe the proposed disposition of the F2006 deferral account balances, including allocation to customer rate classes, and

(d) request continuation and/or termination of approved deferral accounts as described below.

12.1 Accumulated Deferral Balances

The following Table 12-1 provides the forecast balance of each deferral account as at March 31, 2006.

Table 12-1. Deferral Account Summary

	Account Name (1)	Ref.	F2006 Approved	F2006 Forecast	Difference	Interest	Account Balance Surplus (Deficit) as at March 31, 2006
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Revenue Deferral (RDA) 01.0000.17100.000.00	Sec.12.2.1	566.0	584.0	18.0	0.4	18.4
2	Emergency Maintenance Deferral (EMEDA) 01.0000.17200.000.00	Sec.12.2.2	2.0	0.7	1.3	0.0	1.3
3	Cost of Market Deferral (COMDA) 01.0000.17300.000.00	Sec.12.2.3	5.8	4.5	1.3	0.0	1.3
4	Regulatory Exp Deferral (REDA) 01.0000.17400.000.00	Sec.12.2.4	3.3	1.6	1.7	0.0	1.7
5	Grid West Deferral (GWEDA) 01.0000.17500.000.00	Sec.12.2.5	1.5	0.8	0.7	0.0	0.7
6	**Total**				**23.0**	**0.4**	**23.4**

Notes:
(1) For RDA the account will reflect the YTD variance and closing balance from the prior year.
For the EMDA, COMDA and REDA, the deferral accounts reflect the balance at the most recent year end.

12.1.1 Background

Beginning April 1, 2005 BCTC operated with full authority and responsibility for providing transmission services under its own transmission tariff. Recognizing that direct responsibility for certain transmission-related costs exposed BCTC to variances in revenues and costs outside of its control, BCTC requested approval of certain deferral accounts.

BCTC's deferral accounts were approved pursuant to Special Direction 9. Section 6 of Special Direction No. 9 states,

> When regulating the transmission corporation, the Commission:
>
> (a) must allow the transmission corporation to establish the deferral account or accounts contemplated by paragraph 4.13(f) of the Master Agreement;
>
> (b) may allow the transmission corporation to establish one or more other deferral accounts for other purposes; and
>
> (c) must fix or regulate the transmission corporation's rates in such a way as to allow the deferral account or accounts to be cleared from time to time and within a reasonable period of time.

BCTC currently has five deferral accounts:

(a) Revenue Deferral Account ("RDA"),

(b) Emergency Maintenance Expenditure Deferral Account ("EMEDA"),

(c) Cost of Market Deferral Account ("COMDA"),

(d) Regulatory Expenditures Deferral Account ("REDA"), and

(e) Grid West Expenditures Deferral Account ("GWEDA").

BCTC's approved deferral accounts are interest-bearing deferral accounts. An interest charge or credit is applied to the annual average balance in each deferral account using BCTC's weighted average cost of debt during the same period.

The sources of potential variance include the forecast of BCTC's own revenue requirement, BCTC revenues under the Asset Management and Maintenance Revenue Requirement and BC Hydro's Owner's Revenue Requirement. These variances expose BCTC to significant financial risks relative to its current and expected capital structure. BCTC sought and received approval from the Commission for the deferral accounts to mitigate some of these risks.

BCTC recognizes that current circumstances continue to require these deferral accounts. For example, each $0.10/MWh change in the short-term market price changes short-term Point-to-Point ("PTP") revenue by approximately $0.7 million per year. Since the estimated short-term PTP revenue is a credit to the calculation of the transmission revenue requirement, the change in PTP revenue results in excess of a 20% change in BCTC's actual return. Similarly, unexpected events, like the southern interior forest fires during F2004 that caused BCTC to incur emergency maintenance costs in excess of $4.0 million would, in the absence of deferral treatment, result in the elimination of BCTC's actual return for the fiscal year.

12.2 Proposed Disposition of Deferral Account Balances

In this Application, except for the balance in the EMEDA, BCTC proposes to clear the F2006 year-end deferral account balances in each account and dispose of the account balances through direct refunds to customers. It is BCTC's preference to clear the balances annually.

The disposition applicable to each account is discussed below.

12.2.1 Revenue Deferral Account ("RDA")

The RDA was approved through Commission Order G-96-04. This deferral account allows BCTC to accrue annual variances between forecast and actual Point to Point Transmission service and Ancillary service revenues.

During F2005, BCTC did not have its own tariff and there was no requirement for an RDA. During F2006, BCTC administered its own transmission tariff and BCTC experienced variances between the F2006 plan and the actual revenues, $18.0 million. The F2006 forecast balance in the deferral account is $18.4 million including accrued interest. This variance is due to higher PTP revenues resulting from higher

volumes ($2.3 million) and market rates ($16.6 million), and to ancillary revenues relating to Scheduling and Dispatch ($2.4 million) also caused by higher volumes. These higher revenues are offset by the cancellation of the long-term reservation fee, $2.2 million and lower ancillary services revenue, $1.2 million.

BCTC proposes to dispose of this balance through a one time credit to customers.

The balance in the RDA will be allocated between customer rate classes in the following manner:

Table 12-2. Allocation of RDA Balance to Customer Rate Classes

	$ millions	NITS	Long-term Point to Point	Short-term Point to Point	Total
	(a)	(b)	(c)	(d)	(e)
1	Point to Point Services Variance	17.2	-	-	17.2
2	Ancillary Services:				-
3	Scheduling & Dispatch Variance	-	-	2.4	2.4
4	Other Variance	(1.1)	(0.1)	-	(1.2)
5	**Total amounts allocated/assigned**	**16.1**	**(0.1)**	**2.4**	**18.4**

Amounts recorded in the RDA in respect of Point to Point revenue variances are assigned 100% to NITS service because, under the OATT, the NITS service customer class is responsible for any amount of the TRR not recovered through Point to Point rates or ancillary services.

Amounts recorded in the RDA in respect of Scheduling and Dispatch Ancillary Service revenue are assigned 100% to Short-Term Point to Point as this is the only customer class that pays for this service.

Amounts recorded in the RDA in respect of Other ancillary services is allocated between NITS and Long Term Point to Point customer classes on the basis of revenue because these customer classes are responsible for any amount of the TRR not recovered through ancillary services.

12.2.2 Emergency Maintenance Expenditure Deferral Account ("EMEDA")

The EMEDA was approved by Commission Order G-96-04. This deferral account captures variances between forecast and actual non-capital emergency maintenance expenditures incurred as a result of unanticipated major equipment failures, extreme

weather, wildfires, or similar events. The forecast provision in rates for such emergency expenditures is $2.0 million.

The Commission approved a revenue requirement recovery of $2.0 million annually to fund emergency maintenance expenditures. This estimate resulted from the average of emergency maintenance expenditures during the period F1999 to F2003. Recognizing that emergency maintenance expenditures vary beyond the control of BCTC and beyond the ability to accurately forecast such events, BCTC records any variances from this annual funding provision in the EMEDA. The definition of the expenditures qualifying for inclusion in the EMEDA is:

> non-capital emergency expenditures, such as higher-than-forecast costs incurred as a result of unanticipated major equipment failures, extreme weather, wildfires or similar events.

Over the period F2001 to F2005, emergency expenditures averaged $2.8 million annually. These events have included the 2003 summer forest fires, the cable failure to Vancouver Island and the collapse of transmission towers due to heavy snowfall. This funding is to address unexpected maintenance issues as they arise.

Due to the nature of the EMEDA, where unspent balances provide a provision for future years and where the cost of emergency maintenance is greater than the annual plan, BCTC proposes to carry any positive balances over to future years.

Table 12-3 summarizes the extraordinary maintenance occurrences over the years.

Table 12-3. Summary of Extraordinary Maintenance

	$ millions	F1999	F2000	F2001	F2002	F2003	F2004	F2005
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Cable and line repairs for 5L30/32	1.1						
2	5L30/32 transmission tower repair		1.5					
3	Cable repairs 2L39/53			1.0				
4	Kelly Lake Transformer Repair		0.2					
5	Cable repairs, 230kV Submarine, Metro UG Cable Circuits/Trincomali channel and Galiano Ridge				1.6			
6	5L30/32 Line repair, damage caused by mud slide December 2002					2.8		
7	2L90/91 Line repairs, cable failure to Vancouver Island					1.9		
8	Southern Interior Summer Fires						4.1	
9	Pothead repairs (1L018, 5L029 and DC1L2)						0.9	
10	2L090 Fire damage							1.3
11	Firth Substation oil spill and emergency response							0.3
12	**Total Extraordinary Maintenance**	**1.1**	**1.7**	**1.0**	**1.6**	**4.7**	**5.0**	**1.6**
13	**Average Expenditure over 5-year Period**					**2.0**	**2.8**	**2.8**

In F2006, one emergency incident required the use of EMEDA funds. This incident related to the failure of a cable stop joint. A stop joint is a custom-built device connecting two cable ends, isolating the oil systems of each cable section while maintaining appropriate electrical insulation.

On December 20, 2005, a fault occurred on a cable stop joint on circuit 2L064 (Kidd #2 to Sperling). In this case the stop joint connects two cables of different manufacture. The catastrophic failure occurred on Phase A at 49th and Cambie in Vancouver and rendered the joint irreparable; cables for Phases B and C remained intact. The stop joint that failed was installed in November 2002 (as part of a 2L064 Upgrade Project) by a contractor, EHV Power, of Ontario under the supervision of Sumitomo Cable construction representatives. A subsequent test of Phases B and C on December 27th confirmed the electrical integrity of these cables and BCTC replaced the A-phase stop joint only.

The cost of this major equipment failure for F2006 is forecast to be $0.7 million.

BCTC's Asset Management and Maintenance plan for F2007 includes $2.0 million for emergency maintenance, and BCTC proposes to carryover the unused portion of the F2006 Plan, which is $1.3 million (before interest) recorded in the EMEDA to F2007.

12.2.3 Cost of Market Deferral Account ("COMDA")

The COMDA was approved by Commission Order G-96-04. This deferral account captures all variances between forecast and actual Cost of Market Expenditures. Cost-of-Market Expenditures include:

(a) Congestion management expenses relating to the purchase of operating reserves, transmission location credits, unscheduled flow mitigation and operating agreements between control areas.

(b) Ancillary services expenses BCTC incurs for all generation-based ancillary services that it, in turn, sells to customers on a cost flow-through basis as reflected in BCTC's OATT Rate Schedules 04 to 09. Ancillary Service expenses have corresponding Ancillary Service revenues, therefore any over- or under-expenditures will net to zero based on the revenue collected for these services.

Table 12-4. Cost of Market Variance

	$ Millions	F2006 Approved	F2006 Forecast	F2006 Deferral Account Balance – Surplus/(Deficit)
		(a)	(b)	(c)
1	Congestion Management	1.0	0.9	0.1
2	Ancillary Services	4.8	3.6	1.2
3	**COMDA Total**	**5.8**	**4.5**	**1.3**

BCTC proposes to dispose of this balance through a one-time credit to customers.

The balance in the COMDA will be allocated between customer rate classes in the following manner:

Table 12-5. Allocation of COMDA Balance to Customer Rate Classes

	$ millions	NITS	Long-term Point to Point	Short-term Point to Point	Total
	(a)	(b)	(c)	(d)	(e)
1	Allocated Cost of Market Variance	1.2	0.1	-	1.3

Amounts recorded in the COMDA are allocated between NITS and Long Term point to point customer classes on the basis of revenue because, these customer classes are responsible for all cost components of the TRR.

12.2.4 Regulatory Expenditure Deferral Account ("REDA")

The REDA was approved by Commission Order G-96-04. This deferral account permits BCTC to recover the variances between forecast and actual regulatory costs. These costs include costs associated with regulatory applications such as BCTC's counsel, experts and staff, hearing costs, and Intervenor costs as approved by the Commission. The forecast provision in rates for regulatory expenditures is $3.3 million.

In its F2006 Revenue Requirement Application (page 15), BCTC proposed Regulatory expenses of $3.3 million. BCTC's F2006 Revenue Requirement Application, as amended by the Negotiated Settlement Agreement, was approved by Commission Order G-60-05, including $3.3 million for Regulatory expenses.

Actual Regulatory expenses for F2006 total $1.6 million resulting in a variance of $1.7 million that has been placed in the REDA. The actual Regulatory expenses comprise:

(a) labour costs associated with Regulatory staff;

(b) allocated facilities and computer costs;

(c) business expenses (e.g., office supplies, printing); and

(d) legal and consulting costs.

The variance is largely a result of Regulatory expenses that were budgeted as OMA and were charged directly to the VITR capital project.

Reflecting the experience gained in F2006, Regulatory expenses for F2007 have been budgeted to support the level of non-capital activity that is expected for the Regulatory Department in F2007. The proposed Regulatory budget of $3.3 million is more fully discussed in Section 9.4 and is expected to result in a smaller REDA balance at the end of F2007.

BCTC proposes to dispose of this balance through a one time credit to customers.

The balance in the REDA will be allocated between customer rate classes in the following manner.

Table 12-6. REDA Balance to Customer Rate Classes

	$ millions	NITS	Long-term Point to Point	Short-term Point to Point	Total
	(a)	(b)	(c)	(d)	(e)
1	Allocated Regulatory Variance	1.6	0.1	-	1.7

Amounts recorded in the REDA is allocated between NITS and Long Term point to point customer classes on the basis of revenue because, these customer classes are responsible for all cost components of the TRR.

12.2.5 Grid West Expenditure Deferral Account (“GWEDA”)

The GWEDA was approved by Commission Order G-60-05. This deferral account recovers the variances between forecast and actual expenses for BCTC's participation in the Grid West Initiative. These costs include BCTC's counsel, consultants, travel and other out-of-pocket expenses incurred as a result of participation. Under the terms of the Order, which reflected the negotiated settlement of BCTC’s F2006 Revenue Requirement Application, the amount of Grid West costs included in BCTC’s F2006 rates was set at $1.5 million. Any variance from $1.5 million is to be recorded in the GWEDA.

For F2006, Grid West costs totalled $0.8 million resulting in a GWEDA balance at year-end of $0.7 million. Based on events described in Section 13, BCTC does not plan to incur Grid West costs in F2007, and has not included Grid West costs in its revenue requirement calculation for F2007. Accordingly, BCTC does not expect

further entries to the GWEDA in F2007 and applies to clear the balance of the GWEDA, with interest, and cancel the GWEDA, upon approval of this Application.

BCTC proposes to dispose of this balance through a one time credit to customers.

The balance in the GWEDA will be allocated between customer rate classes in the following manner:

Table 12-7. GWEDA Balance to Customer Rate Classes

	$ millions	NITS	Long-term Point to Point	Short-term Point to Point	Total
	(a)	(b)	(c)	(d)	(e)
1	Allocated Grid West Variance	0.7	0.0	-	0.7

Amounts recorded in the GWEDA is allocated between NITS and Long Term point to point customer classes on the basis of revenue because, these customer classes are responsible for all cost components of the TRR.

13.0 GRID WEST

PREFILED EVIDENCE OF CAMERON LUSZTIG, DIRECTOR, STRATEGY AND POLICY

The purpose of this section is to:

(a) report on the current status of BCTC's Grid West Activities, and

(b) report on the status of BCTC loans to Grid West.

13.1 Current Status of BCTC's Grid West Activities

Grid West is a not-for-profit organization that was created to establish an independent, regional transmission operator and planner for the western US grid. BC Hydro, and subsequently BCTC, has participated in Grid West development activities (previously known as RTO West) since 2000.

BCTC announced on January 25, 2006 that it would suspend funding for the next phase of Grid West development. BCTC continues to support Grid West as a vehicle for regional integration in the Pacific Northwest, but BCTC believes the benefits identified for British Columbia in the Grid West proposal do not justify the cost of participation in the next development phase. BCTC has led the province's participation in the development of Grid West and this involvement has been critical to ensuring BC is aware of and able to influence how the interconnected transmission system develops. BCTC's decision is supported by the province's Grid West Steering Committee, which includes representatives from BC Hydro, Powerex and Fortis, and is chaired by the BC Ministry of Energy, Mines and Petroleum Resources. The BC Utilities Commission, also a member of the Steering Committee, did not participate in the decision to terminate Grid West funding, as it is the quasi-judicial body responsible for evaluating utility rates.

In late 2005, Grid West participant Bonneville Power Administration ("BPA") of Portland, Oregon decided to withdraw from the Grid West initiative. Following this, Grid West, along with active involvement from BCTC, completed a cost-benefit analysis to assess the feasibility of a Grid West structure without the involvement of BPA. Although the analysis showed that overall benefits to the Northwest region were still possible, BCTC believes the net benefits to BC were not sufficient to

warrant ongoing funding of the development of Grid West. Had BCTC continued to fund Grid West at this stage, it would have been required to loan Grid West approximately $3.2 million over the next 18-month period, with repayment beginning once the entity became a functioning and revenue producing utility. In addition, BCTC expects it would have spent roughly $1.5 million per year on its own costs related to Grid West development. British Columbia's high-voltage electricity grid has been interconnected to the western US grid for over three decades and BCTC continues to support coordination in this region. BCTC will continue to work to find better, more efficient ways of using and expanding the regional transmission system, by pursuing such regional initiatives as:

(a) harmonizing commercial business practices;

(b) improving system planning and expansion procedures to reduce seams and increase the capacity of the grid;

(c) developing new services to efficiently move and sell electricity across the systems of adjacent utilities; and

(d) coordinating system outages between utilities.

13.2 Status of BCTC Loans to Grid West

BCTC has provided funding to Grid West as part of its participation in Grid West. The amount of BCTC's funding of Grid West was recorded on BCTC's balance sheet as a receivable of CDN $0.9 million as of February 28, 2006. There was uncertainty with the timing and likelihood that these loans would be repaid and as a result, BCTC elected to make provision in F2006 related to this uncertainty. BCTC elected to write-off the balance as at March 31, 2006. On April 11, 2006, the remaining utilities in Grid West voted to dissolve Grid West.

This provision has no impact on F2007 revenue requirements and BCTC will not be seeking recovery of the write-off in rates.

14.0 COMMISSION DIRECTIVES

(This section is reserved for responses to Commission Directives that will be filed at a later date.)

Appendix A

Directive Concordance Table

(Appendix A will be provided with Section 14 at a later date.)

Appendix B

Depreciation Study – Determination of Average Service Lives

DEPRECIATION STUDY

DETERMINATION OF AVERAGE SERVICE LIVES

APPLICABLE TO PLANT IN SERVICE OF BRITISH COLUMBIA TRANSMISSION CORPORATION

AS OF MARCH 31, 2005

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania **Calgary, Alberta** **Valley Forge, Pennsylvania**

DEPRECIATION STUDY

DETERMINATION OF AVERAGE SERVICE LIVES

APPLICABLE TO PLANT IN SERVICE OF
BRITISH COLUMBIA TRANMISSION CORPORATION

AS OF MARCH 31, 2005

GANNETT FLEMING INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania Calgary, Alberta Valley Forge, Pennsylvania

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November 18, 2005

British Columbia Transmission Corporation
Suite 1100, Four Bentall Centre
1055 Dunsmuir Street
Vancouver, BC V7X 1V5

Attention: Mr. Michael Wynne
Manager, Capital Accounting and Projects

Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the utility assets of British Columbia Transmission Corporation (BCTC) as of March 31, 2005. Our report presents a description of the methods used in the estimation of the average service lives, and the calculations of annual depreciation applicable to the plant in service as at March 31, 2005.

A periodic review of the depreciation policies, methods and average service lives is recommended.

Respectfully submitted,

GANNETT FLEMING, INC.
VALUATION AND RATE DIVISION

LARRY E. KENNEDY
Director, Canadian Services

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PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART III. RESULTS OF STUDY

PART I. INTRODUCTION

BRITISH COLUMBIA TRANSMISSION CORPORATION
VANCOUVER, BRITISH COLUMBIA

DEPRECIATION STUDY

DETERMINATION OF AVERAGE SERVICE LIVES APPLICABLE TO PLANT IN SERVICE AS OF MARCH 31, 2005

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted for the public utility assets of British Columbia Transmission Corporation (BCTC or Company) to determine the average service lives to be used in the determination of depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of plant as of March 31, 2005.

The average service lives presented herein were developed on generally-accepted methods and procedures for developing average service life estimates. The estimated survivor curves used in this report are based on studies incorporating data through 2005 for most accounts.

Part I, Introduction, contains statements with respect to the scope of the report and the basis of the study. Part II, Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and in the calculation of depreciation. Part III, Results of Study, presents a summary of the average service life estimates for the plant surviving as at March 31, 2005, and the detailed depreciation calculations indicating the annual depreciation accrual.

BASIS OF THE STUDY

Depreciation. The average service life estimates presented herein were developed using depreciation rate calculations based on the straight-line method, the whole life basis and the Average Group Life (AGL) procedure. The calculation was based on the attained ages and estimated service life characteristics for each depreciable group of assets.

Service Life Estimates. The method of estimating service life consisted of reviewing the use of the asset through site tours and operating and management interviews, reducing this knowledge to retirement trends through the use of techniques that have been generally accepted in various regulatory jurisdictions, and forecasting the trend of survivors for each of the Profile ID's group on the basis of interpretations, and consideration of Company plans for the future. The combination of the actual trends, and the estimated future trend, yielded a complete pattern of life characteristics from which the average service life was derived. The service life estimates were then applied to the aged surviving balances as at March 31, 2005.

RECOMMENDATIONS

The calculated annual depreciation accrual rates set forth herein apply specifically to plant in service as of March 31, 2005. The annual depreciation accrual rates have been converted to an average service life estimate that is applicable to the aged surviving balances for each of the profile ID's. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate depreciation rates.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

Complete depreciation studies, which reevaluate these parameters, should be performed every three to five years.

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. These subjects are discussed in the sections that follow.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves. The use of an average service life for a property group implies that the various units within the group have different lives. The average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units that survive at successive ages. Inasmuch as survivor curves were used in the estimation of service lives, a discussion of the general concept of survivor curves and their derivation is presented.

A survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, as well as other functions, such as the remaining life expectancy, the probable life, and the frequency curve, can be calculated. Figure 1 below graphically depicts the survivor curve and the other information that can be derived from the survivor curve.

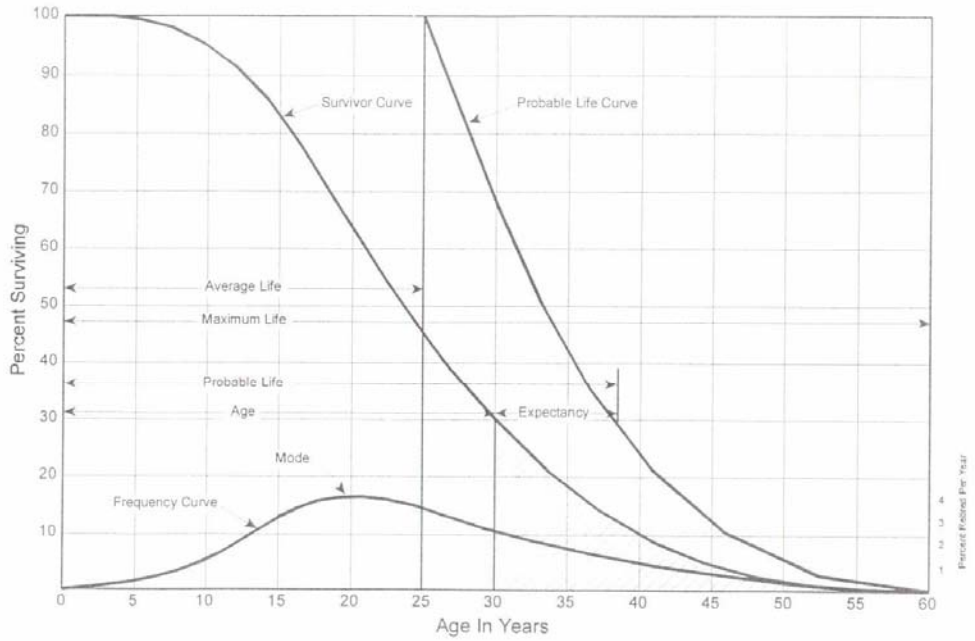

Figure 1. A Typical Survivor Curve and Derived Curves

Geometrically, the average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero, which is 100%. The average remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the attained age to the maximum age, and dividing this area by the percent surviving at the attained age.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of retirement in relationship to the average life and the relative height of the modes. The left moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves are those in which the greatest frequency of retirement occurs at average service life. The right moded curves are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin

125.[1] These type curves have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

Survivor Curve Judgments. The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the current policies and outlook as determined during conversations with management personnel; and survivor curve estimates from previous studies of this Company and other electric transmission companies. The following paragraphs discuss the factors considered in the selection of the survivor curve for the two largest Profile ID's which comprise 83% of the BCTC investment.

Profile ID 68201, SCADA Control Centre, represents 65% of the depreciable plant studied. This system comprises the software and control systems for the effective and safe operation of the electric transmission grid throughout the entire province of British Columbia. The majority of these physical assets are physically located in the Company's control centers located throughout the province, the largest of which is the System Control Center in Burnaby, British Columbia. The company is currently planning on consolidating and modernizing the 5 existing control centers to one main control center in Langley and a

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[1]Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3]Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

back-up control center in Vernon in 2008. At the time of re-location the company is anticipating the replacement of the SCADA system. The current system that is planned for replacement in 2008 is based on 1980's technology and was installed in 1994 and 1995. Therefore at the time of projected retirement the original components of the current system will have been in service for 14 years. However not all of the current system assets were placed into service with the original installation. As indicated at page III-12 investment in this account has primarily been over the years from 1994 through 2003. However, it is anticipated that all of the current investment will be retired at 2008, resulting in a significant potion of the investment having a historical average service life indication of less than the average service life of 5 to 10 years.

In the development of the Iowa 12-R2 curve selected for this account, Gannett Fleming also considered the average service lives for this type of control system asset experienced by peer large electric transmission operators in Alberta and Manitoba and the expectations of Company management as obtained through the staff interviews and site tour. Typical average service lives for this type of equipment range from 13 to 20 years[4.] The current control center software will be replaced with new third party developed software, whose average service life indications will largely result from the long-term vendor support. Vendor support for these types of systems will be through the new release of versions of the software systems. Each new release will have a shorter average service life than the original installation. The Iowa 12-R2, selected in this study, is a reasonable

[4] For example, the approved average service life for the control center assets for the ENMAX Power system is 13 years and the approved average service life for the AltaLink system is 20 years.

interpretation of the historical currently-installed system, and is forecast to be representative of the anticipated future retirement activity.

Profile ID 85001, System Operations – Office Furniture and Equipment, represents 18% of the depreciable plant studied. This account comprises the office furniture and equipment that is housed in the BCTC control centers. The furniture included in this account includes the furniture and operator consoles within the control center and other furniture within the control center buildings such as conference and training furniture. The equipment in this account includes the control center display screens, the alarm and security equipment, and the other equipment required for the efficient operation of the control centers located throughout the province. It does not include the actual computer hardware used in the control room.

Much of the furniture and equipment in this account will be replaced during the control center relocation program to be completed by the end of 2008. While it is anticipated that some of the operators' consoles and display equipment may be reused, the new control system may require differing equipment and console configurations. As indicated at page III-37, most of the investment in this account was installed in 2001. As such, in 2008 when much of this equipment will be retired, it will have a life of no more than 7 years. The Iowa 15-SQ curve selected for this account was based primarily on the experience of Gannett Fleming, on information gained from the site tour of the Burnaby Mountain Control Room, and on the discussions with BCTC. The 15-SQ Iowa curve is a reasonable interpretation of the historical currently-installed system, and is forecast to be representative of the anticipated future retirement activity.

The survivor curve estimates for the remaining accounts were based on similar considerations of historical analyses, management outlook, and estimates for this Company and other electric transmission operators.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, Average Group Life (AGL) and Equal Life Group (ELG).

In the AGL procedure, the rate of annual depreciation is based on the average life or average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life. In this procedure, the accrued depreciation is based on the average life of the group, and the average remaining life of each vintage within the group, derived from the area under the survivor curve between the attained age of the vintage and the maximum age.

In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the

summation of the calculated depreciation based on the service life of each equal life group.

The calculation of the depreciation rates in this study incorporated the use of the ALG procedure applied on a whole life basis. That is, the calculation of the annual depreciation accrual rate, and the calculated accumulated depreciation reserve requirements, were based on the application of the Iowa curve being applied from the initial installation of plant through to its final retirement. In order for the results of this depreciation study to be implemented into the BCTC accounting systems, the depreciation requirements, as indicated in this study, have be been converted to a whole life average service life that is specifically applicable to each asset surviving as at March 31, 2005.

The average service life expectancy of assets surviving as at March 31, 2005 is different than the average life expectancy of plant when it is first placed into service. The average service life estimate of any plant is based on the expectation and related probabilities of a number of forces of retirement. Included in these forces of retirement are causes of retirement that could be experienced at a young age, such as implementation issues with high technology equipment, early and premature failure of computer assets, vendor upgrades to complex software programs, or retirements caused by accidental damage. As discussed in the survivor curves section of this report, the retirement of assets at an early age is represented by the reductions from 100% surviving at years prior to the average service life of the profile ID. Therefore, the BCTC assets that are surviving as at March 31, 2005, have not retired due to the forces of retirement that can occur prior to its attained age as at March 31, 2005, therefore a specific life expectancy for each vintage is determined in the detailed deprecation calculations beginning at page III-5 of this report.

The accounting systems of BCTC determine the depreciation expense based on a formula, which divides the original cost of plant by the average life expectancy, and is applied on an individual asset basis to every asset within the system. In order to determine the composite life expectancy of the entire account, which can then be applied to all assets within the account surviving as at March 31, 2005, the required depreciation rate as determined in the detailed depreciation calculations is divided into 100%. The resultant life in years is the average life expectancy specific to the aged surviving plant as at March 31, 2005. This calculation is shown in Table 1 on page III-3 of this report.

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual depreciation and average life estimates for the plant surviving as at March 31, 2005 are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line method, using the group life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated analysis of retirements, discussions with management and consideration of estimates made for other electric utilities.

The table at page III-3 indicates for each Profile ID, the estimated survivor curve as recommended, the surviving original cost as at March 31, 2005, the annual accrual amount and deprecation rate, and the average life expectancy specific to the plant surviving as at March 31, 2005. The tables of the calculated annual depreciation applicable to plant as of March 31, 2005 are presented in account sequence starting on page III-5. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

BRITISH COLUMBIA TRANSMISSION CORPORATION

ESTIMATED SURVIVOR CURVES, ORIGINAL COST, ANNUAL ACCRUALS AND WHOLE LIFE EXPECTANCY
APPLICABLE TO PLANT AS AT MARCH 31, 2005

Profile ID	Description	Estimated Survivor Curve	Surviving Original Cost at 03/31/2005	Annual Accrual Amount	Annual Accrual Rate	Life Estimate for Current Plant
	(1)	(2)	(3)	(4)	(5)=(4)/(3)	(6)
22005	Buildings, Composite Pool	45-R3	11,311,708.04	251,120	2.22	45
22202	BCTC Office Relocation - Tenant Improvements	10-SQ	1,865,106.18	188,233	10.09	10
48003	Generator - Composite Pool	35-R2	642,889.41	18,387	2.86	35
59001	Power Supply - Uninterruptible	15-R3	2,105,169.97	140,415	6.67	15
59301	Strorage Batteries - Bank	15-SQ	256,863.63	17,133	6.67	15
61101	Alarm Security Systems	15-R2	41,257.63	2,752	6.67	15
65101	Fault Locating and Reporting	10-SQ	11,602.00	1,160	10.00	10
68201	Control Centre (Master Equipment)	12-R2	58,764,047.45	4,895,045	8.33	12
68202	Remote Terminal Unit - Slave	12-R3	582,028.87	48,483	8.33	12
68302	Radio - Microwave, Digital	10-R2	576,101.31	57,610	10.00	10
68501	Radio Systems - UHF/VHF	7-L2	269,799.00	38,554	14.29	7
68901	Telephone Equipment, PBX/PAX	15-SQ	525,622.37	35,059	6.67	15
70001	Cable - Entrance Protection	15-R4	24,373.35	1,626	6.67	15
75202	Fuel Strorage Tank	30-R2	30,748.00	1,024	3.33	30
75204	Tanks - Concrete	30-R2	183,409.00	6,108	3.33	30
80101	Computer Hardware - Micro (PC)	3-SQ	1,293,393.82	384,940	29.76	3
80102	Computer Harware , Mini	5-SQ	2,868,880.98	572,933	19.97	5
80103	Computer Hardware-Input/Output	5-SQ	386,238.00	75,812	19.63	5
80104	Computer Hardware, - Comp. Pool, PCS	4-SQ	1,148,228.96	213,158	18.56	5
80105	Laptops	3-SQ	620,785.42	206,908	33.33	3
80208	Printer, Mainframe, Laser	5-SQ	5,917.79	1,184	20.00	5
80302	Software Mainframe	10-SQ	481,232.81	48,123	10.00	10
80303	Application Software - Mid-Range Systems	3-SQ	21,247,763.71	6,756,057	31.80	3
80304	PC Software	3-SQ	18,054.94	6,018	33.33	3
80305	Software System Upgrades, Mid Range Systems	2-SQ	1,744,058.86	870,571	49.92	2
80306	Network Software	7-SQ	3,443,173.76	492,030	14.29	7
80401	Simulator, Training	5-SQ	2,149,949.99	389,427.40	18.11	5
80502	Routers	5-SQ	77,454.00	15,491	20.00	5
80503	Switches	5-SQ	262,328.00	52,466	20.00	5
80504	Servers	5-SQ	1,083,411.81	216,682	20.00	5
80505	Servers	5-SQ	9,775.41	1,955.08	20.00	5
80508	Misc. Network Equipment	5-SQ	101,681.88	20,336	20.00	5
85001	Furniture and Equipment, Office	15-SQ	4,403,791.73	293,733	6.67	15
85002	Office Equipment	5-SQ	57,945.17	11,589	20.00	5
	Total Plant in Service		**118,594,793.25**	**16,332,120**		

DETAILED DEPRECIATION CALCULATIONS

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 22005 LMC TRANSMISSION MIMIC BOARD REPL.

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 15-R3							
NET SALVAGE PERCENT.. 0							
1972	67,490.68					1.0000	67,491
2003	307,489.46	15.00	6.67	20,509.55	13.53	.0980	30,134
2004	6,986.22	15.00	6.67	465.98	14.51	.0327	228
TOTAL	381,966.36			20,975.53			97,853

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.49

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 22202 BCTC OFFICE RELOCATION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
INTERIM SURVIVOR CURVE.. SQUARE							
PROBABLE RETIREMENT YEAR.. 11-2013							
NET SALVAGE PERCENT.. 0							
2003	1,587,375.23	10.00	10.00	158,737.52	8.50	.1500	238,106
TOTAL	1,587,375.23			158,737.52			238,106

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 10.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 48003 DIESEL GENERATOR - COMPOSITE POOL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 35-R2							
NET SALVAGE PERCENT.. 0							
1995	642,889.41	35.00	2.86	18,386.64	26.74	.2360	151,722
TOTAL	642,889.41			18,386.64			151,722

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.86

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 59001 POWER SUPPLY - UNINTERRUPTIBLE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 15-R3							
NET SALVAGE PERCENT.. 0							
1994	2,562.29	15.00	6.67	170.90	5.74	.6173	1,582
1996	13,241.91	15.00	6.67	883.24	7.26	.5160	6,833
1997	391,769.06	15.00	6.67	26,131.00	8.07	.4620	180,997
2003	12,533.48	15.00	6.67	835.98	13.53	.0980	1,228
2004	323.84	15.00	6.67	21.60	14.51	.0327	11
TOTAL	420,430.58			28,042.72			190,651

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 59301 STORAGE BATTERIES - BANK

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 20-SQUARE							
NET SALVAGE PERCENT.. 0							
2002	2,416.04	20.00	5.00	120.80	17.50	.1250	302
2003	13,590.49	20.00	5.00	679.52	18.50	.0750	1,019
TOTAL	16,006.53			800.32			1,321

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 61101 ALARM SECURITY SYSTEMS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 15-R2							
NET SALVAGE PERCENT.. 0							
1999	13,106.63	15.00	6.67	874.21	10.30	.3133	4,106
2003	281.51	15.00	6.67	18.78	13.66	.0893	25
TOTAL	13,388.14			892.99			4,131

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 65101 CONTROL CENTRE - MINOR CAPITAL FAULT LOCATION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 35-R3							
NET SALVAGE PERCENT.. 0							
2004	116.02	35.00	2.86	3.32	34.51	.0140	2
TOTAL	116.02			3.32			2

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.59

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 68201 SCADA CONTROL CENTRE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 12-R2							
NET SALVAGE PERCENT.. 0							
1985	295,705.72	12.00	8.33	24,632.29	0.75	.9375	277,224
1994	18,224,418.88	12.00	8.33	1,518,094.09	4.09	.6592	12,013,537
1995	26,045,213.72	12.00	8.33	2,169,566.30	4.66	.6117	15,931,857
1996	41,465.03	12.00	8.33	3,454.04	5.28	.5600	23,220
1998	6,274,060.30	12.00	8.33	522,629.22	6.65	.4458	2,796,976
2003	2,488,645.95	12.00	8.33	207,304.21	10.66	.1117	277,982
2004	46,288.78	12.00	8.33	3,855.86	11.55	.0375	1,736
TOTAL	53,415,798.38			4,449,536.01			31,322,532

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.33

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 68202 REMOTE TERMINAL UNIT - LMC

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 20-R2							
NET SALVAGE PERCENT.. 0							
1994	24,147.71	20.00	5.00	1,207.39	11.32	.4340	10,480
1995	21,733.18	20.00	5.00	1,086.66	12.06	.3970	8,628
1996	1,701.30	20.00	5.00	85.07	12.82	.3590	611
1997	13,502.48	20.00	5.00	675.12	13.60	.3200	4,321
1998	55.11	20.00	5.00	2.76	14.40	.2800	15
1999	51.93	20.00	5.00	2.60	15.22	.2390	12
2001	2,579.91	20.00	5.00	129.00	16.91	.1545	399
2003	43.77	20.00	5.00	2.19	18.65	.0675	3
2004	15.80	20.00	5.00	0.79	19.55	.0225	
TOTAL	63,831.19			3,191.58			24,469

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 68302 S.I. AREA CONTROL EQUIPMENT - VERNON

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 12-R2							
NET SALVAGE PERCENT.. 0							
1990	576,101.31	12.00	8.33	47,989.24	2.28	.8100	466,642
TOTAL	576,101.31			47,989.24			466,642

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.33

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 68501 V.I. AREA - DISPATCH & CON

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 12-R2							
NET SALVAGE PERCENT.. 0							
2002	26.25	12.00	8.33	2.19	9.80	.1833	5
2003	2,671.74	12.00	8.33	222.56	10.66	.1117	298
TOTAL	2,697.99			224.75			303

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.34

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 68901 CONTROL CENTRE VOICE RECORDER

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE							
NET SALVAGE PERCENT.. 0							
2003	283,118.37	15.00	6.67	18,884.00	13.50	.1000	28,312
2004	18,537.70	15.00	6.67	1,236.46	14.50	.0333	617
TOTAL	301,656.07			20,120.46			28,929

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 70001 CABLE - ENTRANCE PROTECTION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 15-R4							
NET SALVAGE PERCENT.. 0							
1999	24,373.35	15.00	6.67	1,625.70	9.56	.3627	8,840
TOTAL	24,373.35			1,625.70			8,840

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 75202 FUEL STORAGE TANK - SICEV

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 35-R2							
NET SALVAGE PERCENT.. 0							
1994	307.48	35.00	2.86	8.79	25.92	.2594	80
TOTAL	307.48			8.79			80

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.93

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 75204 TANKS - CONCRETE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 35-R2							
NET SALVAGE PERCENT.. 0							
1996	1,834.09	35.00	2.86	52.45	27.57	.2123	389
TOTAL	1,834.09			52.45			389

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.84

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80101 COMPUTER HARDWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 3-SQUARE							
NET SALVAGE PERCENT.. 0							
2001	66,941.70					1.0000	66,942
2002	72,192.02	3.00	33.33	24,061.60	0.50	.8333	60,158
2003	244,227.64	3.00	33.33	81,401.07	1.50	.5000	122,114
2004	275,300.57	3.00	33.33	91,757.68	2.50	.1667	45,893
TOTAL	658,661.93			197,220.35			295,107

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 29.94

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80102 EDMS TECHNICAL MIGRATION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 12-R2							
NET SALVAGE PERCENT.. 0							
1999	42.14	12.00	8.33	3.51	7.39	.3842	16
2001	25,211.20	12.00	8.33	2,100.09	8.97	.2525	6,366
2002	65,067.34	12.00	8.33	5,420.11	9.80	.1833	11,927
2003	374,190.32	12.00	8.33	31,170.05	10.66	.1117	41,797
2004	91,598.36	12.00	8.33	7,630.14	11.55	.0375	3,435
TOTAL	556,109.36			46,323.90			63,541

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.33

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80103 COMPUTER HARDWARE-INPUT/OUTPUT - DCM HARDWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
1999	71.77					1.0000	72
2002	41.22	5.00	20.00	8.24	2.50	.5000	21
2003	12,502.90	5.00	20.00	2,500.58	3.50	.3000	3,751
2004	301,367.95	5.00	20.00	60,273.59	4.50	.1000	30,137
TOTAL	313,983.84			62,782.41			33,981

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 20.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80104 SYSTEM PLANNING & DEVELOPMENT - ENG. / TECH

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
2000	295,597.21	5.00	20.00	59,119.44	0.50	.9000	266,037
2001	544,067.86	5.00	20.00	108,813.57	1.50	.7000	380,848
2002	233,971.56	5.00	20.00	46,794.31	2.50	.5000	116,986
2003	59,257.45	5.00	20.00	11,851.49	3.50	.3000	17,777
2004	84.92	5.00	20.00	16.98	4.50	.1000	8
TOTAL	1,132,979.00			226,595.79			781,656

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 20.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80105 LAPTOPS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 3-SQUARE							
NET SALVAGE PERCENT.. 0							
2002	64,454.95	3.00	33.33	21,482.83	0.50	.8333	53,710
2003	468,425.82	3.00	33.33	156,126.33	1.50	.5000	234,213
2004	72,143.85	3.00	33.33	24,045.55	2.50	.1667	12,026
TOTAL	605,024.62			201,654.71			299,949

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 33.33

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80208 PC PERIPHERALS / PRINTERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
2004	5,917.79	5.00	20.00	1,183.56	4.50	.1000	592
TOTAL	5,917.79			1,183.56			592

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 20.01

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80302 SOFTWARE MAINFRAME

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 10-SQUARE							
NET SALVAGE PERCENT.. 0							
1999	44,524.65	10.00	10.00	4,452.47	4.50	.5500	24,489
2003	227,331.97	10.00	10.00	22,733.20	8.50	.1500	34,100
TOTAL	271,856.62			27,185.67			58,589

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 10.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80303 APPLICATION SOFTWARE - DATA ARCHIVING

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
1999	53,546.50					1.0000	53,547
2000	80,589.86	5.00	20.00	16,117.97	0.50	.9000	72,531
2001	181,726.80	5.00	20.00	36,345.36	1.50	.7000	127,209
2002	238,683.26	5.00	20.00	47,736.65	2.50	.5000	119,342
2003	226,078.96	5.00	20.00	45,215.79	3.50	.3000	67,824
2004	416,201.62	5.00	20.00	83,240.32	4.50	.1000	41,620
TOTAL	1,196,827.00			228,656.09			482,073

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 19.11

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80304 LOWER MAINLAND - CONTROL SYSTEM SOFTWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 12-R2							
NET SALVAGE PERCENT.. 0							
2003	122.10	12.00	8.33	10.17	10.66	.1117	14
2004	261.34	12.00	8.33	21.77	11.55	.0375	10
TOTAL	383.44			31.94			24

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.35

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80305 SOFTWARE SYSTEM UPGRADES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 2-SQUARE							
NET SALVAGE PERCENT.. 0							
2002	2,916.63					1.0000	2,917
2003	805,459.04	2.00	50.00	402,729.52	0.50	.7500	604,094
2004	4,528.44	2.00	50.00	2,264.22	1.50	.2500	1,132
TOTAL	812,904.11			404,993.74			608,143

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 49.82

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80306 AMP / ORACLE / PAYROLL SOFTWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 10-SQUARE							
NET SALVAGE PERCENT.. 0							
2004	3,166,366.42	10.00	10.00	316,636.64	9.50	.0500	158,318
TOTAL	3,166,366.42			316,636.64			158,318

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 10.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80401 COMPUTER HARDWARE: SYS. MAIN - LMC IMPROVEMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
1995	145,308.99					1.0000	145,309
1998	575.04					1.0000	575
2004	19,471.37	5.00	20.00	3,894.27	4.50	.1000	1,947
TOTAL	165,355.40			3,894.27			147,831

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.35

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80502 BCTC RELOCATION / ROUTERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
2004	774.54	5.00	20.00	154.91	4.50	.1000	77
TOTAL	774.54			154.91			77

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 20.01

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80503 BCTC RELOCATION - SWITCHES / WAN ROUTERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 5-SQUARE							
NET SALVAGE PERCENT.. 0							
2004	2,623.28	5.00	20.00	524.66	4.50	.1000	262
TOTAL	2,623.28			524.66			262

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 20.01

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80504 BCTC - PI SCADA HARDWARE / IT TRANSITION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 12-R2							
NET SALVAGE PERCENT.. 0							
2003	228,220.92	12.00	8.33	19,010.80	10.66	.1117	25,492
2004	530,035.77	12.00	8.33	44,151.98	11.55	.0375	19,876
TOTAL	758,256.69			63,162.78			45,368

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.33

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80505 ORACLE FINANCIAL SYSTEM SOFTWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 10-SQUARE							
NET SALVAGE PERCENT.. 0							
2002	9,775.41	10.00	10.00	977.54	7.50	.2500	2,444
TOTAL	9,775.41			977.54			2,444

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 10.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 80508 BCTC RELOCATION - MISC. NETWORK EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
INTERIM SURVIVOR CURVE.. SQUARE							
PROBABLE RETIREMENT YEAR.. 11-2013							
NET SALVAGE PERCENT.. 0							
2003	112.88	10.00	10.00	11.29	8.50	.1500	17
2004	1,015.69	9.42	10.62	107.87	8.92	.0531	54
TOTAL	1,128.57			119.16			71

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 10.54

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 85001 SYSTEM OPS - OFFICE FURN. & EQUIP / CONSOLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. 15-SQUARE							
NET SALVAGE PERCENT.. 0							
1990	210,011.76	15.00	6.67	14,007.78	0.50	.9667	203,018
1991	74,699.47	15.00	6.67	4,982.45	1.50	.9000	67,230
1992	163,216.78	15.00	6.67	10,886.56	2.50	.8333	136,009
1993	432,836.49	15.00	6.67	28,870.19	3.50	.7667	331,856
1994	378,634.31	15.00	6.67	25,254.91	4.50	.7000	265,044
1995	201,219.62	15.00	6.67	13,421.35	5.50	.6333	127,432
1996	9,435.06	15.00	6.67	629.32	6.50	.5667	5,347
1997	5.76	15.00	6.67	0.38	7.50	.5000	3
1998	9,089.65	15.00	6.67	606.28	8.50	.4333	3,939
1999	147,498.55	15.00	6.67	9,838.15	9.50	.3667	54,088
2000	7,385.14	15.00	6.67	492.59	10.50	.3000	2,216
2001	11,275,640.61	15.00	6.67	752,085.23	11.50	.2333	2,630,607
2002	414,681.04	15.00	6.67	27,659.23	12.50	.1667	69,127
2003	1,711,998.94	15.00	6.67	114,190.33	13.50	.1000	171,200
TOTAL	15,036,353.18			1,002,924.75			4,067,116

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67

BRITISH COLUMBIA TRANSMISSION CORPORATION

ACCOUNT 85002 BCTC RELOCATE OFFICE EQUIP.- AIR. COND / LCD

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	-ACCRUED DEPREC.- FACTOR (7)	AMOUNT (8)
INTERIM SURVIVOR CURVE.. SQUARE							
PROBABLE RETIREMENT YEAR.. 11-2013							
NET SALVAGE PERCENT.. 0							
2002	34,933.48	10.00	10.00	3,493.35	7.50	.2500	8,733
2003	18,447.79	10.00	10.00	1,844.78	8.50	.1500	2,767
TOTAL	53,381.27			5,338.13			11,500

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 10.00

BRITISH COLUMBIA TRANSMISSION CORPORATION

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
SURVIVING AT MARCH 31, 2005

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
220.05		7.0	381,966.36	5.49	20,976	97,853
222.02		1.5	1,587,375.23	10.00	158,738	238,106
480.03		9.5	642,889.41	2.86	18,387	151,722
590.01		7.4	420,430.58	6.67	28,043	190,651
593.01		1.7	16,006.53	5.00	800	1,321
611.01		5.4	13,388.14	6.67	893	4,131
651.01		0.5	116.02	2.59	3	2
682.01		9.2	53,415,798.38	8.33	4,449,536	31,322,532
682.02		9.2	63,831.19	5.00	3,192	24,469
683.02		14.5	576,101.31	8.33	47,989	466,642
685.01		1.5	2,697.99	8.34	225	303
689.01		1.4	301,656.07	6.67	20,120	28,929
700.01		5.5	24,373.35	6.67	1,626	8,840
752.02		10.5	307.48	2.93	9	80
752.04		8.5	1,834.09	2.84	52	389
801.01		1.4	658,661.93	29.94	197,220	295,107
801.02		1.5	556,109.36	8.33	46,324	63,541
801.03		0.5	313,983.84	20.00	62,782	33,981
801.04		3.4	1,132,979.00	20.00	226,596	781,656
801.05		1.5	605,024.62	33.33	201,655	299,949
802.08		0.5	5,917.79	20.01	1,184	592
803.02		2.2	271,856.62	10.00	27,186	58,589
803.03		2.0	1,196,827.00	19.11	228,656	482,073
803.04		0.8	383.44	8.35	32	24
803.05		1.5	812,904.11	49.82	404,994	608,143
803.06		0.5	3,166,366.42	10.00	316,637	158,318
804.01		8.4	165,355.40	2.35	3,894	147,831
805.02		0.5	774.54	20.01	155	77
805.03		0.5	2,623.28	20.01	525	262
805.04		0.8	758,256.69	8.33	63,163	45,368
805.05		2.5	9,775.41	10.00	978	2,444
805.08		0.6	1,128.57	10.54	119	71
850.01		4.1	15,036,353.18	6.67	1,002,925	4,067,116
850.02		2.2	53,381.27	10.00	5,338	11,500
GRAND TOTAL		7.2	82,197,434.60	9.17	7,540,952	39,592,612

APPENDIX 1. GLOSSARY OF TERMS

Glossary of Terms

In this report the following terms have the meanings as described below.

Average Life Group means a depreciation calculation procedure wherein the annual depreciation accrual rate is based on the average life and average net salvage of the entire group. This rate is applied to the surviving balance of the group. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully accrued by the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully accrued.

Average Service Life means the quotient obtained by dividing the sum of all service lives of all units within a group by the number of units within the group. The average service life (in years) is equal to the area under the survivor curve in percent-years divided by 100 percent. Average service life is the estimated length of time (on average) between the date plant is recorded into Plant in Service and the date of its retirement.

Aged Surviving Balances means the balance of investment within a group of assets at a specific point in time sorted by the original installation date of the assets.

Depreciation Accrual or *Annual Accrual* or *Annual Depreciation Accrual* is the amount charged to the income statement of a company to represent the portion of the service value of an asset that is consumed within a fiscal period or a year of service life.

The annual depreciation accrual reflects the loss of service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance.

Equal Life Group means a depreciation calculation wherein the property group is subdivided according to the specific service life of each of the subgroups in such a manner that there is no longer any meaningful retirement dispersion left within any of the subgroups. The relative size of each of the subgroups (or equal life groups) is determined from the survivor estimated for the entire group. Because there is no dispersion of lives within the subgroups, each of these equal life groups has the characteristics of a single unit of property.

Iowa curve means a generalized set of survivor curves. A survivor curve graphically depicts the amount of property existing at each age throughout the life of a property group. The Iowa curves are a set of four families of generalized survivor curves labeled in accordance with the location of the modes of the retirements in relationship to the average life and average height of the curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of ages at which industrial property had been retired.

Net Salvage means the salvage value of property retired less the costs to remove of the property from service

Profile ID refers to the retirement units of BCTC. Profile ID can either refer to a specific item in the circumstances where individual unit depreciation is appropriate such as a specific transformer, or to a group of assets in the circumstances of mass property such as poles.

SCADA refers to the Supervisory Control And Data Acquisition system which is supervisory control system that is interfaced with the field assets via Programmable Logic Controllers.

Service Value means the original cost of plant including installation costs less the net salvage value of the plant.

Straight Line Depreciation refers to a depreciation method which allocates an equal amount of the service value of an asset to each year of service life.

Vintage refers to the year the asset was originally installed into utility service.

Whole Life Basis refers to the application of a depreciation system that is based on the total life of an asset from the date of original installation through to the final retirement.

APPENDIX 2. CURRICULA VITAE OF LARRY E. KENNEDY

LARRY E. KENNEDY

TECHNICAL SPECIALTIES

- Public Utility Plant Depreciation
- Public Utility Plant Accounting

PERSONAL INFORMATION

Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
Member, Society of Depreciation Professionals
Certified Depreciation Professional

EXPERIENCE

Mr. Kennedy joined the firm in January 1999 and is the Director of Canadian Services for the Valuation and Rate Division. His responsibilities include the assembly of data, the preparation and review of depreciation studies. Mr. Kennedy also oversees and provides analysis of other regulatory and accounting issues, and the provision of litigation support services.

Representative assignments include:

- ENMAX Power Corporation. Studies have included the development of annual and accrued depreciation rates for all depreciable Electric Transmission Assets. Elements of the study included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. The study was prepared for submission to the Alberta Department of Energy. A similar study has been completed for submission for the ENMAX Electric Distribution assets for submission to the Alberta Energy and Utilities Board.

- AltaLink LP. A study was developed for submission to the Alberta Energy and Utilities Board in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004.

- Manitoba Hydro. A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements.

- Centra Gas Manitoba, Inc. The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings, other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements.

LARRY E. KENNEDY, cont.

- TransCanada PipeLines Limited – Alberta Facilities. The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were preformed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted.

- TransCanada PipeLines Limited – Mainline Facilities. The study prepared for submission to the National Energy Board of Canada included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta – Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts.

- AltaGas Utilities Inc. A number of depreciation studies have been completed which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board.

- Alberta Municipal Affairs. The first assignment was conducted in two phases. The first phase involved significant consultation with the Alberta Department of Municipal Affairs and various stakeholder groups to develop a report outlining the method of depreciation that would most appropriately result in a fair market value assignment for the provinces oil and gas pipelines, and for all segments of the electric industry (generation, transmission and distribution). The second phase of the project was to develop specific depreciation schedules to implement the recommendations that were accepted by Alberta Municipal Affairs for the oil and gas pipelines as well as for all three aspects of the province's electric industry. A second assignment to develop models for the determination of the fair assessment value for the province's Telecommunication and Railway systems was completed in 2004.

- The City of Calgary. These assignments consisted of providing advice and testimony for the City of Calgary on depreciation issues in various general rate applications. Elements of these assignments include the review of applicant evidence and policies, development of information requests, submission of evidence, response to information requests, and expert testimony.

Mr. Kennedy has appeared as an Expert Witness before various Regulatory Boards as summarized in the attached "Summary of Appearances".

Prior to joining the firm in January 1999, Mr. Kennedy was employed in the energy pipeline industry, as follows:

NOVA Gas Transmission Ltd. (November 1995 - November 1998)
Mr. Kennedy's position at NGTL was Depreciation Specialist - Regulatory Affairs. In this position, he was responsible for making policy recommendations to management and preparing depreciation studies including:

LARRY E. KENNEDY, cont.

- Development and presentation of NGTL strategies and positions regarding the issues of capital recovery, business risk, impact of competition, and public interest to NGTL senior management, industry tasks forces, and Regulators as required.
- Development of appropriate gas reserve depletion policies recognizing the rate of depletion of the gas reserve fields upon which the NGTL system is dependent.
- Assist in the development of written testimony filed on behalf of NGTL witnesses and external expert witnesses in both NGTL's regulatory proceedings and as an intervener in other regulatory proceedings on a broad range of issues.
- Monitoring of regulatory proceedings in which NGTL is not actively participating.
- Develop, present and defend in a regulatory forum, policy recommendations on the appropriate depreciation methodology for NGTL, including:
  - Development of aged life analysis;
  - Development of future salvage and cost of removal estimates;
  - Development of future life estimates, including analysis of the appropriate "Economic Planning Horizon";
  - Preparation of written testimony defending the depreciation study;
  - Preparation of responses to information requests regarding capital recovery.
- Identification of trends and new opportunities to safeguard NGTL investment and ensure recovery of invested capital.
- Represent NGTL externally as an expert on Depreciation matters on industry associations such as the American Gas Association, the Canadian Gas Association, the Canadian Energy Pipeline Association, and the Society of Depreciation Professionals.

Interprovincial Pipe Line Ltd. (December 1980 - November 1995)
Mr. Kennedy served in a series of positions of increasing responsibility at IPL in the areas of plant accounting and depreciation. Key activities included:

- Preparation and filing with the National Energy Board of IPL's 1987, 1992 and 1994 Review of Depreciation Rates.
- Attending the NEB's 1994 Generic Rate of Return hearings on behalf of IPL to provide support regarding IPL's positions on capital recovery, business risk, and appropriate rate of return.
- Significant research on the issue of net negative salvage issue for pipelines.
- Attending and representing IPL at many industry seminars and conferences.
- Supervision of IPL's 6 person Plant Accounting section including:
  - Ensuring compliance of all Plant Accounting transactions to Generally Accepted Accounting Principles and the National Energy Board's Oil Pipeline Uniform Accounting Regulations;
  - Cost control of all physical capital budget items;
  - Preparation and regulatory filing of IPL's annual facility applications;
  - Maintenance of the Plant Accounting completed plant records.
- Team Leader for all Cost Control Functions on the Capacity Expansion Program undertaken by IPL in 1994.
- Development of various IPL policy statements regarding capital transactions, capital versus expense policies, inventory valuations, cost allocation, and other Plant Accounting issues.

Mr. Kennedy has successfully completed the series of week-long programs offered by Depreciation Programs, Inc. and is a past president of the Society of Depreciation Professionals.

LARRY E. KENNEDY

SUMMARY OF APPEARANCES BEFORE REGULATORY BOARDS

Year	Client	Applicant	Regulatory Board	Proceeding Number
1999	ENMAX Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2003	AltaLink Management Ltd	AltaLink Management Ltd	Alberta Energy and Utilities Board	1279345
2003	TransCanada PipeLines Limited	TransCanada PipeLines Limited	National Energy Board of Canada	RH-1-2002
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Westridge Utilities Inc	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A

Year	Client	Applicant	Regulatory Board	Proceeding Number
2005	ENMAX Power Corporation	ENMAX Power Corporation-Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	The City of Red Deer	The City of Red Deer Electric System	Alberta Energy and Utilities Board	Appearance Pending
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc	Northwest Territories Utilities Board	Appearance Pending

LARRY E. KENNEDY

SUMMARY OF CASES WHERE EVIDENCE WAS PROVIDED BUT APPEARANCES WERE NOT REQUIRED DUE TO NEGOTIATED SETTLEMENT OR WHERE EVIDENCE WAS ADOPTED BY AFFIDAVIT

Year	Client	Applicant	Regulatory Board	Proceeding Number
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc	Alberta Energy and Utilities Board	Decision 2002-43
2001	ENMAX Power Corporation	ENMAX Power Corporation – Electric Transmission Assets	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation – Electric Transmission Assets	Alberta Department of Energy	N/A
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric – ISO Issues	Alberta Energy and Utilities Board	N/A
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A

Appendix C

Review of Capital Overhead Allocation Methodology

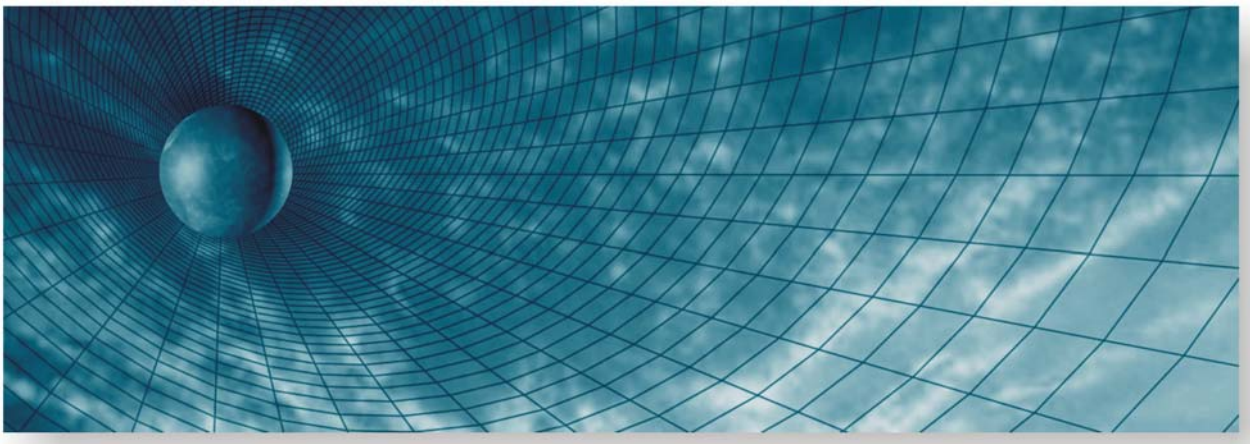
Report to

British Columbia Transmission Corporation

Regarding

Review of Capital Overhead Allocation Methodology

April 4, 2006



R·J·Rudden®
ASSOCIATES
A Black & Veatch Company

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1. SCOPE AND OBJECTIVES

British Columbia Transmission Corporation (BCTC) is a Crown corporation, headquartered in Vancouver, British Columbia. It was created in 2003. BCTC's primary responsibility is to plan and operate the electrical transmission system in British Columbia, and manage the transmission assets. BC Hydro has retained ownership of those transmission assets.

As part of this responsibility, BCTC plans, manages and executes the following capital program elements:

- the capital program of BC Hydro's Transmission Line of Business (TLOB) , approximately $205 million per year
- the portion of the capital program of BC Hydro's Distribution Line of Business that includes substation assets at distribution voltage (below 69kV) , approximately $70 million per year
- BCTC's capital program, approximately $65 million per year.

The total of these three capital program elements is about $340 million per year in capital expenditures. In a typical year, approximately 350 capital projects will be active.

In addition to directly charged expenditures for transmission capital projects, BCTC allocates a portion of its indirect costs and General & Administration (G&A) expenses to its capital program. Prior to F2006, the annual budget for capitalized overhead expenses was $5.2 million. This budget was inherited from BC Hydro and was based on the practices of the BC Hydro's TLOB, since BCTC's cost incurrence patterns were not well established in its formative years.

In its order approving the negotiated settlement to BCTC's F2006 Revenue Requirement proceeding, the British Columbia Utilities Commission (BCUC) adjusted

the budget for capitalized overhead expenses to $6.5 million and directed BCTC to complete a study to support appropriate capitalized overhead allocations.

BCTC has retained R.J. Rudden Associates (Rudden), a unit of Black & Veatch Corporation, to review the capital overhead allocation methodology developed for its F2007 rate filing, and provide an opinion on its reasonableness and appropriateness. Rudden did not conduct an independent analysis or audit of the source data from BCTC on cost levels or cost allocation bases.

2. APPROACH AND METHODOLOGY FOR REVIEW

A. Approach

Rudden's approach to reviewing BCTC's F2007 capital overhead allocation methodology was straightforward, and consistent with our approach in similar assignments. We evaluated the reasonableness and appropriateness of BCTC's methodology on a number of parallel criteria:

- Conformance with general principles for overhead cost allocation
- Fit with BCTC's particular patterns of cost incurrence
- Consistency with accepted industry practices

In the course of this review, Rudden made a number of suggestions for changing BCTC's methodology. BCTC adopted some of these suggestions. However, our review was conducted as an independent party, and our conclusions were developed independently.

B. Methodology

Our review progressed through several major tasks, summarized as follows.

1. Define general principles. Rudden researched the application direction on overhead cost allocation from appropriate accounting and regulatory authorities. These authorities included Generally Accepted Accounting Principles (GAAP), the U.S. Federal Energy Regulatory Commission, the U.S. National Association of Regulatory Utility Commissioners and of course the BCUC.

2. Understand BCTC's cost patterns. We then researched BCTC operational and financial information to understand the nature of its capital expenditures and its overhead expenses, looking for insights on causative or beneficial relationships between these two cost pools. This research included review of BCTC's revenue

requirements exhibits, interviews with BCTC financial managers, and review of BCTC's draft F2007 capital overhead allocation methodology.

3. Characterize accepted industry practice. Rudden drew on its knowledge of industry practices in overhead cost allocation, based on similar previous projects in Canada and the U.S. We also conducted a limited amount of Internet-based and telephone research into current practices in this area at Canadian and U.S. utilities with large capital programs in transmission. As might be expected, many utilities were reluctant to share detailed data. Their particular cost circumstances may differ substantially from BCTC, so both the overhead cost allocation methodologies and the results produced by those methodologies should be interpreted with care.

4. Evaluate BCTC methodology. Based on the above evaluation criteria, Rudden drew conclusions regarding the reasonableness and appropriateness of BCTC's methodology.

3. GENERAL PRINCIPLES FOR OVERHEAD COST ALLOCATION

A. Overhead Cost Accounting Principles

Generally Accepted Accounting Principles (GAAP) provide high-level guidance for the preparation and examination of an enterprise's financial statements. They were not intended to prescribe methods for internal accounting systems such as the construction accounting system. While GAAP does not give detailed directions as to how to distinguish between direct and overhead costs, it does set out general principles for the allocation of overhead costs. Statement No. 4 of the Accounting Principles Board states in part:

> "To apply expense recognition principles, costs are analyzed to see whether they can be associated with revenue on the basis of cause and effect. If not, systematic and rational allocation is attempted." (emphasis added)

The U.S. federal government's Cost Accounting Standards Board, an authority whose standards have the force of law in U.S. government contracts, requires overhead costs to be accumulated in pools according to specific and consistent criteria. Each overhead cost pool should be allocated to cost centres on a basis reflecting their beneficial or causal relationship.

The Canadian Institute of Chartered Accountants (CICA) gives the following guidance in CICA 3061.20:

> "The cost of an item of property, plant, and equipment includes direct construction or development cots (such as materials and labour), and overhead costs directly attributable to the construction and development activity."

Taken together, these accounting principles require that overhead costs charged to construction must bear a strong relationship to the construction activity, and must be allocated to specific construction projects on a consistent and rational basis.

B. Regulatory Standards for Overhead Cost Capitalization

Under the accounting regulations of the U.S. Federal Energy Regulatory Commission, FERC-jurisdictional utilities are permitted to capitalize both direct and overhead costs related to construction. Although utilities have considerable leeway under FERC rules in the definition of overhead costs, they are required to maintain sufficient documentation to support the amounts of overhead cost assigned to construction. FERC-jurisdictional utilities should all have written and defined overhead policies. Electric Plant Instruction No. 4 in the Uniform System of Accounts states:

> "... the records supporting the entries for overhead construction costs shall be kept so as to show the total amount of each overhead for each year, the nature and amount of each overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs."

In Section 6 of its own Uniform System of Accounts, the BCUC provides the following definition:

> "<u>Cost of Overhead Charged to Construction</u> includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes, and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of actual and reasonable costs. The records supporting the entries for overhead charged to construction costs shall be maintained so as to show the total amount of each element of overhead for the year and basis of distribution."

The BCUC has not been prescriptive in defining detailed overhead capitalization rules for its jurisdictional utilities. It has allowed a fair degree of flexibility for utilities to design

overhead capitalization methods that fit their circumstances. Utility proposals have been scrutinized on a case-by-case basis.

C. Overview of Overhead Allocation Process

In order to determine whether BCTC has allocated an appropriate level of overhead expenses to capital, a number of major issues must be addressed. These include:

- Determining which costs will be considered direct and which will be allocated as an overhead.
- Understanding the interrelationships among the overhead cost pools and the direct cost centres to which the overhead pools relate.
- Deciding upon the sequence in which the overhead pools will be allocated.
- Assessing which of the potentially applicable allocation bases best represent the beneficial or causal relationship between the direct and overhead cost pools.

1. Direct vs. Overhead Costs

There are two major categories of cost associated with the construction of electric plant, whether it is generation, transmission, or distribution.

- Direct Costs
- Overhead Costs

A direct cost is any cost which is identified specifically with a particular capital project. A direct cost is assigned directly and exclusively to its related project. The direct costs of construction are those amounts expended for labour, materials and equipment that are directly traceable to the physical construction of a particular item or aggregate of electric plant, e.g., equipment, structures, land, land improvements, or other physical assets. Direct costs can also include amounts similarly expended for long-lived assets such as information technology systems, communications systems, etc.

An overhead cost is any cost not identified specifically with a single capital project, but rather identified with two or more projects or at least one intermediate cost center that

supports more than one project. Overhead costs are indirect, and must be allocated over all the capital projects that they support. Overhead costs of construction are those which are charged to a construction project and are incurred as in support of the construction activities, but are not directly assigned. Overhead construction costs may include the cost of engineering, management and supervision, allowance for funds used during construction (AFUDC)[1], administrative and general expenses, insurance, taxes, security, janitorial services, construction tools, temporary structures, and so on.

Rudden's practice in conducting or reviewing overhead cost allocations is consistent with these principles. In the financial analysis and cost-of-service work we have performed for a very large number of utility clients in the U.S. and Canada, one of our guiding principles states that direct assignment should be used whenever possible.

- Direct Assignment is used when the portion of an activity used by a project can be reasonably established. Direct assignment is preferable to allocation because it is based on a more direct relationship.
- Allocation is used when an activity is used by multiple projects, but the portions of the activity that each uses cannot be directly established. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred.

BCTC's determination of which costs can be direct charged and which costs must be allocated will affect significantly the total costs assigned to capital.[2] The allocation process may yield a different distribution of costs to capital assets than direct charges in that circumstance.

2. Definition of Overhead Cost Pools and Direct Cost Centres

[1] Or, in BCTC's terminology, Interest During Construction (IDC). IDC is not part of the pool of OMA overhead expenses, but is directly applied to costs the relevant capital projects.

[2] We understand that BCTC begins charging design and engineering costs to capital when a specific capital project has been defined and the preferred alternative to a defined problem or opportunity has been selected. The level of direct charges to capital is also affected by BCTC's accounting policies as explained in Section 4.A.

Another guiding principle followed by Rudden in cost allocations states that the cost structure of costs to be allocated should be properly defined. The first step in the allocation process consists of grouping similar types of overhead costs into overhead cost pools. For example, BCTC might form distinct overhead cost pools for certain departments. The legal department may provide a different level of support to capital projects than the regulatory department. Therefore the costs in each department should be grouped in separate cost pools. Next, the relationships that the various overhead cost categories bear to direct charged capital project activities are determined. To satisfy cost accounting rules, all costs in the same overhead cost pool should bear a beneficial or causal relationship to the capital projects over which they will be allocated.[3] For example, if a portion of the legal department's costs are allocated to capital, there must be a causal (or beneficial) relationship between the level of capital spending and the level of legal costs incurred.

Allocation of overhead costs to capital projects can be accomplished through a variety of processes. The simplest process would be to aggregate all overhead costs into one large cost pool. This pool would then be allocated in a single step, using a single broad allocation basis such as total direct cost. At the other extreme, BCTC could establish many overhead cost pools, each spread over a different set of capital projects or intermediate cost centres. Some overhead cost pools may be repeatedly allocated to other increasingly aggregated cost pools. This would result in a complex, multi-step allocation process.

3. Allocation Sequence

As described above, a single step process would involve allocating all overhead costs to all capital projects, using a single allocation basis. This would be reasonable if all overhead costs have the same type of identifiable and causal relationship with the capital projects.

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[3] Therefore, any overhead costs allocated to BCTC's capital program should bear a beneficial or causal relationship. They should support (create benefits) for the resources that are directly involved in the capital program (e.g.

However, the sequence of allocation steps generally progresses from allocating overhead costs that have the greatest identifiable relationship to the direct cost centres to allocating overhead costs that have the least identifiable relationship to the direct costs (e.g., executive salaries or rent expense).

For example, BCTC might attempt to allocate labour costs in its Asset Program Maintenance Department first, since this department works directly on capital and OMA projects. Executive salaries may then be allocated based on the allocation results of this and other departments. This is an example of a multi-step allocation process.

BCTC's actual process for allocating overhead expenses to capital is relatively straightforward and consistent with this sequential approach. It involves up to three steps, as explained in Section 4.

4. Allocation Bases

Once a utility has determined the interrelationships between overhead cost pools and direct cost centres and defined the sequence of allocation steps, it must then decide which bases to use for allocating the various cost pools at the various steps in the allocation process.

If regulatory or contractual specifications are absent, general guidance from industry accounting regulations and principles allows for substantial latitude in determining which allocation bases to use. A utility such as BCTC must rely on its own judgment regarding the best measure of the cost or beneficial relationship between the overhead cost pool and the related final cost centres.

Rudden's practice following regarding allocation bases, which has been accepted by regulatory agencies in many jurisdictions, includes the following principles:

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corporate human resources function), or vary according to the level of capital program expenditures (e.g., communications).

- Cost drivers must be identified. These cost drivers must assign costs using an observable, quantifiable direct measure of the consumption of resources by an activity.

- A consistent method must be followed, which allocates costs according to identified cost drivers.

As stated above, a cost driver is a formula for sharing the cost of an activity among those cost centres that cause the cost to be incurred (or receive the benefits of such cost incurrence). Rudden uses the following high level criteria to evaluate whether certain cost drivers can appropriately serve as allocation bases:

Economic Relationship - Cost drivers for activities should preferably be selected on the basis of cost causation. Cost causation means that there is a causal relationship between the cost driver and the costs incurred in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which cases selecting cost drivers based on benefits received is a fair and consistent treatment.

Implementation - Other factors considered in assigning cost drivers include practicality, stability, materiality, and ability to affect behavior.

5. Types of Cost Drivers

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts.

Internal drivers are based on values computed as part of the allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities.

D. Regulatory Guidance on Overhead Allocation Methods

Regulatory practice and policy offer guidance on which cost allocation bases apply best to specific categories of General & Administration (G&A) overhead costs. The U.S. National Association of Regulatory Utility Commissioners (NARUC) is an industry organization of utility regulators. NARUC has published and periodically updated an Electric Utility Cost Allocation Manual. This manual deals primarily with the issues around allocation of utility costs to customer classes for ratemaking purposes. It suggests the most appropriate bases for allocating G&A expenses to utility operational functions (production/transmission /distribution/customer service). While these rules do not deal explicitly with allocation of G&A cost to capital vs. O&M, the same allocation logic would apply.

Appendix A is an extract from NARUC's 1992 manual, showing the recommended allocation bases for various G&A accounts. As can be seen, it recommends that labour-related G&A expenses be allocated to the operational functions[4] on the basis of directly functionalized labour expense. Similarly, plant-related G&A expenses should be allocated to the operational functions on the basis of directly functionalized plant in service. Departing from these general rules would presumably carry an additional burden of evidence for the filing utility, to demonstrate why its particular circumstances warranted a different approach.

[4] Or, in BCTC's case, to capital vs. OMA

4. BCTC'S OVERHEAD ALLOCATION METHODOLOGY

The following discussion summarizes BCTC's methodology, for the purpose of setting a context for the industry practices to be reviewed in Section 5. Appendix B contains the narratives describing the function of each of the departments, and BCTC's logic for its allocation of that department's costs to capital vs. OMA.

A. Historical Allocation Method

For its capital overhead allocations prior to F2007, BCTC used the following methodology (adopted from BC Hydro) to arrive at Transmission Capital Overhead.

BCTC personnel charged directly to capital projects if:

- The employee is back filled by temporary staff or a contractor[5]
- An employee, contractor, or temporary staff is hired to work directly on the project
- An employee is required to work overtime on a capital project, or
- The employee is working more than 40% of their time in a given month on a specific capital project.

Any costs that are directly charged to capital projects are excluded from the OMA expenses included in BCTC's revenue requirement. That is, costs are recovered through rates as either OMA expense or capital expense (depreciation and financing charges), but not both.

With the exception of the above conditions, BCTC personnel do not track the time they spend working on or indirectly supporting capital project management, execution, and

[5] This is to avoid double recovery of costs, since the employee's labour costs are already included in rates.

administration.[6] Prior to F2006, BCTC used the following process to determine the appropriate proportion of F2006 overhead expense to allocate to capital projects:

- Specific expense items that can be identified as supporting either capital or operations, maintenance, and administration (OMA) were charged directly to the appropriate project or cost centre.
- Non-labour costs (e.g., desktop support, rent) that could not be identified as supporting either capital or OMA were included in the capital overhead pool, and were assigned to each department on a per headcount basis.
- Interviews were conducted with managers and staff in order to determine the portion of the labour hours of their department or group that was expended in support of capital projects.
- The resulting capital vs. OMA percentages were applied to the loaded labour costs of each department, as well as non-labour costs identified for inclusion in the capital overhead pool (as noted above).
- Costs associated with the executive management of BCTC and individual department managers were allocated to capital vs. OMA based on the aggregate allocation percentages of the staff reporting to them.

[6] BCTC has concluded that recording time on a project-by-project basis for a large number of small projects is not cost-effective, and would not materially affect overhead allocations.

B. F2007 Capital Overhead Allocation

BCTC has conducted a review of its capital overhead allocation methodology, and updated its methodology to ensure appropriate overhead costs (whether indirect or G&A) are identified and capitalized. Rudden contributed to this update by reviewing and commenting on a pre-filing version of BCTC's methodology. Several of Rudden's suggested changes were incorporated into the methodology described below.

To determine the appropriate allocation of overhead costs to capital projects for F2007, BCTC used a process similar to its historical practice, but with the following improvements.

- Interviews were conducted with all department managers and/or key staff to determine the percentage of their group's labour hours spent supporting capital projects. Interviewees were asked to base their estimate using the following criteria:
  - Work related to the support and preparation of studies to determine the need for specific capital project proposals (prior to inclusion in an approved capital plan) are considered an OMA expense item.
  - Work related to identifying and analyzing alternatives are considered an OMA expense item.
  - Once the review of alternatives and selection of the preferred project has been completed, the work needed for detailed definition and execution of a project is considered capital.

The following costs from the F2007 department budgets were included in the overhead pool for allocation through the general labour-based methodology:

- <u>Labour</u>: BCTC's total labour budget for F2007 is $44.4 million.. For the purpose of capital overhead allocation, labour has been adjusted to exclude control centre labour billed under the Distribution Operations and Generation

Control Service Level Agreements and other billable labour directly charged to capital projects and studies. The remaining labour budget for allocation to capital vs. OMA is $38.2 million. These labour costs are divided into separate overhead cost pools for each department. The proportion of such costs allocated to capital is determined by the results of the interviews conducted for each department.

- Labour-Related. The costs for a number of functions are related directly to staffing levels, and were allocated to departments based on the number of employees/FTEs.

  - Computer desktop support services: This cost relates to the services provided to BCTC by Accenture Business Services for Utilities (ABSU). The budget for desktop support services is comprised of $1.7 million in direct support costs plus the applicable BC Hydro asset-related overhead charges, $0.5 million. The total of $2.2 million was then adjusted to a cost per person and allocated to departments based on headcount.

  - Rent: This cost relates to the rent BCTC pays for its Bentall office ($1.9 million) and area control centres ($0.2 million). Rent was then adjusted to a cost per person for each location and allocated to departments based on headcount.

  - Other – Furniture & Other Equipment, Office Supplies, Printing, Telephone, Communications and Utilities: BCTC's budget for Other Expenses is composed of the budget captured in resource codes for Furniture & Other Equipment, Office Supplies, Utilities, Printing, Telephone and Communications and Utilities. The total other expense budget of $1.1 million was then adjusted to a cost per person and allocated to departments based on headcount.

Certain costs from the F2007 department budgets were excluded from general overhead allocation methodology. Instead, they were allocated to capital vs. overhead through the following methods.

- Direct billings. Where departmental labour costs were billed to capital projects or studies, they were assigned completely to capital.

- Specific analysis. To the extent that BCTC management determined that departmental labour cost was not an appropriate basis to allocate certain overhead cost items, the cost drivers for these items were analyzed, and specific percentages were allocated to capital, as summarized below.

  - *Human Resources*: BCTC's Human Resources (HR) department has a budget of $2.7 million, consisting of costs that support all aspects of BCTC's labour force plus an allocation of rent. The total budget for the department has been assigned to the overhead cost pool, and allocated to capital on the same basis as aggregate non-HR labour, as indicated by the department interviews (17.5%).

  - *Payroll Administration*: BCTC contracts its payroll administration functions to an external service provider. The total budget of $130k has been assigned to the overhead cost pool and allocated to capital on the same basis as aggregate non-HR labour, as indicated by the department interviews (17.5%).

  - *Oracle Sustainment*: The total budget of sustainment of BCTC's Oracle financial statement is $0.7 million annually. The proportion of this cost allocated to the capital based on the proportion of BCTC financial transactions (projects and work orders) that relate to capital, 15%.

  - *AMP Sustainment*: The Asset Management Program is currently used 95% to support capital planning and asset analysis. This will change over time as additional modules are added to support the maintenance aspect

of the planning process. The total budget for AMP sustainment is $0.5 million.

- *First Nations Negotiations*: BCTC engages First Nations in the system planning meetings to ensure all stakeholders provide input into the process. The discussions would encompass a large portion of BCTC's capital projects, which makes it impractical to directly charge amounts to each project. The total budget for First Nations Negotiations is $0.2 million. This cost is assigned 100% to capital.

C. F2007 Capital Overhead Allocation – Results

Table 1 summarizes BCTC's F2007 overhead costs by type. These costs must be allocated between OMA expense and capitalized expense. Table 1 also summarizes how non-labour overhead cost elements are allocated to departments, and the method for allocating total departmental costs (labour plus allocated non-labour) to capital vs. OMA.

Table 1 – Overhead Costs by Type and Allocation Method

	(a)	(b)	(c)	(d)
	$ millions	**F2007**	**Department Allocation Method**	**Capital Allocation Method**
1	Labour (excl HR)	43,590,377	Labour $	Labour $
2	Desktop Support Costs	2,149,511	FTE	Labour $
3	Rent (Bentall and Control Centres)	2,082,946	FTE	Labour $
4	Furniture & Other Equip, Office Supplies, Printing, Telephone, Communications	1,081,136	FTE	Labour $
5	HR costs including labour, rent	2,683,154	NA	Specific Analysis
6	Other Costs	1,869,932	NA	Specific Analysis
7		53,457,056		
8	Less billable labour costs	(6,214,700)	NA	Direct Billing
9	**Costs for Capital Overhead Allocation**	**47,242,356**		

Number of full time employees (FTE), or headcount, was the primary basis for allocating non-labour overhead expenses to departments. Headcount location is summarized in Table 2. Headcount by function is described in more detail below in Tables 3 and 4.

Table 2 – BCTC Headcount by Location

	(a)	(b)
1	**BCTC Headcount by Location**	
2	Bentall	209
3	Control Centres	140
4	**BCTC Total Headcount**	**349**

The costs shown in Table 1, other than the Specific Analysis costs, were broken out by department. Each department's total cost was allocated between capital and OMA based on the percentage of labour effort by department that was expended on capital projects, as estimated through the interview process. Table 3 summarizes the results of this analysis by division. Table 4 provides the detail by department.

After aggregating across all BCTC functions, and adding the Specific Analysis costs, the result of the above analysis is to capitalize **$9.8 million**, or **21%**, of BCTC's budgeted F2007 indirect and G&A expense.

Table 3. Capital Overhead Allocations – Summary by Division

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1							Cost Components for Inclusion							
2		Labour					Labour	Desktop	Bentall Rent	Control Centre Rent	Billable	Other	Total	Capital Overhead
3	**Division Summary**	**Allocation Method**	**FTE**	**Capital %**	**OMA %**	**Location**		(1)	(1)	(1)		(1)		(2)
4	President and CEO	Total cost roll-up	2	20.0%	80.0%	Bentall	655,167	12,534	18,551	-	-	6,304	692,556	138,511
5	General Counsel	Interview	16	19.6%	80.4%	Bentall	2,417,054	100,269	148,410	-	-	50,432	2,716,164	533,305
6	System Operations	Interview	149	5.0%	95.0%	Bentall & Cont Cent	15,630,752	933,753	83,480	200,000	(5,638,700)	469,648	11,678,933	583,947
7	Asset Management & Planning	Interview	94	24.4%	75.6%	Bentall	11,521,466	589,079	871,906	-	(550,700)	296,288	12,728,039	3,111,399
8	Corporate Services & CFO	Interview	44	28.1%	71.9%	Bentall	8,286,088	275,739	408,126	-	(25,300)	138,688	9,083,341	2,548,102
9	Customer & Strategy Dev	Interview	34	13.8%	86.2%	Bentall	4,242,234	213,071	315,370	-	-	107,168	4,877,843	673,821
10	Major Projects	Interview	4	100.0%	0.0%	Bentall	837,617	25,067	37,102	-	-	12,608	912,395	912,395
11														
12	**Subtotal**		**343**	**19.9%**	**80.1%**		**43,590,377**	**2,149,511**	**1,882,946**	**200,000**	**(6,214,700)**	**1,081,136**	**42,689,271**	**8,501,480**
							Included in HR total Overhead (Col M, L13)							
13	Human Resources	Total cost roll-up	6	17.5%	82.5%	Bentall	796,009	37,601	55,654	-	-	18,912	2,683,154	470,565
14	Specific Cost Assignments			46.6%	53.4%								1,869,932	871,782
15														
16	**Total**		**349**	**20.8%**	**79.2%**		**44,386,386**	**2,187,112**	**1,938,600**	**200,000**	**(6,214,700)**	**1,100,048**	**47,242,356**	**9,843,827**
17														
18							(1) Allocated to divisions based on FTE X corporate cost per FTE.							
19								6,267	9,276	1,429		3,152		
20							(2) Allocated to capital based on capital % of labour plus specific analysis assignments.							

Table 4. Capital Overhead Allocations – Summary by Department (1/2)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1							Cost Components for Inclusion							
2		Assignment Method					Labour	Desktop	Bentall Rent	Control Centre Rent	Billable	Other	Total	Capital Overhead
3	Department Summary		FTE	Capital %	OMA %	Location		(1)	(1)	(1)		(1)		(2)
4	Office of the President & CEO	Total cost roll-up	2	20.0%	80.0%	Bentall	655,167	12,534	18,551	-	-	6,304	692,556	138,511
5	Corporate Cost Centre	Weighted on Total	(1)	20.0%	80.0%	Bentall	2,396,889	(6,267)	(9,276)	-	-	(3,152)	2,378,195	475,639
6	Major Projects	Interview	4	100.0%	0.0%	Bentall	837,617	25,067	37,102	-	-	12,608	912,395	912,395
7	Corporate Services	Weighted on Division	1	30.0%	70.0%	Bentall	381,270	6,267	9,276	-	-	3,152	399,964	119,989
8	Business Improvement	Interview	3	0.0%	100.0%	Bentall	473,066	18,800	27,827	-	-	9,456	529,149	-
9	Controller	Interview	20	24.0%	76.0%	Bentall	2,290,357	125,336	185,512	-	(11,800)	63,040	2,652,445	635,789
10	Regulatory	Interview	6	59.2%	40.8%	Bentall	810,823	37,601	55,654	-	-	18,912	922,989	546,475
11	Technology	Interview	15	35.0%	65.0%	Bentall	1,933,683	94,002	139,134	-	(13,500)	47,280	2,200,599	770,210
12	Legal	Interview	6	15.0%	85.0%	Bentall	1,374,689	37,601	55,654	-	-	18,912	1,486,855	223,028
13	Supply Chain	Interview	10	25.0%	75.0%	Bentall	1,042,365	62,668	92,756	-	-	31,520	1,229,309	310,277
14	Safety & Environment	N/A	-			Bentall	-	-	-	-	-	-	-	-
15	Stations	N/A	-			Bentall	-	-	-	-	-	-	-	-
16	Lines	N/A	-			Bentall	-	-	-	-	-	-	-	-
17	Vegetation	N/A	-			Bentall	-	-	-	-	-	-	-	-
18	Asset Management & Planning	Weighted on Division	8	59.1%	40.9%	Bentall	1,381,960	50,134	74,205	-	(78,500)	25,216	1,453,015	858,082
19	System Plng & Perf Assessment	Interview	43	18.9%	81.1%	Bentall	5,078,640	269,472	398,851	-	(468,500)	135,536	5,413,999	1,021,154
20	Asset Program Management	Interview	19	26.5%	73.5%	Bentall	2,054,879	119,069	176,236	-	-	59,888	2,410,072	638,623
21	Asset Program Definition	Interview	24	17.2%	82.8%	Bentall	3,005,987	150,403	222,614	-	(3,700)	75,648	3,450,952	593,541
22	Customer & Strategy Dev	Weighted on Division	2	15.0%	85.0%	Bentall	421,038	12,534	18,551	-	-	6,304	458,427	68,764
23	Communications	Interview	9	49.6%	50.4%	Bentall	1,020,304	56,401	83,480	-	-	28,368	1,188,553	589,389
24	Market Operations	Interview	17	0.7%	99.3%	Bentall	1,843,057	106,536	157,685	-	-	53,584	2,160,862	15,668
25	Regional Market Policy	Interview	3	0.0%	100.0%	Bentall	600,617	18,800	27,827	-	-	9,456	656,700	-
26	Business & Strategic Planning	Interview	3	0.0%	100.0%	Bentall	357,218	18,800	27,827	-	-	9,456	413,301	-
27	System Operations	Weighted on Division	5	5.0%	95.0%	Bentall	370,315	31,334	83,480	-	(9,300)	15,760	491,589	24,579
28	Real Time Operations		4			Bentall	-	-	-	-	-	-	-	-
29	Telecom Network Operations		12			Cont Cent	-	-	-	-	-	-	-	-
30	Training		11			Cont Cent	-	-	-	-	-	-	-	-
31	Lower Mainland Control	Interviewed as a group	31			Cont Cent	-	-	-	-	-	-	-	-
32	Interior Operations		23	5.0%	95.0%	Cont Cent	15,260,437	902,419	-	200,000	(5,629,400)	453,888	11,187,344	559,367
33	Vancouver Island Control		15			Cont Cent	-	-	-	-	-	-	-	-
34	System Control		33			Cont Cent	-	-	-	-	-	-	-	-
35	EMS Technology		15			Cont Cent	-	-	-	-	-	-	-	-
36														
37	**Subtotal**		**343**	**19.9%**	**80.1%**		**43,590,377**	**2,149,511**	**1,882,946**	**200,000**	**(6,214,700)**	**1,081,136**	**42,689,271**	**8,501,480**

Table 4. Capital Overhead Allocations – Summary by Department (2/2)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1							Cost Components for Inclusion							
2		**Assignment Method**					Labour	Desktop	Bentall Rent	Control Centre Rent	Billable	Other	**Total**	**Capital Overhead**
3	**Department Summary**		**FTE**	**Capital %**	**OMA %**	**Location**		(1)	(1)	(1)		(1)		(2)
4	**Specific Costs**						Included in HR total Overhead (Col M, L5)							
5	Human Resources	Labour cost roll-up	6	17.5%	82.5%		796,009	37,601	55,654	-	-	18,912	2,683,154	470,565
6	Payroll Administration	Labour cost roll-up		17.5%	82.5%								130,000	22,799
7	Oracle Sustainment	Transaction mix		15.0%	85.0%								650,000	97,500
8	AMP Sustainment	Direct assignment		95.0%	5.0%								470,000	446,500
9	Purchasing Services	Supply Chain assigment		25.0%	75.0%								419,932	104,983
10	First Nations Negotiations	Direct assignment		100.0%	0.0%								200,000	200,000
11														
12	Subtotal		349	**29.5%**	**70.5%**		796,009	37,601	55,654	-	-	18,912	**4,553,086**	**1,342,348**
13														
14	**Total**		**349**	**20.8%**	**79.2%**		**44,386,386**	**2,187,112**	**1,938,600**	**200,000**	**(6,214,700)**	**1,100,048**	**47,242,356**	**9,843,827**
15														
16							(1) Allocated to divisions based on FTE X corporate cost per FTE.							
17								6,267	9,276	1,429		3,152		
18							(2) Allocated to capital based on capital % of labour plus specific analysis assignments.							

5. REVIEW OF INDUSTRY PRACTICE

Rudden reviewed the methodologies used by utilities comparable to BCTC, for allocating overhead expense to capital. We reviewed methodologies used by (a) other electric utilities in Canada; (b) non-electric utilities regulated by the BCUC, and (c) other transmission electric utilities in North America.

The results of our research are summarized below. To maintain continuity of thought, we have added commentary at the end of each peer description on the applicability to BCTC.

At the outset, we must stress that the main value of looking at BCTC's peer companies is in the evaluation of the appropriateness of BCTC's overhead capital allocation methods. That is, are the cost drivers that underlie the allocation bases appropriate to BCTC's patterns of cost incurrence, and are they consistent with accepted industry practices?

Direct comparisons of the results of overhead capital allocation methodologies can be misleading, as they conflate a number of variables that depend on utility- specific factors. It should be remembered that each utility's allocation of overhead to capital will depend on the size of the cost accounting framework, overhead cost pool[7] and the percentage allocated to capital. The overhead capitalization rate will depend in turn on the quotient of capital overhead divided by planned capital spending. All of these variables can vary substantially from utility to utility, depending on its circumstances.

The comparative figures stated below for BCTC's peer utilities should be interpreted with that caveat firmly in mind.

[7] The percentage of expenses that are directly charged, as opposed to booked to an overhead cost pool, also varies greatly.

A. Other Electric Utilities in Canada.

Hydro One Networks, Inc.

Rudden performed a study in 2005 of this large regulated electric utility's methodologies for allocating distribution overheads. Hydro One Networks Inc.'s (HONI) Asset Management group is responsible for the utility's operating assets, including investment strategy, investment planning and managing daily operations. It supports Distribution Operations and Maintenance, Distribution Capital Projects, Transmission Operations and Maintenance and Transmission Capital Projects. So HONI's allocation methodology must address transmission vs. distribution functionalization as well as capital vs. O&M allocation.

Due to these additional complexities and the relatively high profile of overhead allocations for HONI's transmission and distribution customers, HONI performed a four-week time study to determine the time devoted in Asset Management to each of the four areas. Rudden reviewed the time study method used by the utility for Asset Management and found it to be appropriate.

Common Corporate Functions and Services (CCFS) also provided support to Distribution and Transmission Capital and Operations and Maintenance projects. Rudden found that while the departments that performed the CCFS activities could determine with reasonable accuracy the portions of time they spent on Distribution, Transmission and the other business units, they were unable to determine with reasonable accuracy the time they spent on O&M vs. capital projects. Therefore, it was necessary to compute the amount of overhead costs to be capitalized to Distribution business Capital Projects using other allocation methods such as cost causation or benefits received. Rudden recommended allocating CCFS costs using an average of two methods:

- Labour Content Method. Percentage of directly charged Distribution labour costs booked to Distribution capital projects (vs. O&M).[8]

- Total Spending Method. Percentage of total directly charged Distribution costs booked to Distribution capital projects (vs. O&M).[9]

Using the above method, which is still under review by the Ontario Energy Board, HONI proposed allocating 47.8% of total Distribution overhead costs to capital. This amount of capital overhead costs resulted in an overhead capitalization rate of 16.6% when applied against HONI's planned spending on Distribution capital projects.

Applicability to BCTC. Hydro One's use of a time-study to allocate Asset Management labour effort and therefore labour expense between capital and O&M is consistent in principle with the method used by BCTC. BCTC elected not to perform a time study, in view of budget and time constraints. However, its interviews with Asset Management managers served to gather the same type of information on personnel direction of effort, albeit at a more approximate level.

In overhead areas outside of Asset Management, BCTC's overhead allocation process was arguably more precise than Hydro One. BCTC choices of allocation bases for splitting overhead costs between capital vs. O&M were based on department-specific data on cost drivers. Hydro One used the same allocation basis for all overheads other than Asset Management.

The use of labour cost or total cost allocation bases is consistent with the way G&A costs are allocated in many traditional utility cost-of-service studies, if one allocation basis is used for all G&A.

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[8] In HONI's case, 44.8% of directly charged labour cost was booked to capital projects.

[9] In HONI's case, 50.7% of total directly charged cost was booked to capital projects.

ATCO Electric.

Rudden was able to find only limited information on the overhead allocation methods used by ATCO Electric, an Alberta electric utility with significant transmission capital expenditures. Based on a June 2005 regulatory filing with the Alberta Energy and Utilities Board, 17.5% of executive salaries are allocated to capital, and the remainder to O&M. We found no discussion on the allocation base or the rationale behind this allocation. Executive salaries typically are allocated between capital and O&M based on the overall split of costs rolling up from the lower layers of the organization, so it is reasonable to conclude that approximately 17.5% of ATCO Electric's overhead costs were allocated to capital. Information on ATCO Electric's overhead capitalization rate was not available.

> *Applicability to BCTC*. ATCO Electric's percentage allocation of overhead (17.5%) to capital is broadly similar to BCTC's proposed allocation of 21.0%.

B. Non-Electric Utilities Regulated by the BCUC.

Terasen Gas

Rudden reviewed the regulatory filings submitted by utilities that are regulated by the British Columbia Utilities Commission (BCUC). Terasen Gas is the largest natural gas distributor in British Columbia. In its 2006-2007 revenue requirements filing, Terasen Gas Inc. (Vancouver Island), a subsidiary of Terasen Gas Inc., requested to standardize allocation of overhead expenses to capital at 16 percent of allowed overhead expenses. The filing stated that it had become a very expensive and time consuming process to complete the TGVI overhead capitalization study on an annual basis as had been the practice historically. Furthermore, the Company had entered a mature phase where capital spending was expected to remain stable. A fixed overhead allocation of 16 percent to capital would also be consistent with the practices of the parent company, Terasen Gas, Inc.

Applicability to BCTC. This data point is again in a broadly similar range with BCTC's overhead allocation to capital of 21.0%.

C. Other Electric Utilities in North America With Substantial Transmission

Large Southwest U.S. Electric/Gas Utility

This large regulated utility has different approaches to allocating transmission and distribution overheads ("division" overheads) and corporate administrative and general overheads ("A&G" overheads). Each process is described below.

Within the Transmission and Distribution department, the current approach to overhead capitalization is to direct charge all costs for which it is reasonable and cost efficient to do so. For example, all Transmission Planners and Engineers charge their time directly to a Capital or Operations and Maintenance Project. However, Distribution Planners and Engineers work on many different smaller projects during a given day, which makes it impractical to direct charge these costs. These costs are included in an overhead cost pool along with all other costs that cannot be directly traced to a specific project. There are separate cost pools for Transmission overhead costs and Distribution overhead costs. The Transmission overhead cost pool is allocated to capital vs. O&M projects using the following monthly cost pools as an allocation base: 100 percent of direct labour dollars plus 65 percent of direct contract dollars.[10] The rationale behind including just 65 percent of contract dollars in the allocation base is that less overhead support is needed for activities performed by contractors than for activities performed by SCE employees. Since the proportion of labour and contract dollars direct charged to capital vs. O&M projects varies each month, the percentage allocation of overhead to capital also varies each month.

The Transmission and Distribution department is currently reviewing its overhead allocation methodologies. It recognizes a need to divide its overhead costs into

separate cost pools for each department based on the level of support each department provides to Capital and Operations and Maintenance projects. This would improve the level of causality of its overhead allocation. One of the approaches it is considering is to perform an annual time study for each department that supports Capital and Operations and Maintenance activities (and does not direct charge) in an attempt to identify the amount of time spent supporting each. All costs of each department would be allocated to Capital based on these percentages.

This utility's Corporate G&A costs are allocated to capital based on a direction of effort study that is updated every three to five years. In this study, each department and location is interviewed to determine the percentage of costs incurred to support capital projects. These departments include corporate budgets, controllers, legal, HR, and executive management.

Some overhead costs, such as vehicle costs, IT costs, and property management costs, are charged out to the various business units using an internal market mechanism. A portion of these costs are capitalized by the internal service provider. The remaining costs of the internal service providers are assigned to O&M and are not included in divisional overhead allocations.

> *Applicability to BCTC.* This utility is moving toward a department-specific allocation of overhead to capital vs. O&M, which will be similar to the approach taken by BCTC. Also like BCTC, it uses an interview approach to gathering data on the direction of effort (capital vs. O&M) for its Corporate overhead cost centers.

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[10] Therefore, the percentage of overhead expense allocated to capital = (100% of Transmission labour expense direct charged to capital plus 65% of Transmission contract expense direct charged to capital) / (100% of direct charged Transmission cost + 65% of direct charged Transmission contract cost).

Large Northwest U.S. Electric Utility 1

This utility's current approach to overhead capitalization is to direct charge all costs for which it is reasonable and cost efficient to do so. For example, the Legal Department charges its time directly to the project it is supporting. Transmission Planning activities are direct charged to a capital or O&M project where possible. Planning activities that cannot be traced to a specific project are split between an O&M account and a Construction Support account. Construction Support is a capital overhead cost pool that is allocated to active capital projects based on direct labour dollars booked to those projects. The split of overhead between O&M and Construction Support is based on a time study that is reviewed annually. The percentage allocations have remained fairly stable.

Cost of certain support functions at this utility are assigned 100% to an O&M account, even though the functions support the entire company. For example, regulatory, senior management, accounting and finance are all assigned 100% to O&M. The Property Accounting group is assigned 100% to the Construction Support account since it supports only Capital Projects. IT costs are split between capital and O&M based on the CPU time devoted to supporting each type of project.

> *Applicability to BCTC.* This utility used a time study as the primary basis for allocating overheads between capital and O&M, so in that sense its allocation basis is built on more precise data than BCTC. However, the time study has not been updated recently, and the utility has elected not to allocate significant portions of higher level overhead expense.

Large U.S. Northwest Electric Utility 2

This utility attempted to direct charge its support costs to capital and O&M wherever possible. Based on a study performed in 2000, the great bulk of its G&A Costs (92%) were directly charged to either capital or O&M. These costs included HR, Public Affairs, Environmental, Legal, Regulatory, Finance, Executive, Marketing, and Retail Products

and Services. The remaining G&A Costs that were not direct charged (8%) were assigned to a "corporate governance" overhead cost pool. The corporate governance cost pool was divided between capital and O&M based on the percentage of directly charged labour booked to capital projects (vs. O&M). This allocation percentage was updated each year based on budgeted labour costs. The same allocation percentage was used for all costs in the corporate governance cost pool, regardless of the source of the cost.

A percentage of transmission and distribution supervision and engineering costs were also reclassified to capital based on the percentage of budgeted line crew labour charged to capital. This percentage was also updated each year based on budgeted labour costs. A similar process was used for construction overhead costs.

Support costs such as facilities, vehicles, and IT were allocated using a multi-step allocation method. The first step included allocating these types of support costs, other than those direct charged, to the various overhead cost pools (corporate governance, supervision and engineering, and Construction OH) described above.

One result of the study of this utility's overhead allocation methodologies was a recommendation that the utility perform a broad review of its G&A costs, similar to that performed by BCTC, to determine the amount of support each G&A department provided to capital projects. The goal was to improve the accuracy of allocations between capital and O&M, between functions (Generation, Transmission, Distribution, Customer Service), and to non-utility products and services. The result of this study would likely be separate overhead cost pools for each G&A department and fewer costs being (inaccurately) direct charged.

Applicability to BCTC. This utility managed to direct charge a very high portion of the types of costs (G&A, supervision/engineering) that would typically be classified to overhead. Apparently, however, the results of this direct charging scheme were not viewed as being consistent with the overall direction of effort (i.e., the proportion of effort devoted to capital projects. This demonstrates again the principle of "GIGO", or "Garbage In – Garbage Out." Direct charging to

capital vs. O&M may sound like a highly accurate method to derive capital costs, but firm-specific accounting rules and inaccurate time-keeping by individuals can lead to a result that does not make sense. There is no substitute for good, well-informed management judgment, such as that applied by BCTC.

Electric Utility Cost Allocation Study -- Department of Justice

An extensive study of electric utility practices for allocating overhead costs was performed in 1993 for the U.S. Department of Justice. The leader of the Department of Justice study is the Rudden professional who is the primary author of this review of BCTC's capital overhead allocation methodology. Although this study focused on the allocation of overhead costs to generation capital projects, the findings are generally applicable also to transmission overhead allocations.

Intensive interviews were conducted with 36 utilities. According to the study, utilities generally attempt to direct charge whenever feasible and cost effective. However, the study found that the level of direct charging to final cost centres varied greatly depending on the level of detail desired by and available to the utility.

Nearly half of the utilities studied used a single step allocation method, with one allocation base for allocating all overhead costs between capital and O&M. The other half used a more complicated process of at least three, and sometimes well over ten, allocation steps. Different allocation bases could be used at different steps in the process, with the results of one step feeding into the allocation basis for the next higher step.

Where one allocation basis was used, by far the most popular basis for allocating overhead costs to capital vs. O&M was Total Cost, i.e., the percentage of directly charged expenses that were charged to capital vs. O&M. Where overhead labour was allocated separately to capital vs. O&M, the most frequently chosen allocation basis was direct charged Total Labour Dollars. A variety of other allocation bases found occasional use, but were not common.

Applicability to BCTC. BCTC's use of labour cost as an allocation basis for many of its overhead cost categories is consistent with prevailing U.S. utility industry practice.

5. CONCLUSIONS

R.J. Rudden Associates has reviewed and commented upon BCTC's draft methodology, as of early February 2006, for allocating overhead expenses to capital. We have also reviewed in detail the final capital overhead allocation methodology used by BCTC in developing its F2007 revenue requirement, and assessed the reasonableness and appropriateness of this methodology in the context of applicable accounting and regulatory guidance and accepted utility industry practice. Finally, given our knowledge of BCTC's pattern of business activities, we have evaluated the reasonableness of the results of BCTC's final methodology, in terms of the percentage of its overhead costs that are allocated to capital.

Our opinion is that BCTC's capital overhead allocation methodology is reasonable and appropriate on all the above grounds.

- It is based on reasonably detailed and validated data, reflecting its line managers' best estimates of the capital vs. OMA direction of effort for their personnel.

- The types of indirect and G&A costs included in the overhead pool for allocation to capital projects are reasonable. They all bear an identifiable causal or beneficial relationship to capital project activities.

- The choice of allocation bases for splitting costs between capital vs. OMA by department is consistent with industry practice for those types of costs, and reasonably reflects the underlying cost drivers.

- The percentage of overhead costs allocated to capital by BCTC (21%) is modestly higher than the percentages used by ATCO Electric and TGVI. This result appears reasonable, given BCTC's more active capital program.

APPENDIX A
EXCERPT FROM NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL

Appendix A

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

Appendix A

II. ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include Accounts 920 through 935 and are allocated with an approach similar to that utilized for general plant. One methodology, the two-factor approach, allocates the administrative and general expense accounts on the basis of the sum of the other operating and maintenance expenses (excluding fuel and purchased power).

A more detailed methodology classifies the administrative and general expense accounts into three major components: those which are labor related; those which are plant related; and those which require special analysis for assignment or the application of the beneficiality criteria for assignment.

The following tabulation presents an example of the cost functionalization and allocation of administrative and general expenses using the three-factor approach and the two-factor approach.

Account Operation		Three-Factor Allocation Basis	Two-Factor Allocation Basis
920	A & G Salaries	Labor - Salary and Wages	Labor - Salary and Wages
921	Office Supplies	Labor - Salary and Wage	Labor - Salary and Wages
922	Administration Expenses Transferred-Credit	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
923	Outside Services Employed	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
924	Property Insurance	Plant - Total Plant [1]	Plant - Total Plant
925	Injuries and Damages	Labor - Salary and Wages[2]	Labor - Salary and Wages
926	Pensions and Benefits	Labor - Salary and Wages	Labor - Salary and Wages
927	Franchise Requirements	Revenues or specific assignment	Revenues or specific assignment

[1] A utility that self-insures certain parts of its utility plant may require the adjustment of this allocator to only include that portion for which the expense is incurred.

[2] A detailed analysis of this account may be necessary to learn the nature and amount of the expenses being booked to it. Certain charges may be more closely related to certain plant accounts than to labor wages.

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Appendix A

Account Operation		Three Factor Allocation Basis	Labor-Ratio Allocation Basis
928	Regulatory Commission Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
928	Duplicate Charge-Cr.	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.1	General Advertising Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.2	Miscellaneous General Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
931	Rents	Plant - Total Plant[3]	Plant - Total Plant
Maintenance		**Three Factor Allocation Basis**	**Labor-Ratio Allocation Basis**
935	General Plant	Plant - Gross Plant	Labor - Salary and Wages

[3] A detailed analysis of rental payments may be necessary to determine the correct allocation bias. If the expenses booked are predominantly for the rental of office space, the use of labor, wage and salary allocators would be more appropriate.

APPENDIX B.
BCTC F2007 CAPITAL OVERHEAD ALLOCATION DETAIL BY DEPARTMENT

Department Narratives

Each of the departments interviewed has provided a brief narrative to support the percentage of time for inclusion in the capital overhead analysis. Other departments that provide executive direction and support to BCTC have been assigned to the capital overhead pool on a weighted cost basis.

Office of the Director of Major Projects

Capital - 100%

OMA - 0%

The role of the Director of Major Projects is to provide executive leadership for the portfolio of major projects in the transmission capital plan. As such all costs are assigned to the capital overhead pool.

Business Improvement

Capital - 0%

OMA - 100%

Currently Business Improvement work does not support the capital program and as such no costs have been assigned to the capital overhead pool.

Controller

Capital - 24%

OMA - 76%

The Controller's department has a staff of 20 and has the following areas of responsibility:

- Financial Accounting and Budgeting (5) is responsible for all aspects of payroll and revenue accounting; OMA planning, budgeting and reporting; and billing and accounts payable. This area is assigned 100% to OMA
- Capital Accounting and Reporting (5) is responsible for the capital accounting policies, procedures, controls and processes; capital budgeting, forecasting and reporting; fixed asset and project accounting and analysis; control and facilitation of the capital planning process and Capital Plan and Certificate of Public Convenience and Necessity (CPCN) support and impact analysis. 75% of the cost for this area has been assigned to the capital overhead pool.
- Costing and Regulatory Support (2) is responsible for the preparation of revenue requirement and associated analysis; rate determination and impact analysis; cost of service analysis and Capital Plan and CPCN support and impact analysis. 20% of the cost for this area has been assigned to the capital overhead pool.
- Financial Systems and Reporting (5) is responsible for financial planning and forecasting; all reporting requirements associated with statutory, management and government bodies; financial policies, procedures, controls and processes; financial systems and support. It is in the area of financial systems and support that this group supports the capital programs. 10% of the cost for this area has been assigned to the capital overhead pool
- Treasury and Pension fund (1) is responsible for forecasting finance charges; credit policy administration and credit facilities and borrowing arrangements; banking and payment arrangements; insurance and investment policies and reporting. These activities are primarily relating to the day to day operations of BCTC and as such 100% of the cost of these activities have been assigned to OMA

The department also has 1 Controller whose cost has been assigned to the capital overhead pool on a weighted basis and 1 Administrative Assistant whose cost has been assigned 100% to OMA.

Regulatory

Capital - 59%

OMA - 41%

Regulatory Affairs works on all applications to the BCUC, including the Transmission Capital Plan, Revenue Requirements and CPCN applications. Work on CPCN applications are part of the definition phase of specific capital projects and is considered to be work on account of capital. The Transmission Capital Plan is considered planning and therefore is an operating activity. Revenue Requirements and most other types of small applications are considered operating activities.

The work of individuals within the Regulatory Affairs group has been proportionally assigned to either operating or on account of capital based on the type of applications each individual works on. The OMA forecast costs of those individuals is then proportionally allocated between capital and OMA. The assignment of work between individuals within the Department is expected to remain the same for F2007.

The Manager, Regulatory Projects and one Senior Advisor work primarily on CPCN applications and have been assigned a weighting of 90% on account of capital; 10% operating.

One Senior Advisor works primarily on the Revenue Requirement and Transmission Capital Plan and has been assigned 100% to operating.

For those individuals that support the entire group (administrative and supervisory staff) the dollar weighted average of the costs of the department as a whole have been used. That is the Director, Regulatory Affairs (supervisor), Administrative Assistant, and Regulatory Projects and Hearings Coordinator have been assigned the dollar weighted average allocation of the group as a whole. Based on the three individuals for which specific assignments have been made, the dollar weighted average for the department is 59% capital, 41% operating and this has been applied to the costs of three positions identified above as supporting the entire group.

Of the effort expended on account of capital, 99% is associated with TLOB capital. The 1% devoted to BCTC capital is in respect of quarterly reporting of the System Control Modernization Project and the participation of the Director, Regulatory Affairs in the BCTC Capital budget review process.

Technology

Capital - 35%

OMA - 65%

In general the technology group is involved in the following broad categories of work:

- Strategy and governance
- Architecture
- IT Operations and SLA
- Capital investment and Project management
- Security

The life cycle of each project involves a number of activities including the feasibility, design, implementation, training and sustainment.

A reasonable estimate for capital overhead on an ongoing basis is 30% to 40% of internal technology department time. For the purpose of capital overhead 35% is a reasonable estimate.

Legal

Capital - 15%

OMA - 85%

The legal department provides ongoing support for capital projects (captured as Capital Overhead) in the following capacity:

- Address legal aspects of customer concerns for specific capital projects
- Provide advice on legal claims (plant, equipment or other damages, warranties, indemnities, credit arrangements, etc.)
- Provide advice on procurement activities and materials
- Assist with internal approvals for project and contract work
- Assist with the receipt of capital funding from BCH and others
- Provide interpretation of the MA and SLAs
- Assist capital project teams with legal questions

A reasonable estimate on an ongoing basis is 10-20% of internal Legal department time. For the purpose of Capital Overhead estimation 15% would be a reasonable number. Of this 15%, it is estimated that 60% relates to support to TLoB Capital Projects and 40% relates to support for BCTC Capital Projects.

Supply Chain

Capital - 25%

OMA - 75%

The Supply Chain covers the functions of Procurement, Outsourcing and Facilities Management. The procurement staff is directly involved in activities related to large capital projects. Other staff members have limited involvement in capital work. An estimate of time spent by multiplied by labour costs indicates a 22/78 split capital/OMA. Given that the capital program is growing it is reasonable to allocate 25% to capital on a go forward basis.

System Planning & Performance Assessment

Capital - 19%

OMA - 81%

System Planning and Performance Assessment is responsible for planning the growth capital associated with transmission and substation distribution assets as well as providing the operational planning required to ensure a safe and reliable power system.

System Planning and Performance Assessment comprises three functionally based departments

- Transmission System Planning (13 including 2 vacancies) is responsible for the long-term planning of the integrated transmission system, including interties to adjoining utilities. The work of technical staff in this department is split 70% operating and 30% capital. Most of their work is in the study phase of capital projects and this is funded out of OMA. As projects proceed through the definition and execution phases and can be capitalized less involvement by planning staff is required. Some major projects such as the Vancouver Island Transmission Reinforcement project require more commitment from staff. Other work performed in this department includes responding to requests for transmission service under the OATT.
- Regional System Planning (11 staff) is responsible for the long-term planning of the regional transmission system, including substation and transformation facilities at the points of delivery to customers. The work of staff in this department is also split 70% operating and 30% capital for the same reasons that apply to the Transmission System Planning department. This department is also responsible for coordinating the preliminary tariff studies required for IPP interconnections and includes the position of one IPP planner/coordinator. This work is primarily OMA related.
- Performance Planning (13 staff) is responsible for ensuring reliability of the existing integrated transmission system, determining operational limits and solving operational problems. All of the costs related to this work are classified as operating expense, since it supports the operation of the existing transmission system.
- The Manager of System Planning and Performance Assessment and the Planning Process Manager enable the planning activities performed in the three departments and have been assigned a weighting of 80% operating and 20% capital
- The Principal Engineer position is occupied by a specialist in Power System Reliability and his work supports the entire group and is assigned the weighted average of the group: 80%operating, 20% capital
- The three administrative support staff have been assigned the weighted average of the group: 80% operating, 20% capital

Of the effort expended on account of capital, 99% is associated with BC Hydro capital projects, and 1% is related to BCTC capital projects. The BCTC projects are small information technology projects associated with System Planning.

Asset Program Management

Capital - 27%

OMA - 73%

Asset Program Management (APM) provides project management services for sustaining capital, growth capital and maintenance projects carried out on BC Hydro's transmission assets.

The work of individuals within the APM group has been proportionally assigned to either OMA or capital accounts based on the estimated level of effort of each individual's role in the management of capital projects and maintenance projects or BCTC administration. The assignment of work between individuals within the Department is expected to remain the same for F2007.

Two Program Managers almost exclusively manage maintenance projects (Vegetation and Substation). These positions have been allocated entirely to OMA accounts. One Program Manager is exclusively assigned capital projects and is entirely allocated to capital accounts. The balance of the department is involved in supporting or managing a mix of capital, maintenance or administrative related projects. The level of effort for each position has been estimated to reflect a reasonable allocation.

The Department Manager and Administrative Assistant providing support for the whole department have been weighted based on the overall department average. The dollar weighted average for the department is 27% capital, 73% operating and this has been applied to the costs of these two positions.

Of the effort expended on account of capital, 100% is associated with TLOB capital.

Asset Program Definition

Capital - 17%

OMA - 83%

The asset program definition department provides ongoing support for capital projects in the following capacity:

- Defines the need and justification for capital programs
- Defines standards for capital procurement
- Provides technical advice on capital project procurement
- Provides commissioning expertise upon completion of capital projects.
- Provides technical expertise on warranty issues associated with capital projects.

Communications

Capital - 50%

OMA - 50%

The Communications and Stakeholder Relations (C&SR) Department works on the applications including the Transmission Capital Plan and Certificate of Public Convenience and Necessity (CPCN) applications in the following capacity:

Consultation on CPCN applications: C&SR designs and implements the consultation process. The result of this process forms part of the CPCN applications. Two senior Community Relations Advisors work on CPCN applications, with both Advisors having an assigned weighting of 65% for capital. The remainder of their work relates to activities that fall into operating activities, which include: communications and consultation around vegetation management programs, maintenance programs, and the Transmission Capital Plan, which is considered planning and therefore is an operating activity.

The department's Communications Coordinator works entirely on media relations and corporate communications, and has been assigned 100% to operating.

For those individuals that support the entire group, the weighted average of the entire group has been used. That is the Director of Communications and Stakeholder Relations (supervisor) and the Administrative Assistant.

Market Operations

Capital - 1%

OMA - 99%

The Market Operations group provides support for capital projects in the following capacity. This responsibility primarily falls to one individual.

- assist in contract preparation and negotiation
- provide assistance in contract process by ensuring tariff regulations are adhered to
- provide tariff and business practice interpretation
- provide customer support and act as customer liaison for customer inquiries, issues, etc.
- ensure appropriate financial and technical approvals

As well, another Market Operations individual provides project management to critical systems capital projects.

Regional Market Policy

Capital - 0%

OMA - 100%

Currently Regional Market Policy does not support the capital program and as such no costs have been assigned to the capital overhead pool.

Business and Strategic Planning

Capital - 0%

OMA - 100%

Business and Strategic Planning main contact with capital projects is in the early part of the strategic evaluation of growth projects. Generally involvement is around the strategic rational for a project (that there is value). There may be input into the agreement that a planning study should be undertaken. Business and Strategic Planning is also involved in the future potential for economic evaluation of a project, i.e. before engineering estimates. As such no costs have been assigned to the capital overhead pool.

System Operations

Capital - 5%

OMA - 95%

System Operations provides support for Capital Projects as follows:

- Establishing work zones for the electric system to allow capital construction to proceed.
- Acceptance of documentation in preparation for energization of new equipment.
- Writing switching orders and implementing switching instructions for testing and commissioning new equipment into service.
- Issuing revised operating documentation, such as Operating Orders and One-Line diagrams, to operate new equipment safely and reliably.
- Communicating with stakeholders and co-ordination of capital work to mesh with ongoing system operations and maintenance schedules.

Appendix D

Report on General Liability Coverage for BCTC

HW ASSET MANAGEMENT INC
RISK MANAGEMENT and INSURANCE CONSULTANCY

REPORT

on

GENERAL LIABILITY COVERAGE

for

BRITISH COLUMBIA TRANSMISSION CORPORATION

Prepared by:
Peter Hindmarch-Watson
and
Stuart Johnson
February 2006

CONTENTS

EXECUTIVE SUMMARY and RECOMMENDATIONS

As a result of our research and considerations for this study, we have reached the following conclusions and recommendations:

- Even though the benchmarking studies that we have detailed in the body of our report indicate that BCTC currently carries a prudent amount of insurance (as compared against other utilities), BCTC faces unusual exposures because of the physical environment within which it operates. Accordingly, BCTC should, subject to an assessment of the risk exposure and cost effectiveness implications, consider obtaining coverage for a limit of liability that is higher than the current limit of $250,000,000.

- With the permission of BCTC, we met with the Risk Management Branch (RMB) of the Ministry of Finance in the Government of British Columbia. We are pleased to report that there is a possible opportunity for BCTC to apply and participate in a pooling arrangement through RMB that would protect BCTC against responsibility for third party losses in excess of a certain pre-agreed dollar amount that would be purchased through regular insurance channels. BCTC is exploring the availability of this option with RMB in the hopes that, if the arrangement is available and acceptable to BCTC, it would reduce the amount of coverage that BCTC currently carries. We strongly recommend that this opportunity continue to be pursued.

- BCTC's general liability coverage is placed with an underwriter that specializes in underwriting power and utility companies. The underwriter is financially stable, as it is strongly rated with a rating of "A" Stable from Best's and "A+" from Fitch.

- The deductible of $500,000 is realistic for British Columbia Transmission Corporation when compared to its peers and should be maintained.

- Considering the very broad insurance protection provided, the deductible level, and the risks attached to BCTC's operations, the premium paid by BCTC for its coverage is reasonable. This is also supported by the benchmarking analysis included in our report, which compares BCTC with many of its Canadian peers.

- There is no financial advantage, or coverage advantage, in considering or pursuing alternate risk financing programs or self insurance possibilities.

- Finally, when considering the increasing awards made by the courts in assessing liability for negligent acts across Canada, we suggest that, depending on the nature of work actually being performed, the limit of liability BCTC requests from its independent contractors is too low for today's standards. We recommend that this policy be reviewed and the required limits of liability be increased in order to keep pace with industry norms and more appropriately protect the Corporation against their possible responsibility for the negligent acts of others.

INTRODUCTION

As an independent electric transmission company, British Columbia Transmission Corporation (BCTC) is responsible for the planning, management and operation of BC Hydro's transmission assets, which includes 18,000 kilometres of high-voltage wires.

BCTC is a provincial Crown corporation, incorporated May 2, 2003. The Minister for the Crown holds 100 per cent of the shares of the Corporation, as required by the *Transmission Corporation Act* of May 29, 2003. BC Hydro continues to own the transmission assets as well as the generation and distribution assets.

The rates for transmission service are based on the cost of service, of which insurance is one component. In its review of the cost of service, the BCUC has requested a review of BCTC's general liability insurance coverage for the fiscal year ending 31st March 2007, including a consideration of optimal coverage levels and self-insurance possibilities.

HW Asset Management, an independent Risk Management and insurance consulting firm located in British Columbia, was engaged to review and report on BCTC's:

- General liability program;
- Advise on the potential optimal level of coverage;
- Explore opportunities for "self-insurance".

The agreements between BC Hydro and Power Authority ("BCH", or "BC Hydro") and BCTC are many and complex, and some clauses contained in the agreements are open to different interpretations.

When BC Hydro was responsible for electrical transmission, they were afforded tariff (WTS – Wholesale Transmission Service Tariff) protection against suits and claims for:

- Any interruptions, terminations, failures or defects in the supply of electricity to tariff customers; and
- Third Party Property damage;

Our sources for researching and the gathering of information for this review have included interviews and meetings, both in person and via telephone, with:

- BCTC Employees at head office and two control centres;
- Risk and claims managers from both utility and non-utility corporations as well as from various public bodies, located both in Canada and abroad;
- Insurance Brokers engaged in large industrial accounts, located both in Canada and abroad; and

- Professionals from other organizations involved in loss prevention.

Through these contacts we were granted access to a number of confidential benchmarking studies together with valuable specific information applicable to power utilities. From an insurance perspective, BCTC is an unusual company with its sole purpose being the transmission of electricity only as opposed to being part of an integrated utility. Further, from an underwriter's perspective, BCTC's relationship with BCH is unique and therefore it is more challenging to determine the real risks that each company faces.

As an example, consider the situation where BCTC repairs property owned by BCH while using BCH as an "independent contractor". BCH, when acting as an independent contractor is responsible for negligent acts to "third parties and their properties", which, in this case, could be property actually owned by BCH.

We have not been able to acquire reliable claims data and statistics. Utility companies protect their claims information with a high degree of confidentiality. It has been a surprise to us that some of the corporations interviewed do not have a formal claims tracking and recording process, or such a system to track incidents. BCTC does track claims and known incidents.

The lack of reliable claims data and statistics suggests that an actuarial review would not be possible at this time.

In the research and preparation of this report, these facts and assumptions are relevant:

FACTS and ASSUMPTIONS

- BCTC as a Provincial Crown Corporation does operate with a commercial focus.

- BCTC anticipates that the new Open Access Transmission Tariff ("OATT"), that has been approved by the BCUC will be implemented and take effect March 1st 2006.

- There will likely be no significant income growth post-2006 for the next few years. This is important since significant revenue increases, or numbers of customers served, may affect premiums paid, the levels of deductibles to be considered, and possibly the limits of liability that should be contemplated for general liability coverage.

- BCTC is responsible for:

    - Transmission system / Grid operations,
    - Administering the OATT;
    - Asset management and maintenance;
    - Providing interconnection services for transmission customers;
    - Planning new transmission investments;
    - Directing investment in transmission projects upon receiving regulatory approval from the BCUC.

- Although BCTC does have commercial relationships with entities located outside of BC, it does not operate outside of BC.

- BCTC does not currently have any "end user customers" – its customers are limited to BC Hydro, other utility companies and power marketers. This situation is expected to change at some point in the future as more customers apply for transmission service under the OATT.

- Currently, BCTC does not own any property except:

    - office contents, computers, equipment and tenants improvements located at its head office;

    - computer and communications equipment, office contents and other similar property in 5 control centers;

    - 13 vehicles that are either owned or leased.

- The "product" (electrical energy) is not owned by BCTC.

- The "products" (electrical energy), being owned by different utility companies, are commingled - it is impossible to determine whose or which product was actually responsible for "causing" a situation that leads to a loss.

- Workers employed by or contracted to BCTC are subject to Workers' Compensation Board of BC rules and regulations and therefore generally have no right of suit against BCTC.

- BCTC requires contractors and sub-contractors to carry Workers Compensation coverage and requires proof that such coverage is in place.

- Under OATT, BCTC will be responsible for any "interruption, deficiency or imperfection of service" if BCTC is found to have caused the damage through its gross negligence or intentional misconduct.

- BCTC has assumed the risk for personal health resulting from the operation of transmission line additions and expansions occurring since its formation in 2003 and that BC Hydro would have otherwise been responsible for.

- When BCTC causes transmission lines or towers to be maintained or repaired by contracting with BC Hydro's Field Services, BCH as asset owner would not be in a position to pursue BCTC for liabilities or damages since they would ultimately be in a position of "suing themselves".

- BCTC is responsible for clearing rights of way.

- BCTC has an exemption from the requirement to carry out fire control as required under the Wildfire Act and is not responsible for any associated costs for fire control unless "willful misconduct" is the cause or unless BCTC is found to have contributed to the spread of an ongoing fire through its practices.

- BCTC has, with one exception, completed interconnection agreements with all interconnected utilities. The exception is very close to completing an agreement at the time of writing. The agreements generally restrict liability to the utilities to "direct damages" only.

BCTC's Responsibilities to Third Parties

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At the time of BCTC's formation, BCTC's dollar loss potential for negligence was limited to $50,000,000 with BC Hydro providing an indemnity for any losses in excess of this amount. This indemnity was in place until April 1st 2005, at which time BCTC became solely responsible for any costs awarded as a result of its negligence.

BCTC currently operates under the terms of an interim Open Access Transmission Tariff. The interim OATT will be replaced once the new OATT is made effective and implemented. This is expected to occur by March 1st 2006. This review and considerations are in respect of BCTC's responsibilities under the new OATT.

Under the new OATT, BCTC will only be found responsible for claims by its customers if it is found to have caused the damage through its gross negligence or if intentional wrongdoing is proven, and then BCTC can only be held liable for "direct damages" – i.e. not consequential losses such as down-time or loss of income. In this context, "customers" currently includes BCH and other utilities, and BCTC anticipates that it will include other generators that elect to buy transmission services from BCTC in the future.

Claims against BCTC by third parties who do not transact with BCTC under the OATT, or under a direct contractual relationship with BCTC, will be governed by "tort law", subject to any tariff protections that may apply.

BCTC's legal responsibilities, aside from contractual and regulated responsibilities, are governed by the doctrines of negligence and gross negligence. These terms are "defined" as follows (written for understanding and not written as strictly legal definitions):

Negligence

"Negligence" arises from the omission to do something, which a reasonable person, guided by those ordinary considerations which ordinarily regulate human affairs, would do, or the doing of something which a reasonable and prudent person would not do.

Gross Negligence

"Gross Negligence" arises from a conscious and voluntary act or omission of a person which is likely to result in grave injury to the life or property of another, when in the face of a clear and present danger of which the person is aware.

In reality, "Gross Negligence" is extraordinarily difficult to establish and / or prove..

The potential risks facing BCTC are multiple and varied and it is impossible to attempt to describe and / or discuss all such exposures. However, an overview of situations that we believe may carry <u>significant</u> liability exposures for the Corporation is provided. This review is concerned with financial repercussions as a result of negligent or gross negligent acts that result in damage to other people's property or third party bodily injury. The review deals with general liability and not other liabilities such as those attributable to directors and officers.

Maintenance and Repairs

BCTC is responsible for maintaining and repairing damage to the high-voltage electrical transmission system, owned by BC Hydro. BCTC engages "independent" contractors, including BC Hydro Field Services, to carry out this work and, does not utilize any of its own employees. The majority of this work is carried out by BCH Field Services. Independent contractors are required to provide proof of general liability insurance for a minimum limit of $2,000,000 **[Recommendation made]** and are required to file certificates of insurance.

If damage is caused to the transmission system as a result of BCTC or its contractor's negligence, then BCH could seek an indemnity payment from BCTC for such damages. Whilst BCTC may have rights of recovery from the independent contractor, such rights would be governed by the contractual terms of that particular agreement and the ability of the contractor to respond – i.e. is the contractor financially able to respond to a loss which is either not covered by their insurance or in excess of the limit of liability actually carried?

BCTC'S general liability policy protects to BCTC for its legal liability for third party bodily injury or third party property damage but specifically excludes damage to any property that is "in BCTC's care, custody and control" (CCC). To be able to precisely establish what might be considered in BCTC's CCC would require a comprehensive legal study. This has not been pursued at this time since virtually all such work is undertaken by BCH's Field Services, and - should BCH attempt to litigate a loss against BCTC - they would, in essence, have the effect of suing themselves. We assume that this will not occur. It is probable that, in the situation where repairs or maintenance is taking place, only a limited number of transmission towers, and the wires between them, would be considered in BCTC's CCC thus substantially limiting the dollar cost of a loss.

Right of Way

As with Maintenance and repairs above, BCTC is responsible for managing, maintaining and clearing all rights of way. BCTC engages independent contractors, including Field Services of BC Hydro, to execute the work and does not utilize any of its own employees to complete the actual maintenance or repair work. Unlike Maintenance and Repairs, very little of this work is carried out by BCH Field Services. Independent contractors are required to provide proof of general liability insurance for a minimum limit of $2,000,000 **[Recommendation made]** and expected to file certificates of insurance.

BCTC's exposure to loss is high because of the potential risk emanating from negligent work resulting in a forest fire that severely damages a major industrial complex. Our research indicates that the replacement cost today for a new sawmill (buildings and equipment) is approximately $200,000,000 and, similarly, for a new OSB (Oriented Strand Board) plant is approximately $300,000,000. It is reasonable to assume that an entire complex could be destroyed in a significant forest fire caused by negligence. In this scenario, the probable legal liability for the commercial value of forest that has also been destroyed, the possibility that other structures were also affected, the potential for loss of life and fire-fighting costs should also be considered.

The actual costs associated with fire fighting can be substantial and, whilst such fire fighting is directed by the Provincial Ministry of Forests, charges for fire fighting may be made against

those legally responsible for the fire under the *Wildfire Act*. In order to mitigate costs associated with this risk, the Ministry of Forests has implemented a policy of cost recovery for fire fighting services and as such they are entering into cost sharing agreements with forest companies and utilities. BCTC has entered into an a cost sharing agreement with the Forest Protection Branch, Ministry of Forests whereby the Ministry has agreed to take all practicable fire control and suppression measures to protect the wood assets owned by BCTC for a fixed annual fee. Additionally, as part of this arrangement the Ministry has agreed to allow BCTC to be exempt from the requirements under the Wildfire Act and Regulations to respond to any fire within one kilometer of its transmission system unless the fire is caused by BCTC or its contractors. One area of this exemption applying to "brush contributing to a loss" is currently being clarified. BCTC, as with any other party, continues to be responsible for negligent acts causing actual loss or damage.

Transmission of power outside B.C.

Considering well publicized experiences from other jurisdictions, such as the Eastern Seaboard blackout of 2003, BCTC's potential liabilities to extra-provincial utilities who are customers of BCTC is a risk.

In our discussions with BCTC's engineering department, we are advised that it is highly unlikely that BCTC could create a situation that would result in such action negligently damaging another utility's power grid. Good utility practice is for BCTC and the other utility to coordinate a response to protect the grid, and any damage that had been caused by BCTC would be limited to a single transmission circuit.

In view of the widespread blackouts that occurred in the North East of the US and Canada in August 2003, consideration was given to the circumstances where BCTC would be held liable for a similar occurrence. This occurrence is regarded as "unique" and that, now that the cause is understood, it is reasonable to believe that reaction by the control centres would eliminate or reduce the likelihood of a repeat occurrence.

Though control centre response is likely to reduce the possibility of damage to other systems, the risk cannot be completely ignored. With one exception, all interconnected utilities have completed interconnection agreements with BCTC, and such agreements generally limit BCTC's liability to direct damage only – i.e. no contingent losses – but they include liability to BCTC if it is simply negligent (i.e. they do not limit liability to gross negligence). Although there is a risk to BCTC of claims of this type, utilities are required to "island their systems" in order to protect against catastrophic losses as part of good utility practice, and hence BCTC may be able to rely on these reciprocal obligations to limit the liability in the event of a catastrophic occurrence.

Construction Projects

New construction of transmission towers and transmission lines is undertaken by independent contractors. In the normal course of events, construction insurance is provided by the contractor. BCTC requires the contractor to provide proof that they are insured for general liability. Where it is cost-effective, BCTC will purchase a project "wrap up" construction liability policy (i.e. the owner and all contractors and sub-contractors are covered under one policy).

With respect to the construction of the new control centres, BCTC is required to "consult with BCH in the planning process, establish a redevelopment advisory committee …and appoint a representative of BCH to serve on such committee". BCH also has the right to approve the scope of "redevelopment". Unless BCTC were not to comply with BCH instructions or directions, BCTC's responsibilities for indemnities are considered to be remote.

Personal Health Claims and Exposures

Transmission of electrical power presents its own special set of challenges when assessing all the possible opportunities of damage to third party property or third party bodily injury or sickness.

Since no causal links have been proven between the operation of transmission systems and significant personal health issues, and since the potential exposure to such losses is not realistically measurable, we have not provided an analysis of these risks in this report.

Environmental

BCTC has a responsibility for these transmission system activities:

- Vegetation management, access roads and public safety on the rights of way;
- Protection of fisheries and water quality;
- Potential "spills" and the clean up of active spills.

BCTC is exposed to two environmental risks: One a legal perspective (where a third party and or Government agency uses a legal process to remedy damages suffered) and two, from a Governmental statutory pursuit which results in fines.

With the exception of potential responsibility for both fire and smoke damage resulting from a forest fire or personal health claims as outlined above, a significant exposure in this area from any occurrence that is not "sudden and accidental" is not envisioned. It is therefore reasonably assumed that BCTC's insurance coverage would respond.

Claims and Occurrences

Obtaining meaningful data and statistics in this very important area is difficult.

The fact that there is no or very limited formal tracking of claims within major utility companies might indicate that there are, in fact, very few incidents that result in claims or losses against the utility companies. However, the accuracy of such a statement concerns us.

Discussions and research have provided the following insights:

- BCH has an extensive claims filing system but has not formally tracked claims or incidents, although we understand that an initiative in this regard was started in November 2005.

- It appears that BCH has not experienced many claims exceeding $100,000. This would certainly support the effectiveness of the tariff protection afforded to BCH.

- These incidents have resulted in possible claims against BCH:

  - In the 1960's, BCH was found mainly responsible for a loss resulting from road construction and blasting. 64,000 acres of mature timber was destroyed. The loss quantum was $1,300,000.

  - In 2002, a teenager was severely injured when he came into contact with transmission lines that were strung on top of old ski towers. $185,000 was awarded, representing 50% of the amount sought.

  - There are a few situations where BCH was sued but found not responsible for any negligence.

  - A "memory" of "three power surges" in the last 5 years causing loss to industrial customers". BCH is exempted from liability.

- BCTC has implemented a claims tracking system that provides basic information on incidents that may give rise to a claim. There are currently 8 "incidents" listed with applicable information as follows:

  - One dated back to 1979 and has now been closed. $2,000 payment made and was BCH's responsibility.

  - Two are workplace injuries and therefore a Workers' Compensation issue.

  - Two are "contractual" issues and not related to insurance.

  - The three remaining incidents involve property damage, the quantum varying between $46,000 and $75,000, and are all BCH's fiscal responsibility.

According to BCH, “most of our incidents are caused by cement trucks, television transmission trucks and cherry-picker units touching our wires”. This statement has been supported in other interviews. These situations often lead to significant injuries and / or fatalities to those operating the equipment. Since these accidents occur in the workplace, claims are Workers Compensation Board Issues. One additional type of incident that appears to reoccur is related to aircraft flying into transmission wires, but, to our knowledge, this has not resulted in any significant claims against BCH or BCTC. Given significant precautions undertaken to provide visual warning of the transmission lines, there are often opportunities for subrogation against the operators of the aircraft for damage to the lines. – BCTC invoices and recovers damage done to the transmission circuits by aircraft.

The examples noted indicate that situations do occur where the utility can and will make payments based on negotiated or judicially directed settlements. However, it is also apparent that, based on the available historical facts, the actual settlements for bodily injury losses is low.

The largest dollar exposure to BCTC for negligent acts involves potential third party property damage losses. The replacement value of industrial complexes indicates the possibility of an exposure running into the hundreds of millions of dollars.

Benchmarking

Five different confidential benchmarking studies were analyzed. As in many benchmarking studies involving major corporations, the information provided is often selective and without complete explanations as to the exact scope of what is included.

It is important to understand that the costing reflects only premium costs and not "risk" costs. Risk costs include:

- All premiums;
- Commissions and / or professional brokerage fees for service;
- Deductible and self retention costs;
- Adjusting and legal costs;
- Incident costs related to situations that cause third party property damage or bodily injury costs that are not or would not normally be covered by insurance.

The graphs and information illustrated on the following pages provides an appropriate guide when reviewing BCTC's premiums, limits of liability and deductibles in comparison with other corporations:

Benchmarking review #1

LIMITS of LIABILITY

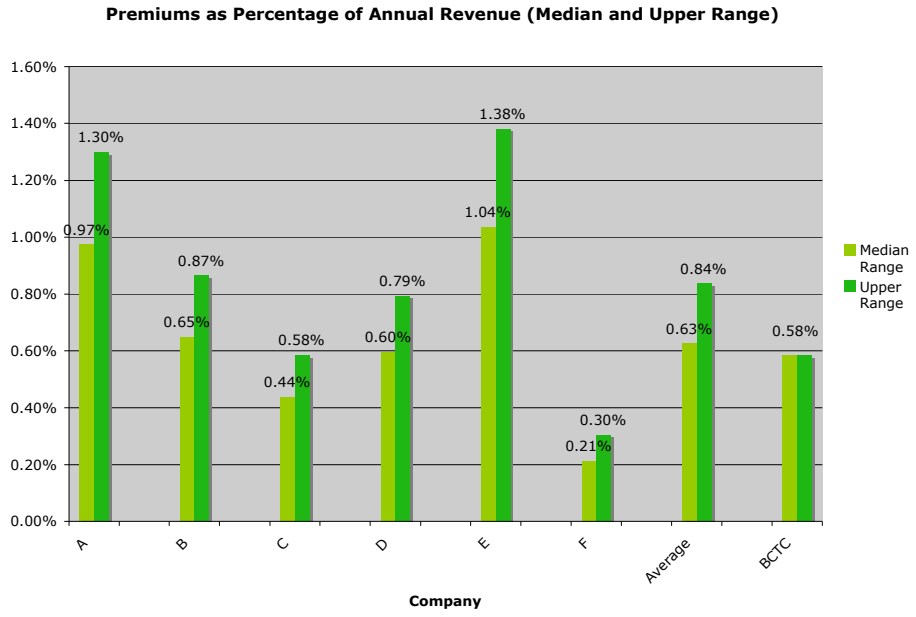
for

GENERAL LIABILITY

A. Canadian Electrical utilities- Revenues less than $1 billion

This review compares BCTC total premiums, expressed as a percentage of annual revenue, to six other Canadian electrical utilities. This study provided premium ranges as opposed to specific premium amounts and the graph illustrates the upper and median premium ranges. The structure of the information provided does not allow for a more specific analysis.

At 0.58% of annual revenue, and based on this graphic information together with our marketplace experience, we suggest that BCTC's current insurance costs are reasonable relative to its peers.



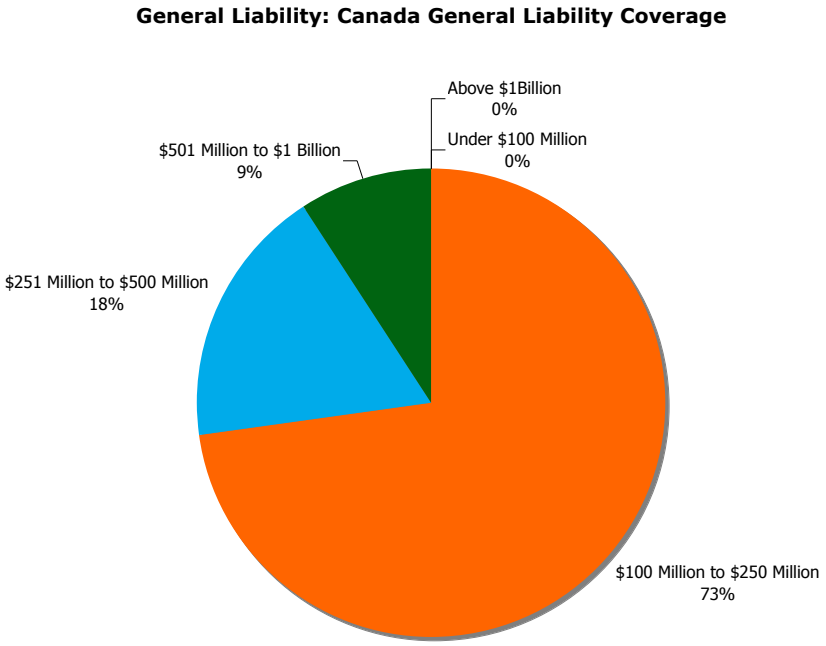
B. Industry benchmarking in Canada

A review of 11 corporations engaged in electrical power generation and distribution; natural gas extraction and distribution and electrical production and distribution; gas distribution and gas plant.

Revenues range fro $200 million to $5 Billion – the average is $1.7 billion per year.

73% (8) of these companies carry liability limits between $100 million and $250 million.

These statistics would suggest that the limit of liability carried by BCTC, $250 million, is in line with the majority of its peers.

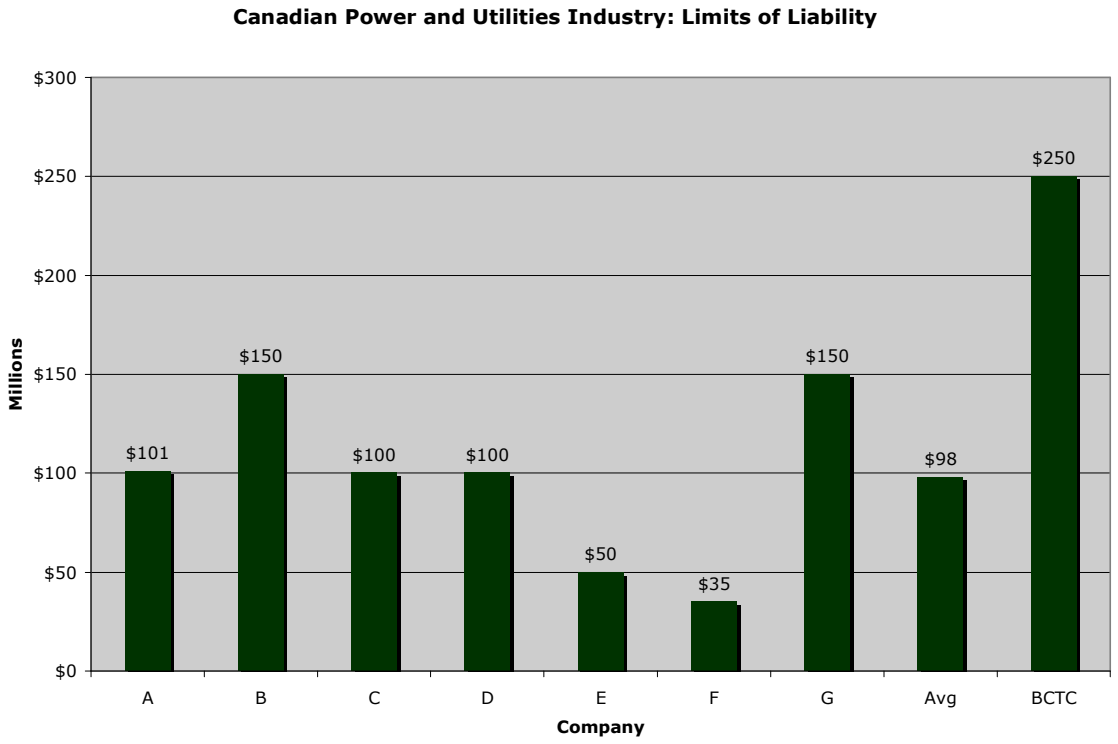


C. Canadian Power & Utilities Industry.

A review of 7 Canadian Power and Utility companies with revenues ranging from $200 million to $5.2 billion.

It is indicated that all companies carry liability limits of $150 million or less. However, we do not know what tariff protection, or Governmental indemnities, if any, that these corporations consider themselves protected by. Different utilities have different tariff protections and government indemnities, which will be a factor in determining limits..

This is a smaller study. Without additional information noted above, it is difficult to make a definitive conclusion.



D. Excess Liability Benchmarking for Electric and Gas Utilities in the USA.

A review of 25 electric and natural gas utilities.

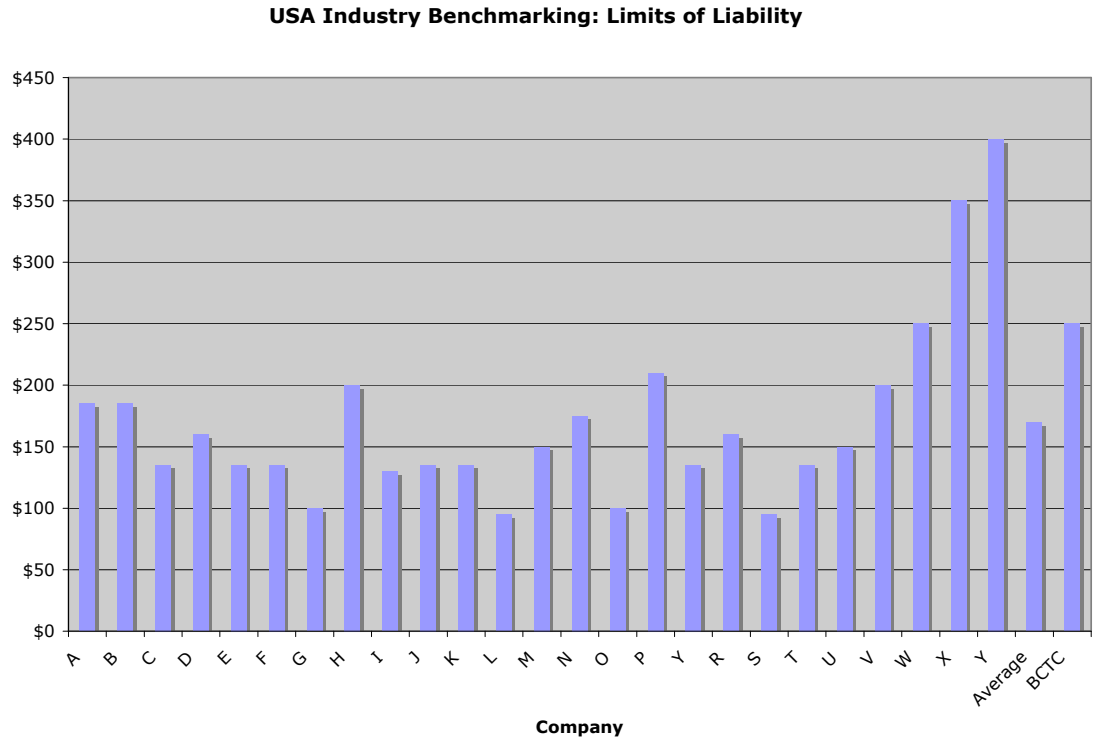
Their number of customers varies between 134,057 and 4,800,000 – the average number of customers being 1,126,104.

The litigious attitude in the USA means that insurance terms (premiums, deductibles and actual coverages) are usually quite different from Canada. One specific item that would always be included in US insurance statistics - and rarely in Canadian insurance statistics - are Workers Compensation premiums.

Benchmarking comparisons with US companies are therefore of limited value. Regrettably, there are considerably more studies undertaken in the USA than in Canada, especially in the insurance arena.

The average limit of liability carried is $169,600,000 (a low of $95,000,000 and a high of $400,000,000

Once again, these statistics would suggest that the limit of liability carried by BCTC in line with the majority of its peers.



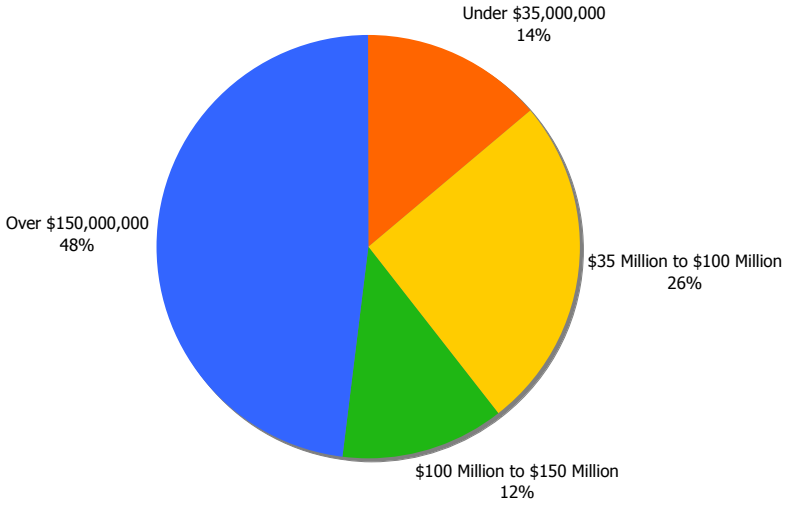
E. Industry benchmarking – mixed USA and Canada (principally USA)

This study comprised a review of 137 US and Canadian gas and electrical utilities -principally US companies.

48% of the gas and electrical utilities carry a limit of liability in excess of $150,000,000.

Again these statistics would suggest that the limit of liability carried by BCTC in line with the majority of its peers.

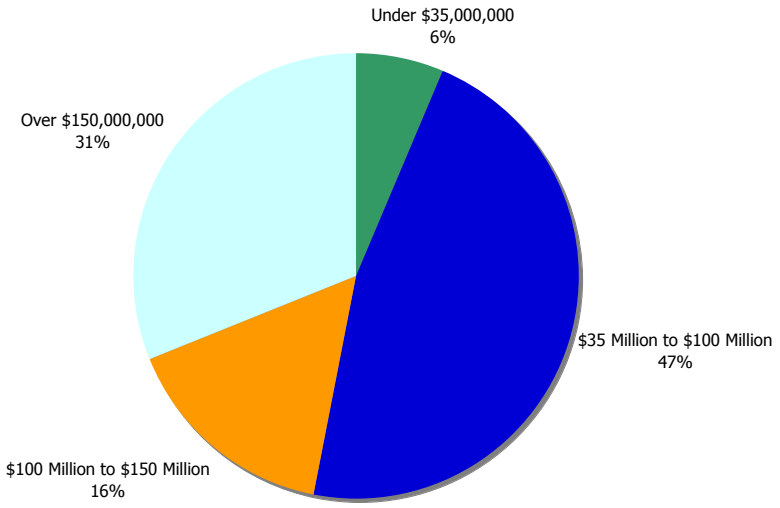
Mixed USA and Canada Industry Benchmarking (Principally USA): Limits of Liability, Gas and Electrical Utility



The statistics from benchmarking study E specifically highlighted 32 electrical utilities. It is noted that 31% of these electrical utilities carry more than $150,000,000 in limits.

The breakdown of the statistics does not provide sufficient clarity for a direct conclusion.

Mixed USA and Canada Industry Benchmarking (Principally USA): Limits of Liability, Electrical Utility Only



Benchmarking review #2

SELF-INSURED RETENTIONS

for

GENERAL LIABILITY

A. Canadian Electrical utilities- Revenues less than $1 billion

There was no information provided in respect to SIR's (self-insured retentions)

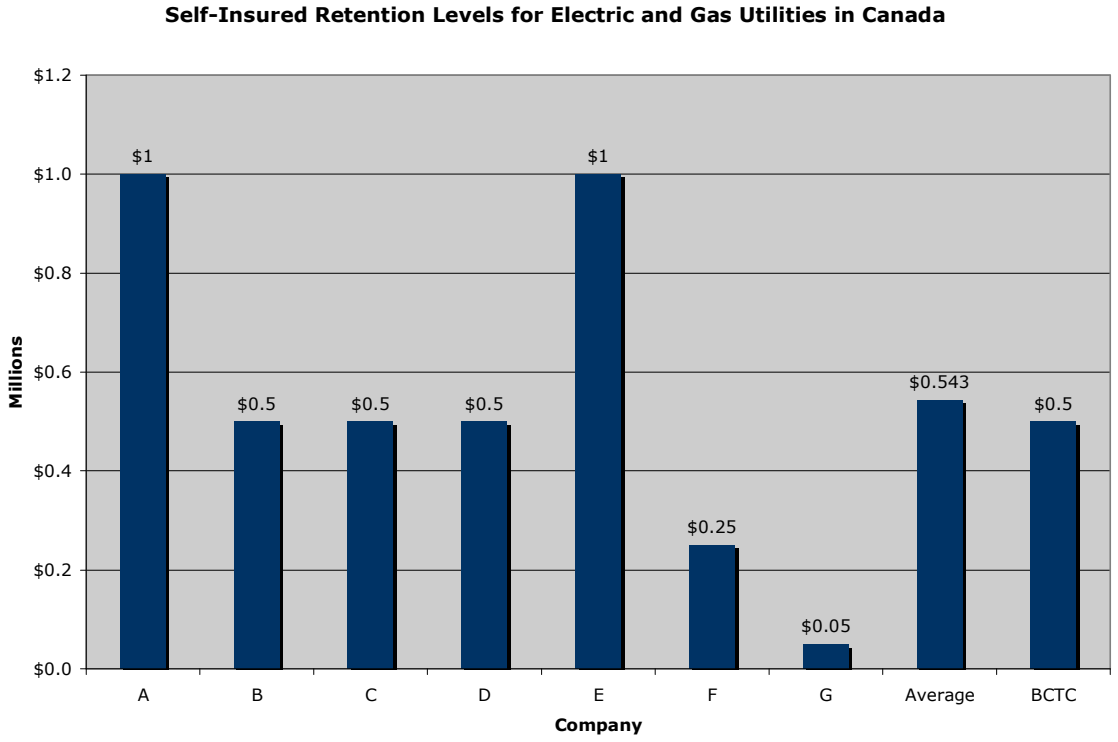
B. Industry benchmarking in Canada

A review of 8 corporations [7 of which provided statistics] engaged in electrical power generation and distribution; natural gas extraction and distribution and electrical production and distribution; gas distribution and gas plant.

Revenues range fro $200 million to $5 Billion – the average is $1.7 billion per year.

It is noted that, of the 8 companies that provided statistics, 88% carry a SIR of $500,000 or more.

This study confirms that BCTC's deductible is similar to the majority of its peers.



C. Canadian Power & Utilities Industry.

There was no information provided in respect to SIR's (self-insured retentions)

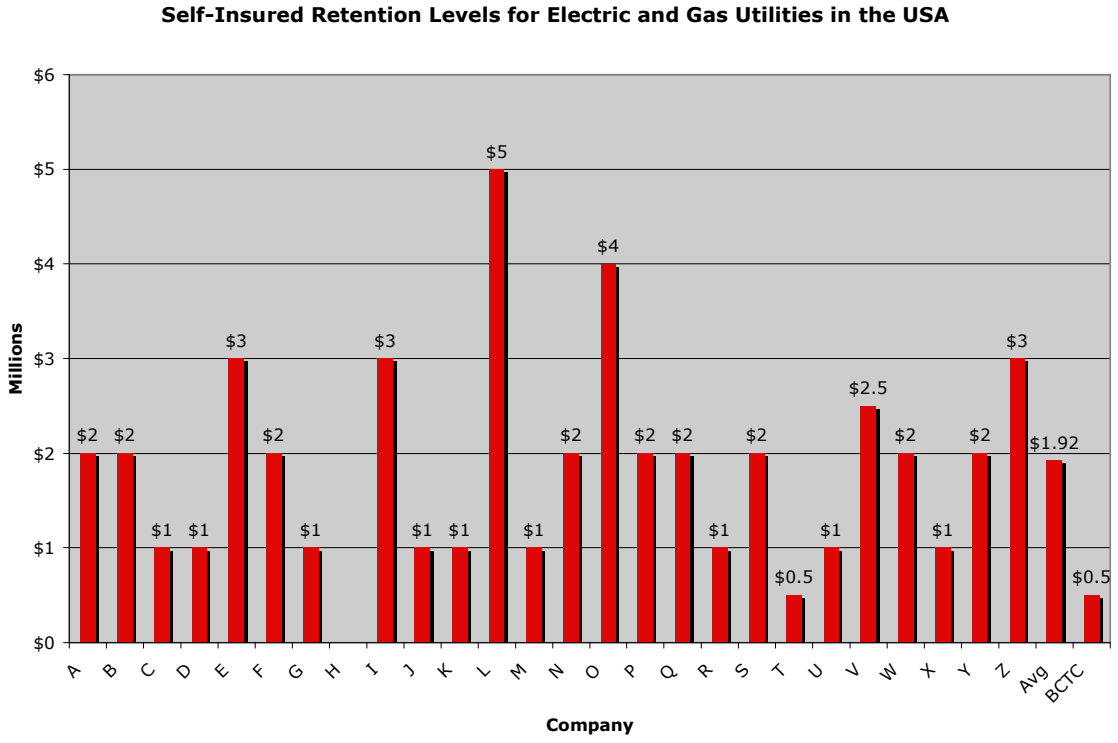
D. Excess Liability Benchmarking for Electric and Gas Utilities in the USA.

A review of 25 electric and natural gas utilities.

Their number of customers varies between 134,057 and 4,800,000 – the average number of customers being 1,126,104.

Of the 24 companies that provided statistics, the average SIR is $1,920,000 (a low of $500,000 and a high of $5,000,000). Only one corporation (4%) carries an SIR of less than $1,000,000.

We are not surprised at the size of the deductibles given that the study is based on US statistics – the size of the SIR's will be largely market driven due to the litigious nature of the US and incidents' size and frequency.



E. Industry benchmarking – mixed USA and Canada (principally USA)

There was no information provided in respect to SIR's.

BCTC POLICY REVIEW

GENERAL LIABILITY

Total Limit of Liability Insured: **$250,000,000** provided as follows:

Policy No. X3095A1A04

Policy Term: December 1, 2003 to April 1, 2006

Insurer: AEGIS

Coverage: To indemnify BCTC for any sums that BCTC shall become legally obligated to pay by reason of bodily injury, personal injury or property damage which is caused by an occurrence and for which a claim is first made during the policy period or during any discovery period.

Limits of Liability:

A. $ 50,000,000 Each occurrence.
B. $ 50,000,000 Combined Products Liability and Completed Operations Liability Aggregate Limit for the policy period.
C. $ 50,000,000 Failure to supply Aggregate limit for the policy period.
D. $ 50,000,000 Pollution Liability Aggregate limit for the policy period.
E. $ 50,000,000 Medical Malpractice Injury Limit each occurrence.

Retention: The limits of liability stated above, are excess of a self insured retention of $500,000 per occurrence, including all legal costs and claims adjustment expenses.

Principal Coverage Extensions:

- Punitive Damages
- Products Completed Operations
- Contractual
- Personal Injury
- Non Owned Automobile
- Failure to Supply
- Employers Liability
- Medical Malpractice Liability
- Non Owned watercraft up-to 75 feet in length
- Sudden and Accidental Pollution Liability – 7 day discovery/ 60 days reporting.

Principal Coverage Extensions (Continued):

- Cross Liability
- Designated Services Activity (Professional Liability)
- Standards Board Activity
- Community Service Activity
- Terrorism (subject to specified limits)
- 90 days notice of cancellation
- Extended Discovery period

Policy No. 501621-05GL

Policy Term: April 1, 2005 to April 1, 2006

Insurer: Energy insurance Mutual

Coverage: Following Form First Excess General Liability, except as declared in endorsement no. 1.

Limit of Liability:

$100,000,000 per Occurrence subject to a
$100,000,000 Annual Aggregate for all Occurrences,
Excess of an underlying limit of $50,000,000.

Policy No. EA0500198

Policy Term: April 1, 2005 to April 1, 2006

Insurer: Lloyds and London Companies

Coverage: Following Form Second Excess General Liability, except as declared under Aon Cover Note dated March 16th, 2005.

Limit of Liability:

$100,000,000 per Occurrence subject to a
$100,000,000 Annual Aggregate for all Occurrences
Excess of underlying limits of $150,000,000.

The annual premium for the three policies providing BCTC's general liability coverage is currently $776,523. It is our opinion that this premium is reasonable.

ALTERNATE CONSIDERATIONS

Coincident with the creation of BCTC, an insurance program was put into effect by duplicating many of the coverages carried by BCH tempered by an analysis to determine reasonable limits and deductibles for BCTC, which has considerably less assets than BCH.

We have recommended possible alternatives to consider in respect of the total limit of liability insurance, including the possible participation in a pooling arrangement administered by the risk management branch of the Provincial government. We have also suggested that, in our opinion, the deductible of $500,000 is appropriate considering:

- The current corporate size and asset base;
- The premiums currently charged;
- Information developed from the benchmarking research.

Similarly, the current premiums currently being charged by underwriters are very reasonable especially when considering the broad coverage being provided by the policy wordings in place.

The premium cost in the future is less certain but will likely be higher. The effects of the catastrophe losses due to hurricanes on the worldwide reinsurance industry have yet to be fully understood and factored into the premium. It is likely that:

- The costs for purchasing insurance in any "potential catastrophe geographic area" will increase;
- The costs for any form of "catastrophe insurance" (i.e. in Canada, for liability insurance, in excess of $50 million or $100 million) will increase.

It is important, as part of any Risk Management strategy, to consider alternate opportunities to the traditional method of the purchase of insurance.

As stated, the current deductible is reasonable and, given the infrequency of liability losses and the anticipated time that it normally takes to settle such losses, it does not seem necessary to consider any sophisticated funding mechanism to allow for a $500,000 deductible amount.

One alternate considered is the formation of a Captive Insurance company. A Captive is "a closely held insurance company whose insurance business is primarily supplied by and controlled by its owners, and in which the original insured's are the principal beneficiaries."

When considering the formation of a Captive Insurance Company, there are certain criteria that must apply if implementation is to be fiscally successful. These criteria include:

- Issues with the cost of insurance coverages;

- Direct access to the reinsurance markets thus eliminating the primary insurance marketplace;
- The inability of underwriters to provide the required complete coverage;
- A method of handling a large frequency and severity of claims;
- An opportunity to “insure” for losses that are not normally the subject of insurance;
- Access to possible tax advantages.

Since none of these criteria are currently applicable to BCTC, we suggest that such a program not be pursued at this time.

ACKNOWLEDGEMENTS

We are most appreciative of the time and effort of many British Columbia Transmission Corporation (BCTC) employees in helping us to understand and interpret the complexities of the various agreements in place between BCTC and BC Hydro (BCH). We are also most thankful for the assistance and confidential information provided to us by both insurance industry professionals and individuals from other segments of business and industry.

QUALIFICATIONS

HW Asset Management Inc. was formed in 2001 to offer Risk Management and Insurance consulting services to corporations, public bodies and individuals. HWAM provides a unique service to its clientele who wish to gain an insider's perspective on today's insurance industry together with a greater understanding of their own insurance programs and risk management initiatives.

We are long-standing industry professionals providing insurance and risk management consultation on a **confidential and independent** basis. We work exclusively for our clients; our revenue is derived solely from consulting fees.

Peter Hindmarch-Watson is the President and Owner of HW Asset Management and he is supported by Stuart Johnson. Their careers have included underwriting, brokering, sales and account management

Peter Hindmarch-Watson's Insurance career has spanned a period of 40 years and his .professional designations include:

- Graduate of IAO's fire protection and loss prevention course
- Fellow of the Insurance Institute of Canada (F.I.I.C.)
- Life Underwriters Association Training course (L.U.A.T.C.)
- Fellow, Chartered Insurance Professional (F.C.I.P. – Incorporates F.I.I.C.)

Stuart Johnson's Insurance career has spanned a period of 35 years and his professional designations include:

- Associate of the Insurance Institute of Canada (A.I.I.C.).
- Graduate of IAO's fire protection and loss prevention course.
- Graduate of IAO's "on the spot" rating courses.

In reviewing and considering our reports, it is important to recognize that they are written from an insurance perspective and not from a legal or engineering perspective.

Appendix E

Strategic Research and Development – Active Projects

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
	Western Region Transmission Collaborative	BCTC is working with a number of Western North American utilities and the Electric Power Research Institute (EPRI) to develop a research portfolio to address critical operating and planning issues in the western interconnected transmission system, to provide state-of-the-art technologies for enabling a reliable, robust and reflexive power grid. The program will allow members to take technical leadership in the industry and reduce the likelihood of major cascading outages. Key initiatives include: - Critical operating constraints – forecasting and predictive state estimation - Transforming Wide Area Measurement (WAMS) into Wide Area Control (WACS) - Intermittent generation and load modeling - Efficient use of existing transmission infrastructure and approval of new transmission corridors - Probabilistic planning tools - Synergistic regional planning including transmission and non-wires solutions.	TBD	$2,000		EPRI and other Western utilities
	Power Systems Engineering Research Center (PSERC)	PSERC is a collaborative research organization comprising 13 major US universities, 40 international industry members and the US National Science Foundation. Research projects are directed by the industry advisors and are conducted in three stems: T&D Technologies; Systems Research; and Markets Research. BCTC has access to results of 70 completed and active research projects of direct interest to the transmission business. Leverage is approximately 100:1 (total annual research budget US$4 million, BCTC contribution US$40,000). Value to BCTC: opportunity to collaborate with leading researchers in power engineering and markets; early access to results of innovative research; leveraged research funding with low overheads; networking with industry partners, universities and government; information source for sound policy making;	$48,000 per year	$48,000 per year		PSERC

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
		education and professional development through tele-seminars; contact with future labour pool. PSERC is a member of the US Department of Energy CERTS initiative (Consortium for Electric Reliability Technology Solutions), allowing BCTC to access research information critical to development of BC's Future Grid.				
	Canadian Electricity Association Technologies Inc. Research Consortium (CEATI)	CEATI coordinates focused interest groups and collaborative research projects to identify and address critical technical issues in the electricity industry. BCTC participates in five interest groups and participates in a number of collaborative research projects that provide direct benefit to asset management, system planning and system operations aspects of BCTC's business. Interest groups and the approximate number of active projects in which BCTC is participating are: - Power System Planning & Operations (4) - Transmission Underground Cables (2) - Transmission Lines Asset Management (6) - Life Cycle Management of Station Equipment and Apparatus (7) - Wind & Ice Storm Mitigation (19)	$133,000 (F2006)	$120,000	Various	CEATI and various contractors
1893	On-line Removal of Corrosive Sulfur from Shunt Reactor Oil	Develop, demonstrate and assess Powertech's oil purification process to remove corrosive sulfur from the insulating oil of BCTC reactive equipment and research improvements in analytical methods for detecting the presence of corrosive sulfur and the mechanisms that support the creation of corrosive sulfur in insulating oil. The corrosive sulfur problem has led to failure of several reactors and is under intense investigation world-wide. If successful, this research will provide a cost-effective method of preventing catastrophic failure to a high value asset class.	$135,000	$0	1.6	Powertech Labs Inc.

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1886	Underground Cable Partial Discharge Measurement Technology	EPRI collaborative research program for developing key technologies for assessing the health of high value transmission cables in the BCTC system. A 3-year program with deliverables: **2006:** Evaluation of New Technologies for Partial Discharge Measurement of Extruded Dielectric Transmission Cables - Technical Update **2007:** Technologies in Partial Discharge Measurement of Oil-Paper Transmission Cables - Technical Update **2008:** Guide for Partial Discharge Measurements of Transmission Cables in the Field - Technical Report	$60,000	$20,000		Electric Power Research Institute
1885	Transmission Circuit Ratings - Optimization	EPRI collaborative research program that will allow BCTC to increase transmission and substation power transfers through real-time changes in the thermal rating for transmission overhead lines, underground cables and substation equipment, to defer transmission expansion. The research deliverable, Dynamic Thermal Circuit Rating (DTCR) technology, is expected to allow increased power flows on the order of 15-20% over the existing static ratings at the modest cost of installing measuring equipment such as weather monitors, sagometers, and temperature sensors. The alternatives to DTCR, re-conductoring and equipment replacement, are more expensive options. The project can potentially improve reliability of conductors, transformers, and cables through low-cost on-line temperature monitoring. Further, the availability of low-cost temperature sensors will allow the industry to move closer to the ideal of a dynamically rated system in which increased dynamic ratings are implemented in a real-time operating environment to maximize power transfers. Specific BCTC benefits include: - Defer capital expenditures by obtaining greater capacity from existing assets - Accommodate IPP capacity without costly equipment upgrades - Avoid damage to system components (extend life) - Identify system constraints (focus for upgrades)	$90,000	$30,000		Electric Power Research Institute

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1878	Investigation of New High Capacity, Low Sag Composite Conductors	A new class of high temperature, low sag conductor has been developed which can carry increased power with low sag characteristics. This provides the opportunity to increase some BCTC circuit ratings without replacing structures and also provides flexibility in dealing with ground clearance constraints. BCTC is in close contact with manufacturers such as 3M, Burndy and Composite Technology Corporation (CTC) and recently visited American Electric Power to witness field installation of CTC's Aluminum Conductor Composite Core Conductor (ACCC). BCTC is evaluating this and similar products for use in upcoming projects.	$5,000	$5,000		BCTC
1876	Failure Investigation of Transformers Subjected to Overloads	Investigate the effects of transformer overload on the oil-paper insulation system and mode of failure. This information will be used to develop techniques and models to monitor key indicators of overload situations and help prevent transformer failures.	$10,000	$0	3.4	Powertech Labs Inc.
1872	Decision Coordination for Critical Linkages in a National Network of Infrastructures	BCTC is an industrial sponsor (along with TELUS, GVRD and YVR) on an NSERC-sponsored research program involving coordination of electricity, communications and transportation networks in major emergencies. This project will benefit BCTC by improving our ability to operate a safe, secure and reliable power system in the event of catastrophic man-made or natural events. The BCTC-related component of the research will focus on: power system visualization tools for system operators to assist in understanding the evolving state of the network under stressed conditions; intelligent management of protection and monitoring information; dynamic reconfiguration of network elements; modeling to improve inter-agency coordination in emergencies; and education and awareness of critical infrastructure systems.	$75,000	$25,000		University of BC

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1868	Forest Engineering Research Institute of Canada (FERIC)	FERIC is a non-profit research and development organization whose goal is to improve Canadian forestry operations. FERIC is funded through private industry, the Government of Canada, provincial and territorial governments including British Columbia. FERIC's mandate extends to assisting governments through technical advice in the development of policy and regulations. BCTC's participation allows us to direct research and influence provincial government regulations and policy that impact BCTC operations in vegetation management. Specifically, participation in FERIC will provide peer review of BCTC standards allowing us to realize the benefits from R&D projects such as SRD 1777 Debris Mitigation and Fuel Management. The FERIC research advisory committee has an annual budget of $800,000. BCTC's annual membership allows participation and receipt of results from a number of collaborative research projects. FERIC has committed to focus resources greater than the $30,000 funding supplied by BCTC.	$30,000	$30,000	2.7	FERIC
1867	Remote Sensing Using Hyperspectral Sensor	BCTC is developing a collaborative research program with the University of Victoria BC Centre for Applied Remote Sensing, Modeling and Simulation (BC CARMS) and Terra Remote Sensing Ltd. (Victoria). The following areas are being explored: - Stem mapping, ortho photos, and road inventory - Terrain assessment - Line temperature – emissivity - Ground conductivity – corrosion and lightning - Pine beetle impacts - Corrosion detection and management - Edge of ROW encroachment - High resolution structures imagery - Partial discharge detection - Assessment of Underwater cables - Snow creep monitoring	Under development	$0		Terra Remote Sensing / UVIC BC CARMS

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1863	Validate Model Calculations of Transmission Conductors to Determine Unused Capacity in Existing Lines	Transmission circuit ratings are limited by the sag of the line which increases with temperature. Circuits are designed using a theoretical model that relates power flow, conductor temperature and sag. Conductor temperature depends in part on the emissivity of the aluminum. Recent BCTC research has found that the emissivity of the aluminum conductor changes with age, thus the conductor temperatures are less than those assumed in the design model. This means that there may be unused capacity in existing lines. The current research will improve the accuracy of existing thermal models and determine the amount of unused capacity which could be up to 10% in some cases.	$80,000	$42,000	12.0	Powertech Labs Inc. (Surrey)
1861	Real Time Application of Service Oriented Architecture and Enterprise Service Bus (ESB) in Energy Management Systems - Proof of Concept	This project investigates whether Service Oriented Architecture (SOA) can be applied in BCTC to incorporate existing real time control centre applications into the new Energy Management System (EMS). The project will provide the appropriate direction for integrating the applications to meet the performance requirements of the real time EMS system. If successful, the SOA architecture will allow a much smoother implementation of BCTC real time applications into the System Control Modernization Project (SCMP), will improve SCMP schedule flexibility, and reduce the costs and risks associated with implementation and maintenance of EMS real time applications.	$100,000	$80,000	4.0	Utility Integration Solutions Inc.
1857	Application & Specification of Metal Oxide Varistor (MOV) Surge Arresters	The performance of MOV surge arresters (SA) during high energy absorption under various fast front waveforms (both lightning & switching) is not well known. Present IEC and ANSI standards for specification and energy absorption tests are inadequate for users and suppliers. Organized by CIGRE, a technical organization that informs international standards, various suppliers will contribute their SA blocks for high energy tests. Based on the test results, CIGRE A3.17 Work Group will recommend necessary changes to the SA energy specification and testing method. The outcome will be improved standards that will allow BCTC to correctly apply surge arresters for protecting high value transmission and substation equipment.	$10,000	$5,000	4.9	CIGRE WG A3.17

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1849	Diagnostic Tool for Insulator Condition Assessment	Research will test BCTC transmission line insulators in-situ to determine the effectiveness of a new low voltage resistance-based diagnostic tool for detecting contamination of the insulators in the presence of road salt and other environmental contaminants. A model of the contamination phenomena will also be developed. This project will: - Optimize washing cycles, reducing OMA costs by washing insulators when the risk exceeds a certain level, while not sacrificing reliability. - Enhance reliability of power delivery by reducing contamination related outages. - Identify new insulators (in storage) that have a high risk of flashover when installed, thereby improving worker safety. - Provide a consistent method for measurement and guidelines for all types of insulators (ceramic and non-ceramic insulators).	$25,000	$25,000		Power Systems Engineering Research Center / Arizona State University
1848	Maintenance & Remedial Actions on Contaminated Insulators	EPRI collaborative research project – produce a Guide, computer applets and workshops for maintenance of insulators in contaminated environments. Will result in new BCTC design standards and construction specifications. Expected to reduce BCTC maintenance cycles and associated OMA expenditures.	$12,000	$12,000	2.6	Electric Power Research Institute
1846	Herbicide Impact on Communities	Research by an industry expert to secure the benefits of continued use of herbicides on rights-of-way. The project will obtain recent scientific data allowing BCTC to secure the full value from continued use of herbicides. BCTC will be able to provide supporting evidence to answer public concerns.	$70,000	$20,000	6.0	Len Ritter Associates Ltd.

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1844	Development and Evaluation of Chemical Tracers for Contact Wear Indicators	Complete the development of chemical tracers and carry out accelerated switching experiments on a voltage regulator at Kent Substation. This will reduce OMA costs by increasing the maintenance interval and improving labor productivity by identifying the transformer load tap changers (LTCs) in need of maintenance. It will also reduce replacement costs and environmental damage from catastrophic failures.	$40,000	$38,000	1.6	Powertech Labs Inc.
1840	Transmission Conductor Splice Test Procedure	Verify the hypothesis that there is a direct correlation of electrical resistance in a full tension compression splice versus the remaining mechanical tensile properties. Verifying the hypothesis will allow development of a set of resistance threshold values to aid in assigning a condition health value to existing in-service splices. A threshold value will be assigned in field inspections of the splices thus allowing repair or replacement of splices to be reflected in asset management plans and maintenance budgets. Maintenance costs can be reduced through planned change-outs in conjunction with planned circuit outages.	$73,000	$30,000	8.0	Powertech Labs Inc. (Surrey)
1839	Remote Sensing of Factors Influencing Corrosion of Transmission Towers	Assess alternatives for remote monitoring and reporting corrosion factors on BCTC's transmission towers. BCTC manages approximately 20,000 steel towers with a replacement cost of $300,000 to $500,000 each, depending on load, type and access. Regular maintenance and monitoring is required to ensure long term safety and reliability. Early detection of corrosion factors would allow BCTC to implement preventive measures and prioritize towers based on corrosion indicators.	$25,000	$25,000	11.0	Spatial Vision (Vancouver)
1837	Repaint Coating Technology Assessment for Asset Life Extension	Lab analysis to confirm samples of an innovative nanotechnology-based coating to meet requirements to protect transmission steel structures. BCTC manages approximately 20,000 steel towers with a replacement cost of each steel tower between $300,000 to $500,000 depending on load, type and access. Approximately $1 million is spent annually to recoat steel lattice towers to ensure long term safety & reliability. This paint technology may extend life expectancy for this asset class.	$4,000	$2,400		Powertech Labs Inc.

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1836	Evaluate Real Time Voltage Stability Assessment (VSA) Tool	Evaluate feasibility of implementing real-time VSA (developed by Powertech Labs Inc.) in BCTC's Control Centre Energy Management System. This is part of a longer term goal to use Dynamic Security Assessment tools to generate on-line total transfer capacity (TTC) for transmission paths, for efficient scheduling of wholesale energy transactions.	$35,000	$30,000		Electric Power Solutions Inc. (Edmonton)
1833	Cyber Security of BCTC SCADA Systems	BCTC will utilize BCIT's Internet Engineering lab to conduct an analysis of potential vulnerabilities in BCTC's Supervisory Control and Data Acquisition systems that are used to monitor and control the power system. The BCIT lab is a leading-edge network security facility in North America, with a successful track record of conducting cyber security research and consulting for a number of industrial clients.	$45,000	$0		BCIT (Burnaby)
1829	Lightning Performance of Transmission Lines & Surge Arresters	EPRI Collaborative Research Program to improve lightning performance of key circuits, particularly radial feeds. Lightning is a significant contributor to transmission outages and damage. BCTC does not utilize overhead shield wires and it is expensive to retrofit lines with shield wires to improve performance. Lightning arresters and improved grounding are viewed as possible solutions. This program aims to increase reliability of new and existing overhead transmission lines by generating new engineering tools that address the leading causes of transmission problems - lightning and grounding issues.	$50,000	$32,000		Electric Power Research Institute
1811	Doble Advisory Services	Doble Advisory Services provides services and knowledge for all aspects of maintenance, testing, repair and operation of high voltage apparatus including new technologies and practices, access to Doble library and knowledge base, tutorials, reference guides, maintenance and test procedures, manufacturer service advisors, discussion forum and test data for diagnosis. Participation in Doble broadens BCTC's access to emerging technologies and techniques to enhance the management of transmission assets.	$12,000 (annual)	$12,000		Doble

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1804	Modeling Enhancements to Identify Vegetation Encroachment on Transmission Line Clearances	This project developed a new feature in BCTC's PLS-CADD software to aid vegetation management by producing plan view drawings with vegetation clearance "iso-lines" plotted on them. These contour-like iso-lines represent a connection of ground points that have equal minimum clearances to the transmission conductors. This is an innovative and low-cost method for maintaining the system, improving reliability, efficiency and environmental health. Data is integrated into BCTC's Enterprise Geographic Information System.	$15,000	$15,000	3.0	BCTC / BC Hydro Engineering Services
1791	Hazard Tree Failure Study	Refine the tool used to determine which trees will fail within transmission rights-of-way. A significant portion of outages are attributed to tree failure. UBC conducted a study in Pacific Spirit Park using BC Hydro protocols for hazard trees and determined that approximately 2/3 of the tree failures in Pacific Spirit Park show no signs of defect prior to failure. The study was only conducted over 3.5 years thus there is a need to extend the study for a longer observation period to encounter a variety of climatic events and verify arborists' predictions. The study identified a need to improve the current hazard tree program since at best only 1/3 of the hazard trees will be identified and removed using existing protocols. This project will contribute to improving management practices and business decisions by providing scientific data rather than subjective analysis. Benefits will accrue from reduced system outages, efficient use of resources and improved public safety.	$31,000	$16,000		University of BC
1777	Debris Mitigation and Fuel Management on Rights of Way	Identify and define effective strategies for debris management and fuel hazard mitigation, and implement these systems in selective prototype areas. BCTC will develop a fuel management model to mitigate risk to the transmission system and prevent spreading fire. The project will contribute to BCTC's responsibility to comply with regulations defined in the Ministry of Forests Wildfire Act which hold BCTC legally accountable. The fuel management model will contribute to asset health, prevent	$170,000	$85,000	9.4	B.A. Blackwell and Associates

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
		environmental damage, reduce environmental risk and contribute to improved environmental health, improve public support, improve public and employee safety, and support BCTC's commitment to making good management decisions based on environmental principles.				
1773	Biological Control of Scotch Broom	Develop a long-term vegetation management program for improved and more efficient methods to manage scotch broom on transmission rights of way, while decreasing costs for its elimination. This project demonstrates environmental stewardship by managing vegetation that is threatening native species, without the use of herbicides. This program will assist in mitigating BCTC's risk as a contributor to spreading forest fires. It will build public acceptance and support and contribute to public consent to operate.	$100,000	$80,000		University of BC
1770	Power System Common Database Simulation Model	This project will implement a consolidated database for simulating the power system for operating and planning purposes. The tool will: 1) Eliminate differences between off-line studies and real-time behavior 2) Improved efficiency - reduce system study errors, reduce human error in model building, improve model accuracy, improve operations planning 3) Reduce turn-around time to update models - save time to create and maintain network models 4) Provide "after the fact" disturbance analysis for public hearings, system losses and regulatory analysis. The current method requires compilation of various data to develop a best guess with known deficiencies. The new tool and model will be used to determine system losses (monetary) and support analysis decisions. 5) Provide a "whole view" of the system network (more consistent representation of offline and real-time data). The new tool will provide more reliable data and improve system analysis. 6) Provide post analysis training – tie to dispatcher training.	$200,000 (preliminary estimate)	$10,000		Siemens Power Transmission & Distribution Inc.

British Columbia Transmission CORPORATION™

Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1767	Reclassification of Protection Accuracy Current Transformers to Metering Accuracy	Power Measurement Ltd. is developing a system to improve end-to-end metering accuracy in transmission revenue metering applications. The project involves field demonstration at Goward Substation of a system to reclassify the accuracy of protection class current transformers to operate at revenue metering accuracy. This will provide important benefits to BCTC for enabling high accuracy metering of transmission / distribution delivery points at low cost (since the primary metering transducer would not have to be replaced). It will also provide more accurate visibility of the power system, allowing it to be operated closer to its design limits. This allows transmission assets to be fully utilized but not placed at risk from overloads.	$100,000	$40,000		Power Measurements Ltd. (Victoria)
1765	Electromagnetic Compatibility Simulation Tool (CRINOLINE)	This collaborative research project will provide the capability to calculate electromagnetic interference between power system lines/cables and other structures such as pipelines, telecommunication cables, fences and all metallic structures installed in the vicinity. The tool will be used to establish standards and guidelines for transmission design. The program will be based on the latest industry knowledge and follows the recommendations of international organizations such as IEEE, CIGRE, IEC and UIT. It will provide: - Ability to respond to public inquiries and concerns regarding electromagnetic interference with specific values - A credible reference for construction and maintenance of transmission lines - A training tool to build in-house expertise in this area - Contribute to public and worker safety.	$50,000	$24,000		Canadian Electricity Association Technologies Inc.

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Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1762	Thermal and Mech. Stresses in Extruded Dielectric Underground Transmission Systems	Collaborative EPRI research program to improve reliability and minimize equipment failures by operating XLPE transmission cable systems below defined maximum thermal and mechanical stress levels. Specific benefits to BCTC include acquisition of strategic knowledge for planning, design and operation of XLPE (oil-less design) cables which promise reduced environmental impact, lower losses, lower costs and increased reliability.	$100,000	$100,000		Electric Power Research Institute
1756	Micro Sensors to Identify Defective Compression Connectors	Proof of concept research co-funded with EPRI. The technology is relatively well known but requires adaptation to the utility environment and components. There are potential BCTC applications for monitoring conductor temperature, conductor vibration and voltage on any piece of equipment, and pressure readings in cable systems, as data can be downloaded to a receiver on a helicopter (or ship) during a regular inspection. This information can provide important benefits for asset management and operation of the transmission system.	$69,000	$69,000		Electric Power Research Institute
1755	Wide Area Measurements Using Synchronized Phasors	Faced with recurring dynamic oscillations and, in recent years, voltage collapse in the western North American power system, BCTC and other WECC utilities are improving their real-time system performance measurements. In 2003, Powertech Labs developed recommendations for BCTC Strategic R&D on the application of synchronized phasor measurements for improving dynamic performance of the power system, including operator displays, enhancement of the state estimator, improvement of Remedial Action Schemes and alarm applications. This project provides a pilot demonstration of wide area measurements in the BCTC system control centre to enable BCTC to identify and quantify the benefits of large scale deployment of wide area measurement technologies. In the near term, it is expected that real-time streaming of phasor measurements will improve system visibility and operator actions. The pilot will also allow BCTC to evaluate the longer term deployment of related advanced applications for automatic control and protection, for improving dynamic performance of the power system.	$225,000	$197,000		BC Hydro Engineering / Matrikon Inc. (Vancouver)

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Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1733	Polymer and Composite Overhead Transmission Line Components	EPRI collaborative research program for improving selection, application and inspection techniques for polymer and composite components, thereby extending component life expectancy and avoiding outages due to premature failure. Composite components such as polymer insulators are proliferating because of a lack of availability of traditional components, reduced cost, ease of handling and resistance to vandalism. However, these components have certain disadvantages and uncertainties. This ongoing multi-year project will address a range of composite component concerns to increase BCTC's confidence in using these components.	$150,000	$117,000		Electric Power Research Institute
1732	Overhead Lines Structure Life Management	This research will reduce capital costs by extending life expectancy of overhead transmission structures and equipment through inspection and assessment procedures, as well as techniques and tools for mitigation of aging. BCTC is faced with a large aging population of transmission line structures. Often the condition of these structures and the remaining life is unknown. In the short term, the degradation of these assets does not necessarily pose a threat to the reliability of the system, but long-term implications may be significant. This ongoing project provides tools to develop and optimize an effective approach to structure management in the short- and long-terms. The project deals with inspection, assessment, and maintenance of steel poles and lattice towers, wood structures, and concrete poles, as well as foundations. Additional benefits to BCTC include: - Reduced learning curve for structure maintenance issues - Reduced study and analysis costs for determining alternatives - Increased accuracy of structure inspections - Earlier identification of defects - Optimize structure maintenance expenditures - Reduce capital costs by extending life expectancy - Increase maintenance and repair alternatives	$86,000	$86,000		Electric Power Research Institute

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Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1726	Effect of Vegetable Based Insulating Oils on Transformer Paper Aging	This project, co-funded by several EPRI members and conducted by Powertech Labs Inc, will investigate a new class of commercially available insulating oil for reactive equipment. This project will: - Greatly improve available tools for selecting alternative insulating oils for transformers and other oil filled equipment. - Provide potential large savings from reduced risk of fire, explosions, environmental clean up, and increased paper insulation life - Lead to improved thermal characteristics resulting in higher loading or longer transformer life	$175,000	$175,000		Electric Power Research Institute / Powertech Labs Inc.
1706	Use of Daytime Corona Camera to Determine When to Wash Contaminated Insulators	EPRI co-funded research project to evaluate whether the EPRI DayCor corona camera can be used to monitor contaminated insulator strings on transmission lines thus allowing field personnel to initiate insulator washing "just in time" rather than on a time-based schedule. Benefits to BCTC will be to optimize insulator washing programs and avoid unplanned outages due to flashovers on contaminated strings. Over US$100,000 of laboratory work will be generated for Powertech Labs Inc. from external funding.	$115,000	$115,000		Electric Power Research Institute / Powertech Labs Inc.
1699	SF6 Circuit Breaker Teflon Nozzle Wear Indicator	Develop a non-invasive diagnostic technique to evaluate Teflon nozzle wear that will aid in avoiding premature failure, reduce maintenance costs and defer capital costs. Vital Teflon nozzle circuit breakers, such as those used in reactor switching for voltage control, are a critical system component and failure in the past has left part of the system without redundancy. Teflon nozzle wear is an indication of imminent failure. There are approximately 3000 circuit breakers of which 1000 are insulated with SF_6. Internal inspections comprise the highest cost for circuit breakers.	$50,000	$24,000		Powertech Labs Inc.

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No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1658	Capacitive Voltage Transformer Calibration Using NxtPhase Optical Transducer - Trailer and Testing Program	This project will improve accuracy of the measured state of the power system allowing operation closer to actual thermal and transient stability limits. Benefits include: - Better identification of operating limits thus reduced risk and possible increase in operating capacity. - Reduced cost of calibration - Identification of equipment defects	$150,000	$87,000		Powertech Labs Inc. / NxtPhase T&D Corporation (Vancouver)
1657	Application of NxtPhase Optical Transducer for 500 kV Revenue Metering	This project will: - Demonstrate the NxtPhase sensors in a revenue metering application. Satisfactory performance in this location will build utility and Measurement Canada confidence required to allow the technology to be applied in revenue metering applications. - Demonstrate sensor accuracy and bandwidth with a goal to show the superiority of the device output compared to conventional technology. This will provide valuable information on power quality for the system. - Demonstrate digital interface, which will allow significant reduction in substation costs in the future.	$470,000	$460,000		NxtPhase T&D Corporation (Vancouver)
1627	SF6 Gas Imaging System - Leak Detection by Infrared Gas Imaging	The electric power industry uses a significant percentage of the 6,500 to 7,500 metric tons of SF6 produced worldwide each year. Ideally, none of this gas should be emitted to the atmosphere, either directly from operating equipment or as a result of losses due to leaks, maintenance and recycling activities. In practice, however, there are emissions from these sources. Estimates place 1997 U.S. emissions of SF6 at 7 million metric tons of carbon equivalent (MMTCE). A significant proportion of these emissions are attributable to the electric power industry. Because SF6 is the strongest greenhouse gas known, its release to the atmosphere is an environmental	$100,000	$70,000		Powertech Labs Inc. (Surrey)

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No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
		concern. In recent years, utilities have undertaken an active role to reduce SF6 leaks in order to minimize environmental impact, reduce costs and comply with regulatory guidelines. BCTC's objective is to develop a low cost imaging system by using a commercially available infrared imaging camera and novel image processing techniques. The contractor, Powertech Labs, will use advanced IR imagers, selected filters integrated with a chopper wheel for dynamic background subtraction and digital image enhancement. The benefits of this research project include: - Reduce lifecycle cost of substation equipment - Advance environmental stewardship - green technology - Prevention of fugitive SF6 - Identification of immediate repairs				
1620	Live Line Detection of Partial Discharge in Substation Bus Tie Cables	This project involves the characterization of the propagation of Partial Discharge (PD) pulses in bus tie cables. It involves: - Demonstration of the feasibility of PD detection at UHF and microwave frequencies - Developing methods of enhancing Signal to Noise Ratio The research will result in a portable instrument that can be used to detect imminent failures of high value bus tie cables so that action can be taken to replace them without loss of service to customers.	$150,000 (BCTC portion of $325,000 total)	$120,000	2.5	Powertech Labs Inc.
1583	Pilot Project to Seismically Qualify Substation Equipment using IEEE 693	EPRI co-funded project - conduct joint testing of equipment that is to be purchased in the next 5 to 10 years and is required to be seismically qualified according to IEEE Standard 693. BCTC specifies all new station equipment to meet requirements of IEEE 693 as confirmed by shake table testing. This is a consortium project involving a number of utilities to share costs, pre-qualify equipment and, in the process, develop experience that will be fed back to improve the next edition of IEEE 693. The consortium approach reduces the cost to BCTC for obtaining seismically qualified equipment.	$50,000	$47,000		Electric Power Research Institute

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Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1566	Performance Evaluation of In-Service 4 Bundle Spacer Dampers	The transmission system has approximately 180,000 4-bundle spacer dampers in service, representing a replacement value of approximately $27 million. Some of these spacer dampers have been in service for more than 30 years and are starting to show signs of deterioration. There is concern that aging of the rubber materials in the articulated joints may be affecting performance, which could lead to conductor damage. In order to prepare for future spacer damper replacements or refurbishment, there is a need to establish the remaining life of the existing spacer dampers. The project involves: - Developing life predictions criteria and verification - Field inspections and establishment of a database identifying current conditions	$63,000	$60,500		Powertech Labs Inc.
1429	Oil Leak Detection in Submarine Cables	This project involves field trials to detect oil leakage in submarine cables. Specific benefits: - Ensure environmental compliance - Demonstrate environmental stewardship - Better identify oil leaks, thus reduce the time to locate submarine oil leaks - Ability to reduce time for analysis - cost saving	$170,000	$125,000		Powertech Labs Inc.
1428	Computer Assisted Diagnostics, Condition Assessment and Life Extension of Substation Equipment	This project will: - Reduce maintenance costs - Predict of end of life with the opportunity to extend the life of equipment - Reduce time for analysis and diagnosing equipment and date retrieval - Have the potential for commercialization	$85,000	$30,000		Powertech Labs Inc.

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Strategic Research and Development – Active Projects 29 March 2006

No.	Title	Description / Value	Estimated R&D Cost	Actuals to Date	Expected Benefit/Cost of Implemented Project	Contractor/ Partner
1187	Real-time Dynamic Rating of 500 kV Cable Circuits Supplying Vancouver Island	The BCTC Strategic R&D program invested $100,000 to develop and demonstrate the use of distributed fibre optic temperature sensing in underground / undersea transmission lines. Initial experience on two 230kV cable circuits in the Vancouver area in the late 1990's showed that the circuits could be dynamically re-rated to produce a 15% increase in emergency current ratings. The technology was used to defer major capital replacement of the two cable circuits by two years. The R&D project further demonstrated that fibre optic temperature sensing could be retrofitted in the two 500 kV cable circuits supplying Vancouver Island. Currently, a $2.4 million capital project is underway to install temperature monitoring, dynamic re-rating and operator displays of unused capacity in the two Vancouver Island 500 kV circuits. This is expected to provide up to 10% (240 MW) of increased emergency capacity, using existing infrastructure. This is the first such application in the world.	$100,000 (R&D Portion)	$100,000		Various Manufacturers, BC Hydro Engineering
1136	Life Extension of Transformer Insulation	This project is developing an analytical technique to measure the residual content of a key chemical in thermally upgraded transformer insulating paper and will determine the onset of aging. This innovative project, if successful, has the potential to extend the life of BCTC's power transformer population and to increase the rating of existing transformers, thus deferring significant capital expenditures in the future.	$270,000	$260,000		Powertech Labs Inc.
	Totals for multi-year projects		**$4,411,000**	**$3,145,900**		

Appendix F

Clarification of "F2006 Approved"

BCH Owner's Revenue Requirement

"F2006 Approved", in the context of the BCH Owner's Revenue Requirement, refers to Commission approval of the total revenue requirement in BCUC Order No. G-96-04. Detailed line items are provided to facilitate explanation only; Commission approval was not provided at the level of detailed line items.

BCTC Revenue Requirement and Asset Management / Maintenance Revenue Requirement

"F2006 Approved", in the context of the BCTC Revenue Requirement and Asset Management/Maintenance Revenue Requirement, refers to Commission approval of the total revenue requirement in BCUC Order No. G-60-05. Detailed line items are provided to facilitate explanation only; Commission approval was not provided at the level of detailed line items, with the exception of those items specifically identified in BCUC Order No. G-60-05.

Appendix G

Pension and Benefits Expense – F2006 / Estimated F2007

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08 May 2006

Mr. H. Sue
Manager, Financial Accounting & Budgeting
British Columbia Transmission Corporation
Suite 1100, Four Bentall Centre
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Private & Confidential

Subject:
Pension & Benefits Expense under CICA 3461 for Fiscal 2006
Estimated Pension & Benefits Expense for Fiscal 2007

Dear Henry:

Further to our meeting of May 3, 2006, we provide below the following:

- BCTC's *actual* pension & benefit expense under CICA 3461 for fiscal 2006;
- BCTC's *estimated* pension & benefits expense under CICA 3461 for fiscal 2007; and
- A discussion of the factors that could result in BCTC's pension & benefits expense for fiscal 2007 being different than our estimate.

As discussed, BCTC's pension expense for fiscal 2007 reflects a 6.50% expected return on plan assets (EROA) assumption – the corresponding EROA for fiscal 2006 was 7.00%. The EROA assumption for fiscal 2007 was approved by the BCTC Pension Management Committee at a meeting of May 5, 2006. We believe that this reduction is both warranted and prudent given today's lower interest rate environment and the fact that about 45% of the plan's assets are invested in bonds.

Pension & Benefits Expense – Fiscal 2006/Estimated Fiscal 2007

The following table shows BCTC's actual pension & benefits expense for fiscal 2006. In addition, we have *estimated* BCTC's pension & benefits expense for fiscal 2007.

Pension & Benefits Expense ($000s)

	Fiscal 2007 (est.)	Fiscal 2006
Registered Pension Plan		
▪ Basic benefits	$1,895	$1,666
▪ Indexing benefits (estimated)	273	266
Non-Registered Pension Plans	586	386
Non-Pension Plan	1,086	899
	$3,840	**$3,217**
Key actuarial assumptions for expense		
▪ Discount rate	5.40%	6.00%
▪ Expected return on plan assets (EROA)	6.50%	7.00%
▪ Salary increases	3.50%	3.50%

As you are aware, BCTC's actual pension expense for fiscal 2007 for indexing benefits under the Registered Pension Plan will be equal to the *actual* BCTC contributions towards indexing benefits during the fiscal year (i.e., 1.1% of members' Plan Earnings).

As you can see from Table 1, BCTC's pension & benefits expense for fiscal 2007 is expected to increase significantly over fiscal 2006. This is primarily attributable to the decrease in the discount rate assumption – a lower discount rate results in higher actuarial liabilities and current service costs for each of the plans. In addition, the increase in the actuarial liabilities from the change in the discount rate is treated as an actuarial loss which is amortized in BCTC's pension & benefits expense over future periods (subject to the 10% corridor).

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Human Resource Consulting

Factors Affecting Fiscal 2007 Estimates

BCTC's actual pension & benefits expense for fiscal 2007 could change from the above estimate if:

- The plan's are amended;
- A downsizing, acquisition or divestiture occurs; or
- Extra contractual benefits are provided under any of the plans.

Lastly, BCTC's pension expense for fiscal 2007 for indexing benefits under the Registered Pension Plan will be equal to the *actual* contributions it makes for these benefits during fiscal 2007.

I would be pleased to discuss this at your convenience.

Sincerely,

Matthew Mignault, F.S.A., F.C.I.A.
604 609 3174
matthew.mignault@mercer.com

Copy:
Ms. E. Hong, British Columbia Transmission Corporation
Ms. D. Wilson, Mercer Human Resource Consulting
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