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December 21, 2007

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

Dear Ms. Hamilton:

Re: British Columbia Transmission Corporation (BCTC)
Transmission System Capital Plan F2009 to F2018

Pursuant to sections 45(6), 45(6.1) and 45(6.2) of the *Utilities Commission Act,* BCTC files with the British Columbia Utilities Commission the Transmission System Capital Plan F2009 to F2018 ("F2009 Capital Plan").

Sincerely,

Original signed by:

Marcel Reghelini
Director, Regulatory Affairs

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LIST OF ABBREVIATIONS

Abbreviation	Definition
ABSU	Accenture Business Services for Utilities
Act	Utilities Commission Act
AMP	Asset Management Project
APD	Asset Program Definition department
APM	Asset Program Management department
ARN	Aboriginal Relations and Negotiations business unit at BC Hydro
ARO	Asset Retirement Obligation
BC Hydro	British Columbia Hydro and Power Authority
BCTC	British Columbia Transmission Corporation
BCTC RR	BCTC Revenue Requirement
BCUC	British Columbia Utilities Commission (or “Commission”)
BPA	Bonneville Power Administration
CAV	Condition Assessment Value
CB	Condition Based maintenance
CFO	Chief Financial Officer
CFT	Call For Tender by BC Hydro
CIAC	Contributions In Aid of Construction
CO	Corrective maintenance
COMDA	Cost Of Market Deferral Account
Commission	British Columbia Utilities Commission (or “BCUC”)
CPCN	Certificate of Public Convenience and Necessity
DSM	Demand Side Management
EAR	Expenditure Authorization Request
ELT	Executive Leadership Team
EMEDA	Emergency Maintenance Expenditure Deferral Account
EMS	Energy Management System
EROA	Expected Return On Plan Assets
Etag	Energy tagging system
FRSR	Future Removal and Site Restoration
G&A	General and Administrative (costs)
GRTA	Generation Related Transmission Assets
GRTL	Generation Related Transmission Lines
GRTS	Generation Related Transmission Substations
HVDC	High Voltage Direct Current
IDC	Interest During Construction
IEP	Integrated Electricity Plan for 2006 by BC Hydro
kV	kilovolt

Abbreviation	Definition
LMC	Lower Mainland control Centre
NCC	Northern Control Centre
NITS	Network Integrated Transmission Service
NWPP	Northwest Power Pool
OAD	Operator / Area Dispatcher
OASIS	Open Access Same time Information Service
OATI	Open Access Technology International
OATT	Open Access Transmission Tariff
OEM	Original Equipment Manufacturer
OMA	Operations, Maintenance and Administration
PM	Preventive Maintenance
PTP	Point-to-Point
R&D	Research and Development
RCM	Reliability Centred Management
RDA	Revenue Deferral Account
REDA	Regulatory Expenditures Deferral Account
ROE	Return on Equity
SCADA	Supervisory Control And Data Acquisition system
SCC	System Control Centre
SCMP	System Control Modernization Project
SD9	Special Direction No. 9, Order in Council No. 1107
SDA	Substation Distribution Assets
SIC	Southern Interior Control Centre
SLA	Service Level Agreement
SO	System Operations department
SPPA	System Planning and Performance Assessment department
TNO	Telecom Network Operations
TRR	Transmission Revenue Requirement
TSS	Transmission Scheduling System
VIC	Vancouver Island Control Centre
VITR	Vancouver Island Transmission Reinforcement Project
WECC	Western Electricity Coordinating Council

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 its
F2009 Transmission System Capital Plan

1.0 APPLICATION

Pursuant to sections 45(6) and (6.1) of the *Utilities Commission Act* (Act), British Columbia Transmission Corporation (BCTC) applies to the British Columbia Utilities Commission (Commission) for an order that this Capital Plan meets the requirements of these sections, to approve this Capital Plan pursuant to subsection 45(6.2)(a) of the Act, and for an order that capital expenditures relating to certain projects and programs in this Capital Plan are in the public interest under subsection 45(6.2)(b) of the Act. The specific Orders Sought are set out in Section 1.6 below.

The specific form of the Order sought by BCTC is set out in Appendix L of the Application.

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) 699-7229
Email: marcel.reghelini@bctc.com

and

Attention: Laurence Gray, Senior Regulatory Advisor, Regulatory Affairs

Phone: (604) 699-7511
Fax: (604) 699-7229
Email: laurence.gray@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

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1.3 Regulatory Context

Capital Plans are a major component of planning, constructing, operating and managing the transmission system, reflecting proposed and potential projects and their capital requirements over the planning horizon. BCTC has filed three Capital Plans for approval by the Commission: the F2005 Capital Plan in May 2004, the F2006 Capital Plan in March 2005, and the F2008 Capital Plan in December 2006. BCTC also filed an Update to the F2006 Capital Plan in January 2006.

BCTC plans to publish its Capital Plan and to file it with the Commission bi-annually beginning with the F2010 Capital Plan. Previous filings were rolling two-year plans, but in discussions with the Commission and Intervenors it was determined that bi-annual plans will be more efficient administratively. The next BCTC Revenue Requirement application will also be a two-year application, and it is scheduled to alternate with the timing of the next two-year BCTC Capital Plan.

In this F2009 Capital Plan, BCTC seeks approval of projects and programs for F2009 and F2010. Next year, BCTC intends to file its F2010 Capital Plan, which is anticipated to request approval for any additional projects identified for F2010 and to seek approval for projects and programs beginning in F2011.

From a regulatory perspective, BCTC's Capital Plan is guided by section 45 of the Act. The relevant portions of section 45 are as follows:

> **45** (1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.
>
> […]
>
> (6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.
>
> (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission:
>
> (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
>
> (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;
>
> (c) a plan of how the public utility intends to reduce the demand for energy, and the expenditures required for that purpose.
>
> (6.2) After receipt of a plan filed under subsection (6.1), the commission may
>
> (a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in that plan;
>
> (b) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility; and
>
> (c) determine the manner in which any expenditures referred to in the plan can be recovered in rates.

As set out in Section 1.6, BCTC seeks orders under these sections for approval of this Capital Plan and that certain programs and projects are in the public interest.

With respect to the manner in which any expenditures can be recovered in rates, BCTC forecasts the amount of capital expenditures for projects going "in-service" each year in its Transmission Revenue Requirement applications, and seeks recovery in those proceedings. Accordingly, BCTC is not seeking an order in this

Application determining the manner in which these expenditures can be recovered in rates under subsection 45(6.2)(c) of the Act.

1.3.1 Commission Directives

The Commission has provided Directives to BCTC in each of its Decisions on BCTC's previous Capital Plan applications. BCTC addresses a number of Directives from these Decisions in this Application. A Concordance Table included in Appendix A lists the relevant Directives from previous Decisions and references the location of BCTC's responses in the Application. Responses are provided within various sections of the Application where appropriate, or in Section 9.

1.3.2 Resource Planning Guidelines

Commission Letter No. L-5-04 directs public utilities under the Commission's jurisdiction to file Resource Plans under subsection 45(6.1) of the Act using the Commission's Resource Planning Guidelines.

The Resource Planning Guidelines reflect a planning model that includes the three parts of subsection 45(6.1) of the Act:

(a) A capital expenditure plan for the utility (subsection 45(6.1)(a));

(b) A plan for the acquisition of energy supplies by the public utility (subsection 45(6.1)(b)); and

(c) A plan for demand side management (DSM) activities (subsection 45(6.1)(c)).

As indicated in BCTC's letter to the Commission of February 27, 2004, as a transmission utility, BCTC does not currently engage in the acquisition of energy supplies to meet the demand for energy or, currently, in the implementation of DSM activities. Therefore, BCTC does not develop the type of plans contemplated in subsections 45(6.1)(b) and (c) of the Act. Accordingly, this Application is essentially a capital expenditure plan under subsection 45(6.1)(a) of the Act and applies the Commission's Resource Planning Guidelines in that context.

1.3.3 Approval of Capital Expenditures

Article 19 of the Master Agreement between BCTC and BC Hydro addresses the subject of transmission system capital expenditures. Under Article 19.5, BCTC is required to obtain the Commission's approval, or BC Hydro's consent, before BC Hydro is required to fund these expenditures.

Article 19.5 of the Master Agreement reads as follows:

> **19.5 Transmission System Capital Expenditures**
>
> (a) Subject to paragraph (c) below, BC Hydro will make capital expenditures relating to the Transmission System when construction or acquisition of the relevant capital asset has been:
>
> (i) approved by the Commission:
>
> A. by the issuance of a certificate of public convenience and necessity under section 45(1) of the UCA;
>
> B. by a determination under section 45(6.2)(b) of the UCA that the applicable expenditure contained in a Capital Plan filed under section 45(6.1)(a) of the UCA is in the public interest; or
>
> C. by another Commission approval procedure; or
>
> (ii) consented to by BC Hydro.
>
> (b) BCTC will provide to BC Hydro reasonable information relating to such capital expenditure as requested by BC Hydro for the purpose of BC Hydro's consent as contemplated by subparagraph (a)(ii) above.
>
> (c) BC Hydro will not be required to make expenditures that the Commission has determined may not be recovered in the rates of BC Hydro.

Article 19.6 of the Master Agreement provides that if the Commission subsequently determines that any of these expenditures were imprudent and not recoverable in rates, BCTC is required to bear these costs.

Given the concurrent requirements of section 45 of the Act and Article 19 of the Master Agreement, BCTC will generally seek the Commission's approval prior to proceeding with transmission system capital investments. This approach adds certainty to the capital spending interaction between BCTC and BC Hydro. This should also prevent delays in needed transmission system capital investments. Given BCTC's relatively low level of equity capitalization, the risk to BCTC of proceeding with transmission system capital projects without prior approval would be unacceptable in most instances.

In addition to transmission system assets, under Article 12 of the Master Agreement BCTC is responsible for planning related to substation distribution assets (SDAs). However, BC Hydro is responsible for obtaining regulatory approval for these projects. There are some projects that include capital expenditures related to both transmission and SDAs. Rather than attempt to divide these projects into transmission and distribution-related components, BCTC has identified the full scope of these combined projects in this Application but is only seeking approval for the transmission-related aspects of these projects.

It should also be noted that, as with BCTC's previous Capital Plans, BCTC is not seeking Commission approval for the precise amount associated with each project or group of projects identified in this Application. The amounts identified in association with each project are estimated costs and actual expenditures will vary from these estimates in some cases. If BCTC were limited to expenditures in the precise amounts set out in this Capital Plan it would need to re-apply to the Commission in those cases where actual project spending exceeds estimates. BCTC does not believe this is a practical approach. Accordingly, for those projects that are identified in Section 1.6.2, BCTC is seeking the Commission's approval that capital expenditures on these projects are in the public interest, rather than for a precise expenditure. As outlined by the Commission in its Decision on BCTC's F2006 Capital Plan (page 2, as amended by Commission Letter L-12-06), BCTC will provide explanations for any projects whose actual costs vary significantly from the estimate provided to the Commission and recognizes that in some cases a prudency review may follow for such projects. As further indicated by the Commission in its Decision, it is more likely that actual expenditures will be considered when the amount to be recovered in rates will be determined, in most cases during a revenue requirements proceeding.

1.3.3.1 Emergency Capital Expenditures

Emergency Capital Expenditures are addressed in the Sustaining Capital portfolio. Generally, an emergency is an unplanned event that results in a reduction or loss of service or presents an unsafe condition. A loss of resource that creates a high risk of service interruption may also be treated as an emergency. The common element is that the correction must be implemented as quickly as possible. While many emergency situations can be corrected without capital expenditures, more extensive equipment failures will generally require capital expenditures to restore the system.

Article 19.9 of the Master Agreement provides that BC Hydro will fund emergency capital expenditures, subject to BCTC having obtained Commission approval, if required. In the event of an emergency, BCTC's first step is to establish a safe condition, and then carry out any repairs necessary to restore service. Where capital expenditures are involved, this process will involve the preparation of a plan, including cost estimates. Most emergency capital expenditures will not require CPCNs and, therefore, absent other considerations, pre-approval of capital expenditures by the Commission is not required. In these circumstances, concurrent with the planning process, BCTC will request funding from BC Hydro under Article 19.9, and also inform the Commission of the emergency and the intended response. At the conclusion of the repair, BCTC will request approval of the capital expenditure in a subsequent Capital Plan application, to satisfy the requirements of Article 19.9. This process has now been used on a number of occasions and appears to work well. For example, F2004 Emergency Replacements of HVDC Minor Equipment and Station Equipment were approved through the F2005 Capital Plan by Order G-103-04. Through the F2006 Capital Plan, two emergency circuit breaker replacements at Williston Substation were approved by Order G-91-05.

1.3.3.2 Unplanned Capital Expenditures

Although significant time and effort is taken in the preparation of the capital portfolios, some capital expenditures emerge over the course of a year that are not included in the current year of the Capital Plan. Article 19.10 of the Master Agreement provides that BCTC will, subject to the Commission's approval, include an unallocated contingency component in its Capital Plan to cover these expenditures. BCTC has not applied for an unallocated contingency component in this Capital Plan.

1.3.4 CPCN Criteria

Commission Order G-103-04 accepted BCTC's proposed CPCN criteria. BCTC will make a CPCN application when one or more of the following five criteria are met:

(a) Total project cost is expected to exceed $50 million;

(b) The impact on a particular community or constituency likely cannot be mitigated to its satisfaction;

(c) The risk associated with a project, as established through BCTC's corporate risk management framework, is identified as High or Extreme;

(d) The project establishes a precedent for significant future investment, where "significant" means $50 million or more over either a ten-year period or the life of the asset; and

(e) The Commission exercises its discretion to require a CPCN application.

The Commission's F2005 Capital Plan Decision further stated at page 25, "Also, the Commission Panel expects that, as a rule of thumb, approximately 15 percent of transmission projects should be subject to CPCN review, and notes that the CPCN criteria may be adjusted over time to achieve this." BCTC understands and supports the adjustment of CPCN criteria over time. However, in any given year, it is reasonable to expect significant variance from the 15 percent level as a result of on-going shifts in the composition of the capital portfolios. Depending on system needs, capital spending may shift between Growth and Sustaining, and between larger projects and numerous smaller projects. Stakeholder interest in transmission projects may also vary over time according to the nature and location of projects, and the changing concerns of different stakeholders. BCTC continues to monitor the impact of the CPCN criteria on the number and types of projects that are subject to CPCN treatment each year, and will apply to the Commission for changes to the criteria when required. At this point in time, BCTC does not believe there is any reason to adjust the CPCN criteria.

1.4 Proposed Review and Approval Process

The Commission's role in reviewing and approving Resource Plans is outlined in subsection 45(6.2) of the Act. Subsection 45(6.2)(a) allows the Commission to establish a review process for the approval of a Capital Plan.

As with BCTC's previous Capital Plans, BCTC recommends a written process for this review. BCTC believes that this form of process provides an effective forum and best reflects the ongoing nature of its Capital Plan and the type of expenditures BCTC is seeking approval for under subsection 45(6.2)(b). These projects are generally of a routine nature, with respect to both content and magnitude and, in many cases, reflect current expenditures on ongoing programs that have been previously approved. The approval of projects during the review of the Capital Plan will in turn provide input to the subsequent revenue requirement process. In accordance with the CPCN criteria, larger scale and non-standard projects may require CPCN treatment. Some of these projects may be the appropriate subject of oral hearings.

1.5 Structure of the Application

The Application comprises the following sections:

Section	Description
1.	Application
2.	Corporate Outlook
3.	State of the Transmission System Report Summary
4.	Capital Planning Process Overview
5.	Growth Capital Portfolio
6.	Sustaining Capital Portfolio
7.	BCTC Capital Portfolio
8.	Revenue Requirement Impacts
9.	Commission Directives

<u>Appendix</u>

A. Directive Concordance Table

B. 2007 State of the Transmission System Report

C. Growth Planning Standards

D. Risk Matrices

E. MMK Consulting Report – BC Hydro Construction Cost Trends and Outlook

F. Two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor Banks at Ashton Creek Substation – Project Justification Report

G. Goto Sargent Report – F2008 Q1 Project Forecast Update Report on Forecast Sensitivities

H. Report on Infrastructure Spending, Reliability, and Customer Impacts

I. UMS Group Report on BCTC

J. Prioritization Model User Manual

K. Planning Assumptions for IEP/LTAP/CRP Transmission Analyses and Subsequent NITS Application

L. Draft Order

1.6 Orders Sought

1.6.1 General

BCTC is applying for the following:

(a) An Order that this Capital Plan meets the requirements of sections 45(6) and (6.1) of the Act;

(b) An Order approving this Capital Plan under subsection 45(6.2)(a) of the Act; and

(c) Certain Orders under subsection 45(6.2)(b) of the Act that capital expenditures relating to the projects set out below are in the public interest.

1.6.2 Orders Under Subsection 45(6.2)(b) of the Act

1.6.2.1 Growth Capital Portfolio

1.6.2.1.1 Bulk System Reinforcements

F2009 and F2010 Projects for Approval as follows:

(a) Ashton Creek Substation Shunt Capacitor Banks – Implementation Phase

(b) RAS - GMS Generation Shedding Modifications – Stage 2

(c) RAS - Bridge River Generation Shedding Modifications

(d) RAS – Revelstoke G5 Generation Shedding Modifications

1.6.2.1.2 Area Reinforcements

F2009 and F2010 Projects for Approval as follows:

(a) Golden 69 kV System Reinforcement – Definition Phase

(b) Woods Lake Area Reinforcement – Definition Phase

1.6.2.1.3 Station Expansions and Modifications

F2009 and F2010 Projects for Approval as follows:

(a) Port Kells Substation Shunt Capacitor Additions

(b) Qualicum Beach Substation Reconfiguration

(c) Sidney Substation Transformer Cooling Upgrade

(d) Tumbler Ridge Substation Transformer Replacement

1.6.2.2 Sustaining Capital Portfolio

1.6.2.2.1 Stations

Revised F2009 and new F2010 Programs for Approval as follows:

(a) Auxiliary Equipment Annual Program

(b) Circuit Breakers Annual Program

(c) Horsey GIS Replacement (Circuit Breakers)

(d) Mica GIS Replacement (Circuit Breakers)

(e) Other Power Equipment Annual Program

(f) Protection and Control Annual Program

(g) Third Party Requested Projects (Protection and Control)

(h) Risk Mitigation Annual Program

(i) Murrin Substation Reconfiguration and Seismic Upgrade (Risk Mitigation)

(j) Telecommunications Annual Program

1.6.2.2.2 Lines

F2009 and F2010 Programs for Approval as follows:

(a) Cable Sustainment Annual Program

(b) Overhead Lines Life Extension Annual Program

(c) Overhead Lines Performance Improvements Annual Program

(d) Overhead Lines Risk Mitigation Annual Program

(e) Right-of-Way Sustainment Annual Program

(f) Third Party Requested Projects (Right-of-Way Sustainment)

1.6.2.3 BCTC Capital Portfolio

1.6.2.3.1 Information Technology

F2009 and F2010 Projects for Approval as follows:

(a) Asset Management Program (AMP) Server Refresh F2010

(b) B2B (Business to Business) Portal F2009

(c) Data Centre Redundancy F2009 and F2010

(d) E-Business Financial Upgrade F2009 (Oracle Upgrade)

(e) Enterprise Server, PCs, Printers and Peripherals F2010

(f) Financial System Sustainment Project F2009 and F2010

(g) HR/Payroll Sustainment F2009 and F2010

(h) Identity and Access Management F2009 and F2010

(i) Laptop, Desktop and Removable Media Encryption F2009

(j) Market Operations Workflow SGIP Sustainment F2009

(k) Mobile Station Inspection Enhancement F2009 and F2010

(l) Network Segmentation F2009

(m) Reliability and Loss Program Integration F2009 and F2010

(n) Security Information Management F2009

(o) SharePoint Version 2007 Upgrade F2009

(p) Transmission Scheduling System (TSS) Enhancements F2009

(q) wesTTrans OASIS Upgrades F2009 and F2010

1.6.2.3.2 Control Centre Technologies

F2009 and F2010 Projects for Approval as follows:

(a) Control Centre Sustainment F2009 and F2010

(b) Control Centre Business Application Enhancement F2009 and F2010

(c) Real Time Operations (RTO) Servers and Infrastructure Refresh F2009

(d) Site Information System (SIS) FileNet Upgrade F2009

1.6.2.3.3 Facilities

F2009 and F2010 Projects for Approval as follows:

(a) BCTC Facilities Enhancements F2009 and F2010

2.0 CORPORATE OUTLOOK

PRE-FILED EVIDENCE OF JULIUS PATAKY, VICE PRESIDENT, SYSTEM PLANNING & ASSET MANAGEMENT

This section begins with a summary of the Application (section 2.1), followed by a discussion of the primary determinants for the planned capital expenditures in the F2009 Capital Plan (section 2.2) and then an examination of the major risks and uncertainties facing the Capital Plan (section 2.3). Concluding the section is a discussion of continuous improvement initiatives being undertaken by management to enhance the processes and procedures of the Asset Management function (Section 2.4).

The F2009 Capital Plan identifies capital investments totaling $5.1 billion over the 10-year period, an increase of $1.8 billion over the 10-year period set out in the F2008 Capital Plan. Tables 2-1 and 2-2 summarize the changes over the F2008 Capital Plan.

Table 2-1. Changes from F2008 Capital Plan

	Particulars ($ billions)	F2009 Capital Plan (note 1)	F2008 Capital Plan (note 1)	Increase (Decrease)	Reason for Change
	Transmission:				
1	Growth Portfolio	$2.7	1.6	1.1	See Table 2-2
2	Sustaining Portfolio	1.4	1.1	0.3	Asset demographics, downtown reliability, cost escalation
3	BCTC Capital Portfolio	0.1	0.2	(0.1)	
4	Total	4.2	2.9	1.3	
5	Add: SDA (note 2) and Other	0.9	0.4	0.5	
6	Grand Total	$5.1	$3.2	$1.8	

Note 1: These amounts represent expenditures in the 10-year period starting with F2009. It excludes any prior expenditures of projects started prior to F2009.

Note 2: These capital expenditures relate to distribution and are the responsibility of BC Hydro. Only SDA projects with partial transmission components are described in this Capital Plan.

Note 3: Numbers do not add exactly due to rounding.

Table 2-2. Changes from F2008 Capital Plan Growth Portfolio

	Growth Portfolio ($ billion)	F2009 Capital Plan	F2008 Capital Plan	Increase (Decrease)	Reason for change
1	ILM Project	$0.6	$0.3	$0.3	Cost increase related to project definition and escalation
2	Generation Interconnection projects	1.0	0.3	0.7	Revised forecast of additional energy required over the period.
3	Other Growth	1.1	1.0	0.1	Updated load growth forecast
4	Total - Growth	$2.7	$1.6	$1.1	

BCTC notes that some of the costs included in these components are not based on estimates from project plans, but are directional indicators based on forecasts; the $1.0B estimate for generation interconnection projects is an example.

BCTC also notes that the Northwest Transmission Line (NTL) project is not included in the F2009 Capital Plan. BCTC has worked on the development of this project over the past year. Due to the recently announced deferral of the Galore Creek mine project, which was to be served by this line, the NTL project is currently on hold and BCTC and the provincial government are working together to determine the next steps for the NTL project.

2.1 Summary of the Application

BCTC's Capital Plan is comprised of three major portfolios. The Growth Portfolio is comprised of those investments required to extend and reinforce the system to meet growth in load, to transfer power from new generation resources, and to accommodate transmission customer and generation interconnection requests. The Sustaining Portfolio addresses transmission infrastructure capital equipment replacements, refurbishment, and enhancements necessary to meet safety, reliability, environmental and regulatory standards. The BCTC Portfolio consists of three major asset groups: information technology, control centre technologies, and facilities.

2.1.1 Growth Portfolio

The Growth Portfolio consists of projects starting in F2009 totaling $0.5 billion, and identifies potential projects from F2010 through F2018 totaling $2.8 billion. BCTC is presently managing previously approved Growth Portfolio projects totaling $0.3 billion.

Section 4 describes the process used to plan the projects and programs identified in this Capital Plan under the Growth portfolio. Detailed information on individual Growth Capital expenditures is found in Section 5 of this Capital Plan. The Interior to Lower Mainland Transmission Project is the single largest project in this portfolio with an estimated total cost in excess of $600 million. On November 5, 2007, BCTC submitted an application for a Certificate of Public Convenience and Necessity (CPCN) for the ILM Project to the Commission.

Transmission growth projects are required in response to Network Integration Transmission Service (NITS) requests which reflect the BC Hydro forecast of service connections, load growth, and generation resources as well as known IPP connections. Also included in the Growth Portfolio are SDA projects, which are comprised of transmission and distribution components. These projects are investments planned and executed by BCTC on behalf of BC Hydro and in response to BC Hydro forecast increases in load. SDA projects which do not have any transmission components (i.e., they comprise a 100% distribution component) are not included in the Capital Plan but are included in the summary table in Section 2.0 for information only. BCTC expects BC Hydro will seek the necessary approvals from the Commission for the SDA portion of capital expenditures.

2.1.2 Sustaining Portfolio

The Sustaining Portfolio is structured on a program basis. In F2009 BCTC is proposing to invest $112.9 million in Sustaining Capital programs. The preceding amount represents an increase of $24.4 million over the F2009 Sustaining investments of $88.5 million approved in the Commission’s Decision, dated June 15, 2007. BCTC proposes to invest a further $123.4 million in Sustaining Capital programs in F2010, and future programs are anticipated to escalate to $157.1 million per year (including inflation) in F2018.

Section 4 describes the process used to plan the projects and programs identified in this Capital Plan under the Sustaining portfolio. Detailed information on Sustaining Capital expenditures is found in Section 6 of this Capital Plan.

The Sustaining Portfolio includes programs and projects to replace end-of-life assets; to refurbish assets when it is cost effective to do so; to replace failed assets; and to replace or upgrade assets because of safety concerns, regulatory requirements or increased asset performance risk. These programs and projects are undertaken when it is not cost effective to maintain asset performance under OMA activities. In addition, BCTC alters assets at the request and cost of third parties to accommodate their construction needs.

In August 2007, BCTC commissioned a study and report by the independent consulting firm UMS Group Inc. (UMS). UMS is a management consulting firm with a global client base. The company is a well established leader in benchmarking and the identification of best practices for utilities and uses proprietary techniques for normalizing data to allow valid comparisons among companies operating in different regions with varied market drivers and regulatory requirements. UMS' terms of reference primarily required the assessment of BCTC's levels of spending in comparison to other transmission utilities and those known to be good and superior performers.

UMS concluded that BCTC's costs for transmission system investments (Growth, Sustaining and OMA) are below the range of what should be expected for a system like BCTC's. More importantly, with respect to Sustaining expenditures UMS states that:

> "Based on relative age and failure analysis and BCTC's spending levels in comparison to its peers, we see several indications that BCTC's current spending levels may not be sufficient to allow it to maintain the current level of system performance. The current spending levels appear to be below many of its peers. While BCTC appears to have done well at extending the useful life of many of its assets, the age demographics of the system, and the experience of other utilities, strongly suggest that BCTC could see a sharp climb in the number of assets requiring replacement over the next ten years.

> We do not believe that current spending levels will support the increase in the end of life replacements that will be required over the next 10 years." (UMS report, p.5-20)

The UMS report, including conclusions and recommendations pertaining to levels of spending and other matters such as its assessment of BCTC's Asset Management processes, capabilities and effectiveness (discussed in Section 2.4), can be found in Appendix I.

2.1.3 BCTC Capital Portfolio

BCTC Capital projects for approval, to start mostly in F2009, total $13.5 million, and future projects through F2018 are estimated to total $105.4 million.

Section 4 describes the process used to plan the projects and programs identified in this Capital Plan under the BCTC portfolio. Detailed information on BCTC capital expenditures is found in Section 7 of this Capital Plan.

2.2 Business Considerations

The fundamental business considerations driving the planned capital expenditures in the F2009 Capital Plan are:

Overarching:

(a) Achievement of BCTC's Corporate Goals (listed in Section 2.2.1);

Specific:

(a) Meeting forecast load growth as reflected in the NITS Agreement;

(b) Meeting the resource plan requirements as reflected in the BC Hydro 2006 IEP/LTAP and NITS Agreement;

(c) Integrating new generation resources;

(d) Addressing aging infrastructure;

(e) Ensuring transmission system safety and reliability;

(f) Capitalizing on opportunities afforded through the Transmission Expansion Policy;

(g) Responding to applicable codes and regulations; and

(h) Responding to third party requests.

It should be noted that certain projects, although identified in this Capital Plan for completeness, will be brought to the Commission for approval through separate CPCN filings. These include, for example, the Central Vancouver Island Project and the South Interior Series Compensation Project.

Prior to discussing the impact of the above business considerations, Sections 2.2.1 and 2.2.2, respectively, provide a brief overview of BCTC's mandate and of recent significant government initiatives.

2.2.1 BCTC Overview

BCTC's mandate is to ensure fair and open access to the grid and create value and new opportunities for our customers and other stakeholders by providing safe, reliable and cost-effective transmission services.

The transmission system receives power from approximately sixty generating stations and interties with the US and Alberta, and delivers it through approximately 18,300 circuit kilometers of transmission lines to approximately 400 delivery points throughout the province. BCTC's primary roles, responsibilities and services include:

(a) Responsibility for electric transmission reliability of the BC Hydro-owned transmission assets;

(b) Operation of the BC Hydro-owned transmission system, including real-time operation of transmission, generation, distribution and telecommunications systems, and transaction scheduling;

(c) Provision of services under BCTC's OATT, including all aspects of the regulatory process, tariff administration, and customer relations. The OATT defines the rates and terms and conditions of transmission service and interconnection to the transmission system;

(d) Planning of the transmission system in coordination with BC generation and distribution entities and neighbouring control areas and transmission organizations;

(e) Management and maintenance of the transmission system assets (including lines, substations and telecommunications systems), as well as of BCTC's control centres;

(f) Sustaining, replacing and expanding the transmission assets and BCTC's control centre assets, to ensure reliable service for domestic customers and for electricity trade; and

(g) Participating in the maintenance of relative low electricity rates in British Columbia, including the cost effective management of all BCTC functions.

2.2.1.1 Corporate Goals

The Corporate Goals that BCTC has relied on for this Capital Plan are as follows:

(a) Goal 1: Reliability, Costs and Service – Achieve reliability improvements while lowering costs and delivering outstanding service.

(b) Goal 2: Market Efficiency – Ensure efficient use and development of the transmission system.

(c) Goal 3: Environment and Safety – Continually improve our environmental and safety management performance.

(d) Goal 4: Relationships – Build open and constructive relationships with stakeholders and First Nations.

(e) Goal 5: Organization and People – Build an engaged and highly skilled workforce.

(f) Goal 6: Financial Return – Deliver the allowed return to our shareholder annually.

2.2.2 Significant Government Initiatives

2.2.2.1 The New Energy Plan

The new BC Energy Plan: A Vision for Clean Energy Leadership was released in February 2007. A core element of the Energy Plan is the commitment that British Columbia will be electricity self-sufficient by 2016. Under self-sufficiency, BC Hydro will have excess power to sell in all but the most critical water situations.

Among the various Policy Actions stated in the new Energy Plan the following have particular significance for BCTC:

(a) Policy Action 12: The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.

(b) Policy Action 13: Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.

(c) Policy Action 14: Ensure that the province remains consistent with North American transmission reliability standards.

BCTC believes that overall this Capital Plan is consistent with the above policy actions but does not respond fully to them. Completeness will likely occur once BC Hydro has filed and received Commission approval for the 2008 LTAP and BCTC has had the opportunity to integrate the resource plan in its planning.

BCTC notes that the F2009 Capital Plan does not reflect any incremental expenditures that may arise from implementation of the new Energy Plan.

This Capital Plan also does not reflect any initiatives in response to the recently announced Climate Action Change Plan.

2.2.3 The Impact of Forecast Load Growth as Reflected in the NITS Agreement

Provincial demand for electricity continues to grow at a vigorous rate (BC Hydro has identified growth of between 25 and 45 percent over the next twenty years), and as a result, BCTC faces significant increases in the scale of investment requirements.

These requirements are discussed in detail in Section 5 entitled Growth Capital portfolio.

2.2.4 The Impact of the Resource Plan Requirements as Reflected in the 2006 BC Hydro IEP/LTAP and NITS Agreement

Over the next 10 years, 3319 MW of new dependable resources is forecast to be added to the system. This will require significant reinforcements on the bulk electric system to transmit this power from the generators to the load.

2.2.5 The Impact of Integrating New Generation Resources

BCTC's generation interconnection work level is forecast to increase significantly as new IPP projects resulting from the initiatives related to BC Hydro's Calls for Energy are added to the system. This Capital Plan forecasts that BCTC will need to expend over $1 billion on interconnection work during the period from F2009 to F2018 (see Section 5). As indicated in the Commission's F2008 Capital Plan Decision, expenditures related to generation interconnection work are generally governed by the provisions in the OATT and BCTC is not seeking public interest approval for these expenditures in this F2009 Capital Plan.

2.2.6 The Impact of the Need to Address Aging Infrastructure, and the Impact of Ensuring Transmission System Safety and Reliability

Increases in Sustaining Capital investments are needed as major transmission investments that occurred in the 1960s and 1970s reach the end of their useful lives. As the existing infrastructure ages, reliability and safety need to be addressed. These investments are discussed in detail in Section 6 entitled Sustaining Portfolio. Significant examples of capital expenditures in this portfolio include for example, circuit breakers, and expenditures for risk mitigation regarding stations and lines. Not only is BCTC proposing to increase Sustaining expenditures in F2009 and F2010, the outlook expenditures for the remaining eight other years of the Capital Plan period are also higher than in previous Capital Plans. UMS' report, introduced in Section 2.1.2 and included in Appendix I also discusses this need.

2.2.7 The Impact of Capitalizing on Opportunities Facilitated Through the Transmission Expansion Policy (TEP)

In its F2008 Capital Plan decision, the Commission directed BCTC to report on potential TEP projects in the next capital plan, and provide a detailed description of the highest ranked potential TEP project. It further directed that in the event that BCTC identifies a potential TEP project and then decides that the project should be implemented, BCTC should seek approval of the project prior to the next capital plan.

BCTC identified such a TEP project, the Thermal Upgrade of Transmission Circuits 5L51 and 5L52, and submitted a separate application for this project to the Commission on 12 December 2007. This project was prioritized with other non-TEP Growth capital projects during the process which culminated in this F2009 Capital Plan.

2.2.8 The Impact of Responding to Applicable Codes and Regulations

Examples of BCTC's responses to applicable codes and regulations include the following:

(a) BCTC is planning to initiate a project which will remove from service the last remaining PCB-filled equipment at VIT Station and replace it with non-PCB equipment in accordance with the current Environment Canada proposed regulations;

(b) BCTC supports the CEA/Environment Canada Memorandum of Understanding to control and minimize SF6 gas releases and plans to replace all double-pressure SF6 circuit breakers by F2015; and

(c) BCTC is also addressing environmental risks due to oil spill hazards by installing spill containment, oil/water separators, and oil stop valves, and replacing existing above-ground diesel tanks with double-walled tanks.

2.2.9 The Impact of Accommodating Third Party Requests

Requests are made by third parties such as the Ministry of Transportation and Highways and developers, which typically involve relocation of existing electric plant. The Sustain Capital portfolio contains an annual provision of approximately $2.5 million for the F2009 to F2018 period to cover these types of requests.

2.2.10 The Impact of Inflation

The F2009 Capital Plan includes a provision for inflation that is different from the 2 percent annual inflation in the Commission Decision's on the F2008 Capital Plan. The revised inflation provision is required to address increasing costs for labour and materials that are generally known to be higher than CPI as measured by Statistics Canada for the overall economy. To ensure that the forecast of expenditures is realistic in F2009 and beyond, BCTC has applied cost escalation that is appropriate to the construction/electrical industry, consistent with the MMK Report filed in Appendix E of this Capital Plan. Specifically, the MMK Report states:

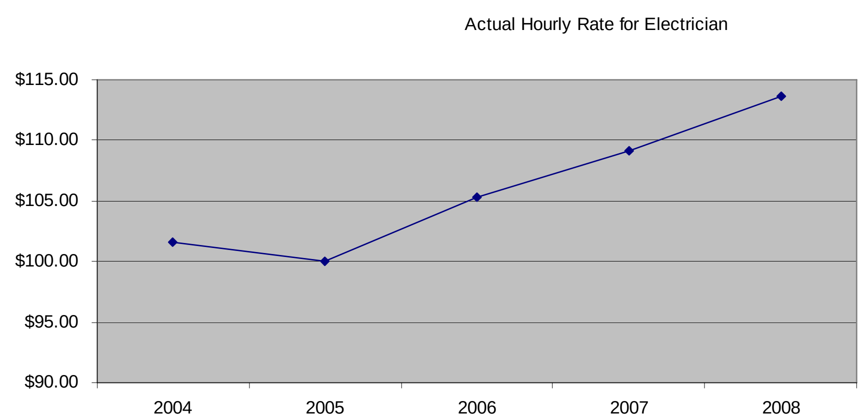
> **Cost inflation outlook for BC Hydro**
>
> For **heavy construction**, there are some signs of softening in component price indices. However, both the BC construction industry and the Canadian industrial construction industries continue to show high activity levels and price inflation.
>
> Accordingly, for 2007 to 2010, our recommended cost inflation allowance range is unchanged at 4% to 6% annually. For 2011 through 2015, our recommended range is 3% to 4% annually, up slightly from our March report.
>
> For **transmission, stations and distribution**, based on the recent strength of US equipment price indices, confirmed by the recent experiences of BC Hydro staff, we expect future Canadian cost inflation pressures for transmission, stations and distribution to be much stronger than in the past few years. Accordingly, we have increased our recommended cost inflation ranges for transmission, stations and distribution construction to bring them into line with those for heavy construction and power generation.
>
> In summary, our recommended cost inflation allowances, for all major construction projects, are 4% to 6% for 2007 through 2010, and 3% to 4% for 2011 through 2015.

Based on the MMK Report, the F2009 Capital Plan assumes an inflation factor of 6% for F2008, 5% for each of F2009 and F2010, 4% for F2011, and 3% for F2012 and onwards for this transmission work.

Cost escalation increases due to inflation are illustrated in the following two examples:

(a) Figure 2-3 indicates that BC Hydro's Electrician labour rate, as determined through collective agreement, has been increasing at approximately 5 percent annually since 2005.

Figure 2-3. BC Hydro Electrician Labour Rate



(b) Selkirk Transformer (T1a and T1 Spare – these are identical transformers and are made by the same manufacturer). The following table shows the increase in costs. The increase experienced in one year for identical equipment is shown to be 55 percent.

Table 2-3. Transformer Cost Increase

	Year of Order	Cost	% Increase
1	2006	$2.2M	n/a
2	2007	$3.4M	55%

BCTC recognizes that not all cost components are increasing at such a high rate, but these examples are indicative of inflation pressures in the construction/electrical industries that appear to support a higher escalation rate than the rate previously approved by the Commission.

2.3 Major Uncertainties and Risks to Capital Plan

Capital investments, especially those comprising the Growth and Sustaining Capital portfolios must be managed in the context of:

(a) Cost escalation pertaining to material supply, equipment, and construction labour;

(b) Higher expectations for stakeholder and First Nations engagement; and

(c) Changing business and customer drivers (e.g. the configuration of new interconnections).

However, given the projected increase in the level of capital investment in the Growth portfolio over the 10-year horizon, the most significant challenge is expected to be BCTC's ability to deliver all of the projects in the time periods that they are required (Execution risk). Several of the planned area reinforcements will require significant upgrades to existing transmission facilities, or the construction of new facilities, and may require CPCN applications. BCTC has to ensure that the necessary resources are in place to plan and implement these projects and programs.

The Execution risk is also present in the case of the capital investments proposed in the Sustaining portfolio. However, in the case of the BCTC Capital portfolio, this risk is significantly smaller since the types of resources required for execution differ.

BCTC is addressing this resource issue on the supply side by implementing human resource initiatives to attract and retain skilled staff, and arranging for external resources. The Capital Planning process also addresses these resource issues by considering the timing and volume of work associated with the portfolios. Where possible, BCTC has adjusted the timing of a number of potential CPCN projects (e.g., Golden Line upgrade, South Interior Series Compensation), to stagger the resource requirements from key skill groups.

BCTC has also secured additional engineering and construction capacity for projects. BCTC negotiated and signed a multi-year engineering services agreement with SNC-Lavalin and may increase its current level of commitment with SNC to address the increasing capital program. Alternatively, BCTC may explore the option of contracting with an additional engineering service provider. BCTC continues to use BC Hydro Engineering Services at or above levels of previous years. BCTC is also considering the development of strategic alliances with contractors. More specifically, BCTC will, after performing an appropriate analysis, consider Public-Private Partnership (P3) opportunities on projects of sufficient scale.

The Growth portfolio is also exposed to risk from the BC Hydro forecasts. The timing of the proposed projects is based on the 'probable' load forecast. The growth in the province is very robust and the 'high' forecast may materialize, resulting in the need to advance projects. However, accelerating some projects may not be possible, especially in the first two years of the plan. This would potentially impact reliability during high load periods until the need is addressed. In the case of some of the major projects, this timing risk is partially mitigated by proceeding with Definition Phase work to provide a measure of readiness.

2.4 Significant Management Initiatives

BCTC has and continues to use a formal process to plan the projects and programs identified in this Capital Plan under the Growth, Sustaining and BCTC portfolios. A detailed description of this planning process is provided in Section 4.2.

As part of its pursuit of continuous improvement and particularly in view of the growing capital requirements, BCTC has and continues to identify, evaluate and implement improvements in its business processes and procedures. The commissioning of the study and report by UMS, previously noted in Section 2.1.2, is a demonstration of this effort by BCTC. While the primary purpose of the study focused the matter of BCTC's spending levels, a secondary focus of the UMS study deals with BCTC's Asset Management processes, capabilities and effectiveness. UMS provides its independent view of BCTC's performance, including strengths and gaps as compared to the global transmission industry. UMS' complete report is included in Appendix I.

Highlights among UMS' conclusions are:

(a) BCTC's system performance is good and is reflective of solid work being done by BCTC in managing the assets and making sound investment decisions;

(b) BCTC is a solid Asset Manager. Its analytical capabilities are logical, credible and can reasonably be relied upon; and

(c) BCTC has continuously improved upon its Asset Management capabilities with results evident in the system cost and operations performance, and is actively working on continuous improvement efforts.

UMS also identified certain gaps in performance that are consistent with other Asset Management organizations at BCTC's stage of implementation. Highlights among their recommended actions for closing these gaps are:

(a) Continue the evolution toward a "One Asset" view. In the short-term, this would consist of finding cross group working strategies that ensure better cross portfolio collaboration;

(b) Ensure there is a clear, uniform and well understood vision of the transmission system 20 years out;

(c) Develop a Asset Management IT strategy, and system architecture;

(d) Review the externalities identified in the UMS report (e.g., NERC/WECC mandatory standards) and evaluate which should be addressed in the near term and medium term;

(e) Develop a strategy and comprehensive plan to address the end of life replacement wave that appears to be on the horizon; and

(f) Improve Performance Management systems and reporting by going beyond asset performance to include, for example, Contractor performance.

BCTC was aware of the gaps identified by UMS and, consistent with its objective of continuous improvement, is committed to working to close them. For example, BCTC was or is currently taking the following actions which are partly addressing the above highlighted recommendations by UMS (actions are presented in corresponding order of the above recommendations). To fully address all of UMS' recommendations, BCTC will be taking further actions but will (as UMS also recommended) need to be thoughtful about how and when it executes these to avoid becoming over-committed.

(a) In November 2006, BCTC initiated a process which led to a detailed review of its system planning function. The objective of this review was to analyze the overall effectiveness of the system planning function and the development of strategies on how this function could be improved to provide increased business value. As a result of the review, a number of changes will be implemented, including:

i. Development of several cross-functional processes that will increase the efficiency and effectiveness of conducting various planning studies; and

ii. Re-organization of the System Planning and Performance Assessment (SPPA) group (SPPA is principally responsible for the Growth Portfolio in the Capital Plan). With the new organization, SPPA will be able to provide more comprehensive planning solutions.

(b) BCTC takes a comprehensive, long-term perspective in planning the system when anticipating the requirements for the grid. A new component of this planning, initiated in May 2007, will be a Long-Term Transmission Outlook Report (Report). This Report will be developed to operate on a time frame that matches the planning horizons of our customers – including BC Hydro's self-sufficiency objectives which look 20 years into the future – and it will be tailored to recognize the long lead times of transmission planning. It will show areas of planned system development – an important element in helping customers make their own investment decisions. The Report will incorporate need identified through the proposed Congestion Relief Policy being developed by the Province, BCTC's own Transmission Expansion Policy, and the Company's new loss reduction strategy which is under development. The Report will also include and incorporate the long-term requirements of extending the life and maintaining the performance of the existing infrastructure. BCTC expects the Report will be an important input document in the preparation of its future capital plans.

The Congestion Relief Policy and the Long-Term Transmission Outlook Report are core elements of BCTC's new comprehensive, long-term planning initiative. BCTC will begin, as part of its implementation actions, to put in place the resources required to take on the new forecasting, planning, and construction activities created by these and other initiatives.

(c) The Chief Technology Officer group is currently engaged in two key strategic initiatives: the IT Applications Strategy, and the Information Strategy Projects. These initiatives were started in April 2007 and September 2007, respectively. A number of key areas, including the Asset Management function, are included as part of this assessment and subsequent strategy.

The IT Applications Strategy is assessing the state of BCTC's current technology portfolio, and determining key aspects such as the maturity, sustainment strategy and business process enablement of these applications. The study is expected to result in the formulation of a 5 to 10 year Roadmap for the consolidation, technology leveraging and integration of BCTC's applications portfolio.

The Information Strategy initiative consists of determining the state of information management, the information flows between different areas and systems of the organization, and the state of data and information governance. Following this effort, BCTC will formulate a strategy for Information management and governance for the next 3-5 years.

(d) In January 2007 BCTC completed, with the assistance of a third party, an analysis to identify areas where BCTC practices were not aligned with NERC standards. This analysis identified gaps, their nature and significance. Based on the gap analysis it was identified that BCTC's gaps primarily relate to documentation, process and training (the analysis excluded the NERC CIP standards for which BCTC initiated an implementation project in the summer of 2006). BCTC developed a project plan in the spring of 2007 to remediate the identified gaps. Currently BCTC is in the process of implementing the gap remediations with an expected completion of spring/summer 2008.

For the NERC CIP standards the project initiated in 2006 is in progress to implement the required processes for NERC CIP compliance. As part of that project BCTC is also progressing on the implementation of the systems that were identified in the approved Capital Plan for F2008. It is expected that BCTC will complete the initial NERC CIP in the spring/summer of 2008.

As the NERC standards are evolving it is expected that further process and system enhancements may be required as changes to the NERC standards are introduced.

(e) With regard to addressing the replacement wave and potential associated resourcing constraints, BCTC has identified aging infrastructure as an issue which requires a long range development plan. BCTC is analyzing the age profile of its asset categories and is developing long range plans to address this asset aging. Specifically, it has analyzed circuit breakers, a high criticality asset category, and developed medium term strategies for replacement and is now developing its longer range strategy for this asset category.

(f) In addressing Performance Management Systems and specifically as these relate to contractor performance, as indicated, BCTC has entered into a multi-year service arrangement with SNC (contract was signed in June 2007) and is implementing project performance measures under this service arrangement. BCTC regularly updates the service measures under its Service Level Agreements with BC Hydro and will seek to have common service measures between all its service providers.

In the course of its work, UMS also identified two areas not generally in their mandate that they believed are worthy of mention. These are Cost Estimating and Project Management.

UMS concluded that BCTC's ability to generate consistent and reliable cost estimates at each stage of the investment lifecycle, and BCTC's program and project management activities, are not yet at the level evident in the rest of industry.

BCTC had already recognized these issues and had previously commenced the following improvement initiatives to address these matters within its organization and with its service providers.

In June 2007, BCTC retained the outside consulting firm GoTo Sargent Inc. to conduct a study which required an assessment of the sensitivities in the Q1 F2008 forecast update and the provision of an opinion on the level of confidence BCTC should have in the Life and Annual Forecast numbers for the project portfolio. The

GoTo Sargent Inc. study is included in Appendix G. The subsequent assessments and recommendations were made from GoTo Sargent Inc.'s perspective - the perspective of managing projects for cost and schedule performance. The recommendations arising from this study indicate that BCTC will require better estimates, better tools, and disciplined project execution by itself and its service provider to improve the level of confidence in forecast costs and the efficient execution of projects. UMS' assessment of these issues, which occurred subsequent to the work performed by GoTo Sargent Inc. served to confirm these findings.

BCTC has already commenced an action plan with its service provider, which addresses the initial recommendations made by GoTo Sargent Inc. Initiatives under this action plan first focused on the risks related to the execution of projects currently in progress. Second, BCTC is focusing on the extension of this risk management to planning and estimating of projects before they are initiated for implementation. Third, another initiative focuses on enhancing the project and risk management skills of its service provider, BC Hydro Engineering, as well as BCTC staff. BCTC is working closely with BC Hydro Engineering on these initiatives. BCTC is confident that the expected outcome (i.e. better estimates, better tools and enhanced efficiency in the execution of projects) will be realized.

2.5 Summary

BCTC is developing transmission projects during a period of substantial growth in both load and resource supply, a requirement for system expansions and refurbishment and in a climate of cost escalation for materials and construction. BCTC has implemented improvements in its processes and has further improvement initiatives underway to enhance its project development capabilities. BCTC will consider and incorporate the request from the Commission in the response to BCTC's Fox Creek report as it seeks to better define the scope, improve the estimates of projects presented to the Commission for approval, and improve its execution of approved projects.

3.0 STATE OF THE TRANSMISSION SYSTEM REPORT SUMMARY

The STSR provides stakeholders with a “big picture” of the issues that BCTC is attempting to address in relation to the proposed projects included in the Growth, Sustaining and BCTC Capital portfolios. It includes sections on issues facing the bulk system, the regional systems, local systems, problems with specific equipment, and strategic issues.

The 2008 STSR is attached as Appendix B. BCTC has attempted to address the issues originally envisaged by the Commission for the STSR and has also attempted to address the Commission’s comments on BCTC’s previous STSRs.

Section 1 of the STSR introduces the STSR and provides a brief overview of the remainder of the Report. BCTC’s analysis of the transmission system’s performance and needs is linked to BC Hydro’s load forecasts and resource plans with locational generation forecasts. BCTC has prepared the STSR and its F2009 Capital Plan on the basis of BC Hydro’s updated Long Term Acquisition Plan (LTAP) in the form of Base Resource Plans (BRPs), BC Hydro’s Load Forecasts, and how BC Hydro expects to meet these needs, as reviewed by the Commission in BC Hydro’s 2006 Integrated Electricity Plan (IEP) proceeding.

Section 2 of the STSR provides an overview of the physical facilities which make up the existing transmission system. This includes the bulk and regional transmission systems, internal interties with Alcan and FortisBC, and external interties to Alberta and USA. The physical facilities also include Communication, Protection and Control systems. This section presents the current issues related to the need to expand or reinforce the system to integrate new generation and serve the load growth. The options under consideration or proposed to meet these needs are also presented. This discussion is broken down between different parts of the bulk transmission system, the interties to Alberta and the US, and the regional transmission systems.

At the bulk system level, the current most significant needs relate to the South Interior System and the Interior to Lower Mainland (ILM) portions of the system. The South Interior System is currently experiencing constraints and significant new transmission facilities may be required in the near future to address increased requirements. BCTC prepared a South Interior System Bulk System Development Plan to address the currently required and potential future reinforcements in the South Interior, included as Appendix C in the previous F2008 Capital Plan. More detail is found in Section 5.5 (Growth Capital Portfolio Descriptions) of the Capital Plan. The ILM System is also constrained. The STSR discusses the current status of the ILM System and some of the alternatives that BCTC has considered to address these constraints during the Definition Phase work on the ILM Reinforcement Project. The Application for a CPCN for the ILM reinforcement project was filed by BCTC on November 5, 2007. Existing needs on the Lower Mainland to Vancouver Island portion of the bulk system are generally being addressed by the Vancouver Island Transmission Reinforcement (VITR) Project which received a CPCN from the Commission in July 2006. This project is now under construction. The Northern portion of the bulk system has adequate capacity to meet present needs but new development in either the North Coast area or the Peace River area could trigger the need for new facilities.

Intertie capacity is currently sufficient to meet the needs of both Alcan and FortisBC. The STSR discusses these Wheeling obligations as well as initiatives that are presently underway that may lead to increased capacity and greater use of both the Alberta and US interties and this may place greater demands on the domestic system.

At the regional level most of the proposed reinforcements are required due to load growth, customer requests for service, or system reliability issues in radial parts of the system. Seismic issues, and age related asset deterioration issues also result in system reinforcements being required. Some of the projects proposed at the regional level are short-term solutions designed to respond to increases in load, while longer-term alternatives are being considered and planned. Major reinforcements will likely be needed in each of the Vancouver Island and South Interior regions, and BCTC continues to study needs in the Metro Vancouver area.

Section 2 also addresses BCTC's transmission system control centres and communication systems. In 2005, BCTC received a CPCN to replace its existing control centres and Energy Management System (EMS) with a new centralized System Control Centre, a back up control centre, and a new EMS. The System Control Modernization Project (SCMP) is on schedule and is expected to be in service in late F2008. SCMP will address the current issues with the existing control centres and EMS. The existing control centres and old EMS equipment will be decommissioned once the new control centres and EMS are fully operational. The issues facing the communications system are being addressed through SCMP and ongoing Sustaining Capital investments.

Section 3 of the STSR discusses the impact of the Independent Power Producers (IPP) required to meet BC's electricity needs on the transmission system perspective. BC Hydro's recent Calls for Tender have resulted in a large number of possible generation additions distributed throughout BC. These IPP projects impact the transmission system through added facilities requirements to interconnect and integrate the IPPs.

The integration of wind energy remains a concern. Due the intermittent nature of this generation source, large amounts of rapidly changing power flows can create problems for circuit loadings. To address this problem BCTC has developed a draft wind interconnection standard to ensure the reliability of the system is not compromised.

Section 4 of the STSR discusses projects external to BC and how they may impact the transmission system. These projects include the Juan de Fuca project and the Montana-Alberta intertie, as well as a number of other projects that are in the planning stages.

Section 5 provides a brief overview of the BCTC Transmission Expansion Policy (TEP) as it relates to the Special Direction No. 9. The policy paper developed in 2005 sets out how BCTC approaches the incorporation of customer and stakeholder requirements in advance of requests for service and how BCTC may advance opportunities for strategic transmission expansion. The Transmission Expansion Policy Paper identifies three types of projects that BCTC may put forward under Special Direction No. 9. These are projects supporting development of generation in BC, projects that restore or enhance existing capacity, and projects that expand import/export capacity. Section 5 also provides details of the TEP Implementation Plan including establishing a Technical advisory Committee to oversee the evaluation of TEP proposals. The discussion for the TEP also provides brief description of the

5L51 and 5L52 Thermal Upgrade project that BCTC filed with the Commission in December 2007.

Section 6 of the STSR provides a description of existing equipment condition and performance. Overall, the condition of the transmission system assets is considered to be generally good. However, assets are deteriorating at an increasing rate, and there are some assets on the transmission system that are in poor condition. Section 6 provides details on some of the Sustaining Capital projects which BCTC relies on to maintain the system. Section 6 also outlines steps that BCTC is taking to improve data collection techniques to improve the Asset Health Index assessments and to allow continued improvement in both its equipment maintenance and Sustaining Capital programs directed at asset health. A description of the steps BCTC is taking in developing risk models to identify the end of life of assets and optimizing programs for their repair or replacement is also provided. Finally, Section 6 discusses the Sustainment Investment Model that BCTC continues to develop to forecast the long-term level of Sustaining Capital investments to ensure that the system is maintained to provide safe, reliable service.

Section 7 of the STSR provides a discussion of the risks to the transmission system that may impact system reliability and that are driving Sustaining Capital investments and/or maintenance programs. These consist of natural risks, such as the risk of seismic events on transmission lines, substations, and microwave sites; the impact of river erosion, avalanches, snow creep, mudslides and ice storms on transmission towers; and lightning strikes and forest fires. Section 7 also discusses other risks to the transmission system such as operational and maintenance risk, security risk, oil spills and fire.

In Section 8, the STSR concludes with a discussion of system performance measures. BCTC measures service interruptions from planned and unplanned outages. The current performance measurements for the system are reported for System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Delivery Point Unreliability Index (DPUI). In addition, intertie congestion is measured and reported. Commission Order G-91-05 directed BCTC to also report on equipment reliability in order to identify on the worst performing asset classes. Section 8.4 provides outage indices relating to transmission lines, transmission cables, transformers, and circuit breakers with comparisons to CEA averages.

4.0 CAPITAL PLANNING PROCESS OVERVIEW

4.1 Introduction

PRE-FILED EVIDENCE OF GINETTE HANDFIELD, MANAGER, CORPORATE CAPITAL PLANNING PROCESS

This section describes the process used to plan the projects and programs identified in the F2009 Capital Plan under the Growth, Sustaining and BCTC portfolios. A detailed description of the process is provided in Section 4.2.

Section 4.3 presents the framework that has been developed and implemented to conduct risk assessments. The Capital Planning process relies on risk assessments for two main purposes: first, to assess asset and corporate risks that might trigger the need for projects or programs; and second, to evaluate the risk associated with specific projects and programs, or portfolios.

The planning process includes the prioritization of projects and programs as a method of optimizing the portfolios and allocating resources. BCTC's prioritization methodology is presented in Section 4.4.

Engagement with stakeholders and First Nations forms an integral part of the Capital Planning process. Section 4.5 describes the engagement activities that take place throughout the Capital Planning process.

While the planning process used for the three portfolios is common, the objectives of each portfolio are quite different, as are the inputs to the process. Sections 4.6 to 4.8 describe these objectives as well as some of the specific planning inputs for the Growth, Sustaining and BCTC portfolios, respectively.

4.2 Process Description

PRE-FILED EVIDENCE OF GINETTE HANDFIELD, MANAGER, CORPORATE CAPITAL PLANNING PROCESS

Capital Planning is an annual process which identifies individual projects and programs, and then creates prioritized portfolios. The process culminates in the preparation of the annual Capital Plan, which is submitted to the Commission for approval. The process is timed to attempt to ensure timely internal and external approvals so that projects and programs can be executed as planned.

All projects and programs are planned using accepted project management principles. Under these principles, projects and programs are developed in defined phases with management reviews before continuing on to the next phase. Each project or program goes through three phases:

(a) Planning (includes Needs Identification and Study Work);

(b) Definition; and

(c) Implementation.

The same process is used for projects and programs in all three portfolios. These phases are described further in Sections 4.2.1 through 4.2.4.

Once a year, the projects and programs in the Planning and Definition Phases are brought together into the Growth, Sustaining and BCTC portfolios. The portfolios include projects and programs for the following ten years. Investments for approval within the first two years of the portfolios are prioritized within each portfolio using a common methodology. The prioritized projects and complete portfolios are then reviewed and approved by Management, prior to inclusion in the Capital Plan, to ensure that they are appropriate and are aligned with BCTC's Corporate Goals. Stakeholder and First Nation engagement activities occur throughout the Capital Planning process.

4.2.1 Planning Phase – Needs Identification

Regular asset, transmission system and organizational performance reviews are undertaken to identify equipment, areas of the system, and business processes that do not perform adequately, or do not meet standards or legal and regulatory requirements. These reviews may also identify opportunities to improve system or business efficiencies. Electric system load forecasts and customer requests (including those from IPPs) are also reviewed to assess the need to reinforce the system.

Managers screen the identified needs or opportunities to ensure that limited resources are properly directed to subsequent study work, and approve funding from operating budgets to proceed with the study work.

4.2.2 Planning Phase – Study Work

The Study Work first examines the need in detail, and then establishes criteria for identifying and assessing alternatives. Once criteria are established, alternative solutions to address the need or opportunity are identified and examined. These alternatives include initiatives to address the need immediately as well as initiatives to address the need on a temporary basis. The risk of deferral is also considered. Further stakeholder and First Nations issues and interests are also identified during this phase, particularly if any alternatives require new property or a significant change in land use. Alternatives are assessed for their ability to address the established criteria as well as for their feasibility and cost. Those alternatives that do not meet the established criteria may be removed from consideration at this point. Remaining alternatives are also assessed for their impact on factors which may be unrelated to the need or opportunity. These factors include safety, environment, reliability, market efficiency, relationships, and financial considerations. Estimates are developed to a level of accuracy sufficient for the selection of the preferred alternative. The Study Work also examines the consequences of deferring a project.

Study Work results in the identification of a preferred alternative, with sometimes a subset of options which need to be further addressed.[1] Study Work also results in a preliminary estimate(s) and a plan for Definition work. The preliminary estimate(s) may range in accuracy from +100% / -50% or ± 30% depending on the complexity of

[1] For a project whose preferred alternative is to build a new transmission line, options could be different line routings

the project and what level of detail BCTC can define the scope of the project ahead of the Definition work. Managers review the Study Work results, and authorize capital funds to proceed with the Definition Phase work. Approval to proceed with Definition Phase work may be sought from the Commission for larger non-routine projects, or for projects that are expected to require CPCNs. Other projects in the Definition Phase (i.e., smaller, generally routine non-CPCN projects), or ready for the Definition Phase, are included in the Capital Plan to seek public interest approval from the Commission for the entire project. The request to seek public interest approval at this stage excludes IPP projects. The treatment of IPP projects is discussed in Section 5.5.5.

In certain circumstances, the difference in timing between the annual Capital Planning process and the planning activities for an identified need is such that BCTC needs to request an approval ahead of completing the Study Work. For example, in this Capital Plan, BCTC is applying for approval of the Golden 69 kV Reinforcement – Definition Phase before it has established a preferred alternative in order to meet the in-service date (see Section 5.5.2.1.1). In such case, BCTC will only proceed with the Definition Phase once the Study Phase is completed, regardless of the timing of the request for approval.

In certain other circumstances, timing differences between forecast and potential future needs are such that BCTC needs to do Definition Phase work in anticipation of the need becoming firmly established in order to meet in-service dates. Accordingly, BCTC may seek Definition Phase funding for certain larger projects in advance of a firm need where it considers this to be prudent. There are no examples of this in this Capital Plan.

4.2.3 Definition Phase

Definition Phase work includes the analysis of all remaining options leading to the finalization of the project scope. The analysis includes benefits quantification, value assessment, and identification of deferral and implementation risks.

Once the scope of the project is established, a detailed Project Plan with a schedule for implementing the project, and a cost estimate is prepared. The accuracy of cost estimates at this stage will range in value from ± 50% to ± 10% depending on the complexity and stage of definition work completion. For many projects, a ± 10 % accuracy level can only be achieved after detailed engineering work is completed and bid prices are known, which do not occur until the project Implementation Phase.

In this phase, stakeholder and First Nations issues and interests will be addressed, as will any regulatory (e.g., CPCN) or other agency licensing, permitting or approval requirements. The scope and schedule included in the Project Plan identifies appropriate levels of stakeholder and First Nations consultation for the Implementation Phase.

It is also in this phase that BCTC, after performing an appropriate analysis, will consider Public-Private Partnership (P3) opportunities for large scale projects.

All required internal and external project approvals are obtained before the project proceeds to the implementation phase, excluding some minor licensing or permitting requirements (e.g., a building permit).

In this plan, BCTC has noted the level of cost estimate accuracy and stage of development associated with each of the capital projects for which BCTC is seeking approval.

4.2.4 Implementation Phase

This phase covers the implementation of the work to build the asset. The work includes all of the required project management, engineering, procurement, and construction work described in the Project Plan.

Projects are continuously monitored against their Project Plans, including cost, progress (schedule), and quality of work. Risk factors are also continuously monitored, and mitigation plans are implemented as needed. Whenever cost is forecast to exceed the internally approved amount by 10%, or a significant schedule slippage[2] occurs, a variance review is conducted and internal approval is sought.

The options that are considered when variances occur include changes to the scope as well as changes to the schedule. The identified options are assessed for their

[2] Reviews are initiated for slippage of key project milestones, or for changes to a project in-service date that has been agreed to in writing with a customer. Key project milestones are identified in the Project Plan and typically identify the required completion date of critical path items.

impact on the need or opportunity (including timing) that the project is addressing. The option of extending the schedule of a project will be preferred over increasing cost if the impact is acceptable.

BCTC may choose to seek further approval for a project from the Commission before continuing with the project if BCTC considers that there is a material change in scope, timing or cost compared to the information provided to the Commission at the time the project was approved.

The project concludes upon acceptance of the new asset for use and completion of the Project Plan. The final step of the Project Plan consists of the preparation of a project completion report, which includes a final variance review and a discussion of lessons learned. The completion report addresses any issue that may have contributed to a cost and/or schedule variation including project management, contracting, external factors and project risks.

4.3 Risk Assessment Framework

PRE-FILED EVIDENCE OF AJAY KUMAR, MANAGER, BUSINESS IMPROVEMENT

Since F2005, BCTC has used an Enterprise Risk Management (ERM) framework to identify, assess, mitigate, and monitor risks. BCTC's risk management practices are designed to provide reasonable assurance that its Corporate Goals and business objectives will be met. BCTC's ERM efforts are overseen by a Risk Management Committee composed of five members of the Executive Leadership Team that reports to the Audit Committee of the Board of Directors.

BCTC's ERM framework is comprised of four distinct phases that are used to manage risks at both the corporate level and the project level:

(a) Risk Identification - This phase involves the identification of potential risks related to the achievement of Corporate Goals or project objectives. Risks can be identified either in a group environment through facilitated workshops or by individuals.

(b) Risk Assessment - In the risk assessment phase, the likelihood and impact of the identified risks are assessed using risk matrices. Three risk matrices have been developed to reflect the tolerances of the corporation based on BCTC's six corporate goals. The three risk matrices apply to corporate, project deferral, and project implementation risks. The matrices provide a common set of defined criteria for assessing the likelihood and impact associated with individual risks. Both the likelihood and impact of risks is evaluated on a scale of 1 to 5. Details on the risk matrices are provided below:

   i. Corporate Risk Matrix: This matrix is used to manage BCTC's corporate risks. An assessment of corporate risks using this matrix can potentially result in the launch of new capital and OMA projects for mitigating key corporate risks.

   ii. Project Deferral Risk Matrix: This matrix is used for prioritizing the portfolio of projects included in BCTC's capital plan. The investment prioritization tool described in Section 4.4 provides further details on how the project deferral risk matrix is used in the prioritization of the Capital Plan.

iii. Project Lifecycle Risk Matrix: This risk matrix is used for managing the risks throughout the lifecycle of a specific project. This risk matrix is being finalized and has not been fully implemented within BCTC.

Copies of the three risk matrices are attached in Appendix D.

(c) Mitigation - Once risks have been assessed, the risks that are determined to be unacceptable require mitigation. The objective of this phase is to ensure that residual risks (risks after mitigation) are within tolerable limits.

(d) Monitoring - Monitoring is an essential activity in the management of risks. Even though risks may be mitigated, the tolerance for the risk may change or the status of the risk itself may change over time.

4.4 Prioritization

PRE-FILED EVIDENCE OF GINETTE HANDFIELD, MANAGER, CORPORATE CAPITAL PLANNING PROCESS

A significant development in BCTC's Capital Planning process in F2007 was the implementation of a formal methodology for project prioritization in each portfolio. The prioritization methodology is used to assist BCTC's senior management in making project selection and deferral decisions for portfolio planning.

All proposed projects are evaluated using this methodology. The results are reviewed and discussed and become an input into the portfolio decision-making process. The methodology does not relieve BCTC of its decision-making responsibility, but aids management in identifying the critical and valuable projects that should be undertaken in order to ensure the success of BCTC, as well as those projects which may be candidates for complete or partial deferral in a resource or outage constrained environment.

The methodology was used for the second time for the preparation of the F2009 Capital Plan. Using the experience gained from the F2008 Capital Plan, BCTC made a number of adjustments to improve the effectiveness of the methodology. Adjustments were also made in response to Commission Directives. Finally, adjustments have been made to reflect changes in the business environment. The prioritization methodology is expected to continue to evolve over time as BCTC gains more experience with project prioritization and as the business environment changes. A summary of the methodology is provided in Section 4.4.1 and a description of the adjustments made for the F2009 Capital Plan is provided in Section 4.4.2. A more detailed description of the methodology is provided in the Prioritization Model Users' Manual in Appendix J.

4.4.1 Prioritization Methodology Overview

BCTC uses the prioritization methodology to evaluate proposed projects within each of the Growth, Sustaining and BCTC portfolios. The prioritization methodology considers two attributes of each project:

(a) Value: the value achieved by implementing the project; and

(b) Deferral Risk: the risk associated with deferring the project for one year.

For each attribute, a numeric figure, or score, is calculated by assessing each project against nineteen criteria in six categories:

(a) Financial

(b) Reliability

(c) Market Efficiency

(d) Asset Condition

(e) Relationships

(f) Environment and Safety

Once value and deferral risk scores are calculated for all proposed investments, a review is undertaken to ensure investments are scored consistently within each portfolio. The value and deferral risk scores are then compared within each portfolio to identify lower deferral risk and lower value projects, which become candidates for deferral if required by resource and outage scheduling constraints. Prioritization results for each of the three portfolios are provided in Sections 5.4, 6.4, and 7.4.

The Deferral Risk and Value attributes are defined in the following sections.

4.4.1.1 Deferral Risk Attribute

Deferral risk is the risk associated with the project being deferred one year. For each of the criteria, the consequence and probability components of the most likely risk scenario (the consequence with the highest probability) are computed on a scale of 0 to 5 using the Deferral Risk Matrix, shown in the Prioritization Model Users' Manual in Appendix J. Once these components have been determined, the risk score for each criterion is calculated by multiplying the consequence and the probability. This results in a deferral risk score between 0 and 25 for each criterion. The deferral risk of each category is then the highest risk score of the criteria within that category. Similarly, the highest risk score of the six categories becomes the deferral risk of the project.

4.4.1.2 Value Attribute

The value of a project is measured by evaluating the benefits associated with implementing the project. Within each of the six categories, the individual criteria are weighted to arrive at a score for that category. The weightings have been chosen through consensus judgment by BCTC managers and BCTC transmission experts. The overall value attribute or score is then computed as a weighted average of the scores across the categories, again with impacts ranging from 0 to 5 using the Value Matrix, shown in Appendix J. The determination of the weights for each individual category is arrived at through discussions with senior BCTC staff using a methodology called Analytical Hierarchy Process (AHP). AHP is based on a series of pair-wise comparisons to develop group consensus on relative weighting across various elements. The methodology is further discussed in Appendix J. The weightings applied to the categories to compute the value score are:

Table 4-1. Value Score Category Weightings

	Category	Weighting
1	(a) Financial	21%
2	(b) Reliability	25%
3	(c) Market Efficiency	22%
4	(d) Asset Condition	17%
5	(e) Relationships	8%
6	(f) Environment and Safety	8%

A low weighting was determined for Environment and Safety, but this does not mean this is a low priority category. BCTC's rigorous environmental and safety standards ensure that projects driven by safety and environment will score high in terms of deferral risk. Furthermore, projects that are undertaken to meet codes and regulations are considered mandatory.

The nineteen criteria in the six categories are set out in the following subsections.

4.4.1.3 Financial Criteria

(a) Net present value: discounted cash flow;

(b) Benefit to cost ratio: net present value of hard savings and revenue compared to net present value of all costs;

(c) Rate impact of each investment; and

(d) Savings related to time savings, efficiency, or effectiveness.

4.4.1.4 Reliability Criteria

(a) Transmission System Average Interruption Duration Index (TSAIDI): the average outage duration across all delivery points over a one-year period;

(b) Distribution Customer Hours: the number of end-use customers experiencing an outage combined with the duration of that outage;

(c) Transmission Reliability Index (TRI): a function of the weighted duration and number of failures over a five-year period, the mean time between failures over a five-year period, and the duration since the last failure; and

(d) EENS (Expected Energy Not Served): the amount of energy not served based on the frequency of planned and unplanned outages, the duration of these outages, and the load curtailment.

4.4.1.5 Market Efficiency Criteria

(a) Real Line Losses Reduction: the estimated reduction in transmission line energy losses due to the investment;

(b) Congestion Reduction: the estimated reduction in annual congestion due to the project;

(c) Trade Benefits: the investment’s expected impact on trade; and

(d) Transmission Expansion Opportunity: the benefits to ratepayers of the investment related to BCTC's Transmission Expansion Policy.

4.4.1.6 Asset Condition Criteria

(a) Equipment Spares Support: the level of support provided by the Original Equipment Manufacturer (OEM) and the availability of spares before and after the proposed investment;

(b) Asset Health: based on the pre- and post-investment assessment of the assets that will be impacted by the proposed investment. Asset Health scoring comprises the following areas: Remaining Life, Failure Rates, Asset Condition and Criticality (assessed by scoring Load, Role, Redundancy and Voltage for Stations, Circuit Criticality for Lines, and System Criticality for BCTC Assets); and

(c) Failure Rate (Beta): the change in the time between failures rate.

4.4.1.7 Relationships Criteria

(a) The Community/Public relations criterion measures the impact of the investment on relationships with the Community and the general public, focusing on BCTC's relationships with Industrial, Commercial and Residential Customers; IPPs and Wholesale Transmission Customers; Municipal Governments; Provincial Governments; and the general public.

(b) Similar to the Community/Public relations criterion, the First Nations criterion measures the impact of the investment on relationships with First Nations, specifically on First Nations satisfaction and BCTC's relationship with First Nations.

4.4.1.8 Environment and Safety Criteria

The Environment and Safety criteria assess the construction, operation and decommissioning impacts of the investment on Greenhouse Gas Emissions, Air Quality, Waste, Land, Water, Species at Risk and Environmental Management Systems, as well as Employee, Workforce and Public Safety. Projects which are initiated to meet Federal, Provincial, or Municipal environmental or safety requirements are considered to be mandatory, but are still scored.

4.4.2 Methodology Adjustments for the F2009 Capital Plan

4.4.2.1 Revised Category Weightings

Each year, changes in BCTC's business environment can impact the criteria and categories that are used to calculate each project's value score. Consequently, BCTC reviews each category and criteria to assess their ongoing relevance to project evaluation and identifies any new categories or criteria that need to be added. The review also includes an analysis of the category and criteria weightings used to calculate the value score. The AHP is used to revise category and criteria weightings.

For the F2009 capital planning cycle, changes were made to the category weightings as follows:

Table 4-2. Revised Category Weights for F2009

	Category	F2008 Capital Plan Weighting	F2009 Capital Plan Weighting
1	Financial	30.6%	21%
2	Reliability	21.5%	24%
3	Market Efficiency	13.7%	22%
4	Asset Condition	20.0%	17%
5	Relationships	5.3%	8%
6	Environment and Safety	8.8%	8%

Changes to the category weightings for the F2009 capital planning cycle were driven mainly by the direction set in the new Energy Plan. The Market Efficiency category weighting increased substantially as a result of the new Energy Plan's focus on congestion and line loss reduction.

Also, while the overall combined weighting of the Reliability and Asset Condition categories remained almost the same for F2009, the focus shifted slightly to the Reliability category to reflect the increased urgency of projects addressing assets that are impacting system reliability.

As a result of the shift in focus away from the Financial category, the weighting assigned to the Financial category was reduced.

4.4.2.2 Changes to the Market Efficiency Category

Following each capital planning cycle, BCTC reviews the prioritization methodology to identify areas for improvement. From the F2008 cycle, it was determined that the impact groupings used to evaluate projects in terms of Market Efficiency were not appropriate for the projects in BCTC's Growth portfolio; many of the Growth projects were being rated a '5' for Market Efficiency because the range was too low. To address this issue, the impact groups were revised upward from $416 K to $10 million at the high end.

Similarly, the range of impact groupings for Expected Energy Not Served (EENS) criterion in the Reliability category was found to be much too great; most Growth projects were scoring a ‘0’ for this criterion. Consequently, the range of impact groupings was reduced from 8,333 MWh to 2,000 MWh at the high end.

Both of these changes have improved the effectiveness of the framework for the F2009 capital planning cycle as they have resulted in a better distribution of deferral risk scores, allowing projects to be more easily distinguished from each other, thereby aiding the portfolio planning process.

In its Decision on the F2008 Capital Plan, the Commission directed BCTC to include Transmission Expansion Policy (TEP) projects in the prioritization methodology:

> “The Commission Panel directs BCTC to prioritize potential TEP projects with other projects using the Prioritization Model.”[3]

To accommodate potential TEP projects in the prioritization methodology, an additional criterion was added to the Market Efficiency category for value scoring. The new criterion is ‘Transmission Expansion Opportunities’ and is measured by assessing the benefits to ratepayers.

The addition of the Transmission Expansion Opportunities criterion necessitated a review and revision of the weightings applied to the Market Efficiency criteria for value scoring. Using the AHP to evaluate the weightings applied to the Market Efficiency criteria resulted in the following weightings:

Table 4-3. Revised Market Efficiency Criteria Weights for F2009

	Criteria	F2008 Capital Plan Weighting	F2009 Capital Plan Weighting
1	Real Line Losses Reduction	33%	39%
2	Congestion Reduction	53%	20%
3	Trade Benefits	14%	14%
4	Transmission Expansion Opportunities	N/A	27%

4.4.2.3 Changes to the Financial Category

In the Commission’s F2008 Capital Plan decision the Commission also stated:

[3] F2008 Capital Plan Decision, Directive 21, page 53.

> "In the 2006 IEP/LTAP Decision, the Commission provided certain directions regarding project evaluations that are expected to be relevant to BCTC's analysis of transmission projects because such projects are owned and financed by BC Hydro (2006 IEP/LTAP Decision, Directives 25, 26 and 27)."[4]

In the Commission's 2006 BC Hydro IEP/LTAP Decision, Directive 26 states:

> "BC Hydro borrows at rates that reflect the Provincial Government's credit rating and current nominal interest rate on 20 to 30-year debt for BC Hydro, and thus its ratepayers, is approximately 4.60 percent per annum. The Commission Panel concludes this is the appropriate discount rate for BC Hydro to use to evaluate resource options under the current assumption of 100 percent debt financing."[5]

As a result of this Directive, BCTC has updated the discount rate it uses in its prioritization methodology to 4.60% nominal (or 2.50% real after adjusting for inflation at 2.10%) and modified the project financing assumption to 100% debt. Both of these rates are used only for BC Hydro assets (i.e., the Growth and Sustaining capital portfolios).

Additional changes to the Financial value section were made to reflect BCTC's changing business environment and improve the effectiveness of the methodology, such as:

(a) Modifications to allow for Contributions in Aid of Construction to be considered when calculating value and deferral risk scores; and

(b) Adjustments to give flexibility for year-to-year modifications of financial assumptions, such as finance charges, interest on construction and overhead rates.

4.4.2.4 Changes to the Asset Condition Category

The prioritization methodology was adapted to allow for the BCTC Capital portfolio to evaluate their projects in terms of Asset Condition. This change is reflected in the

[4] F2008 Capital Plan Decision, page 99.
[5] 2006 BC Hydro IEP/LTAP Decision, Directive 26, pages 202 and 203

F2009 version of the Project Deferral Risk Matrix, which now shows a general 'Asset Criticality' criterion instead of the Stations and Lines Criticality criteria that were shown in the F2008 version.

4.5 Stakeholder and First Nations Engagement

PRE-FILED EVIDENCE OF DONNA MCGEACHIE, MANAGER, COMMUNITY & STAKEHOLDER RELATIONS AND
CLAIRE MARSHALL, MANAGER, ABORIGINAL RELATIONS

Each year, BCTC participates in a large number of public engagement events, workshops and presentations with a wide range of stakeholders and First Nations. As BCTC is still a young organization, many of the engagement activities continue to focus on sharing information about BCTC and its planning processes, and identifying key areas of interest or concern. Activities range from basic information sharing and relationship building to specific project and regulatory consultations.

4.5.1 Public Planning Activities

BCTC continues to refine its public planning process. The public planning process is designed to involve stakeholders and First Nations in planning for the long-term development of the transmission system. This process helps to ensure that the transmission system continues to meet provincial and customer needs by:

(a) Building understanding with stakeholders and First Nations on the transmission planning process and future system requirements;

(b) Identifying and considering stakeholder and First Nations views and values concerning transmission planning; and

(c) Understanding community issues around new transmission investments so that issues can be identified and addressed early in the investment planning process.

To meet these objectives, BCTC engages stakeholders and First Nations through multi-level public planning activities that include:

(a) A Transmission Planning Advisory Committee;

(b) An annual Provincial Planning Forum (and Technical Workshop);

(c) Regional and Stakeholder meetings;

(d) First Nations engagement; and

(e) Investment specific consultations.

In 2007, BCTC made several improvements to its public planning process. These improvements included providing more opportunities for engagement earlier in the investment planning process, improving regional representation, and expanding efforts to engage a broader audience. Regional Planning meetings were added in areas of emerging transmission constraints to provide an opportunity for dialogue and input earlier in the investment planning process. In addition, three new members joined TPAC, increasing representation from the interior of the province.

Since 2005, BCTC's main public planning activities have attracted a disproportionate number of industry stakeholders while project consultations have tended to be dominated by impacted residents. In 2007, BCTC made a focused effort to involve a broader audience by increased advertising, expanded mail-outs and expanded outreach. Between November 2006 and November 2007, BCTC participated in over 75 engagement activities. Highlights of the year are described in the following sections.

4.5.1.1 Transmission Planning Advisory Committee

In 2007, TPAC continued to focus on the need for long-term transmission system adequacy and had regular discussions about BCTC's Capital Plan and major investments such as the Interior to Lower Mainland Transmission Project and the Central Vancouver Island Transmission Project. In-depth discussion topics included Energy Plan Implementation, Mandatory Reliability Standards and Congestion Relief.

4.5.1.2 Public Engagement

4.5.1.2.1 Regional Planning Sessions

Over fifty people attended two regional planning sessions in Victoria and Nanaimo in February 2007. The purpose of these meetings was to provide information and facilitate discussion around the current state of the transmission system on Vancouver Island as well as emerging issues or concerns. Participants represented a wide range of stakeholders including local government, business, industry, academia, non-governmental organizations, and the general public. At the sessions, there was strong interest in green energy and conservation as well as ensuring ongoing transmission reliability and integrating green power from the Northern region of the Island. Participants also spoke very positively about the use of the power flow model to demonstrate the existing use of the transmission system and to highlight areas of emerging constraints. In addition to the broad public meetings, BCTC made a similar presentation to interested local government representatives when they gathered for the Vancouver Island and Coastal Communities Municipal Conference in April.

4.5.1.2.2 2007 Public Information Session

Over twenty people attended a Public Information Session held in Vancouver in June. Participants represented a variety of interests including government, independent power producers, environmental groups and the general public. There was strong interest in BCTC's capital planning process and a desire to ensure that it was robust enough to provide a long-term outlook and flexible enough to respond to future changes such as the integration of new technologies. Similar to other sessions, a desire for more joint BC Hydro-BCTC Planning Sessions and the need for additional information about EMF also arose.

4.5.1.2.3 2007 Technical Planning Forum

Over fifty participants attended BCTC's Second Technical Planning Forum in June 2007. Topics included the transmission implications of the new BC Energy Plan, the status of current intertie studies, BCTC's Transmission Expansion Policy as well as planning for bulk and regional transmission systems reinforcements. Discussion also included the need for more regional or zonal planning (integration of IPP interconnection and load requirements in area studies), importance of transmission adequacy and long-term planning, and the role of transmission as an enabler (of dispatch flexibility, trade, development of clean and renewable energy, etc). At a technical level, many participants expressed an interest in working with BCTC on transmission planning issues. Linkages between generation, transmission and distribution planning were recognized with several participants indicating a desire for more integrated planning discussions.

4.5.1.2.4 Transmission Expansion Policy

In 2007, BCTC also conducted consultation on its Transmission Expansion Policy (TEP) implementation. In the late spring and over the summer BCTC met with a number of stakeholders, including the Transmission Planning Advisory Committee, to discuss TEP implementation including the process for identification and methodology for evaluation of potential projects.

The TEP was also a focus of BCTC's Technical Planning Forum in June 2007. At this session, BCTC presented its TEP implementation plan and also invited customers and other interested parties to submit Expressions of Interest for project ideas or concepts for potential advancement under the TEP.

In response, BCTC received a considerable number of submissions, the majority of which highlighted opportunities for transmission expansion to provide access to clusters with high potential of IPP projects.

In October 2007, BCTC held the first open TEP workshop to review the submissions and discuss the future process. The workshop was attended by approximately 50 individuals, representing BCTC, BC Hydro, IPPs, market participants, and other stakeholders. At the workshop, BCTC provided an overview of the TEP submissions, and facilitated stakeholder discussion on the next process steps, including establishing a Technical Advisory Committee to review the assessment of TEP project concepts. In the coming months, BCTC will analyze the TEP submissions in conjunction with the Technical Advisory Committee and, where appropriate, will make recommendations to further pursue TEP project concepts.

BCTC filed the 5L51 and 5L52 Thermal Upgrade Project application with the Commission on 12 December 2007. This project is proposed to be the first project under BCTC’s Transmission Expansion Policy under Special Direction 9. This is discussed in Section 5.5.1.2.1 of this Capital Plan.

4.5.1.2.5 Public Awareness Campaign

In 2007, BCTC’s Public Awareness Campaign was expanded to include newspaper advertising and development of a micro-website.[6] The “It’s Time” theme of this

[6] The micro-website is reached by going to www.bctc.com and then clicking on the “It’s Time” feature.

campaign focused on increasing awareness about the need to invest in new transmission infrastructure to meet the increasing electricity requirements of a growing province.

4.5.1.3 Project Consultation

At a project level, public meetings and other consultation activities help ensure that BCTC understands and is responsive to local needs and concerns about major transmission projects impacting communities, and that future development is constructed in a responsible and cost-effective manner.

In 2007, BCTC conducted a number of specific project consultation programs, including:

4.5.1.3.1 Interior to Lower Mainland (ILM) Transmission Project

Six community Open Houses were held during February and March 2007 to provide information about and get input on options to reinforce the capacity of the ILM system. In June, five additional Open Houses were held to provide information on the preferred option and to get input on the draft Terms of Reference (TOR) for the environmental review process by the BC Environmental Assessment Office (BCEAO). The BCEAO also established a 30 day public comment period for the draft TOR. In addition to the activities above, BCTC has held over 44 meetings with local and regional stakeholders and made numerous presentations regarding the ILM project. BCTC distributes Project Updates at key milestones to almost 12,000 stakeholders including all levels of government, the general public, property owners and other interested parties. BCTC filed an application for a CPCN with the Commission in November 2007.

4.5.1.3.2 Central Vancouver Island (CVI) Transmission Project

Following the regional planning meetings held on Vancouver Island in February, consultation on the CVI Project began in April 2007 with a mail-out to a wide range of stakeholders including property owners and local government representatives. In May, an Open House was held to get input on a variety of route options and a number of meetings were held with local government representatives. BCTC is continuing to consult with local property owners and other stakeholders. A decision on a preferred routing option was made in the fall and will be communicated to property owners and stakeholders in January 2008.

4.5.1.3.3 Southern Interior Series Compensation (SISC) Project

To meet the growing demand for electricity in the Southern Interior and ensure a continued reliable power supply, BCTC is considering building two 500 kV series capacitor stations – one in the Edgewood area near Needles and one at Trout Creek near Summerland in the Okanagan. An information package has been mailed to all landowners within a 2 km radius of these sites, to all residents and businesses in the area, and to other interested stakeholders including local government. The information package also included an invitation to participate in a field trip to each of the sites to learn more about the project. BCTC will continue to consult with local residents in preparation for the potential filing of a CPCN application with the Commission.

Additional consultation on these and other projects will continue through 2008.

4.5.1.4 Stakeholder Survey

In 2007, overall impressions of BCTC improved with government and stakeholders and remained stable among commercial customers. The percentage of stakeholders with a neutral, somewhat positive or very positive impression of BCTC remained at 91%.

While awareness of BCTC among the general public remained low at 18% there has been a significant increase of awareness among municipal government officials which has increased to 88%. Key areas of importance continue to include:

(a) ensuring adequate transmission infrastructure is in place to support economic growth;

(b) completing project studies in a timely and cost effective fashion; and

(c) providing opportunities for early and open consultation.

4.5.1.5 First Nations Engagement

In 2007, BCTC and BC Hydro continued to engage First Nations regarding the transmission system and BCTC's Capital Plan. For BCTC's F2006 Capital Plan, engagement was conducted jointly with BC Hydro's Integrated Electricity Plan (IEP). This year, because BC Hydro did not file an IEP, BCTC and BC Hydro decided to focus engagement efforts in areas where significant changes or additions had been made to the previous year's Capital Plan (e.g., Vancouver Island and the South Interior).

Two regional planning meetings were held with First Nations on Vancouver Island and one in the South Interior earlier this year. At these meetings, BCTC and BC Hydro received positive feedback from several participants for providing an opportunity for dialogue earlier in the investment planning process. Several participants commented on the need to provide the information more broadly to their community members and the need to keep the information easy to understand and relevant to First Nations' interests. Participants also felt that a 10-year planning horizon was too short and that longer term planning was necessary. Through the recent regional planning meetings and other information sharing meetings, First Nations have commented that there is a need for greater First Nation involvement at BCTC's strategic planning and policy level.

BC Hydro led a number of First Nations consultations in 2007. BCTC participated in these consultation processes. Major projects currently being consulted on include:

4.5.1.5.1 ILM Project

Discussions with First Nations on the ILM project were initiated in the summer of 2006; early in the planning process and before a preferred alternative was identified. Over the last year, four separate rounds of consultation have been completed to discuss topics including project introduction, capacity funding, the regulatory and environmental processes, and First Nations participation in studies such as the Heritage Overview Assessment and Traditional Land Use Studies. Consultation is on-going.

4.5.1.5.2 CVI Project

Consultation began with First Nations in April 2007 regarding possible routes for new 230 kV transmission lines. Interests are primarily on the exercise of rights to fish and hunt, environmental and archaeological impacts, and possible impacts on use of Crown lands for treaty settlement purposes. An excellent dialogue has occurred between the project team and the First Nations. An environmental review by the EAO is not anticipated.

4.5.1.5.3 SISC Project

Discussions with First Nations have been initiated regarding the potential Southern Interior Series Capacitor Station to be located near Edgewood. Similar discussions are also underway with First Nations regarding the second Series Capacitor site near Summerland. A preliminary site visit did not identify any particular archaeological interests at either location. Consultations with the interested First Nations are ongoing.

4.5.1.6 First Nations Survey

In 2007, BCTC conducted a provincial survey to gauge awareness and perception of BCTC amongst First Nations leaders. The results indicated that a greater level of communication is required between BCTC and First Nations governments and communities in order to increase mutual understanding between the parties. First Nations leaders indicated a strong desire to receive more information from BCTC on transmission planning, vegetation and pest management, transmission line maintenance, and contract and procurement information. BCTC will continue to meet with First Nations groups around the province to share information about its activities, to clarify its roles and responsibilities as a transmission provider, and to enhance its relationship with First Nations.

4.5.2 Other Consultation Activities

In addition to its public planning process, BCTC conducts a number of additional consultation activities including:

(a) Independent Power Producer meetings

In June 2007, BCTC and BC Hydro co-hosted a wind integration discussion forum to increase understanding of wind integration issues and learn from other jurisdictions. BCTC subsequently met with the IPPBC Transmission Committee in October and announced several initiatives related to wind integration including planned revisions to its wind power generator interconnection requirements and plans to conduct wind planning studies to identify the potential for wind generation to integrate into various regions of the system. BCTC also held a technical conference in November 2007 to review and discuss wind generator interconnection requirements with stakeholders.

(b) Tariff Consultation

BCTC consults with stakeholders on tariff initiatives and applications. In 2007, the key focus was Short Term Rate designs introduced in the BCTC Rate Design Report filed with the Commission in December 2006, pricing of Loss Compensation, and other tariff amendments. A number of presentations, meetings and workshops were held to obtain stakeholder input on these issues.

4.5.3 Incorporating Stakeholder and First Nations Feedback

A number of key themes emerged during BCTC's stakeholder and First Nations dialogue in 2007 that BCTC is actively working to incorporate into its planning and processes. These include:

(a) Long-term, integrated planning: The need for BCTC to take a longer-term, integrated approach to planning has been a key message from stakeholders since the Public Planning process was initiated. It is also identified as a high priority in the new BC Energy Plan. In response, BCTC has committed to developing a long-term system outlook for the transmission system and has made organizational changes within its Planning Division to provide increased focus on longer-term planning initiatives. A Congestion Relief Policy is also being developed by the provincial government to help ensure that adequate transmission infrastructure is in place to meet provincial energy objectives and customer needs. From a First Nations perspective, BCTC will continue to work with BC Hydro to ensure First Nations receive effective, timely information on transmission planning activities.

(b) Open and transparent consultation for projects early in the planning process: In 2007, BCTC initiated an advertising campaign (It's Time) in an effort to raise public awareness about transmission planning and the need for new transmission investment. In addition, BCTC has held regional planning meetings in areas where emerging transmissions have been identified. At a project level, BCTC reached out to a broader audience through expanded advertising and mail-outs. In addition, to ensure that ratepayer interests were included in project consultations, additional meetings were held with the Joint Industry Electric Steering Committee, the Commercial Energy Consumers and the British Columbia Old Age Pensioners.

(c) Continued focus on costs and reliability: Cost and reliability continue to be important considerations for the majority of BCTC's customers and stakeholders as learned through consultation processes and in BCTC's annual stakeholder survey. These priorities are reflected in the financial and reliability criteria used to evaluate alternatives during the study phase of a project, and to assist with the prioritization of projects through the use of BCTC's investment prioritization tool. The implementation of Mandatory Reliability Standards in BC, consistent with the Energy Plan direction, will continue to keep a high priority on reliability and make the process more transparent.

(d) Electric and Magnetic Fields (EMF): Interest in the topic of EMF has been increasing with new project development. The need for BCTC to provide additional up-to-date and accurate information on the topic was identified during numerous consultation events. BCTC is committed to openly communicating accurate and balanced information on EMF. BCTC has established an EMF Working Group that monitors scientific research and policy developments on an on-going basis, it participates in the Canadian Electricity Association's EMF Task Force, and it has been directed to report any material developments in the field of EMF to the Commission on a regular basis. Most recently, BCTC filed an EMF Update Report with the Commission as part of its ILM CPCN application.

BCTC is also updating EMF communication materials to ensure the public has the information necessary to understand the facts about EMF.

(e) Aboriginal Business Development: After discussion with Aboriginal groups, BCTC developed the Aboriginal Business Development program to increase contracting and employment opportunities for Aboriginal people and businesses. The program includes providing information about the types of contracting and procurement opportunities available, and also maintaining a directory of Aboriginal businesses that can potentially meet BCTC's contracting needs. BCTC also utilizes a number of contracting and procurement strategies to facilitate Aboriginal business development.

4.6 Growth Portfolio

PRE-FILED EVIDENCE OF DON GILLESPIE, MANAGER, TRANSMISSION SYSTEM PLANNING

4.6.1 Objectives

Growth Portfolio projects reinforce the transmission system to meet the capacity and energy transfer demands for firm domestic load, generation dispatch, and firm Point-to-Point deliveries. Investments typically upgrade or add station equipment and transmission lines.

The objectives of the Growth Capital portfolio are:

(a) Serving Firm Domestic Load – Projects should meet the capacity requirements of the customers for most hours of the year and under the most common contingencies. Limited service interruptions are acceptable for less common outages if restoration of service can be accomplished within a reasonable period of time. Uncontrolled interruptions over wide areas are not acceptable and their risk must be minimized.

(b) Enabling Economic Generation Dispatch – Projects should support the efficient dispatch of generation to provide customers access to low cost capacity and energy. This prevents operating inefficiencies, higher energy costs and lower reliability.

(c) Enabling Firm Point-to-Point Power Transfers – Projects should facilitate this activity by increasing transmission access, reliability and security. Non-firm power transfer capabilities of the system are usually enhanced when the firm power transfer capability of the system is increased, although system reinforcement is not required for non-firm transmission service.

(d) Affordability – Projects should provide benefits commensurate to their cost. Projects may have to be deferred in some cases if their cost is prohibitive relative to the benefit.

(e) System Performance – The system with its new reinforcements must have a minimum level of system performance to be acceptable to the stakeholders.

Stakeholders expect that the electric system will be reliable with few if any localized blackouts, reasonable frequency and duration of outages, fast restoration of service, high power quality (e.g., few harmonics, and voltages within the standard limits), and seismically secure. To ensure adequate performance, BCTC adheres to a set of Planning Standards that have been proven through over 40 years of experience. The Planning Standards referenced in this document include both BCTC's Planning Standards and the NERC/WECC Planning Standards and are summarized in Appendix C.

(f) Community and First Nations Impact – Projects should minimize physical impact on communities and First Nations to the extent that it is economically feasible.

(g) Environmental Compliance – Projects are designed and selected to meet applicable environmental legislation and common utility practices. In selecting a preferred alternative from a number of alternatives that meet these requirements, BCTC selects alternatives that have the least environmental impact relative to the other alternatives, where economically feasible.

4.6.2 Key Drivers

In general, Growth projects are customer and volume driven. BCTC determines the transmission investments required to meet peak demand, OATT requests, and generation additions identified and forecast by BCTC's customers. Projects range from minor facility enhancements to major transmission line projects and can be required at three levels:

(a) Bulk transmission system facilities that are used to transfer bulk amounts of capacity and energy between large generating stations and the major load centres. The bulk system includes the 500 kV system, parts of the 230 kV system, the transmission connections to Vancouver Island, and interconnections to other utilities;

(b) Regional transmission system facilities within specific geographic areas. These facilities are closer to the loads and are generally 230 kV and below; and

(c) Substations or points of connection for loads or generators.

Bulk system reinforcements to meet increasing demand and maintain compliance with NERC/WECC Planning Standards are triggered by growth in the coincident BC Hydro service area system peak demand load forecast. This includes the BC Hydro domestic peak load plus firm exports to FortisBC, New Westminster, Alberta, and the US. The system-wide peak is known as the coincident system peak demand.

Regional, or area, system transmission requirements are determined using the coincident regional peak demand forecast; while local area or substation reinforcement requirements are determined using non-coincident station peak demand forecasts.

The impacts of the forecast load growth on system performance are evaluated against the Planning Standards. This evaluation is complemented with probabilistic analysis to validate the reinforcement needs when necessary.

4.6.2.1 Service Agreements

Under the terms of the OATT, BCTC is obliged to meet the needs of customers that request service. This includes NITS customers using the system to meet loads in multiple locations from multiple sources, Point-to-Point customers transferring energy from and to specific points on the network, and Generator Interconnection customers seeking to inject energy into the network at specific locations (e.g., a new generation source).

To determine the impacts of the proposed use on system performance, BCTC conducts planning studies to determine if the proposed change in use results in any violations of the BCTC and NERC/WECC Planning Standards, potentially resulting in system damage or sustained interruptions of service. Based on these studies, BCTC identifies the system reinforcements that are required to accommodate these requests.

BC Hydro is presently the only NITS customer on the transmission system and is the predominant user. BC Hydro is experiencing significant load growth throughout the province and has identified growth of between 25 and 45 percent over the next twenty years. Earlier this year, the Commission accepted BC Hydro’s resource plans (e.g., IEP/LTAP) to meet its domestic loads and firm exports (Commission Order G-29-07).

As a part of its resource plan, BC Hydro will continue to acquire electric energy from IPPs through its Call for Tender process and by entering into Energy Purchase Agreements with IPPs.

The increasing load demand and BC Hydro's resource plans will require system-wide transmission reinforcements. These requirements are identified in a NITS study process and implemented through a NITS service agreement. In addition, individual IPP interconnections may trigger some local extension of the system to accommodate energy flow into the system. Customer requests for long-term Point-to-Point transmission services are also tracked and considered in BCTC's review of the capability of the system to meet customer needs. All of these services together can create a need to reinforce the system at both the regional and the bulk levels. The need is identified by power flow and stability studies of the system which take into account the forecast load on the system as well as these three types of service requests. Growth projects are planned when the aggregated service requirements exceed the capability of the system, and implemented when BCTC obtains service request commitments in accordance with BCTC's OATT.

4.6.2.2 Demand and Resource Forecasts

The transmission system capacity requirements are dictated primarily by MW transfer forecasts. These are provided by BC Hydro in the form of a system load forecast which includes peak demand load on the system as well as generating resource nominations to meet that load.

The continuing growth of BC Hydro's loads, requests for service from other customers, and interconnections of new resources, including IPPs, requires continuing expansion of the transmission system. The addition or modification of substation equipment or upgrading of existing circuits is often sufficient to meet these needs. However, new bulk transmission circuits may be required to:

(a) Incorporate new generating stations into the transmission grid; or

(b) Increase the capacity of the grid if line or station upgrading cannot carry the added transfers.

BCTC currently uses a number of inputs to forecast future requirements for transmission services:

(a) BC Hydro’s Long-Term Acquisition Plan (currently, 2006 Amended Long-Term Acquisition Plan (the Amended LTAP));

(b) Information updates provided by BC Hydro as part of its NITS 10-year service agreement application. BC Hydro NITS requirements include BC Hydro’s retail loads and generation resources as well as:

   i. Service to the City of New Westminster;

   ii. Service to Point Roberts (US);

   iii. Service to FortisBC as required under its Power Purchase Agreement with BC Hydro;

   iv. Transmission service between BC Hydro and the systems of FortisBC, Teck Cominco and Columbia Power Corporation, as specified by the Canal Plant Agreement between these parties; and

   v. IPPs with whom BC Hydro has contracted to purchase the output, and designated by BC Hydro as Network Resources to supply BC Hydro’s loads.

The BC Hydro NITS Service Agreement includes the following information:

   i. Coincident peak-day probable load forecasts for the integrated system are used for the bulk system studies;

   ii. Regional coincident peak-day probable load forecasts are used for the regional transmission system studies; and

   iii. Non-coincident substation peak-day probable load forecasts are used for the substation studies.

(c) Identification of transmission service requirements by other customers such as:

i. Transmission capacity specified by FortisBC's resources in the East Kootenays to its loads in other service areas, such as the Okanagan. This transmission service is provided under the General Wheeling Agreement with FortisBC, a grandfathered transmission services agreement which existed prior to the establishment of the OATT;

ii. Long Term Firm Point-to-Point Transmission Service contracts with OATT customers; and

iii. Requests by generator owners to interconnect new generators, or to accommodate changes to existing generators.

4.6.2.3 Current Planning Assumptions

A detailed description of the planning assumptions used in the IEP portfolio evaluation, in the LTAP analysis, and possibly in the future analysis of BC Hydro's next NITS application was filed with the Commission in the 2006 BC Hydro IEP/LTAP Proceeding as Exhibit B-102 and attached as Appendix K. The major planning assumptions in the Growth portfolio in the F2009 Capital Plan build on the assumptions used in the LTAP analysis while work is underway between BC Hydro and BCTC to refine some of the assumptions to be used in the next NITS application.

The major planning assumptions applied in the F2009 Growth portfolio are outlined as follows:

4.6.2.3.1 Load Forecast

The Growth Capital portfolio is based on BC Hydro's December 2006 Load Forecast for the bulk system and the July 2007 Distribution Substation Load Forecast for the Regional system.

4.6.2.3.2 Resource Plan

The resource plans provide the general location and size of generation facilities or supply sources and assumptions regarding the generation capacity and dispatch patterns.

This Capital Plan also considers information from the Amended LTAP, CRP1 and CRP2, as described in Exhibit B146A filed with the Commission in February 2007 as part of the 2006 LTAP/IEP proceeding. The F2009 Capital Plan also considers the information in the Base Resource plans with and without Burrard generation submitted by BC Hydro to BCTC in August 2007.

4.6.2.3.3 Committed Use (CU)

The data for determining the CU on a particular cut-plane is obtained from the IEP/LTAP resource plans and load forecast nominated by BC Hydro though its NITS applications and information updates. BCTC adds to this requirement any Point to Point obligations from other users of the system. BCTC applies the following assumptions to determine the benchmark CU for each cut-plane. The benchmark CU is considered to be a firm service requirement under the OATT to meet the loads. The determination of the benchmark CU for intermittent resources likely in the Peace region is still under consideration.

(a) South Interior Region

The CU on the South Interior cut-planes is determined by using the Maximum Continuous Rating (MCR) of the region's generation in the Spring Freshet and the Dependable Generation Capacity (DGC) in the winter less the season's light load. The Spring Freshet CU is the largest transfer and this determines the CU. A range of CUs are shown in Section 5.5.1.1.1 Ashton Creek Substation Shunt Capacitors.

(b) North Interior Region

The CU on the North Interior cut-planes is determined by using the DGC for the heritage resources and the Equivalent Load Carrying Capacity (ELCC)[7] for the intermittent resources in the winter less the local load during the winter light load period. The CU approximates the historic maximum observed flows on the system.

[7] ELCC is a way to measure a power plant's capacity contribution based on its impact on system reliability

BC Hydro suggested nominating MCR for the North Interior resources including intermittent resources until a study is done jointly with BCTC to see if MCR should be dispatched instead of DGC. This study has not reached a conclusion and BCTC has used the resource dispatch that most closely matches the usage of the system.

(c) ILM Network

The CU on the ILM grid is determined by using the peak winter load and either the total DGC from the South Interior or the total DGC from the North Interior System, and subtracting the DGC in the Coastal Region. This CU approximates the maximum observed flows on the ILM system during the winter peak season and during the late summer/early fall heavy export period.

BC Hydro suggested nominating MCR for the South Interior and North Interior resources including intermittent resources until a study is done with BCTC to see if MCR should be dispatched instead of DGC. This study has not reached a conclusion and BCTC has used the resource dispatch that most closely matches the usage of the system.

(d) Use of Burrard Generation Plant and CE

This assumes the full Burrard plant capacity or Columbia River Treaty Downstream Benefit Entitlements (also called Canadian Entitlement, or CE) is dispatchable until 2013 to the extent necessary until the ILM grid is reinforced. According to Special Direction 10 of 25 June 2007, self-sufficiency should be achieved solely from clean and renewable generation facilities located within the province by 2016. This could imply that the CE cannot be relied upon by BC Hydro for planning its generation resources. BCTC expects that this issue will likely be addressed in BC Hydro’s next LTAP proceeding.

4.6.2.3.4 Transmission Thermal Rating

The Transmission Thermal Rating to be used for planning purposes is the continuous rating (for winter and summer) to provide firm service. The 1-hour rating can be used if resources are available for re-dispatch after an outage. The 1-hour rating assumption is used for planning the ILM system until 2013 because Burrard and other Coastal resources can be re-dispatched after an outage to serve the load.

4.6.2.3.5 Use of Deterministic and Probabilistic Analysis

Two types of analysis are carried out by planners in the planning process – deterministic and probabilistic studies.

Deterministic analysis considers whether the system is secure, that is, whether the system is able to withstand sudden disturbances and achieve acceptable system performance such as no loss of load, equipment damage, or cascading. BCTC applies the NERC/WECC Planning Standards for deterministic adequacy and security of the system in the planning horizon.

Deterministic analysis is the traditional kind of analysis and it is based on industry standards developed through years of experience. Deterministic standards are used to meet the primary objective of planning which is to keep the bulk electric system secure, thus avoiding cascading and blackouts. The transmission system is also operated using similar deterministic techniques, that is, to be able to withstand the next single and double contingency and still meet acceptable performance.

Probabilistic analysis is used to quantify the relative reliability improvements of options that meet the deterministic criteria. BCTC studies consider the likelihood of equipment outages and system loading to quantify a probabilistic Expected Energy Not Served (EENS).

Deterministic criteria provide planners with industry recognized benchmarks for assessing system adequacy and security. Probabilistic analysis provides additional supporting information with respect to system adequacy based on a premise that the system must always be operated to meet the security requirements if the deterministic criteria.

The application of probabilistic analysis is now being applied at BCTC as a means of assessing planning problems. This analysis allows the comparison of the value of the various reinforcement alternatives, particularly in parts of the system where security is not the primary concern. More BCTC staff are learning probabilistic techniques, and improvements are being made in the data and programs used. An understanding of the results is beginning to develop and is being incorporated in the planning processes. The two types of analyses complement one another, resulting in a deeper understanding of the performance of the system.

4.6.2.4 Special Direction No. 9

With Special Direction No. 9, the Commission has the power to allow BCTC to undertake projects that consider the anticipated demand for electricity and electricity service beyond those required by its Service Agreements.

In January 2006, the Commission responding favourably to BCTC's Transmission Expansion Policy Paper, which represents BCTC's interpretation of Special Direction No. 9, noting that it regarded BCTC's policy as a dynamic document which the Commission expected would evolve over time as updates to the 2002 Provincial Energy Plan and other events occurred.

BCTC has identified and is seeking approval from the Commission in a separate application for a Transmission Expansion Project pursuant to Special Direction No. 9 (see Section 5.5.1.2.1 regarding the 5L51 and 5L52 Thermal Upgrade).

4.6.3 Planning Studies

Within the overall Growth Capital Planning process, the following specialized planning studies are conducted.

4.6.3.1 Need Phase

Ongoing studies of the transmission system are carried out to determine the Total Transfer Capability of the system, the Committed Use, and the Available Transfer Capability for a variety of load growth, resource addition, and wholesale transfer scenarios. The purpose of these studies is to test the system under various assumptions, load forecasts and resource plans to determine if it meets the required level of performance without the addition of reinforcements.

Determining the transfer capability for a given area requires identifying the largest transfer the system can provide while still meeting the BCTC and NERC/WECC Planning Standards. Under normal system conditions, this means that:

(a) All equipment must be operating within ratings, and system voltages must be in their normal operating range; and

(b) The system must be able to withstand the defined contingencies (according to the BCTC and NERC/WECC Planning Standards) during peak power transfers without operator action or loss of firm load, and still remain within emergency ratings and voltages. Loss of generation under defined contingencies may be acceptable when justified.

In addition, the system must be maintainable such that facilities can be taken out of service for maintenance and the BCTC and NERC/WECC Planning Standards will still be met.

The system is tested under stressed conditions such as worst-case generation patterns and load levels during normal and first contingency conditions. This is the step that identifies a need to resolve future congestion on the system.

4.6.3.2 Options Phase

Once a need is identified, BCTC conducts technical and economic studies to identify and evaluate various alternatives in order to select the preferred option. These studies include evaluating thermal constraints, voltage stability limits and transient stability limits, as well as reliability improvements of the system associated with different reinforcement options by using power system simulation tools.

The economic evaluation of the alternatives is supported by the following studies:

(a) Line losses will be studied if the impact of the various alternatives on line losses varies materially;

(b) When one alternative creates more capacity than the others, a capacity credit is applied to this alternative to reflect the value of this residual capacity; and

(c) Sensitivity studies are often conducted to examine a wide range of values for the most significant variables, such as the electricity cost in valuing power losses, the discount rate, and the residual capacity credit due to the lack of predictability of future economic conditions.

Each alternative is also assessed for its flexibility to adapt to uncertain load growth and resource plans.

4.6.3.3 Definition Phase

In the Definition Phase, technical planning studies are done to refine the details of the preferred alternative. For larger projects, two alternatives are often considered, especially if more detailed engineering design and cost information is required to determine the best choice. A technical description and performance specification outlining the requirements of the project is detailed in a System Application document or scope notes for small projects. These documents are used as to complete the preliminary engineering design, project plan and estimate, and CPCN application if required.

4.6.3.4 Implementation Phase

In the Implementation Phase, detailed engineering studies and designs are conducted for constructing the proposed project. Certain additional planning studies are performed during this stage to ensure proper integration of the new equipment into the system. Examples of these studies include:

(a) Setting Studies – These studies are done to provide information for setting relays, excitation systems, power system stabilizers, minimum excitation limiters (MEL), line drop compensators, series capacitors, and HVDC systems. This information can be provided subsequent to the selection of equipment and is provided to the project team for implementation on the newly installed equipment; and

(b) Operating Studies – Prior to the commissioning and operation of the new equipment, the system operators must be given information about the new equipment and its impact on the system. This information is normally provided through the annual operating guide or updates to Local or System Operating Orders. For projects that have significant impact on operating limits, a System Operating Guide for that specific project will be produced and, in many cases, training (including simulation training) for control room staff will be conducted.

4.7 Sustaining Capital Portfolio

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

The Sustaining Capital Portfolio addresses transmission infrastructure capital equipment replacements, refurbishment, and enhancements necessary to meet safety, reliability, environmental and regulatory standards. The Sustaining Capital Portfolio is focused on the efficient and cost-effective management of existing transmission infrastructure assets.

4.7.1 Objectives

The Sustaining Capital Portfolio supports the BCTC Corporate Objectives by addressing:

(a) Safety – Ensuring the transmission system does not negatively impact the safety of employees, contractors, and the public. BCTC is acutely aware of the inherent hazards of operating a transmission system, and places a very high priority on ensuring public safety. As a result, those programs that are designed to improve safety, or remedy a situation that could escalate into a serious safety hazard are considered to be a priority. Examples include: upgrade substation perimeter fencing to prevent access by the public; modify fire suppression systems within substations to ensure the safety of employees and contractors; substation grounding grid upgrades to prevent high step and touch potentials; and installation of tower barriers and signage to prevent unsafe climbing of towers by the public.

(b) System Reliability – A reliable transmission system is a cornerstone of economic development and the continued high standard of living in BC. As such, BCTC attempts to maintain system reliability at designed levels or slightly better and places high priority on those projects that ensure a reliable system. Examples include: adding bonding to the insulators on transmission line poles which have a history of causing pole-top fires, initiating system faults, and sometimes initiating forest fires; replace pin-and-cap insulators to mitigate system faults caused by asset failure; mitigating interruptions to the power system by replacing failing circuit breakers in specific asset classes; and replacing failing transmission pole cross-arms.

(c) Financial (cost-effectiveness) – Undertaking Sustaining Capital expenditures in a cost-effective manner leads to a lower rate impact to customers and is a very important consideration in the prioritization of Sustaining Capital projects. Projects for the replacement or refurbishment of major capital components of the transmission system are assessed using a total life-cycle cost approach, on a Net Present Value basis, which lowers system costs by evaluating the replacement costs vs. refurbishment costs considering the cost of continued maintenance in either case, over its useful life. Examples include: Chapman's Fibre Optic Replacement where replacement with a different technology is more cost-effective than maintaining the existing technology; and 500 KV air blast circuit breaker replacements where the cost of replacement is lower than the cost of major refurbishment and continuing maintenance/replacement of air compressor systems.

(d) Environment – BCTC is committed to minimizing the environmental impact of transmission infrastructure and complies with current and changing environmental standards. Therefore, projects are proposed that mitigate environmental risks or are designed to comply with changing environmental standards. Examples include: reducing equipment oil leaks by installing oil-filled equipment spill containment systems and replacing circuit breakers that have non-maintainable and unacceptable Sulphur Hexafluoride gas leaks.

4.7.2 Key Drivers

The Key Drivers for the Sustaining Capital Portfolio are:

(a) Maintain System Reliability (Asset Health, Asset Performance);

(b) Manage Risks (Safety, Seismic, Environment, Fire/Explosions, Weather, Security, Relationships); and

(c) Address Third-Party Requested Projects.

4.7.2.1 Maintain System Reliability (Asset Health, Asset Performance)

4.7.2.1.1 Asset Health

Asset health is an assessment of the physical condition of the equipment. Asset health is a leading indicator of asset performance and reliability. Poor asset health leads to lower asset reliability, and to lower system reliability if the asset impacts the system.

A function of asset health is obsolescence which can also make maintenance of equipment not feasible. Obsolescence occurs when there is no longer original equipment manufacturer support, third party support, lack of replacement parts and shortage of technical expertise, which may make repairs very expensive or impossible. When equipment is replaced, serviceable spare parts are salvaged in order to extend the life of the remaining population.

The health of transmission system assets is determined through a study of maintenance records, inspection data, test results, and awareness of industry practices. Asset health is evaluated on a regular basis and is affected by the physical environment, age, and operating and maintenance history.

In F2006, BCTC developed its Sustainment Investment Model, which takes into account the type of asset, the asset age, the number of assets in the system, the theoretical mean life, and the historical replacement frequency and costs, to determine a base-level annual capital expenditure required to sustain the system. The model is useful in predicting long-term replacement or refurbishment capital expenditures related to the Sustainment of the transmission system at its design level of reliability. The Sustainment model does not take into consideration those Sustaining Capital expenditures that are required to mitigate risks, such as the Cathedral Square Fire Suppression risk project, or the Murrin Seismic risk project. The Sustaining Investment model also does not consider those assets that enhance the transmission system to a level of reliability that is greater than its original design, such as Arcing Horn installations, or Bonding Wire installations. The key findings of the study are:

(a) The transmission infrastructure investment bubble from the 1960s and 1970s will have a lasting impact on lifecycle investments. An increasing amount of assets built during this period are reaching end-of-life condition and require replacement; and

(b) In 2006 dollars, the average annual capital expenditure required to replace assets that are at end-of life is estimated to be $87 million, the midpoint of the range of between $72 million and $102 million. In F2009 dollars, based on actual and forecast inflation as described in the MMK Report included in Appendix E of the Capital Plan, the mean value would increase to approximately $103 million, based on a range of between $85 million and $123 million. Over the past several years, the Sustaining Capital Portfolio capital expenditures have been in the lower end of the range of the model target. The expenditure investment range is based on a moving 10-year average. The model predicts that Sustaining Capital investments need to increase to keep up with obsolescence and end-of-life asset condition over time. Much of the existing infrastructure is now more than 40 years old, and is at or exceeds end-of-life condition, but has remained in service due to continued maintenance or refurbishment, allowing the deferral of replacement of those assets. However, for many long-lived assets, continued maintenance may no longer be appropriate due to obsolescence, making parts or service knowledge no longer available, or new technology providing for better and cheaper solutions.

Therefore, the appropriate annual capital expenditure level now must increase to reflect the previous deferral of Sustaining Capital activities as BCTC has managed the system to maximize its investment in assets from previous decades. BCTC is predicting that annual capital expenditures on Sustaining Capital activities will need to continue to grow (Table 6-2) as it manages through a period of high replacement requirements due to end-of-life conditions, obsolescence, changing risk conditions and tolerances.

4.7.2.1.2 Asset Performance

Asset performance is the ability of any asset, whether it is in a healthy or a degrading condition, to function as designed when required to ensure system reliability. Transmission system assets are constantly evaluated by reviewing operating history and performance. If an asset fails to meet operational requirements, this results in the need to repair, replace or redesign the asset or system. Examples include: adding bonding to the insulators on transmission line poles which have a history of initiating system faults due to pole-top fires and Burrard Circuit Breaker Replacement which targets replacement of units that have demonstrated unpredictable performance (i.e., when called to operate, may not respond or may operate outside of design parameters).

The Sustaining Capital program is designed to address both asset health and asset performance issues on a prioritized basis.

4.7.2.2 Manage Risk (Safety, Seismic, Environment, Fire/Explosions, Weather, Security, Relationships)

In addition to system reliability, there are a number of other risks that need to be managed. In some cases these may directly impact system reliability, in other cases they may not. These risks are described in detail in Section 7 of the STSR.

The risk environment is continually evolving, and with it, acceptable risk tolerance levels within the broader public community. Together these changes are driving the need for increased capital expenditures. The following categories and examples describe specific risks that must be addressed in a timely manner, and are related to safety, environmental, seismic, weather and flood, security and fire:

(a) Safety – Unacceptable life-safety risks related to CO_2 Fire Suppression System at Cathedral Square substation;

(b) Seismic – Recently, BCTC initiated changes to risk tolerance for seismic events and standards from a 1 in 475 year event to a 1 in 2475 year event, requiring seismic improvements to transmission infrastructure. BCTC initiated this change for future projects because there was very little incremental difference in cost in upgrading to the 1 in 2475 event;

(c) Environment – Emerging regulations (e.g., regulations to control Sulphur Hexafluoride gas emissions from older SF6 circuit breakers);

(d) Weather – Recent severe weather conditions (e.g., wind storms, ice loading, and flooding) have highlighted system weaknesses in the face of rare weather occurrences, and require infrastructure enhancements; and

(e) Security – Increasing material thefts, vandalism, and unauthorized access to substations are increasing the need for capital expenditures to reduce financial loss, reduce inadvertent outages and maintain public and employee safety.

Each risk is evaluated based on business impact and probability of occurrence to determine the appropriate duration and magnitude of investment that is required to mitigate the risk to acceptable levels. Many risks that have been identified in the past have not been addressed because of financial constraints. This results in a continued backlog of unresolved risk issues that require attention and are being addressed in part by this plan.

4.7.2.3 Address Third-Party Requested Projects

Third-party requested projects are those projects for which BCTC enters into an agreement with a third-party to respond to their request for modification or enhancement to the transmission system infrastructure. Third party requested projects are normally funded in whole or in part by the third-party.

4.7.3 Program Development

The Sustaining Capital Portfolio is developed through the process described in Section 4.2. The following sections provide a discussion of the specific inputs and activities used for the development of the Sustaining Capital Portfolio.

4.7.3.1 Needs Identification

Needs are identified by assessing asset condition, performance, operational effectiveness, risks, and third-party requests. As discussed above, asset health is periodically assessed, the results of which establish replacement or refurbishment priorities. Asset performance is witnessed through observations by BCTC Real-time Operations, System Planning and Performance Assessment, and Asset Management, enabling BCTC to target specific problem areas within the system. Risks and the changing risk environment are continually monitored and mitigation strategies are developed to minimize impacts on the transmission system.

4.7.3.2 Assess the Needs from Strategic Perspective and Identify Opportunities

Once needs are identified, a strategic assessment is conducted to identify opportunities. The assessment considers the need from multiple views:

(a) Asset view – replace a specific asset like-for-like;

(b) Asset-class view – replace all assets within an asset class (e.g., an asset class that has an identified fatal common-mode failure);

(c) Integrated asset view – replace/remove a group of related substation or line assets (e.g., replace disconnects, current transformers, and circuit breakers with a single integrated Gas Insulated Switchgear (GIS) unit); and

(d) Regional/System view – close consultation with the system planners addressing system growth issues to ensure alignment of transmission planning strategy to asset management strategy, and avoid the potential for stranded investments (e.g., assets would not be replaced in a station that is soon to be retired).

4.7.3.3 Identify and Assess Solution Alternatives

Alternative solutions are identified and evaluated using the following decision support framework:

(a) Invest no further in the asset - e.g., run to failure and replace (Capital);

(b) Continue routine maintenance (OMA);

(c) Adjust routine maintenance (OMA);

(d) Repair (OMA);

(e) Refurbish/rebuild (OMA or Capital – depending on cost, impact to life, and capacity);

(f) Replace (Capital); and

(g) Redesign (Capital).

In some cases, the recommended alternative may be a combination of solutions. For example, equipment lacking available spares may result in a program that combines the rebuild/refurbish and replace alternatives. The assets in the poorest condition would be replaced, while serviceable spare parts from the removed assets would be used as spares to extend the expected life of the remaining asset population.

Each solution alternative is evaluated using a cost/benefit analysis. In evaluating alternatives, a quantitative and qualitative approach is used. The quantitative analysis may include one or more of the following analysis methods: Net Present Value (costs); WEIBULL failure analysis; root-cause analysis; and analysis of mean time between failures. Qualitative analysis includes benchmarking, asset intelligence collected from relationships with other utilities and industry organizations (e.g., identification of asset class defects), industry practices, and lessons learned from others.

4.7.3.4 Prioritize Investments

Once all needs and preferred alternatives have been identified, the prioritization method described in Section 4.4 is followed.

Expert judgment is then applied to the results to finalize the Sustaining Capital Portfolio plan. The expert judgment considers factors not addressed by the optimization process tool, such as limited resources by the service providers and equipment suppliers, minimum levels of activity to sustain engineering expertise without additional cost, volume and duration of investments to ensure stable expenditures and long duration programs that still addresses risk but minimize rate impact. Not all investments that are prioritized are included in a specific year's Capital Plan, and some are deferred to future years. An example of this is the Horsey Gas Insulated Switchgear replacement where the project is high risk and high value, however the deferral allows BCTC to properly consider options and execution strategies to allow for lowest cost, most effective capital replace/refurbishment solutions.

4.8 BCTC Capital Portfolio

PRE-FILED EVIDENCE OF EBRAHIM VAAHEDI, CHIEF TECHNOLOGY OFFICER

4.8.1 Objectives

The BCTC Capital portfolio addresses all capital assets owned by BCTC and consists of three major asset groups:

(a) Information Technology;

(b) Control Centre Technologies; and

(c) Facilities.

The objectives for Information Technology are to:

(a) Sustain existing business systems;

(b) Implement business improvements and facilitate efficient and effective business processes as justified with the Commission;

(c) Implement innovative technology developments and introduce new technologies to business as justified with the Commission; and

(d) Mitigate risks.

The objectives for Control Centre Technologies are to:

(a) Implement the System Control Modernization Project (SCMP);

(b) Maintain control centre technology and infrastructure; and

(c) Implement efficient and effective business improvements.

The objectives for Facilities are to:

(a) Implement business requirements regarding office space, furniture, fixtures, and equipment as justified with the Commission; and

(b) Implement business improvements and facilitate efficiency improvements as justified with the Commission.

4.8.2 4.8.2 Key Drivers

The key drivers for the BCTC Capital Portfolio are:

(a) Increase efficiency;

(b) Cost avoidance;

(c) Improve decision support;

(d) Sustain system reliability;

(e) Sustain asset health;

(f) Improve stakeholder relationships; and

(g) Compliance.

4.8.2.1 Opportunities to Increase Efficiency

Investment in Technology and Facilities Assets can improve efficiency of BCTC's staff and contractors. By improving personnel efficiency, BCTC can redirect resources to other activities.

4.8.2.2 Direct Cost Avoidance

Investment in Technology can assist BCTC to substantially reduce the cost of performing certain activities and avoid the need to hire additional staff and contractors. This driver also addresses efficiency and mitigates financial risks.

4.8.2.3 Improve Decision Support

Technology can assist BCTC to make better business decisions, by making the right data available in the right format to the right person at the right time. Better business decisions bring efficiency and support reductions in both cost and risk.

4.8.2.4 Sustain System Reliability

Technology is used in the control centres to maintain control and operation of the real time system. Maintaining the technology in these systems supports the ability of the control room operator to prepare before system disturbances occur and to respond to minimize outages in an effective manner. This driver addresses System Risk.

4.8.2.5 Sustain Asset Health

BCTC assets experience a decline in health over time. Health is defined in two dimensions:

(a) Functional health; and

(b) Technical health.

Functional health is the degree to which the asset meets the needs of its business. As business needs changes over time, the functional health declines.

Technical health relates to the asset condition as compared to a baseline, such as a new version of the asset. The decline in technical health and performance is caused by wear and tear resulting from usage and environmental exposure, from system growth, and from obsolescence (e.g., withdrawal of vendor support for older technologies).

Assets must be renewed, replaced and upgraded to maintain their functional and technical health.

4.8.2.6 Improve Stakeholder Relationships

Technology can be used to facilitate communication and interfacing with key BCTC stakeholders, making the appropriate information available in a fair and transparent manner to stakeholders when and where they need it. This driver addresses Stakeholder risks.

4.8.2.7 Compliance

Compliance continues to be a prominent driver for the BCTC Capital portfolio. There are currently three sources of requirements that drive compliance:

(a) Regulatory requirements, whereby BCTC is obliged to comply with regulatory orders and decisions, including tariff changes;

(b) BCTC’s own security and business continuity requirements that are aligned with industry’s best practices; and

(c) Legislative requirements, whereby BCTC is obliged to comply with federal or provincial legislation. This year, BCTC does not have any project within this category.

5.0 GROWTH CAPITAL PORTFOLIO

PREFILED EVIDENCE OF DON GILLESPIE, MANAGER, TRANSMISSION SYSTEM PLANNING

BCTC's Growth Capital Portfolio is comprised of those investments required to extend and reinforce the system to meet growth in load, to transfer power from new generation resources, and to accommodate transmission customer and generation interconnection requests.

For planning and management purposes, the Growth Capital portfolio is divided into five programs:

(a) Bulk System Reinforcements;

(b) Area Reinforcements;

(c) Station Expansion and Modification Projects;

(d) Customer-Requested Projects; and

(e) Generation Interconnections.

5.1 Growth Capital Portfolio Table

Table 5-1 divides the Growth Capital portfolio into these five programs. For each program, the table also indicates whether the projects are in progress, for approval, or for future consideration.

Table 5-1. Growth Capital Portfolio

	Growth Capital Portfolio	Page	SDA %	IS Date	Project Total ($'000)	Prior Years ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Bulk System Reinforcements															
	Projects in Progress															
1	500/230 kV Selkirk Transformer T4 Addition			Mar 2010	23,887	200	4,211	19,378	98							
2	Ashton Creek - 2X250 MVAr - 500kV Switchable Shunt Capacitor - Definition Phase			Oct 2010	253	253										
3	ILM - Interior to Lower Mainland Reinforcement - Definition Phase			Oct 2014	31,815	18,554	13,261									
4	RAS - Provision for Unidentified Additions - F2008-F2009			Mar 2009	875	35	840									
5	RAS - Vancouver Island			Oct 2008	3,665	2,745	920									
6	Selkirk - 500 kV 123 MVAr Shunt Reactor			Mar 2009	6,134	560	5,574									
7	South Interior Series Compensation (SISC) Project - Definition Phase			Oct 2011	1,600	1,498	102									
8	Vancouver Island Reinforcement Project (VITR)			Oct 2008	287,261	122,105	164,916	240								
9	**Sub-total**				**355,490**	**145,950**	**189,824**	**19,618**	**98**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Projects for Approval															
10	Ashton Creek - 2X250 MVAr - 500kV Switchable Shunt Capacitor - Implementation Phase	128		Oct 2010	20,049		1,552	13,339	5,158							
11	RAS - Bridge River Generation Shedding Modifications	130		Oct 2008	2,300	700	1,600									
12	RAS - GMS Generation Shedding Modifications - Stage 2	132		Oct 2010	2,090		220	770	1,100							
13	RAS - Revelstoke G5 Generation Shedding Modifications	135		Oct 2010	1,677		112	1,062	503							
14	**Sub-total**				**26,116**	**700**	**3,484**	**15,171**	**6,761**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Future Projects															
15	5L51 & 5L52 Thermal Upgrade	136		Mar 2010	3,303	69	432	2,802								
16	5L76/5L79/5L96 Series Compensation Project	137		Oct 2017	60,000								2,000	2,000	14,000	42,000
17	ILM - Interior to Lower Mainland Reinforcement - Implementation Phase	137		Oct 2014	570,328		1,207	11,054	17,869	33,147	170,467	246,387	86,956	3,242		
18	Meridian 2X110 MVAr - 230 kV Switchable Shunt Capacitor	138		Oct 2011	5,304			58	898	4,348						
19	Nicola 1X250 MVAr - 500 kV Switchable Shunt Capacitor	138		Oct 2011	5,655			57	816	4,782						
20	Nicola 500 kV Station Reconfiguration - New Project	139		Oct 2013	10,000							10,000				
21	RAS - Provision for Unidentified Additions - Future	140			4,500			500	500	500	500	500	500	500	500	500
22	South Interior Series Compensation (SISC) Project - Implementation Phase	140		Oct 2011	52,968		1,571	8,529	21,434	21,434						
23	Undefined Upgrades for GMS X WSN X KLY System	140			95,000				20,000	15,000	15,000	15,000	15,000	15,000		
24	**Sub-total**				**807,058**	**69**	**3,210**	**23,000**	**61,517**	**79,211**	**185,967**	**271,887**	**104,456**	**20,742**	**14,500**	**42,500**
25	**TOTAL Bulk System Reinforcements**				**1,188,664**	**146,719**	**196,518**	**57,789**	**68,376**	**79,211**	**185,967**	**271,887**	**104,456**	**20,742**	**14,500**	**42,500**

Notes:
1. % SDA: Projects that contain both transmission and SDA components have been included in the Application. Cash flows in this table reflect both components. Application for approval of SDA portions is the responsibility of BC Hydro.
2. IS Date = In Service Date
3. IS Date shown for Definition Phase projects is actually the in service date for the complete project.
4. The total capital cost for projects split between definition and implementation phases is the sum of the two amounts.

Table 5-1. Growth Capital Portfolio (continued)

	Growth Capital Portfolio	Page	SDA %	IS Date	Project Total ($'000)	Prior Years ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Area Reinforcements															
	Projects in Progress															
26	Central Vancouver Island Project (CVI) - Definition Phase			Oct 2010	2,500	2,500										
27	Highland - 138/69 kV Transformer Replacement			Oct 2010	4,687	37		470	4,180							
28	Mission and Matsqui Area Supply		13	May 2009	56,900	38,406	17,389	1,105								
29	Retermination of Sidney 60 kV Supply to Keating			Oct 2009	30,249	2,186	8,625	19,438								
30	**Sub-total**				**94,336**	**43,129**	**26,014**	**21,013**	**4,180**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Projects for Approval															
31	Golden 69 kV System - 69 kV Reinforcement - Definition Phase	141		Oct 2012	3,000		3,000									
32	Woods Lake Area Reinforcement - Definition Phase	147	20	Oct 2010	500		500									
33	**Sub-total**				**3,500**	**0**	**3,500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Future Projects															
34	2L39 Como Lake Loop	152		Dec 2011	12,000			500	5,500	6,000						
35	Central Vancouver Island Project (CVI) - Implementation Phase	153		Oct 2010	81,775		9,455	30,875	41,445							
36	Colwood Area Reinforcement	153		Oct 2013	47,000			1,500	1,000	2,500	17,000	25,000				
37	Courtenay Area Reinforcement	154	70	Oct 2010	5,000			3,500	1,500							
38	Definition Funding for Future Projects	154	50		1,000		1,000									
39	East Fraser Valley Reinforcement	154		Oct 2010	20,000			10,000	10,000							
40	Fort St. James Var Support Addition	155		Oct 2009	5,500			5,500								
41	Golden 69 kV System - 69 kV Reinforcement - Implementation Phase	155		Oct 2012	75,000			5,000	10,000	30,000	30,000					
42	Horne Payne Substation Expansion	155	80	Oct 2012	15,000				5,000	5,000	5,000					
43	Long Beach Reinforcement - Transmission Line Upgrade	155		Oct 2014	42,000					1,400	12,600	14,000	14,000			
44	Long Beach System Reinforcement - Great Central Transformer	156		Oct 2012	4,900				700	700	3,500					
45	Metro Supply Reinforcement	156	80		87,000			2,000	5,000	10,000	10,000	10,000	15,000	15,000	10,000	10,000
46	Mission Area Reinforcement	156	85	Oct 2010	14,000			4,000	10,000							
47	Mount Pleasant Substation - Definition Phase	157	15	Oct 2011	5,000	1,500	3,500									
48	Mount Pleasant Substation - Implementation Phase	159	15	Oct 2011	145,000			15,000	65,000	65,000						
49	New Westminster Area Reinforcement	159	80	Oct 2010	15,000			7,000	8,000							
50	North Thompson Area Reinforcement	159		Oct 2013	78,000			1,000	2,000	15,000	30,000	30,000				
51	Westbank 138 kV System Reconfiguration	160		Oct 2013	33,800				1,600	6,200	13,000	13,000				
52	Woods Lake Area Reinforcement - Implementation Phase	160	20	Oct 2010	23,000		5,500	6,000	11,000							
53	**Sub-total**				**709,975**	**1,500**	**19,455**	**91,875**	**177,745**	**141,800**	**121,100**	**92,000**	**29,000**	**15,000**	**10,000**	**10,000**
54	**TOTAL Area Reinforcement**				**807,811**	**44,629**	**48,969**	**112,888**	**181,925**	**141,800**	**121,100**	**92,000**	**29,000**	**15,000**	**10,000**	**10,000**

Notes:

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Table 5-1. Growth Capital Portfolio (continued)

	Growth Capital Portfolio	Page	SDA %	IS Date	Project Total ($'000)	Prior Years ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Station Expansion & Modification															
	Projects in progress															
55	Cathedral Square - 230/12 kV Transformer		90	Mar 2009	13,649	580	11,719	1,350								
56	Chetwynd - T1 and T2 Transformer Replacements		96	Aug 2008	4,760	100	4,660									
57	Colwood - 138/25 kV Transformer Addition		85	Oct 2008	7,578	178	7,400									
58	Gavin Lake Transformer Upgrade and Network Upgrade		70	Oct 2008	2,765	2,196	569									
59	Golden - 69 kV Capacitor Bank Addition			Oct 2008	1,542	242	1,300									
60	Grief Point 12 kV Circuit Conversion		97	Oct 2008	3,105	255	2,850									
61	Hope - 25 kV Conversion		95	Apr 2008	3,398	2,498	900									
62	Kidd 1 - Substation Redevelopment		90	Jun 2010	22,200	200	2,000	8,000	12,000							
63	Oyster River - 132-25 kV Transformer Addition		90	Oct 2008	3,475	100	3,375									
64	Porteau Station Expansion		70	Oct 2008	2,500	50	2,450									
65	Sechelt Transformers Replacement (T1 and T2)		95	Oct 2008	5,201	221	4,980									
66	Seventy Mile House - 69/25 kV Transformer Addition		61	Jun 2009	2,692	242	1,895	556								
67	Shawnigan Lake Substation - Transformer Replacement		95	Aug 2008	5,572	322	5,250									
68	Walters Transformer Addition			Oct 2008	5,177	159	5,018									
69	Westbank - T1 Transformer Replacement		80	Jun 2008	2,750	100	2,650									
70	**Sub-total**				**86,364**	**7,442**	**57,016**	**9,906**	**12,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Projects for Approval															
71	Port Kells Substation - Shunt Capacitor Addition	161	85	Oct 2008	1,939	339	1,600									
72	Qualicum Substation - Reconfiguration	163	75	Oct 2008	1,637	165	1,472									
73	Sidney Substation Transformer Cooling Upgrades	167	80	Jul 2008	1,277	677	600									
74	Tumbler Ridge - Transformer Replacement	169	97	Aug 2009	8,219	93	2,428	5,698								
75	**Sub-total**				**13,072**	**1,274**	**6,100**	**5,698**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Future Projects															
76	Future Station Expansion Projects - Fraser Valley	172	75		36,000					8,000	8,000	8,000	3,000	3,000	3,000	3,000
77	Future Station Expansion Projects - Metro	172	75		40,000			4,000	4,000	4,000	4,000	4,000	5,000	5,000	5,000	5,000
78	Future Station Expansion Projects - North Central	172	75		12,000				1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
79	Future Station Expansion Projects - North East	172	75		18,000			2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
80	Future Station Expansion Projects - North Shore Coastal	172	75		53,000				10,000	10,000	8,000	5,000	5,000	5,000	5,000	5,000
81	Future Station Expansion Projects - North West	172	75		18,000			2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
82	Future Station Expansion Projects - South Interior	172	75		65,000					10,000	15,000	15,000	10,000	5,000	5,000	5,000
83	Future Station Expansion Projects - Vancouver Island	172	75		80,000					5,000	5,000	5,000	5,000	20,000	20,000	20,000
84	McLellan Capacity Increase - Future	173	80	Oct 2011	10,000			900	6,300	2,800						
85	North Vancouver Substation Upgrade	173	80	Oct 2010	16,000			6,000	10,000							
86	Richmond Area Reinforcement	173	80	Oct 2010	10,000			6,000	4,000							
87	**Sub-total**				**358,000**	**0**	**0**	**20,900**	**39,800**	**45,300**	**45,500**	**42,500**	**33,500**	**43,500**	**43,500**	**43,500**
88	**TOTAL Station Expansion & Modification**				**457,436**	**8,717**	**63,116**	**36,504**	**51,800**	**45,300**	**45,500**	**42,500**	**33,500**	**43,500**	**43,500**	**43,500**

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Table 5-1. Growth Capital Portfolio (continued)

	Growth Capital Portfolio	Page	SDA %	IS Date	Project Total ($'000)	Prior Years ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Customer Requested Projects															
	Projects for Approval															
1	Kinder Morgan Canada (KMC) TMX-1 Project - Upgrade	173		May 2008	8,831	8,084	747									
2	**TOTAL Customer Requested Projects**				**8,831**	**8,084**	**747**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Generation Interconnection Projects															
	Projects in Progress															
3	Ashlu IPP Construction Load and Interconnection			Mar 2008	4,026	4,012	14									
4	East Toba and Montrose Creek Hydroelectric Project			Jun 2010	39,632	2,606	17,578	18,653	795							
5	Forest Kerr IPP			Oct 2010	46,298	0	667	16,002	29,629							
6	Savona ERG IPP		71	Apr 2008	1,636	1,627	10									
7	Zeballos Lake Hydro IPP			Apr 2008	3,800	3,724	76									
8	**Sub-total**				**95,392**	**11,969**	**18,344**	**34,655**	**30,424**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Future Projects															
9	Future Distribution IPPs	178	75		70,000	5,000	5,000	5,000	10,000	10,000	10,000	5,000	5,000	5,000	5,000	5,000
10	Future Transmission IPPs	178			863,781	29,663	141,835	109,248	69,738	82,349	79,003	71,018	75,855	72,710	70,425	61,936
11	**Sub-total**				**933,781**	**34,663**	**146,835**	**114,248**	**79,738**	**92,349**	**89,003**	**76,018**	**80,855**	**77,710**	**75,425**	**66,936**
12	**TOTAL Generation Interconnection Projects**				**1,029,173**	**46,632**	**165,179**	**148,903**	**110,162**	**92,349**	**89,003**	**76,018**	**80,855**	**77,710**	**75,425**	**66,936**
13	**TOTAL GROWTH PORTFOLIO**				**3,491,915**	**254,781**	**474,530**	**356,084**	**412,263**	**358,660**	**441,570**	**482,405**	**247,811**	**156,952**	**143,425**	**162,936**
14	Less: SDA				(550,333)	(17,141)	(58,417)	(50,995)	(85,065)	(63,365)	(53,625)	(43,625)	(40,875)	(48,375)	(44,375)	(44,375)
15	**NET TRANSMISSION GROWTH PORTFOLIO**				**2,941,583**	**237,639**	**416,113**	**305,089**	**327,198**	**295,295**	**387,945**	**438,780**	**206,936**	**108,577**	**99,050**	**118,561**

Notes:
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5.2 Historical and Trend Explanations

Table 5-2 summarizes actual and planned expenditures for each of the Growth Portfolio programs for the period F2006 to F2018.

Table 5-2. Growth Portfolio Expenditures

Growth Capital Portfolio ($ M)	**Actual F2005***	**Actual F2006**	**Actual F2007**	**Forecast F2008**	**F2009**	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**
Bulk System Reinforcements	14.9	14.1	24.2	112.8	196.5	57.8	68.4	79.2	186.0	271.9	104.5	20.7	14.5	42.5
Area Reinforcements	3.3	30.4	56.3	41.3	49.0	112.9	181.9	141.8	121.1	92.0	29.0	15.0	10.0	10.0
Station Expansion & Modification	1.3	11.3	28.9	19.6	63.1	36.5	51.8	45.3	45.5	42.5	33.5	43.5	43.5	43.5
Customer Requested Projects	2.2	0.8	30.4	19.8	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation Interconnection Projects	3.8	0.6	0.8	47.4	165.2	148.9	110.2	92.3	89.0	76.0	80.9	77.7	75.4	66.9
Total Growth Portfolio	**25.5**	**57.2**	**140.7**	**240.9**	**474.5**	**356.1**	**412.3**	**358.7**	**441.6**	**482.4**	**247.8**	**157.0**	**143.4**	**162.9**
Less: SDA	(1.7)	(16.1)	(7.2)	(27.4)	(58.4)	(51.0)	(85.1)	(63.4)	(53.6)	(43.6)	(40.9)	(48.4)	(44.4)	(44.4)
Net Transmission Growth Portfolio	**23.8**	**41.1**	**133.5**	**213.5**	**416.1**	**305.1**	**327.2**	**295.3**	**387.9**	**438.8**	**206.9**	**108.6**	**99.1**	**118.6**

* SDA component of F2005 has been estimated

BCTC has identified the need for significant Growth Capital investment to meet future transmission requirements as the robust economy continues to drive domestic load and the need to integrate new generation resources increases. At the same time, most of the existing transmission system capacity is required to meet the current load. The impact on each Growth portfolio program is anticipated to be as follows:

(a) Investments to upgrade the Bulk system over the next ten years are forecast to grow significantly. The higher level of investment is primarily due to the Vancouver Island Transmission Reinforcement (VITR) (in-service in F2009) and Interior to Lower Mainland (ILM) (in-service in F2015) projects. Additional projects will likely be required to reinforce the South Interior Bulk system and the North Interior Bulk system depending upon the location and timing of the resource additions identified in BC Hydro resource plans.

(b) Costs associated with area reinforcements to meet local demand increased in F2007 and F2008 mostly due to the need for new transmission lines and stations that will be completed in 2008. This high level of work is expected to continue in F2009 as work on projects such as the Mission and Matsqui Area Supply project continue. BCTC expects that this level of activity will likely continue in the medium-term with major reinforcement projects for Central Vancouver Island, Golden, Woods Lake, North Thompson, and Metro Vancouver.

(c) Station Expansion and Modification work also increased in F2007 and F2008. The F2008 level of activity is expected to continue over the ten-year period. However, most of the work in this program involves SDAs with only a small percentage attributable to transmission.

(d) The only project for approval in the Customer-requested category at this time is Kinder Morgan Canada's (KMC) TMX-1 project. Customer-requested projects are only included in the Capital Plan after a Facilities Agreement has been signed in accordance with BCTC's OATT. Work in the Customer-requested program can change rapidly with economic conditions.

(e) The Generation interconnection work level is expected to increase to accommodate the thirty-eight generators with an Electricity Purchase

Agreement from BC Hydro's 2006 CFT. This work is expected to continue at that increased level as new generation projects resulting from the initiatives related to the new Energy Plan are added to the system.

The Growth portfolio expenditures shown in Table 5-2 decrease in the later part of the 10-year period with very few projects identified. Although more effort has been directed to forecasting long-term capital spending, very few projects have been identified for F2017 and beyond, due to the high level of uncertainty associated with the long range plan. Some expenditures have been estimated on a notional basis for the Station Expansion and Modifications programs based on the understanding that work will be required to address normal load growth, and for generators based on the expectation of future CFTs. BCTC is developing a Long-Term Transmission Outlook Report which will address these matters (see Section 2.4: Significant Management Initiatives).

5.3 Changes from Previous Capital Plan

In accordance with Directive 16 in Commission Decision G-91-05, the F2009 Capital Plan has been reviewed to identify changes from prior Capital Plans to identify any approved projects that have been accelerated, deferred, or cancelled. These changes are reflected in Table 5-3. For ongoing projects, revised expenditure patterns and in-service dates can be found in Table 5-1 under the heading "Projects in Progress".

Table 5-3. Changes to Approved Projects from Previous Capital Plan

(Variance exceeds both 10% and $100,000, or project has significant delays)

	Description	BCUC Order	F2009 Capital Plan		F2008 Capital Plan		Plan over Plan Change		Comments
			IS Date	Total Project ($'000)	IS Date	Total Project ($'000)	IS Date (months)	Total Project ($'000)	
	Bulk System Reinforcements								
1	500/230 kV Selkirk Transformer T4 Addition	G-69-07	Mar 2010	23,887	Oct 2008	17,756	17	6,131	Note 1
2	ILM - Interior to Lower Mainland Reinforcement - Definition Phase	G-103-04	Oct 2014	31,815	Oct 2014	21,976	0	9,839	Note 2
3	Nicola 500 kV Station Reconfiguration - Definition Phase	G-91-05		0	Oct 2010	249		(249)	Note 3
4	RAS - Vancouver Island	G-69-07	Oct 2008	3,665	Oct 2008	1,850	0	1,815	Note 4
5	Selkirk - 500 kV 123 MVAr Shunt Reactor	G-103-04	Mar 2009	6,134	Oct 2008	4,961	5	1,173	Note 5
6	Vancouver Island Reinforcement Project (VITR)	C-4-06	Oct 2008	287,261	Oct 2008	248,800	0	38,461	Note 6
	Area Reinforcements								
7	Highland - 138/69 kV Transformer Replacement	G-103-04	Oct 2010	4,687	Oct 2008	3,908	24	779	Note 7
8	Mission and Matsqui Area Supply	G-91-05	May 2009	56,900	Oct 2007	41,442	19	15,458	Note 8
9	Retermination of Sidney 60 kV Supply to Keating	G-69-07	Oct 2009	30,249	Oct 2009	13,607	0	16,642	Note 9
	Station Expansion & Modification								
10	Cathedral Square - 230/12 kV Transformer	G-103-04	Mar 2009	13,649	Feb 2009	12,262	1	1,387	Note 10
11	Chetwynd - T1 and T2 Transformer Replacements	G-69-07	Aug 2008	4,760	Aug 2008	3,650	0	1,110	Note 11
12	Gavin Lake Transformer Upgrade and Network Upgrade	G-69-07	Oct 2008	2,765	Jun 2007	1,992	16	773	Note 12
13	Golden - 69 kV Capacitor Bank Addition	G-67-06	Oct 2008	1,542	Oct 2007	1,498	12	44	Note 13
14	Hope - 25 kV Conversion	G-69-07	Apr 2008	3,398	Oct 2007	2,701	6	697	Note 14
15	Kidd 1 - Substation Redevelopment	G-69-07	Jun 2010	22,200	Oct 2009	10,409	8	11,791	Note 15
16	Porteau Station Expansion	G-67-06	Oct 2008	2,500	n/a	n/a			Note 16
	Generation Interconnection Projects								
17	Ashlu IPP Construction Load and Interconnection	G-7-07 / G-69-07	Mar 2008	4,026	n/a	n/a			Note 17
18	East Toba and Montrose Creek Hydroelectric Project	Tariff (Note 19)	Jun 2010	39,632	n/a	n/a			Note 17
19	Forest Kerr	G-103-04	Oct 2010	46,298	Jan 2010	34,719	10	11,579	Note 18
20	Savona ERG IPP	Tariff (Note 19)	Apr 2008	1,636	n/a	n/a			Note 17
21	Zeballos Lake Hydro IPP	G-157-06	Apr 2008	3,800	n/a	n/a			Note 17

Table 5-3 Note 1:	In-service delay due to a delayed procurement process and additional engineering. New definition estimates show higher costs. See also Table 5-4 Note 1.
Table 5-3 Note 2:	Definition Phase cost changed primarily due to task scope refinements for regulatory, environmental and First Nations consultation. See also Table 5-4 Note 3.
Table 5-3 Note 3:	This project is deferred because it is not needed for Rev G5 stage of the system development. A future project will be required when the second peaking units are added at the Mica and Revelstoke generating plants.
Table 5-3 Note 4:	The project cost increased due to additional load shedding requirements including the need for 10 additional loads to be made available for shedding and also at a faster speed. The new requirement is to address the transient stability and thermal issues recently identified as part of the RAS definition work. See also Table 5-4 Note 5.
Table 5-3 Note 5:	In-service delay of 5 months (total 32 months since approval). Project was given lower priority than projects addressing security of supply. New definition estimates show higher costs. See also Table 5-4 Note 6.
Table 5-3 Note 6:	Cost increase due to inflation and increased legal and environmental costs. See also Table 5-4 Note 8.
Table 5-3 Note 7:	In-service date delayed due to the time necessary to resolve a potential Customer Service Request (Kinder Morgan will not proceed with their TMX-2/3 stages of development within the near future) and longer delivery lead-time for transformers; cost increased due to escalation. See also Table 5-4 Note 10.
Table 5-3 Note 8:	The project cost increased due to cost escalation and project scope changes. The increased cost delayed the in-service date of the Mission portion of the project. There will be additional

engineering to investigate savings and incorporate new project scope. See also Section 9.25.

Table 5-3 Note 9: A planning estimate (+100% / -50% accuracy) was submitted with the F2008 Capital Plan. The Definition Phase of this project is nearing completion and the cost estimate is now more accurate. See also Table 5-4 Note 12.

Table 5-3 Note 10: Transformer cost was $1.05 million over estimate. Inflated costs are impacting this project. See also Table 5-4 Note 13.

Table 5-3 Note 11: New definition estimates show higher costs. See also Table 5-4 Note 14.

Table 5-3 Note 12: New definition estimates show higher costs. Customer request added a second stage to the project. See also Table 5-4 Note 16.

Table 5-3 Note 13: In-service date was deferred due to a lower load growth rate. See also Table 5-4 Note 17.

Table 5-3 Note 14: Difficulties in obtaining outages to perform the work forced increased scope and delayed completion. See also Table 5-4 Note 19.

Table 5-3 Note 15: Spot loads did not materialize as previously forecast, allowing deferral to F2010. It is not practical to seismically secure the site using a planned protective dike. The new scope will add a feeder building in the stable area of the substation. The cost also increased due to inflation. See also Table 5-4 Note 20.

Table 5-3 Note 16: Shown erroneously as cancelled in the F2008 Capital Plan. This project was on hold pending land development. BC Hydro's load forecast now requires this project. Preliminary $2.5 million estimate will be refined in F2008. See also Table 5-4 Note 22.

Table 5-3 Note 17: This is a new generation project since the F2008 Capital Plan Submission.

Table 5-3 Note 18:	New estimates show higher costs due to inflation. See also Table 5-4 Note 30.
Table 5-3 Note 19:	Refer to discussion on Generation Interconnection Projects approvals in Section 5.5.5.

Table 5-4. Growth Portfolio Projects in Progress

	Growth Portfolio - Projects in Progress	BCUC Order		Priority Group	IS Date	% $Change	Project Total ($'000)	Prior Years ($'000)	F2008 ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Bulk System Reinforcements																		
1	500/230 kV Selkirk Transformer T4 Addition (Note		F09 Plan		Mar 2010		**23,887**	41	159	4,211	19,378	98	0	0	0	0	0	0	0
2	1)	G-69-07	Original Submission	3	Oct 2008		**17,756**	27	1,396	16,136	197	0	0	0	0	0	0	0	0
3			Variance			35%	**6,131**	14	(1,237)	(11,925)	19,181	98	0	0	0	0	0	0	0
4	Ashton Creek - 2X250 MVAr - 500kV Switchable		F09 Plan		Oct 2010		**253**	0	253	0	0	0	0	0	0	0	0	0	0
5	Shunt Capacitor - Definition Phase (Note 2)	G-69-07	Original Submission	2	Oct 2010		**253**	0	253	0	0	0	0	0	0	0	0	0	0
6	(Note 2)		Variance			0%	**0**	0	0	0	0	0	0	0	0	0	0	0	0
7	ILM - Interior to Lower Mainland Reinforcement -		F09 Plan		Oct 2014		**31,815**	5,345	13,210	13,261	0	0	0	0	0	0	0	0	0
8	Definition Phase (Note 3)	G-103-04	Original Submission		Oct 2013		**15,700**	6,827	3,026	3,722	2,125	0	0	0	0	0	0	0	0
9			Variance			103%	**16,115**	(1,482)	10,184	9,539	(2,125)	0	0	0	0	0	0	0	0
10	RAS - Provision for Unidentified Additions - F2008-		F09 Plan		Mar 2009		**875**	0	35	840	0	0	0	0	0	0	0	0	0
11	F2009 (Note 4)	G-69-07	Original Submission	1	Mar 2009		**1,000**	0	500	500	0	0	0	0	0	0	0	0	0
12			Variance			-13%	**(125)**	0	(465)	340	0	0	0	0	0	0	0	0	0
13	RAS - Vancouver Island (Note 5)		F09 Plan		Oct 2008		**3,665**	0	2,745	920	0	0	0	0	0	0	0	0	0
14		G-69-07	Original Submission	1	Oct 2008		**1,850**	50	1,200	600	0	0	0	0	0	0	0	0	0
15			Variance			98%	**1,815**	(50)	1,545	320	0	0	0	0	0	0	0	0	0
16	Selkirk - 500 kV 123 MVAr Shunt Reactor (Note 6)		F09 Plan		Mar 2009		**6,134**	21	539	5,574	0	0	0	0	0	0	0	0	0
17		G-103-04	Original Submission		Oct 2006		**6,103**	6,103	0	0	0	0	0	0	0	0	0	0	0
18			Variance			1%	**31**	(6,082)	539	5,574	0	0	0	0	0	0	0	0	0
19	South Interior Series Compensation (SISC)		F09 Plan		Oct 2011		**1,600**	9	1,489	102	0	0	0	0	0	0	0	0	0
20	Project - Definition Phase (Note 7)	G-69-07	Original Submission	3	Oct 2010		**1,600**	0	1,400	200	0	0	0	0	0	0	0	0	0
21			Variance			0%	**0**	9	89	(98)	0	0	0	0	0	0	0	0	0
22	Vancouver Island Reinforcement Project (VITR)		F09 Plan		Oct 2008		**287,261**	28,726	93,379	164,916	240	0	0	0	0	0	0	0	0
23	(Note 8)	C-4-06	Original Submission		Oct 2008		**248,800**	31,160	60,312	157,105	223	0	0	0	0	0	0	0	0
24			Variance			15%	**38,461**	(2,434)	33,067	7,811	17	0	0	0	0	0	0	0	0
	Area Reinforcements																		
25	Central Vancouver Island Project (CVI) - Definition		F09 Plan		Oct 2010		**2,500**	0	2,500	0	0	0	0	0	0	0	0	0	0
26	Phase (Note 9)	G-69-07	Original Submission	1	Oct 2010		**2,500**	0	1,500	1,000	0	0	0	0	0	0	0	0	0
27			Variance			0%	**0**	0	1,000	(1,000)	0	0	0	0	0	0	0	0	0
28	Highland - 138/69 kV Transformer Replacement		F09 Plan		Oct 2010		**4,687**	37	0	0	470	4,180	0	0	0	0	0	0	0
29	(Note 10)	G-103-04	Original Submission		Oct 2006		**4,380**	4,380	0	0	0	0	0	0	0	0	0	0	0
30			Variance			7%	**307**	(4,343)	0	0	470	4,180	0	0	0	0	0	0	0
31	Mission and Matsqui Area Supply (Note 11)		F09 Plan		May 2009		**56,900**	10,375	28,031	17,389	1,105	0	0	0	0	0	0	0	0
32		G-91-05	Original Submission		Oct 2007		**43,205**	25,174	18,031	0	0	0	0	0	0	0	0	0	0
33			Variance			32%	**13,695**	(14,799)	10,000	17,389	1,105	0	0	0	0	0	0	0	0
34	Retermination of Sidney 60 kV Supply to Keating		F09 Plan		Oct 2009		**30,249**	0	2,186	8,625	19,438	0	0	0	0	0	0	0	0
35	(Note 12)	G-69-07	Original Submission	5	Oct 2009		**13,607**	26	60	1,159	12,362	0	0	0	0	0	0	0	0
36			Variance			122%	**16,642**	(26)	2,126	7,466	7,076	0	0	0	0	0	0	0	0

Table 5-4. Growth Portfolio Projects in Progress (continued)

	Growth Portfolio - Projects in Progress	BCUC Order		Priority Group	IS Date	% $Change	Project Total ($'000)	Prior Years ($'000)	F2008 ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Station Expansion & Modification																		
37	Cathedral Square - 230/12 kV Transformer (Note 13)		F09 Plan		Mar 2009		**13,649**	150	430	11,719	1,350	0	0	0	0	0	0	0	0
38		G-103-04	Original Submission		Mar 2007		**8,605**	7,275	0	0	0	0	0	0	0	0	0	0	0
39			Variance			59%	**5,044**	(7,125)	430	11,719	1,350	0	0	0	0	0	0	0	0
40	Chetwynd - T1 and T2 Transformer Replacements (Note 14)		F09 Plan		Aug 2008		**4,760**	0	100	4,660	0	0	0	0	0	0	0	0	0
41		G-69-07	Original Submission	6	Aug 2008		**3,650**	528	3,122	0	0	0	0	0	0	0	0	0	0
42			Variance			30%	**1,110**	(528)	(3,022)	4,660	0	0	0	0	0	0	0	0	0
43	Colwood - 138/25 kV Transformer Addition (Note 15)		F09 Plan		Oct 2008		**7,578**	28	150	7,400	0	0	0	0	0	0	0	0	0
44		G-69-07	Original Submission	6	Oct 2008		**7,513**	69	1,978	5,466	0	0	0	0	0	0	0	0	0
45			Variance			1%	**65**	(41)	(1,828)	1,934	0	0	0	0	0	0	0	0	0
46	Gavin Lake Transformer Upgrade and Network Upgrade (Note 16)		F09 Plan		Oct 2008		**2,765**	96	2,100	569	0	0	0	0	0	0	0	0	0
47		G-69-07	Original Submission	4	Jun 2007		**1,992**	0	1,415	577	0	0	0	0	0	0	0	0	0
48			Variance			39%	**773**	96	685	(8)	0	0	0	0	0	0	0	0	0
49	Golden - 69 kV Capacitor Bank Addition (Note 17)		F09 Plan		Oct 2008		**1,542**	13	229	1,300	0	0	0	0	0	0	0	0	0
50		G-67-06	Original Submission		Oct 2006		**1,810**	1,810	0	0	0	0	0	0	0	0	0	0	0
51			Variance			-15%	**(268)**	(1,797)	229	1,300	0	0	0	0	0	0	0	0	0
52	Grief Point 12 kV Circuit Conversion (Note 18)		F09 Plan		Oct 2008		**3,105**	66	189	2,850	0	0	0	0	0	0	0	0	0
53		G-69-07	Original Submission	7	Oct 2008		**3,272**	241	300	2,731	0	0	0	0	0	0	0	0	0
54			Variance			-5%	**(167)**	(175)	(111)	119	0	0	0	0	0	0	0	0	0
55	Hope - 25 kV Conversion (Note 19)		F09 Plan		Apr 2008		**3,398**	198	2,300	900	0	0	0	0	0	0	0	0	0
56		G-69-07	Original Submission	3	Oct 2007		**2,701**	162	2,539	0	0	0	0	0	0	0	0	0	0
57			Variance			26%	**697**	36	(239)	900	0	0	0	0	0	0	0	0	0
58	Kidd 1 - Substation Redevelopment (Note 20)		F09 Plan		Jun 2010		**22,200**	0	200	2,000	8,000	12,000	0	0	0	0	0	0	0
59		G-69-07	Original Submission	6	Oct 2009		**10,409**	409	1,000	3,000	6,000	0	0	0	0	0	0	0	0
60			Variance			113%	**11,791**	(409)	(800)	(1,000)	2,000	12,000	0	0	0	0	0	0	0
61	Oyster River - 132-25 kV Transformer Addition (Note 21)		F09 Plan		Oct 2008		**3,475**	16	84	3,375	0	0	0	0	0	0	0	0	0
62		G-67-06	Original Submission		Oct 2008		**3,000**	100	2,900	0	0	0	0	0	0	0	0	0	0
63			Variance			16%	**475**	(84)	(2,816)	3,375	0	0	0	0	0	0	0	0	0
64	Porteau Station Expansion (Note 22)		F09 Plan		Oct 2008		**2,500**	25	25	2,450	0	0	0	0	0	0	0	0	0
65		G-67-06	Original Submission		Mar 2007		**3,553**	3,553	0	0	0	0	0	0	0	0	0	0	0
66			Variance			-30%	**(1,053)**	(3,528)	25	2,450	0	0	0	0	0	0	0	0	0
67	Sechelt Transformers Replacement (T1 and T2) (Note 23)		F09 Plan		Oct 2008		**5,201**	21	200	4,980	0	0	0	0	0	0	0	0	0
68		G-69-07	Original Submission	7	Oct 2008		**4,993**	51	548	4,395	0	0	0	0	0	0	0	0	0
69			Variance			4%	**208**	(30)	(348)	585	0	0	0	0	0	0	0	0	0
70	Seventy Mile House - 69/25 kV Transformer Addition (Note 24)		F09 Plan		Jun 2009		**2,692**	14	228	1,895	556	0	0	0	0	0	0	0	0
71		G-91-05	Original Submission		Jun 2006		**1,205**	1,205	0	0	0	0	0	0	0	0	0	0	0
72			Variance			123%	**1,487**	(1,191)	228	1,895	556	0	0	0	0	0	0	0	0
73	Shawnigan Lake Substation - Transformer Replacement (Note 25)		F09 Plan		Aug 2008		**5,572**	22	300	5,250	0	0	0	0	0	0	0	0	0
74		G-69-07	Original Submission	6	Aug 2008		**5,472**	47	4,004	1,420	0	0	0	0	0	0	0	0	0
75			Variance			2%	**100**	(25)	(3,704)	3,830	0	0	0	0	0	0	0	0	0

Table 5-4. Growth Portfolio Projects in Progress (continued)

	Growth Portfolio - Projects in Progress	BCUC Order		Priority Group	IS Date	% $Change	Project Total ($'000)	Prior Years ($'000)	F2008 ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	Station Expansion & Modification																		
76	Walters Transformer Addition (Note 26)		F09 Plan		Oct 2008		**5,177**	9	150	5,018	0	0	0	0	0	0	0	0	0
77		G-69-07	Original Submission	2	Oct 2008		**5,056**	39	3,879	1,139	0	0	0	0	0	0	0	0	0
78			Variance			2%	**121**	(30)	(3,729)	3,879	0	0	0	0	0	0	0	0	0
79	Westbank - T1 Transformer Replacement (Note		F09 Plan		Jun 2008		**2,750**	0	100	2,650	0	0	0	0	0	0	0	0	0
80	27)	G-69-07	Original Submission	6	Jun 2008		**2,680**	17	1,950	712	0	0	0	0	0	0	0	0	0
81			Variance			3%	**70**	(17)	(1,850)	1,938	0	0	0	0	0	0	0	0	0
	Generation Interconnection Projects																		
82	Ashlu IPP Construction Load and Interconnection		F09 Plan		Mar 2008		**4,026**	528	3,484	14	0	0	0	0	0	0	0	0	0
83	(Note 28)	G-7-07 /	Original Submission	5	Mar 2008		**4,494**	586	3,808	100	0	0	0	0	0	0	0	0	0
84		G-69-07	Variance			-10%	**(468)**	(58)	(324)	(86)	0	0	0	0	0	0	0	0	0
85	East Toba and Montrose Creek Hydroelectric		F09 Plan		Jun 2010		**39,632**	0	2,606	17,578	18,653	795	0	0	0	0	0	0	0
86	Project (Note 29)	Tariff	Original Submission		n/a		**0**	0	0	0	0	0	0	0	0	0	0	0	0
87			Variance				**39,632**	0	2,606	17,578	18,653	795	0	0	0	0	0	0	0
88	Forest Kerr (Note 30)		F09 Plan		Oct 2010		**46,298**	0	0	667	16,002	29,629	0	0	0	0	0	0	0
89		G-103-04	Original Submission		Jan 2007		**27,541**	27,541	0	0	0	0	0	0	0	0	0	0	0
90			Variance			68%	**18,757**	(27,541)	0	667	16,002	29,629	0	0	0	0	0	0	0
91	Savona ERG IPP (Note 31)		F09 Plan		Apr 2008		**1,636**	0	1,627	10	0	0	0	0	0	0	0	0	0
92		Tariff	Original Submission		n/a		**0**	0	0	0	0	0	0	0	0	0	0	0	0
93			Variance				**1,636**	0	1,627	10	0	0	0	0	0	0	0	0	0
94	Zeballos Lake Hydro IPP (Note 32)		F09 Plan		Apr 2008		**3,800**	54	3,670	76	0	0	0	0	0	0	0	0	0
95		G-157-06	Original Submission		Mar 2008		**3,760**	47	3,670	43	0	0	0	0	0	0	0	0	0
96			Variance			1%	**40**	7	0	33	0	0	0	0	0	0	0	0	0

Table 5-4 Note 1: 500/230 kV Selkirk Transformer T4 Addition

The F2008 Capital Plan to increase the Selkirk substation capacity by adding a transformer to be in-service in October 2008 was based on a planning estimate of $17.8 million with an accuracy of ± 30%. The subsequent definition engineering work developed a detailed project plan and estimate which determined that the funding needed for this project is $6.1 million higher than the planning estimate. This increase is related to general cost increases for capital goods, material and labour associated with the current construction boom. There has been a more than doubling of the inflation rate used for each year of the project compared to that which was used in the F2008 estimate (from a 2.1% flat rate to 6% for 2007, 5% for 2008, 5% for 2009 and 4% for 2010). There are capacity problems in the transformer supply chain and the transformer delivery had to be adjusted from a schedule of 12-18 months to a new schedule of 18-24 months. The delivery of the three phases cannot meet the original in-service date, adding time and inflation cost to the project. The first phase will arrive in the spring of 2009 and the last two phases will not be in service until March 2010. The project team also found it necessary to add some steel towers due to the longer spans needed to connect to the available transformer location and a firewall for the new transformer installation which had not been anticipated. The contingency allowance in the estimate has been increased from $1.0 million to $2.2 million to allow for the possibility of further price or minor scope changes.

The F2009 Capital Plan estimates a project completion in October 2010 at a cost of $23.9 million with an accuracy of +15% / -10%.

Table 5-4 Note 2: Ashton Creek – 2X250 MVAr - 500 kV Switchable Shunt Capacitor – Definition Phase

This project is unchanged since its original submission in the F2008 Capital Plan.

Table 5-4 Note 3: ILM – Interior to Lower Mainland Definition Phase

The F2005 Capital Plan prepared in 2004 included an estimated $15.7 million to complete the Definition Phase work to develop a detailed project plan and estimate for the ILM project which had an earliest possible in-service date of October 2013. The final Definition Phase budget submitted in the November 5, 2007 CPCN filing is $38.4 million, which includes: $32.2 million in direct costs, $5.2 million in interest during construction, and $1.0 million in overhead. The new proposal has an earliest possible in-service date of October 2014.

After the initial Definition Phase was approved by the Commission in November 19, 2004 (Commission Order G-103-04), a project team was assigned and detailed scoping and assessment of the project began. Budgets were subsequently revised for several tasks including: First Nations consultation, environmental assessment, stakeholder consultation, engineering services, regulatory, and legal costs.

The number of First Nations groups and the costs to involve and engage First Nations has increased significantly. BCTC is currently engaging 67 groups, not 41 as originally expected. This has substantially increased the First Nations budget for consultation work, negotiating, and capacity funding.

In the fall of 2006 BCTC secured a consultant to prepare an environmental assessment application. The work has estimated environmental assessment costs which were previously not known. The archaeological impact assessment, required as part the environmental assessment is one of the largest and most complex ever carried out in the province, the cost of which was not anticipated in 2004.

The preliminary engineering, stakeholder consultation and regulatory cost estimates have also increased, based on BCTC's experience with the recent extensive CPCN process for VITR. Engineering budgets include additional work for extensive alternatives analysis and to support environmental and regulatory work. Some detailed engineering work was moved from the implementation phase to the Definition Phase to improve the project time line.

Overhead, interest during construction, and contingency increased together with the overall budget increase.

Table 5-4 Note 4: RAS - Provision for Unidentified Additions F2008-F2009

The project was for miscellaneous RAS schemes and a variance was expected, reflecting the actual work that had to be done.

Table 5-4 Note 5: RAS - Vancouver Island

This project estimate has been increased by $1.8 million to an estimated total cost of $3.7 million and the majority of the work will be done in F2008 as originally intended. The in-service date remains unchanged as October 2008. The project cost increase is due to additional load shedding requirements including the need for 10 additional loads to be made available for shedding and at a faster speed than previously anticipated.

Table 5-4 Note 6: Selkirk - 500 kV 123 MVAr Shunt Reactor

This project has a minor variance of <1% or $31k compared to the original submission, reflecting more accurate estimates than were available at the time of the F2008 Capital Plan filing as explained in Table 5-3. The in-service date is 29 months later than originally scheduled as a result of assigning a lower priority to the project compared to others.

Table 5-4 Note 7: South Interior Series Compensation (SISC) Project – Definition Phase

The estimated cost of this project is unchanged since originally submitted in the F2008 Capital Plan and the in-service date has been delayed by 12 months because of changes in the resource plan. The definition work is progressing on schedule.

Table 5-4 Note 8: Vancouver Island Reinforcement Project (VITR)

The Total Capital Cost forecast for the VITR has increased to $288 million, up from $249 million in the original CPCN submission which was approved in 2006. This is due to increases in execution costs for equipment, materials, labour and services plus increased contingency allowances related to the current market conditions in BC and in the utility industry. Costs have also increased due to legal and related matters associated with appeals and other activities of project opponents. In addition, the project has incurred higher costs for habitat compensation and other environmental measures included in the Table of Commitments issued with the Environmental Assessment Certificate and for other requirements of Canadian and US permitting authorities. The scheduled in-service date remains unchanged.

Table 5-4 Note 9: Central Vancouver Island Project (CVI) – Definition Phase

This project will be completed in F2008, not F2009 as originally expected. There is no change in the estimated total cost of the definition work.

Table 5-4 Note 10: Highland 138/69 kV Transformer Replacement

This project has an in service delay of 48 months from the original completion date as a result of a lack of an expected Customer Service Request. The project estimate has increased due to a general escalation in project costs for equipment, materials and labour.

Table 5-4 Note 11: Mission and Matsqui Area Supply.

Refer to the BCUC directive Section 9.25 and BCTC's earlier submission in response to this project.

Table 5-4 Note 12: Retermination of Sidney 60kV Supply to Keating

The F2008 Capital Plan to reterminate the Sidney 60 kV supply to Keating from Goward Substation (GOW) was based on a planning estimate of $13.6 million with an order-of magnitude accuracy of +100% / -50%. Engineering resource shortages did not allow time to prepare estimates for 5 kilometres of new 60 kV transmission lines, necessary telecom upgrades, or the removal costs at GOW prior to the Capital Plan filing. Consequently the estimate had a low accuracy because these estimates were still to be completed. The subsequent definition engineering work to develop a detailed project plan and estimate was done when BCTC contracted with a new engineering service provider. The previously omitted costs were added to the estimate at:

(a) transmission lines ($3.5 million),

(b) upgrades to the telecom system ($2.2 million), and

(c) Goward Substation component removal/salvage ($1.0 million).

Additional costs were identified in the detailed estimate including:

(a) materials and labour cost escalation to expand Keating substation ($5 million),

(b) contingency allowance ($1.7 million),

(c) additional project management ($0.7 million),

(d) overhead ($0.5 million),

(e) IDC ($1.2 million), and

(f) consultation, environmental, P&C, SCADA, property ($0.9M).

The F2009 Capital Plan estimates a project completion at a cost of $30.3 million with an accuracy of ± 10%.

Table 5-4 Note 13: Cathedral Square – 230/12kV Transformer

The F2006 Capital Plan to add a Cathedral Square transformer was based on a planning estimate of $7.3 million with an accuracy of ± 50%. The subsequent definition engineering work to develop a detailed project plan and estimate included discussions with the manufacturer which determined that the intended SF6 transformer design would not fit the space available without expensive modifications. To reduce the project cost, BCTC changed the scope to use an oil insulated transformer instead. The completion of the definition work, with the new scope, resulted in a cost estimate increase to $9.9 million which was subsequently revised to account for increases in equipment and labour costs. The revised estimate of $12.3 million with an accuracy of ± 10% was reported in the F2008 Capital Plan.

When the transformer was purchased there was only one bidder. The price was $1.0 million more than the original estimate. Consequently the cost estimate is now $13.6 million ± 10%. The change in scope to incorporate the design with an oil-filled transformer resulted in a 24 month delay to the in-service date.

Table 5-4 Note 14: Chetwynd – T1 and T2 Transformer Replacements

The F2008 Capital Plan to increase the Chetwynd substation capacity was based on a planning estimate of $3.7 million with an accuracy of ± 50%. The subsequent definition engineering work to develop a detailed project plan and estimate determined that the cost of the project had increased by $1.1 million, mostly due to cost increases of $0.75 million for electrical materials and equipment. The F2009 Capital Plan estimates a project completion in August 2008 at a cost of $4.8 million with an accuracy of ± 10%.

Table 5-4 Note 15: Colwood 138/25 kV Transformer Addition

This project has a minor variance of <1% or $65k and the in-service date is unchanged.

Table 5-4 Note 16: Gavin Lake Transformer and Network Upgrade

The F2008 Capital Plan to reinforce the transformation and feeder network at Gavin Lake Substation, to meet a major customer request for more load, was based on a planning estimate of $2.0 million with an accuracy of ± 50%. The scheduled in service date was in October 2007. The subsequent definition engineering work to develop a detailed project plan and estimate for the project identified more accurate costs which increased the estimated completion cost due to schedule, scope and design changes which resulted from a change in the customer request. In January 2007, the customer requested an increase in its demand from 2 MVA to 4 MVA by July 2007. This requirement was met by organizing the project in two steps. First, BCTC installed a mobile transformer and other temporary equipment and met the additional load in a very short time and with high construction costs. The second project started in late July 2007 to replace this temporary installation with the final design. To meet the load within the accelerated time frame much of the design and construction work needed to be done twice which has both increased the scope of work and delayed the project completion.

The F2009 Capital Plan estimates this project will be completed in January 2008 at a cost of $2.8 million with an accuracy of ± 10%.

Table 5-4 Note 17: Golden 69 kV Capacitor Bank Addition

The in-service date for this project was deferred due to the use of a more accurate system model and a forecast lower rate of load increase which resulted in a delay in the majority of project expense to F2009. Detailed project plans indicate a reduction in the estimated completion cost of $268k compared to the original submission.

Table 5-4 Note 18: Grief Point 12 kV Circuit Conversion

This project has a minor variance since originally proposed of -5% or -$167k and the in-service date is unchanged.

Table 5-4 Note 19: Hope 25 kV Conversion

Difficulty obtaining station outages has delayed this work and has increased the cost by $0.7 million compared to what was originally proposed in the F2008 Capital Plan. The cost increase is related to scope changes in the execution work to enable continuing the work without the requested outages.

Table 5-4 Note 20: Kidd 1 – Substation Redevelopment

Two factors increased the cost of this project: the need to seismically secure the new installations and the schedule advancement of a second transformer.

The F2008 Capital Plan to increase the Kidd 1 substation capacity was based on a planning estimate of $10.4 million with an accuracy of ± 50%. The plan was to replace the transformer cables (to fully utilize the available capacity of the existing 50+ year old transformers for a few years), add one 75 MVA transformer and add a new feeder section. The estimate included minimum work to seismically secure the new facilities because a protective dike was planned in the future to secure the station.

The subsequent definition engineering work to develop a detailed project plan and estimate determined that the protective dike would be ineffective and that the new transformer and feeder section could not be installed at the location originally planned. Field investigations revealed that the unstable soil in the northern portion of the site is relatively shallow, making it possible to add equipment there in a seismically secure manner.

This geotechnical definition work required a scope change including excavation to solid ground to construct a secure building for the indoor feeder section. The planned building will have enough space for a second feeder section for capacity expansion in the future. Piling is also required to seismically secure any new transformer additions.

Detailed cost estimating determined that the cost to replace the transformer cables is substantially higher than expected, making their replacement cost ineffective compared to accelerating the replacement of the two small transformers at the station.

The revised project scope is to construct a seismically secure building on the northern portion of the substation property, install an indoor feeder section and install two 60/12 kV transformers on piles to replace the two existing 25 MVA transformers. Because the original forecast spot load increase did not materialize the project in-service date has been deferred to 2010. The new cost estimate of the project is $22.2 million with an accuracy of ± 50%

Table 5-4 Note 21: Oyster River 132/25 kV Transformer Addition

This project was submitted in the F2007 Capital Plan with a budget of $3.0 million and an in-service date of October 2008. The estimate was a planning level estimate with an accuracy of ± 35%. Escalating cost of materials and labour resulted in a revised estimate of $ 3.5 million ± 10% when the project plan was prepared. The scope and in-service date remain unchanged.

Table 5-4 Note 22: Porteau Station Expansion

The project was originally proposed in the F2007 Capital Plan with an estimated cost of $3.6 million and an in-service date of March 2007. The project has been delayed because the expected land development did not occur at the expected date.

Subsequent to the delay, a different substation design was proposed and a planning estimate of $2.5 million with accuracy of +100% / -50% was prepared with a cost reduction. A project plan is being prepared for January 2008 and this will provide more accurate costs.

Table 5-4 Note 23: Sechelt Transformers Replacement (T1 and T2)

This project has a minor variance of 4% or $208k.

Table 5-4 Note 24: Seventy Mile House - 69/25 kV Transformer Addition

The F2006 Capital Plan estimated this project at a cost of $1.2 million with an in-service date of June 2006. Since then the load growth forecast has changed and the in-service date has been deferred. The project is presently on hold due to the possible conversion of the industrial load to transmission service which would reduce the station load. Updated project plans have estimated the cost to a ± 10% level of accuracy and the new estimate has increased to $2.7 million due to the general increase in equipment, material and labour costs.

Table 5-4 Note 25: Shawnigan Lake Substation - Transformer Replacement

This project has a minor variance of 2% or $100k and no change in in-service date.

Table 5-4 Note 26: Walters Transformer Addition

This project has a minor variance of 2% or $121k and no change in in-service date.

Table 5-4 Note 27: Westbank - T1 Transformer Replacement

This project has a minor variance of 3% or $70k and no change in in-service date.

Table 5-4 Note 28: Ashlu Generation Construction Load and Interconnection

This project was proposed in the F2007 Capital Plan and is now moving forward. It will be in service in March 2008 with an expected project cost of $4.0 million. The project cost has been reduced by $ 0.5 million due to a change in scope by the generator.

Table 5-4 Note 29: East Toba and Montrose Creek Hydroelectric Project

This project was not in the F2008 Capital Plan. This project is Tariff driven and is now moving forward. It is planned to be in service in June 2010 with an expected project cost of $39.6 million. The project was originally estimated at a cost of $29.0 million in the Interconnection Facilities Study Report that had been prepared for BCTC by BC Hydro Engineering Services. The cost estimate had a +20% / -10% accuracy. In October 2007, the client executed the Facilities Agreement and Interconnection Agreement with BCTC. SNC, BCTC's engineering service provider, developed updated cost estimates and schedules for the project using additional information and analysis that was not included in the initial estimates provided by BC Hydro. The updated project schedule confirmed the Customer's target in-services dates of March 2010 for the East Toba plant and November 2010 for the Montrose plant, and the updated cost estimate provided a ± 10% accuracy level.

Table 5-4 Note 30: Forrest Kerr

This project was originally proposed in the F2005 Capital Plan with an in-service date of January 2007. It has been delayed by the client and has a new expected in-service date of October 2010. Cost estimates have been updated and the most recent estimated cost is $46.3 million, reflecting general increases in the cost of equipment, materials and labour which are impacted by the delays in the project.

Table 5-4 Note 31: Savona ERG IPP

This project was not in the F2008 Capital Plan. It is tariff driven and work for this Distribution level generator is required under the terms of BCTC's SDA Service Level Agreement with BC Hydro. The generator will be in service in April 2008 with an expected project cost of $1.6 million.

Table 5-4 Note 32: Zeballos Lake Hydro IPP

This project has a minor variance of 1% or $40k since the original submission in the F2007 Capital Plan and a one month delay for the expected in-service date.

5.4 Growth Capital Prioritization Results

The Growth Portfolio projects considered for approval for F2009 have been prioritized using the prioritization process described in Section 4.4. Prioritization results are summarized in Table 5-4.

The Grid Connection for KMC's TMX-1 project is considered mandatory to fulfill contractual customer obligations. Based on the application of the prioritization process, all other projects have been ranked in Groups 1 to 5, with Group 1 as the highest priority.

Of the six categories of criteria used in the prioritization methodology, the Financial, Market Efficiency and Reliability criteria are the most influential in determining the ranking of Growth projects in the F2009 Capital Plan as follows:

(a) Financial Objectives were the most significant factor affecting priorities, due to the significant dollar value and revenues of Growth projects, and that financial value can be positive or negative. A high positive Financial Value reflects high revenue due to additional load served relative to the cost of the project. A negative Financial Value reflects a relatively high project cost relative to the additional BCTC revenue from the project. Priority Groups 1 to 3 have high to moderate Financial Value.

(b) Bulk System projects that contribute to Market Efficiency Objectives achieve a higher priority than some other types of Growth projects. Also, Area Reinforcement projects involving construction of new lines or rebuilding of existing lines, resulting in a reduction in transmission losses, also contribute to Market Efficiency Objectives, resulting in these projects being ranked higher than other projects.

(c) Reliability Objectives measured the project's contribution to reducing EENS. High EENS reduction for an Area Reinforcement or Station Expansion and Modification project is due to the project providing significant reliability improvements such as removing an overload that would occur with all facilities in service or a significant overload during an N-1 contingency.

(d) Relationships with Communities and First Nations, although a consideration for many projects, did not materially affect the prioritization results.

The remaining two categories of 'Asset Condition' and 'Environmental and Safety' did not influence the Growth priority ranking because no Growth projects have significant issues in these areas.

The ranked set of projects is summarized in Table 5-4. Ranking is based primarily on value, but the deferral risk was also considered in this process. All projects in Priority Groups 1 and 2 contribute significantly to Financial objectives, as well as to Reliability or Market Efficiency Objectives. Priority Group 1 projects have a high overall value score. Priority Group 2 is a group of Remedial Action Scheme (RAS) projects, also with a high overall value score.

Projects in Priority Group 3 have similar moderate value scores and have been prioritized within this Group by overall risk scores. Priority Group 4 projects have low overall value scores and are listed in order of overall risk score. Priority Group 5 projects have the lowest overall value scores and moderate deferral risks.

BCTC has reviewed the projects in the lowest priority grouping to decide whether to defer these projects, but has decided that all of these projects are appropriate to proceed.

Table 5-4. Prioritization Results

Line No.	Priority Group	Project Name	Portfolio	F2009 Plan Funding Reques
	Mandatory	Kinder Morgan Canada TMX-1	Customer Requested Projects	Project funding requested
1	1	ILM Project	Bulk System Reinforcements	CPCN Project
2	1	Central Vancouver Island Reinforcement Project	Area Reinforcements	CPCN Project
3	1	Qualicum Substation Reconfiguration	Area Reinforcements	Project funding requested
4	1	Tumbler Ridge Substation Transformer Replacement	Station Expansion and Modification	Project funding requested
5	2	GMS Generation Shedding Modifications	Bulk System Reinforcements	Project funding requested
6	2	RAS for REV Unit 5 Generator Shedding	Bulk System Reinforcements	Project funding requested
7	2	RAS for Bridge River Generator Shedding	Bulk System Reinforcements	Project funding requested
8	3	5L51 & 5L52 Upgrade	Bulk System Reinforcements	Project funding requested
9	3	Ashton Creek 2x250 MVAr, 500kV Shunt Capacitors	Bulk System Reinforcements	Project funding requested
10	3	Port Kells Substation Shunt Capacitor Addition	Station Expansion and Modification	Project funding requested
11	4	Woods Lake Area Reinforcement	Area Reinforcements	Project funding requested
12	4	Sidney Substation Transformer Cooling Upgrade	Station Expansion and Modification	Project funding requested
13	5	Golden 69kV System Reinforcement	Area Reinforcements	Definition Phase funding reque
14	5	Mount Pleasant Substation	Area Reinforcements	Separate Filing

5.5 Growth Capital Portfolio Descriptions

5.5.1 Bulk System Reinforcements

The Bulk System is comprised of high-voltage transmission lines and related equipment that interconnect the large remote generating stations in the Peace River and Columbia River areas of the province with the major load centres in the Lower Mainland and on Vancouver Island. The Bulk System includes the 500 kV transmission system, parts of the 230 kV system, the transmission connections to Vancouver Island, and interconnections with other utilities through external and internal interties to FortisBC, Alcan, Alberta and the US.

Reinforcements to the Bulk System are typically required to ensure that these facilities continue to provide the system capacity and operational flexibility necessary to reliably serve increased domestic load, and support new generation facilities. Typical reinforcement projects involve the implementation of Remedial Action Schemes (RAS), installation of reactive power compensation equipment, high-capacity transformer additions or replacements and, ultimately, the construction of new transmission lines.

The following section provides a description of the Bulk System projects submitted for approval and those currently contemplated for future consideration.

5.5.1.1 Projects For Approval

5.5.1.1.1 Ashton Creek Substation Shunt Capacitor Banks – Implementation Phase

In-Service Date: October 2010 Priority Rating: 3

Total Capital Cost: $20.3 M

Implementation Phase Cost: $20M Estimate accuracy: ± 10%

Definition Phase: 95% complete

Description

BCTC is seeking approval for Implementation Phase work related to the addition of two 500 kV, 250 MVAr switched shunt capacitor banks at the Ashton Creek Substation (ACK) to support generation expansion in the Columbia River system, including the addition of Revelstoke Unit 5. The Definition Phase work completed the preliminary engineering design, provided a +/-10% accurate cost estimate, and a project plan as approved by the Commission's F2008 Capital Plan Decision.

Justification

Report SPA 2007-87, dated December 2007 is attached as Appendix F and provides the justification for installing two 500 kV-250 MVAR Mechanically Switched Shunt Capacitor banks at Ashton Creek Substation. It updates previous reports on the Ashton Creek Shunt Capacitor reinforcement by including more information on West of Selkirk Cut-plane seasonal flows, the Available Transfer Capability (ATC) for pre-contingency and post-contingency flows on this cut-plane, and an analysis on the generation shedding option.

Without the reinforcement, there is a shortage of ATC during the winter season. No ATC is available when the load level is 88 percent of the peak load. The ATC is between negative 200 MW during the lightest load period and positive 106 MW during the maximum peak load period during the winter season.

Without any reinforcements, there is a shortage of ATC during the freshet season. The post-contingency ATC is between negative 583 MW during the lightest load period and negative 364 MW during the maximum peak load period. To manage this shortfall in ATC, a combination of reinforcements and operational re-dispatch are used.

Two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks at Ashton Creek substation are required to accommodate Revelstoke Unit 5 and the addition of generation in the South Interior East area by 2010. This is the lowest cost solution to meet this need and prevent system voltage collapse under first single contingencies, during an outage on 5L91, 5L96, or 5L98.

Discussion of Alternatives

Discussion of alternatives is included in Appendix F.

Project Risk / Impacts

The project has a low overall risk because of the extensive planning, engineering and regulatory review. Technically the reinforcement is a routine and standard method for solving voltage stability limits. The financial risk is low because the project plan and estimate (with an accuracy of 10%) are completed.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation.

Related / Dependent Projects

The SISC project is a related project and is shown in Section 5.5.1.2.8. The SISC will be scheduled after the Ashton Creek Shunt Capacitor Bank project.

5.5.1.1.2 RAS - Bridge River Generation Shedding Modifications

In-Service Date: October 2008 Priority Rating: 2

Capital Cost: $2.3M Estimate Accuracy: +35% / -15%

Definition Phase: 70% complete

Description

This project is to expand and upgrade the existing Bridge River Generation Shedding RAS to include additional contingencies. Wahleach generator shedding is proposed to be added to the RAS and made available for shedding when required. The new RAS would be designed with built-in redundancy.

Justification

An investment of approximately $2.3M is proposed to expand and upgrade the Bridge River generation shedding RAS. This investment will help to meet the immediate needs by adding newly identified contingencies[8] into the RAS and by shedding

[8] The contingencies for Bridge River units are for loss of ROS T1, 2L78, 2L77, 2L5, 3L3, 2L9, 2L13, and 2L17. The contingencies for Wahleach units are for loss of 3L2, 3L3, 2L78, ROS T1, and 2L77.

Wahleach Generating Station (WAH) G1. This provides the benefit of reducing constraints on Bridge River generation and protecting WAH G1 from being subjected to excessive high torque caused by the loss of 3L2, 3L3, 2L78, ROS T1 or 2L77. The existing Bridge River RAS does not have the capability to mitigate the impact caused by these disturbances. Without the new RAS and expanded capability, the Bridge River System capability would be significantly constrained.

The Bridge River generator shedding RAS must meet an N-1 contingency in order to be effective in maintaining system stability. This project will upgrade the existing RAS to include built-in redundancy.

Finally, the new RAS would also provide additional room to accommodate and facilitate the integration of new generators in the area (e.g., the proposed 160 MW Upper Harrison generator for service in December 2008).

Discussion of Alternatives

The only alternative is to defer the RAS upgrade. This alternative requires accepting the risk of cascading the system if the Bridge River RAS fails due to the lack of functional capability to mitigate the impact caused by certain unaddressed contingencies and the resulting potential risk of damaged equipment and load loss. BCTC believes this risk is not acceptable given the direction to improve system reliability by North American power utilities. BCTC has followed NERC/WECC Planning Standards on the basis that this is good utility practice.

Project Risks / Impacts

The overall risk of this project is low because it is based on proven technology and will be implemented by experienced engineering and field staff.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

Not applicable.

5.5.1.1.3 RAS - GMS Generation Shedding Modifications – Stage 2

In-Service Date: October 2010 Priority Rating: 2

Capital Cost: $2.1M Estimate Accuracy: +35% / -15%

Definition Phase: 60% complete

<u>Description</u>

This project is to upgrade the existing GM Shrum Generating Station (GMS) generation shedding RAS to include built-in redundancy and to add additional capability to integrate new generation and contingencies.

<u>Justification</u>

The GMS generator shedding RAS is presently non-compliant with the NERC/WECC Planning Standard III.F.S1.

This standard provides as follows:

> III. System Protection and Control F. Special Protection Systems
>
> **Introduction**
>
> A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions, include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. The use of an SPS is an acceptable practice to meet the system performance requirements as defined under Categories A, B, or C of Table I of the I.A. Standards on Transmission Systems. Electric systems that rely on an SPS to meet the performance levels specified by the NERC Planning Standards must ensure that the SPS is highly reliable.
>
> Examples of SPS misoperation include, but are not limited to, the following:

1. The SPS does not operate as intended.

2. The SPS fails to operate when required.

3. The SPS operates when not required.

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A. Standards on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

S4. All SPS misoperations shall be analyzed for cause and corrective action.

S5. SPS maintenance and testing programs shall be developed and implemented.[9]

To comply with this requirement, the GMS RAS needs to be upgraded with built-in redundancy. In addition, the existing GMS RAS has used nearly all of its capacity and can only accommodate one additional input. Therefore, BCTC considers it is prudent to upgrade the GMS generation shedding capability to accommodate potential future requirements, such as proposed large wind generation projects in the Northern area, at the same time as upgrades are put in place to meet the new NERC/WECC Standard. For supporting analysis, please see the GM Shrum Generating Station Genshed Redundancy Upgrade, Preliminary Project Report, prepared by BC Hydro

[9] Western Electricity Coordinating Council, NERC/WECC Planning Standards (Revised April 20, 2003), online: www.wecc.biz/documents/library/procedures/planning/WECC-NERC_Planning%20Standards_4-10-03.pdf.

Engineering, Report No. E372 June 2005, filed in response to BCUC IR 1.81.1 (19 February 2007) with respect to the F2008 Capital Plan.

<u>Discussion of Alternatives</u>

The only alternative is to defer this upgrade and accept the risk of cascading the system if the GMS RAS fails. The physically long 500 kV Peace transmission system is transient stability limited. Failure of generation shedding in response to disturbances and loss of lines could result in the GMS and Peace Canyon generators becoming unstable, resulting in separation from the grid. This separation would cause a severe generation shortage on the main grid, which could result in cascading outages under certain conditions. BCTC believes this risk is not acceptable given the direction to improve system reliability by North American power utilities. BCTC has followed NERC/WECC Planning Standards on the basis that this is good utility practice.

The NERC/WECC Planning Standards may become mandatory in BC, consistent with BC government policy as outlined in the new Energy Plan.

> Policy Action 14: Ensure that the province remains consistent with North American transmission reliability standards.
>
> Government will commit to ensure that industry developed reliability standards are introduced in British Columbia, cost-effectively and in a manner that respects BC's regulatory sovereignty.
>
> The analysis of recent large-scale electricity blackouts has confirmed the value of common and mandatory reliability standards for the electricity industry. New North American standards are emerging from the North American Electric Reliability Council, an industry body made up of technical experts from Canada and the United States. British Columbia will follow the industry practice of making these common standards mandatory for users, owners, and operators of the bulk power transmission system in BC. Consultations with industry will be undertaken to discuss the options for BC to implement these standards.

The BC Utilities Commission will determine, set and enforce reliability standards in the province, and can approve variances if it determines that a variance is appropriate. This approach is consistent with steps taken by other Canadian jurisdictions.

Project Risks / Impacts

The overall risk of this project is low because it is based on proven technology and will be implemented by experienced engineering and field staff.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

Not applicable.

5.5.1.1.4 RAS – Revelstoke G5 Generation Shedding Modifications

In-Service Date: August 2010 — Priority Rating: 2

Capital Cost: $1.7M — Estimate Accuracy: +35% / -15%

Study Phase: 100% complete

Description

This project is to expand and upgrade the existing Revelstoke Generating Station (REV) generation shedding RAS to integrate REV G5 into the existing RAS making REV G5 available for generation shedding in response to contingencies. The new RAS would also be designed with built-in redundancy.

Justification

REV G5 was nominated by BC Hydro in its recent NITS Update with an earliest in-service date of August 2010. In this update, REV G5 is designated to serve domestic load in BC.

This reinforcement is required to expand and upgrade the REV generation shedding RAS to address the increased levels of REV generation. This reinforcement will also improve the overall reliability of the REV RAS by providing redundant equipment at REV as specified by the NERC/WECC Planning Standards discussed in Section 5.5.1.1.2 above.

Discussion of Alternatives

BCTC believes that deferring the project is not acceptable. The unit should be operable if a single contingency or maintenance outage occurs on the system. The unit should also be able to be selected for shedding in the case of double outages.

The REV generator shedding RAS is also presently non-compliant with the new NERC/WECC Planning Standard III.F.S1.

Project Risks / Impacts

The overall risk of this project is low because it is based on proven technology and will be implemented by experienced engineering and field staff.

Stakeholder Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

The project requirement is directly related to the REV G5 project schedule.

5.5.1.2 Future Projects

The following list sets out potential future Bulk System projects which could form the basis for future project approval submissions. The projects that will need Certificate of Public Convenience and Necessity (CPCN) processes for approval are also listed in this category.

5.5.1.2.1 5L51 and 5L52 Thermal Upgrade

In-Service Date: April 2010

Capital Cost: $3.3M Estimate Accuracy: +20% / -10%

The Thermal Upgrade Project involves upgrading the 500 kV 5L51 and 5L52 transmission circuits that comprise the Ingledow-Custer transmission tie, also referred to as the western tie of the BC-US intertie. The circuits connect the Ingledow Substation (ING) in the BCTC Control Area to the Custer Substation in the Bonneville Power Administration Control Area. By increasing the circuit ratings of 5L51 and 5L52 from 2520 and 2000 Amperes respectively, to 3000 Amperes, the upgrade will result in an additional 870 MW of south-to-north firm transmission capacity on the BC-US intertie.

This project is proposed to be the first project under BCTC's Transmission Expansion Policy under Special Direction 9, which BCTC filed with the Commission in a separate application on December 12, 2007.

5.5.1.2.2 5L76/5L79 and 5L96 Series Compensation

In-Service Date: October 2017

Capital Cost: $60.0M

BC Hydro is considering the addition of REV G6 (500 MW) between 2012 and 2018. The existing transmission network will not be adequate to interconnect the expanded REV into the system. This project would add approximately 50% series compensation to the two 500 kV circuits 5L76/5L79 between ACK and Nicola Substation (NIC) and the 500 kV circuit 5L96 between SEL and Vaseux Lake Terminal Station (VAS).

5.5.1.2.3 Interior to Lower Mainland Reinforcement – Implementation Phase

Earliest In-Service Date: Fall 2014

Total Capital Cost: $602.1M

Definition Phase Cost: $31.8M

Implementation Phase Cost: $570.3M

Continued load growth in the Lower Mainland and Vancouver Island, firm export commitments, and flexibility of dispatching large interior generating resources will require reinforcement of the ILM transmission grid. Definition work is on-going as approved by Commission Order G-103-04. On November 5, 2007, BCTC submitted its application to the Commission for a CPCN. The approval of the implementation phase will depend upon the outcome of the CPCN application. The capital cost shown for the implementation phase of the project includes definition activities which are expected to continue after approval from the Commission.

5.5.1.2.4 Meridian 2x110 MVAr, 230 kV Shunt Capacitors

In-Service Date: As early as October 2011

Capital Cost: $5.3M

After 5L83 is in service, this reinforcement at Meridian (MDN), along with the shunt capacitors at NIC (see Section 5.5.1.2.5) and with modifications to line-drop compensation settings on the Burrard Thermal Generating station units, would increase the voltage stability of the ILM grid to serve firm load. However, building this project at its earliest in-service date of approximately 2011 could increase the non-firm capability of the ILM grid by about 450 MW. This increase in capacity is considered non-firm as, while the voltage stability of the system would remain within acceptable limits following an N-1 contingency, it would still overload the thermal limit of the existing lines after one hour. As the additional capacity is non-firm, it can be cut following an N-1 contingency, ensuring the system remains within acceptable limits. The economics of the non-firm trade needs to be determined, along with the risk of cost escalation, and compared to the incremental cost of an earlier in-service date to determine if this project should be advanced.

5.5.1.2.5 Nicola 1x250 MVAr, 500 kV Shunt Capacitor

In-Service Date: As early as October 2011

Capital Cost: $5.7M

After 5L83 is in service, this reinforcement, along with the shunt capacitors at MDN and with modifications to line drop compensation settings on the Burrard Thermal Generating station units, would increase the voltage stability of the ILM grid to serve firm load. However, building this project at its earliest in-service date of 2011 could increase the capability of the ILM grid by about 450 MW for non-firm trade if this is economic (see above).

BCTC will evaluate the economic benefits of the Nicola and Meridian shunt capacitors once the non-firm benefits are determined by customers.

5.5.1.2.6 Nicola 500 kV Substation Reconfiguration

In-Service Date: October 2013

Capital Cost: $10.0M

Seven 500 kV transmission lines currently terminate at Nicola Substation (NIC). As more than 50% of BC Hydro's generation flows through NIC, and in light of potential generation additions in the region, BCTC is considering reconfiguration of NIC to minimize the probability of loss of the entire station in the event of multiple contingencies or natural disasters such as seismic events. This project is a low-probability high-impact type of reinforcement where the need depends upon the long-term development of the South Interior resources and the determination of acceptable risk for these types of events.

The Definition Phase for this project was approved by Commission Order G-91-05. This project has subsequently been deferred and re-listed as a future project due to a re-evaluation of the risk and the uncertainty of the resource plans. For example, BC Hydro has recently made an OASIS request for Mica G5, Mica G6 and REV G6, but their approval and in-service dates are still uncertain. Given this, there is now more opportunity to evaluate the reliability-based justification and the timing of the station's configuration changes. The project was cancelled as a Definition Phase item but the system planning evaluation of the possible reconfiguration alternatives is continuing. The system planning work will evaluate alternatives, select a feasible preferred alternative, and provide a reliability-based indication of the justification for the project. When this system planning work is available, BCTC plans to seek Definition Phase funding from the Commission

5.5.1.2.7 RAS – Provision for Unidentified Additions

In-Service Date: Various

Capital Cost: $4.5M

This project relates to additional RAS that may be identified over time.

5.5.1.2.8 South Interior Series Compensation Project – Implementation Phase

In-Service Date: After 2011

Total Capital Cost: $54.6M

Implementation Phase Cost: $53.0 M

This project will be needed to accommodate additional forecast generation additions in the SI, such as the Waneta expansion. BCTC is currently working on the Definition Phase work related to the installation of two series capacitors for the 5L91 and 5L98 transmission circuits in the South Interior as approved by Commission Order G-69-07. Approval for Implementation Phase work will likely be sought following conclusion of the project's Definition Phase and finalization of BC Hydro's Resource Plans.

5.5.1.2.9 Undefined Upgrades for GMS x Williston x Kelly Lake System

In-Service Date: After 2010

Capital Cost: $95.0M

The existing available transfer capacity from GMS and Peace Canyon Generating Station (PCN) to Williston Substation (WSN) is approximately 350 MW and is forecast to be adequate to cover the dependable generation capacity additions up to 2010, including the dependable generation capacity from BC Hydro's F2006 CFT. BCTC continues to conduct studies to address future transmission upgrades to accommodate new resource addition in this region.

5.5.2 Regional System Reinforcements

The regional transmission systems are generally comprised of a large portion of the 230 kV system and all of the 138 kV and 60 kV systems. Regional transmission systems include transmission facilities that service localized geographic areas. Growth projects at this level often involve the installation of additional regional capacity in order to support area load growth and maintain area supply reliability. Regional reinforcement projects are designed to enhance regional transmission facilities, and can include additions to or upgrades of lines or substation equipment.

The following sections provide a description of the regional reinforcement projects submitted for approval, and those contemplated for future consideration.

5.5.2.1 Area Reinforcement Projects For Approval

5.5.2.1.1 Golden 69 kV System Reinforcement – Definition Phase

In-Service Date: October 2012	Priority Rating: 5
Total Project Cost: $78.0M	Study Phase: 30% complete
Definition Phase Cost: $3.0M	Estimate Accuracy: ± 50%

<u>Description</u>

Definition Phase funding is requested to complete preliminary environmental, engineering and consultation work associated with the facilities necessary to reinforce or upgrade the 69 kV system supplying load growth in the upper Columbia Valley. System planning studies are presently being undertaken to identify the preferred alternative for system reinforcement/upgrading purposes, including an assessment of the 230 kV, 138 kV and 69 kV transmission options available and further consideration of potential Special Direction No. 9 applications, consistent with the Direction provided by the Commission on page 66 of its Decision on the F2008 Capital Plan:

> Several costly transmission projects, such as the Golden 69 kV System Reinforcement project and the North Thompson 138 kV System Reinforcement project have been proposed for areas currently served by single radial transmission lines. The Commission Panel encourages BCTC to consider the application of SD9 in such situations, and examine the feasibility of alternate routes to the remote ends of the radial lines, rather than paralleling existing transmission lines.

This funding request is for project definition and scoping work for the preferred alternative, including the preparation of a Project Plan and a CPCN application. This work is planned to be initiated in F2009, after the preferred alternative has been identified.

Justification

The upper Columbia Valley is supplied radially from Invermere Substation (INV) by a 69 kV transmission line approximately 129 km in length, resulting in a high impedance system with severe voltage constraints during peak load periods. This situation is exacerbated by the load at Golden being located at the very end of the 69 kV transmission line. It is the Golden area load growth that primarily drives the need to upgrade or reinforce this system.

The latest forecast (see table below) shows Golden Substation (GDN) peak load to be 27.0 MVA in F2008, increasing to 29.0 MVA in F2013, primarily due to potential development at the Kicking Horse Ski Resort and tunnel lighting and ventilation associated with the provincial government's Kicking Horse Highway project.

Table 5-5. Golden Load Growth

South Interior	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Substation																		
Golden	12	GDN	7.6	9.9	9.4	9.6	10.0	10.4	10.5	10.5	10.6	10.6	10.7	10.7	10.8	10.8	10.8	10.9
				29.7%	-5.1%	2.1%	4.2%	4.1%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.3%	0.3%	0.3%
Golden	25	GDN	14.7	14.2	15.1	14.9	16.2	16.6	18.0	18.1	18.2	18.3	18.4	18.4	18.5	19.1	19.2	19.2
				-3.4%	6.3%	-1.3%	8.7%	2.4%	8.7%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	3.1%	0.3%	0.3%
Total Golden			22.3	24.1	24.5	24.5	26.2	27.0	28.5	28.6	28.7	28.9	29.0	29.2	29.3	29.9	30.0	30.1
				7.9%	1.7%	0.0%	6.9%	3.0%	5.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	2.1%	0.3%	0.3%

Table 5-6. South Interior Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
South Interior*			849.5	907.7	897.6	947.0	1005.6	1036.3	1060.6	1072.9	1086.1	1094.9	1103.1	1109.7	1115.4	1120.7	1124.5	1128.4
				6.8%	-1.1%	5.5%	6.2%	3.1%	2.3%	1.2%	1.2%	0.8%	0.7%	0.6%	0.5%	0.5%	0.3%	0.3%

GDN supplies load at both 12 kV and 25 kV. On the 12 kV system, the peak demand depends heavily upon LP Engineering operations (a major industrial customer), as any variation in their peak demand causes variation in the station peak demand. On the 25 kV system, small variations can be experienced due to industrial/commercial load activity. In 2007, a large increase occurred on the 25 kV system due to spot load increases and higher general load growth. When comparing the Golden load with the overall South Interior regional load, similar trends are seen except in F2006. Due to the reasons outlined above for Golden specific load behavior (the spot loads and industrial/commercial customers of the Golden service area), Golden load changes are not always mirrored in the South Interior load changes. In the future, more spot load increases are forecasted on the 25 kV system.

In F2009, the total load increase in the Golden load forecast due to spot load developments is 1.36 MVA, representing approximately a 4.9% increase in the GDN load. To meet this immediate load growth, one 69 kV 5.4 MVAr capacitor bank will be added at GDN in F2009.[10] However, by F2013, the existing 69 kV system will not be capable of meeting the peak load demand at GDN under single-contingency outage conditions (i.e., either the loss of Spillimacheen Substation (SPN) generation or a GDN transformer).

Discussion of Alternatives

While the preferred solution has not yet been identified, several alternatives are being presently being considered.

Option 1: Shunt VAr Compensation

Option 1 is to increase the VAr support at GDN by installing an additional 69 kV capacitor bank and a Static Compensator (STATCOM). Apart from providing additional VAr support, the STATCOM would also provide a means to control capacitor bank switching and dynamic voltage conditions resulting from faults or switching operations. However, preliminary studies indicate that with GDN at the maximum 35 MVA supply level, the losses could exceed 19 MW under normal peak-load conditions.

Option 2: Series Compensation

Option 2 is to provide series compensation in the existing transmission line. Series compensation is usually used in higher voltage transmission

[10] Approved by Commission Order G-67-06.

systems to reduce the inductive impedance of a transmission line, thus reducing the voltage drop over the line due to the flow of reactive power from the source end to the load end. The reduction in voltage drop over the line due to this component of load flow helps to resolve voltage constraints within these systems. This is not usually practical in lower voltage transmission systems due to the significantly higher component of resistive impedance relative to inductive impedance. Due to the higher resistive impedance, the reduction in voltage drop due to series compensation in lower voltage systems is not usually very significant. In this particular situation, the use of series compensation would be even less effective due to the high degree of reactive power compensation provided at GDN. Because the reactive power component of the Golden load is already more than compensated by the installation of capacitor banks in GDN, there is no reactive power flow from Invermere to Golden, hence there is no voltage drop normally associated with this component of load flow.

Option 3: Upgrade 60L271 INV-GDN Conductor

Option 3 is to replace the existing conductor with a higher-capacity, lower-impedance conductor. This may not be practical or economically feasible due to the frequency and duration of outages required to facilitate the upgrade.

Option 4: 69 kV System Reinforcement

Option 4 is to construct a second 69 kV transmission line from INV to GDN.

Option 5: 69/138 kV System Conversion

Option 5 is to construct a 138 kV transmission line from INV to Golden. This option would necessitate the installation of 230/138 kV transformation facilities at INV and either the development of a new 138/69 kV step-down substation in the vicinity of Golden, the conversion of GDN to 138 kV operation, or the development of a new 138/25 kV distribution substation in the vicinity of Golden. The last 63 km of 60L271 was constructed to 138 kV standards (i.e., from SPN to GDN) and could be used as part of a new 138 kV circuit from INV to GDN; however, use of this section for 138 kV purposes would necessitate the conversion of both Parson Substation (PSN) and GDN to 138 kV operation.

Option 6: 138 kV System Reinforcement, Initial Operation at 69 kV

Option 6 is to construct a new 138 kV transmission line from INV to Golden and initially operate it at 69 kV in parallel with 60L271. In the longer-term, when the load increases beyond the supply capability of the 69 kV system, the system would be converted to 138 kV operation by converting the SPN-GDN section of 60L271 to 138 kV and installing the associated substation facilities as in Option 5 above.

Option 7: 230 kV System Reinforcement

Option 7 is to construct a 230 kV transmission line from INV to Golden. This option would necessitate either the development of a 230/69 kV step-down substation or a new 230/25 kV distribution substation in the vicinity of Golden.

Option 8: Local Generation or Energy Storage Systems

Option 8 is to develop a new thermal generating station in the vicinity of Golden for longer-term supply purposes or to install peaking generating plants or stored-energy systems for peak-load supply purposes.

Option 9: Transmission Expansion Policy Alternative

In response to the Commission’s Direction on page 66 of its Decision on the F2008 Capital Plan, requiring BCTC to consider the application of SD9, BCTC issued a Request for Transmission Expansion Policy (TEP) Project Proposals on June 12, 2007. In response to that request, BCTC received, and will consider in its system planning studies, a submission that proposes the construction of several branches of new transmission line interconnecting the North Thompson Valley line (1L210), the Mica radial line (60L223) and the Golden line (60L271). This alternative is intended to facilitate the integration of numerous small hydro projects in the Goldstream to Mica and Golden areas and, along with Option 8 above, will address the Commission's instructions regarding SD9 and the use of alternate routes to supply load at the remote ends of the radial lines, as opposed to paralleling existing transmission lines.

Option 10: Defer the Project

BCTC believes that deferring the project is unacceptable as it would initially expose customers to the risk of unacceptably low voltage levels, hence a lower standard of power quality, and ultimately result in insufficient system capacity to supply future load growth in the upper Columbia Valley.

If a transmission option is selected, there is existing property and transmission right-of-way available for Options 1 to 8. Property for a new substation in the vicinity of Golden (designated the Alpine Substation site) and a transmission line right-of-way from INV to the substation site sufficient to accommodate a 230 kV transmission line were acquired in the early 1980s to facilitate long-term supply to the Golden area. Issues with site and route selection will be identified and assessed during the definition phase

Project Risks / Impacts

The two main risks associated with this project are:

(a) Long lead time to implement a transmission solution; and

(b) Uncertainty about area load growth.

If one of the transmission reinforcements is identified as the preferred alternative, significant lead time is needed to complete the required consultation, environmental assessment, engineering work and to obtain the necessary regulatory approvals (e.g., potential CPCN).

The load growth rates forecast for GDN in 2007/2008 and beyond are presently between 0.3% and 0.5% per year, whereas the average historical load growth rate, based on the normalized data provided in BC Hydro's annual load forecast, indicates that the load growth rate over the 19-year period from F1987 to F2006 was 2.6% per year. If load develops more quickly than presently forecast, or if the project is delayed or deferred beyond F2013, it may be necessary to either install diesel generators for peak load supply purposes or provide additional VAr support (likely a STATCOM) to meet load demand.

Stakeholder Consultation

Although BC Hydro presently owns the right-of-way and a substation site in the vicinity of Golden upon which any new transmission or substation facilities would likely be located, First Nations issues, social issues and environmental issues will still need to be addressed.

Related / Dependent Projects

None.

5.5.2.1.2 Woods Lake Area Reinforcement – Definition Phase

In-Service Date: October 2010 Priority Rating: 5

Total Capital Cost: $23.0M Estimate Accuracy: +100% / -50%

Transmission Capital Cost: $18.4M (80% of total)

SDA Capital Cost: $4.6M (20% of total)

Definition Phase Cost: $0.5M Study Phase: 80% complete

Description

BCTC is requesting Definition Phase funding to complete preliminary environmental and engineering work associated with the facilities necessary to reinforce or upgrade the 69 kV system to supply load growth in the Woods Lake service area.

System planning studies are presently being undertaken to identify the preferred alternative for system reinforcement/upgrading purposes. This includes an assessment of the 138 kV and 69 kV transmission options and 25 kV distribution options available, including upgrading the existing Woods Lake Substation (WDS) to meet long-term requirements, establishing supply to a new BC Hydro substation in the WDS supply area via the FortisBC 138 kV system, and direct supply to the BC Hydro distribution system via FortisBC distribution substations. BCTC has been coordinating its planning with FortisBC to ensure the overall solution is the lowest cost option.

<u>Justification</u>

The 69 kV system supplying WDS will require a number of upgrades over the next several years to meet area load growth.

The critical issues driving these upgrades are:

(a) The maximum feasible upgradeable capacity of 60L205;

(b) The right-of-way deficiency for 60L205 from Vernon Terminal (VNT) to WDS; and

(c) The 138/69 kV transformation capacity available at VNT.

By F2011, the capacity of the single 69 kV transmission line supplying WDS will also be exceeded.

Table 5-7. Woods Lake Load Growth

South Interior	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Substation																		
Woods Lake	12	WDS	6.0	7.1	6.8	8.0	7.2	9.2	9.3	9.5	9.7	9.8	9.9	10.0	10.1	10.1	10.2	10.2
				18.3%	-4.2%	17.6%	-10.0%	27.8%	1.4%	1.4%	2.1%	1.0%	1.0%	1.9%	0.5%	0.5%	0.5%	0.5%
Woods Lake	25	WDS	14.2	16.8	15.4	19.2	21.1	20.7	22.3	23.8	25.0	25.9	26.9	27.1	27.2	27.3	27.4	27.5
				18.3%	-8.3%	24.7%	9.9%	-1.9%	7.6%	7.0%	4.9%	3.7%	3.6%	0.8%	0.4%	0.4%	0.4%	0.4%
Total Woods Lake			20.2	23.9	22.2	27.2	28.3	29.9	31.6	33.3	34.7	35.7	36.7	37.1	37.3	37.4	37.6	37.8
				18.3%	-7.1%	22.5%	4.0%	5.7%	5.7%	5.4%	4.1%	3.0%	2.9%	1.1%	0.4%	0.4%	0.4%	0.4%

Table 5-8. South Interior Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
South Interior*			849.5	907.7	897.6	947.0	1005.6	1036.3	1060.6	1072.9	1086.1	1094.9	1103.1	1109.7	1115.4	1120.7	1124.5	1128.4
				6.8%	-1.1%	5.5%	6.2%	3.1%	2.3%	1.2%	1.2%	0.8%	0.7%	0.6%	0.5%	0.5%	0.3%	0.3%

WDS supplies load at both 25 kV and 12 kV voltage levels and experiences small variations due to industrial/commercial activity. Because of load transfer from the 12 kV to the 25 kV system, respective decreases and increases can be seen in 2006, while a spot load increase on the 12 kV system caused a large increase in 2007. The 2007 load transfer from the 25 kV system at WDS to the neighboring VNT results in negative growth. Similar relative trends can be seen between the Woods Lake and South Interior load forecasts; however, due to the activity (e.g., load transfers) and high load growth at Woods Lake as outlined above, very little similarities exist when comparing these two load forecasts in the absolute sense.

The capacity of the VNT 138/69 kV LTC transformer normally used to supply the VNT 69 kV system (i.e., T12 is nominally rated 33.3 MVA but has a winter rating of 49.3 MVA based on its hot-spot temperature of 105 ˚C, to be verified by field testing) will be exceeded by F2014. Further, subject to real-time rating studies planned for the backup transformer, the firm VNT 138/69 kV transformation capacity will be exceeded no later than F2014, possibly earlier.

The existing transmission line is very old with mixed construction. As a result, significant upgrades would be required to increase the capacity of this circuit and, in order to minimize the frequency and duration of outages to WDS, special construction techniques would likely be required that would significantly increase the cost of the upgrade.

In addition, there are deficiencies with the right-of-way rights associated with the existing 69 kV circuit supplying WDS (60L205 VNT-WDS). The existing right-of-way is only 3 meters wide over several sections of the transmission line route whereas a 69 kV circuit requires 10 meters. BCTC proposes to address this issue as part of the project.

Discussion of Alternatives

Option 1: Retain the existing WDS 69/12-25 kV substation, convert the 12 kV load to 25 kV and upgrade the existing VNT-WDS 138/69/25 kV system to meet long-term requirements, including upgrades to the VNT 138/69 kV transformation, VNT-WDS 69 kV transmission and WDS 69/25 kV Substation.

Option 2: Retire the existing WDS 69/12-25 kV substation, convert the 12 kV load to 25 kV, construct a new 138/25 kV substation at the undeveloped WDS No. 2 substation site and interconnect it to the FortisBC 138 kV system in the vicinity of WDS No. 2.

Option 3: Retain the existing WDS 69/12-25 kV substation, convert the 12 kV load to 25 kV, construct a minimal WDS No. 2 – 138/25 kV substation at the undeveloped WDS No. 2 substation site to meet the demands of future WDS area load growth and interconnect it to the FortisBC system as in Option 2 above.

Option 4: Retain the existing WDS 69/12-25 kV substation, convert the 12 kV load to 25 kV, construct a 25 kV feeder extension from the BC Hydro service area into the FortisBC service area to meet the demands of future WDS area load growth and interconnect it to the FortisBC system at the distribution level.

Option 5: Retire the existing WDS 69/12-25 kV substation, convert the 12 kV load to 25 kV, construct four 25 kV feeders from the BC Hydro service area into the FortisBC service area and interconnect them to the FortisBC system at the distribution level.

Option 6: Demand side management was not considered to be practical in this instance because the magnitude of the likely achievable DSM effects would be insufficient to address the need. This is due to the high load growth rate in the Woods Lake area, the nature of the single-circuit system supplying the existing WDS, and the type of customers supplied in this area. Load is growing rapidly in this area and high load growth rates are expected to continue for the foreseeable future, resulting in an ever increasing requirement for DSM initiatives that could be increasingly difficult to meet. Further, when the capacity of this single-circuit system is exceeded, any DSM initiatives implemented at that time would be required under normal system conditions on an ongoing basis and would likely require more-or-less permanent seasonal adjustments to present energy use patterns. However, the Lake Country District is primarily a residential area consisting largely of retirees, young families and commuters working in the Vernon or Kelowna areas. These energy consumers may be reluctant or unable to alter their energy consumption patterns and lifestyle to meet demand side management requirements.

Option 7: Generation developments were not considered to be a feasible solution due to the likelihood that any run-of-river hydroelectric plants would experience watershed freeze-up during the critical winter peak load period and that the nature of the Lake Country District (primarily residential) would preclude any thermal generation developments. Further, no generation proposals were received for developments in this area in response to the recent Calls For Tender.

Option 8: BCTC believes that deferring the project would be unacceptable. Not upgrading or reinforcing the VNT 138/69 kV transformation facilities could eventually result in damage to the two existing transformers due to overload conditions and an inability to supply area load demand. The right-of-way deficiency issue must be resolved as the right-of-way is only 10 feet wide for 80% of the line which is located on private land and not within a road allowance (the typical right-of-way width of a 69 kV line is 10 meters). There are public safety concerns associated with such a narrow right-of-way. BCTC is working to resolve this issue by acquiring deficient right-of-way or relocating facilities.

A substation site designated Woods Lake No. 2, and right-of-way between the substation site and FortisBC’s 230 kV right-of-way between VNT and FortisBC's Lee Terminal Substation (LEE), were acquired in the early 1980s to facilitate long-term supply to this area. Any new BC Hydro transmission and substation requirements will likely be located on this right-of-way and substation site as well as on right-of-way adjacent to FortisBC’s 230 kV inter-utility tie circuits.

BCTC is continuing planning discussions with FortisBC in order to develop the preferred option. In the event that the preferred option uses the substation site and right-of-way acquired in the early 1980s or FortisBC's Duck Lake substation to supply WDS, it would be necessary to obtain the required approvals and negotiate agreements and contracts with FortisBC for the use of their facilities.

Project Risks / Impacts

There are several risks associated with this project. First, regardless of which option is chosen, the deficient rights associated with the existing right-of-way must be resolved. Another significant risk is load growth. Load growth is presently forecast at 1.5% from F2008 to F2011, 1.0% from F2012 to F2013, and 0.5% thereafter, whereas the average load growth rate over the last 10 years has been marginally above 3%, based on normalized load growth data provided in BC Hydro's annual load forecasts. Further, the load growth rate presently used by FortisBC for its entire North Okanagan supply area is over 4% for the next several years. If load develops more quickly than presently forecast and there is insufficient capacity available to supply new load prior to completing the project to be implemented, it may be necessary to temporarily transfer load to the FortisBC system or install diesel generators for peak load supply purposes. The residual risk for these alternatives would be the costs incurred to facilitate supply via FortisBC or the operating costs for the diesel generators.

Stakeholder Consultation

Although BC Hydro presently owns the substation site and associated right-of-way upon which a new substation and part of the new transmission facilities would likely be located, First Nations issues, social issues and environmental issues will still need to be addressed. These issues would likely be exacerbated for any new right-of-way requirements necessary to facilitate supply from either the FortisBC system or the BC Hydro system via VNT, the additional right-of-way required for both options likely being located adjacent to the FortisBC inter-utility tie circuits.

Related / Dependent Projects

None.

5.5.2.2 Future Projects

5.5.2.2.1 2L39 Como Lake Loop

In-Service Date: December 2011

Capital Cost: $12.0M

Circuit 2L52 (Meridian-Como Lake) is a major circuit in the Metro North 230 kV Transmission System that supplies power from MDN to the northern area of Coquitlam, Burnaby and Downtown Vancouver. Supply from MDN to these areas is redirected if 2L52 is not available, resulting in heavy power flow on the other 230 kV circuits in the Metro North 230 kV Transmission System, especially 2L50. Due to load growth, Circuit 2L50 would be overloaded by F2011. By looping 2L39 into Como Lake Substation (COK) there will be two circuits connecting MDN to COK and, as a result, loss of 2L52 would not jeopardize the supply of power from MDN.

5.5.2.2.2 Central Vancouver Island Transmission Project – Implementation Phase

In-Service Date: October 2010

Total Capital Cost: $84.3M

Implementation Phase Cost: $81.8M

Load growth in central Vancouver Island has resulted in the transmission system experiencing thermal constraints in two portions of the system, the 138 kV circuits 1L115/1L116 and the VIT transformers. Definition Phase work is ongoing, as previously approved by the Commission in Order G-69-07. An application for a CPCN is expected in 2008. Approval of the Implementation Phase will depend on the outcome of the CPCN application.

5.5.2.2.3 Colwood Area Reinforcement

In-Service Date: October 2013

Total Project Cost: $47.0M

Definition Phase Cost: $1.5M

Implementation Phase Cost: $45.5M

BCTC is considering reinforcement of the transmission system serving the Colwood/Langford, Sooke, and Jordan River areas, which are supplied radially by one 138 kV circuit from Goward Substation (GOW) in the Victoria area. The peak load in this area is forecast to exceed the peak output of the Jordan River generation in less than five years, which presently can be used as back up when there is an outage on the radial transmission system. BCTC will undertake a study to determine the most cost effective option to reinforce the system.

5.5.2.2.4 Courtenay Area Reinforcement

In-Service Date: October 2010

Capital Cost: $5.0M

BCTC plans to undertake an area study to develop a plan to reinforce the transmission system in the Courtenay area on Vancouver Island. Based on BC Hydro's 2007 distribution substation load forecast, the load growth in the area will exceed the firm capacity of Puntledge and Comox substations that serve the area in approximately five years.

5.5.2.2.5 Definition Funding for Future Capital Projects

In-Service Date: Various

Capital Cost: $1.0M

BCTC is conducting a number of area studies to identify available system capacity to meet load growth in a variety of areas. Given the significant increases in local area and/or spot load increases that BCTC has seen over the past few years, these studies often identify an immediate need for reinforcement to meet customer demand. In some situations this may result in the advancement of an existing project, while in others a new reinforcement may be identified. This funding is to define future capital projects prior to seeking Commission approval.

5.5.2.2.6 East Fraser Valley Reinforcement

In-Service Date: October 2010

Capital Cost: $20.0M

BCTC is considering potential construction of facilities necessary to reinforce the Fraser Valley East area. The area is weakly connected to the rest of the transmission system due to double transformation and single circuit connection. The Fraser Valley East system also islands upon a single contingency which is not desirable from a system security point of view. There are aging assets and high generation connection activities in the area. An area plan is being developed to address the area's shortcomings.

5.5.2.2.7 Fort St. James VAr Support Addition

In-Service Date: October 2009

Capital Cost: $5.5M

BCTC is considering the development of a plan to alleviate existing low voltage problems at the Fort St. James Substation (FM2) in northern BC. FM2 is radially supplied by transmission circuit 60L344 and, with the recent connection of new transmission customers on that circuit, additional reactive power support is needed to support peak loads.

5.5.2.2.8 Golden 69 kV System Reinforcement – Implementation Phase

In-Service Date: October 2012

Total Capital Cost: $78.0M

Implementation Phase Cost: $3.0M

Approval for Implementation Phase work for the preferred project alternative will be sought upon conclusion of the project's Definition Phase.

5.5.2.2.9 Horne Payne Substation Expansion

In-Service Date: October 2012

Capital Cost: $15.0M

Horne Payne Substation serves the northern part of Burnaby and the northeast area of Vancouver. Load in the area is forecast to exceed the firm capacity of the transformers by 2012.

5.5.2.2.10 Long Beach System Reinforcement – Transmission Line Upgrade

In-Service Date: October 2014

Capital Cost: $42.0M

BCTC is considering potential reinforcement or upgrades to the existing 69 kV transmission line that radially supplies LBH on Vancouver Island in order to meet area load growth.

5.5.2.2.11 Long Beach System Reinforcement – Great Central Transformer

In-Service Date: October 2012

Capital Cost: $4.9M

BCTC is considering installation of a transformer with an on-load tap changer at Great Central Substation (GCL) in order to meet area load growth and correct the low voltages experienced at Long Beach Substation (LBH).

5.5.2.2.12 Metro Supply Reinforcement

In-Service Date: Various dates

Capital Cost: $87.0M

BCTC is considering potential reinforcement or upgrading of the Metro Vancouver transmission system to address emerging constraints caused by increasing load growth.

5.5.2.2.13 Mission Area Reinforcement

In-Service Date: October 2010

Capital Cost: $14.0M

BCTC is considering potential construction of facilities necessary to serve load growth in the area near Mission. Studies are presently being undertaken to identify the preferred alternative to provide feeder positions and transformation capacity. Alternatives being studied include expanding Mission substation, building a new substation, and rebuilding Whonnock substation. The Mission and Matsqui Area Supply Project (refer to Commission Order G-91-05) to reinforce transmission supply to the area is in progress, while this project is designed to expand the transformation and feeder capacity to the area to meet growing demand.

5.5.2.2.14 Mount Pleasant Area Reinforcement – Definition Phase

In-Service Date: October 2011 Priority Rating: 5

Total Project Cost: $150M

Transmission Capital Cost: $123M (85% of total)

SDA Capital Cost: $22M (15% of total)

Definition Phase Cost: $5M

Description

The Mount Pleasant / False Creek area in the City of Vancouver extends from Knight Street to Oak Street and from False Creek to King Edward (25th) Avenue. Its forecast load demand for F2008 is 110 MVA and this is expected to be 139 MVA in 10 years, 175 MVA in 20 years and 213 MVA in 30 years. Three substations presently supply this area:

(a) Sperling Substation (SPG) (20 MVA) at Arbutus and 25th Avenue;

(b) Murrin Substation (MUR) (70 MVA) at Main and Georgia Street; and

(c) Mainwaring Substation (MAN) (20 MVA) at Waverly and Inverness Street.

All three substations are loaded to their capacity. BCTC is now installing a partial feeder section at SPG to increase the area capacity in 2008.

The condition of some distribution infrastructure and its seismic risk exposure is a critical factor in determining the best long-term alternative for the area supply. The MUR feeders which supply 70 MVA of the Mount Pleasant area load are now at risk because the duct banks and associated manholes have significant deterioration and they pass through seismically unstable ground.

BC Hydro recommends abandoning this infrastructure and implementing an alternative supply.

BCTC and BC Hydro identified two basic options to replace the at-risk MUR feeders and meet the forecast area load growth:

Option 1: Efficiently expand the existing Metro substations to supply the Mount Pleasant area load and eventually build a new substation (Mount Pleasant Substation) in the area. Two solution examples for Option 1 are:

(a) Add duct banks from SPG for the growth portion of the Mount Pleasant area load and build new MUR duct banks in solid ground from MUR to replace the problematic MUR duct banks, or

(b) Add duct banks from SPG for the growth portion of the area load and replace the existing 70 MVA of MUR duct bank load. The capacity to supply the 70 MVA MUR load would be provided by adding a transformer and new feeder sections at SPG.

Option 2: Advance the installation of the new Mount Pleasant Substation in the South False Creek area. The new substation will supply the forecast area load growth and absorb the 70 MVA load currently supplied from MUR. Two transmission options are being considered to connect the new Mount Pleasant substation:

(a) Extend and loop the adjacent Horne Payne – MUR 230 kV circuit (2L32) to supply the substation, or

(b) Build a new 230 kV circuit from MUR to the new substation to SPG. This option is more expensive but has the benefit of improving the supply reliability of the west area of Vancouver by adding a third supply circuit.

BCTC conducted three studies showing that a new substation is the more expensive option. Two of the studies were the Mount Pleasant Supply Report SPA2005-36 and its Addendum, and these were provided to BCUC in response to BCUC IR 1-7.1 to the Transmission System Capital Plan F2006 Update, filed in April 2006. Option 1 is feasible and less expensive.

BCTC and BC Hydro are jointly reviewing the studies with the present cost of construction and load growth data available. If the review supports Option 2, the substation could be in-service as early as 2011.

5.5.2.2.15 Mount Pleasant Area Reinforcement – Implementation Phase

In-Service Date: October 2011

Total Capital Cost: $150.0M

Implementation Phase Cost: $145.0M

Approval for Implementation Phase funding to construct the preferred project alternative will be sought upon conclusion of the project's Definition Phase.

5.5.2.2.16 New Westminster Area Reinforcement

In-Service Date: October 2010

Capital Cost: $15.0M

The City of New Westminster is a BC Hydro transmission voltage customer, served from two distribution substations: New Westminster Substation (NWR) and Royal Number 2 Substation (RO2). New Westminster is currently loaded to firm capacity. The load growth will need to be supplied from RO2 which is expected to also be loaded to capacity by 2009. New Westminster is requesting a long-term area study to supply the forecast load demand. One of the likely options is to increase the supply capacity of the area. This includes the rebuilding of NWR to higher capacity and constructing a new transmission line to supply the substation.

5.5.2.2.17 North Thompson 138 kV System Reinforcement

In-Service Date: October 2013

Total Project Cost: $78.0M

Definition Phase Cost: $3.0M

Implementation Phase Cost: $75.0M

BCTC is considering reinforcement of the transmission system serving the North Thompson Valley areas, which are supplied from Brocklehurst Substation (BKL) in Kamloops via a single 138 kV circuit over 320 km in length, resulting in a high impedance system with severe voltage constraints during peak load periods. This situation will be exacerbated in the near future due to upgrades presently being implemented by KMC at their pipeline pumping stations located in the North Thompson Valley. In addition to capacity constraints, the reliability of supply to the communities in this area is at risk due to the supply by a long single-circuit radial system. BCTC will undertake a study to determine the most cost effective option to reinforce the system.

5.5.2.2.18 Westbank 138 kV System Reconfiguration

In-Service Date: October 2013

Capital Cost: $33.8M

This project is driven by reliability concerns associated with the single-circuit radial transmission system that presently supplies the Westbank area. From the perspective of load growth, the existing NIC to Westbank Substation (WBK) 138 kV system is capable of supplying the Westbank area for at least the next ten years based on the present load forecast. However, the community of Westbank recently experienced a 7-hour outage due to a lightning strike that damaged the line. A similar 6-hour outage due to a lightning strike occurred in June 1994. Westbank is the largest community in the BC Hydro system supplied by a single-circuit radial system. A study is planned to be undertaken within the next year to review the options available to improve the reliability of supply to Westbank.

5.5.2.2.19 Woods Lake Area Reinforcement – Implementation Phase

In-Service Date: October 2010

Total Capital Cost: $23.0M

Implementation Phase Cost: $22.5M

Approval for Implementation Phase work for the preferred project alternative will be sought upon conclusion of the project's Definition Phase.

5.5.3 Station Expansion and Modification

Station expansion and modification projects replace, upgrade, or add capacity to existing substations to alleviate operational constraints or limitations resulting from local load growth. These projects impact transmission and distribution facilities within the substation, and may involve installing additional transformer capacity, adding switchgear, converting to higher voltages, and reconfiguring existing facilities to accommodate increased capacity requirements.

The following sections provide a description of the station expansion and modification projects submitted for approval and those contemplated for future consideration.

5.5.3.1 Projects For Approval

5.5.3.1.1 Port Kells Substation Shunt Capacitor Additions

In-Service Date: October 2008 Priority Rating: 3

Total Capital Cost: $1.9M Estimate Accuracy: +15% / -10%

Definition Phase: 100% complete

Transmission Capital Cost: $0.3M (15% of total)

SDA Capital Cost: $1.6M (85% of total)

Description

Install two 9.6 MVAr switched shunt capacitors and related facilities at the 25 kV voltage level of Port Kells Substation (PKL).

Justification

The capacitor additions at PKL substation are needed to address the unacceptably low voltages that occur when the station loses either one of the two transmission lines (60L7/60L8) that feed it. At the forecast peak load for winter 2008, and with the loss of either of the transmission lines supplying PKL, the PKL 25 kV bus voltage would drop dramatically, resulting in 19 MVA of load being curtailed to bring voltages back to a safe level and avoiding the loss of all load.

To determine the likelihood of such an event, an EENS and cost benefit study for the next 10 years at PKL was done. A total EENS for both 60L7 and 60L8 interruptions of

309 MWh was determined as well as a benefit-to-cost ratio of 5.75 using a 2.5% discount rate.

PKL supplies industrial as well as residential load in the Port Kells area. Changes in the timing of the industrial load peak can cause variations in the peak demand. The negative load growth seen in 2006/2007 and 2011/2012 is a result of load transfer to Harvie Road Substation (HRD). The HRD historical and forecast loading is included to more readily see this load transfer. HRD receives load transfer from both PKL and Whalley Substation (WHY).

Average load growth over the last five years and for future years:

Table 5-9. Port Kells Load Growth

Lower Mainland	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Area																		
Port Kells	25	PKL	97.3	100.2	114.1	126.1	125.0	92.0	95.0	97.6	100.2	92.9	95.7	97.8	99.9	101.6	98.4	100.1
				3.0%	13.9%	10.5%	-0.9%	-26.4%	3.3%	2.7%	2.7%	-7.3%	2.9%	2.2%	2.2%	1.7%	-3.2%	1.8%
Harvie Road	25	HRD	0.0	0.0	0.0	0.0	0.0	70.0	70.0	70.0	82.0	92.0	92.0	92.0	92.0	92.0	97.0	97.0
									0.0%	0.0%	17.1%	12.2%	0.0%	0.0%	0.0%	0.0%	5.4%	0.0%

Table 5-10. Lower Mainland Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Lower Mainland			4003.8	4258.3	4356.2	4395.7	4581.2	4720.1	4848.3	5037.3	5077.6	5149.9	5212.4	5274.5	5338.0	5403.3	5467.1	5531.5
				6.4%	2.3%	0.9%	4.2%	3.0%	2.7%	3.9%	0.8%	1.4%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%

PKL supplies industrial as well as residential load in the Port Kells area. Changes in the timing of the industrial load peak can cause variations in the peak demand. The negative load growth seen in F2007 and F2012 is a result of load transfer to HRD. The HRD historical and forecast loading is included to more readily see this load transfer. HRD receives load transfer from both PKL and WHY. When comparing the Port Kells Load Forecast with the Lower Mainland forecast little similarity is seen. This is due to the high load transfers outlined above.

Discussion of Alternatives

Option 1: Defer Capacitor Additions:

If nothing is done, PKL will continue to violate minimum acceptable voltages when PKL loses either line supplying the station under heavier loading. Specifically, a 60L7 or 60L8 outage occurring for any loading in excess of 78 MVA will cause load shedding.

Over the past 10 years, a total of 62 forced outages for both 60L7 and 60L8 occurred which, if they were to continue in the same frequency and duration over the next 10 years, will result in load shedding and a total EENS cost of about $3.0M.

Option 2: Load Transfer from PKL to HRD:

19 MVA of load would be required to be transferred to HRD to increase PKL voltage to minimum acceptable level during the loss of a transmission line supplying PKL. This option was rejected because there is not enough capacity at HRD to accommodate this load transfer and it would cost approximately $1.0M for the addition of two feeder positions while adding no capacity to the system.

Project Risks and/Impacts

This project is routine and the project risks are low.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

Not applicable.

5.5.3.1.2 Qualicum Beach Substation Reconfiguration

In-Service Date: October 2008 — Priority Rating: 1

Total Capital Cost: $1.6M — Estimate Accuracy: +15% / -10%

Transmission Capital Cost: $0.4M (25% of total)

SDA Capital Cost: $1.2M (75% of total)

Definition Phase: 50% complete

<u>Description</u>

Strong load growth has occurred in the Central VI region. Although BCTC has a project to address the long-term constraints on this system (e.g., CVI), there is a risk that the two 138 kV circuits between Dunsmuir Substation (DMR) and Jingle Pot Substation (JPT) (1L115/116) could overload before the CVI project is in service. This reconfiguration project involves the conversion of Qualicum Beach Substation (QLC) to a “Jones type” station which will even the flows on the two lines and maximize the total flow before reaching an overload condition. This will reduce the risk of overloading and the resulting load shedding. This conversion reduces the risk of overloading by allowing QLC to be served by both 1L115 and 1L116 (which balances the flow on these circuits). In addition, the reconfiguration of the station would improve the overall reliability of supply to the station since it would be supplied by 1L115 and 1L116 simultaneously.

Average load growth in Central Vancouver Island over the last five years and for future years:

Table 5-11. Central Vancouver Island Load Growth

Vancouver Island	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Area																		
Central VI			1169.1	1250.6	1240.3	1276.1	1331.7	1360.2	1383.3	1404.5	1425.9	1440.5	1448.7	1465.8	1481.7	1495.7	1506.9	1518.1
				7.0%	-0.8%	2.9%	4.4%	2.1%	1.7%	1.5%	1.5%	1.0%	0.6%	1.2%	1.1%	0.9%	0.7%	0.7%

NOTES:
** Substation + industrial

Table 5-12. Vancouver Island Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Vancouver Island*			2291.6	2410.2	2431.9	2495.5	2595.4	2634.3	2671.6	2719.0	2765.0	2792.0	2802.9	2834.8	2868.0	2893.5	2913.4	2933.6
				5.2%	0.9%	2.6%	4.0%	1.5%	1.4%	1.8%	1.7%	1.0%	0.4%	1.1%	1.2%	0.9%	0.7%	0.7%

NOTES:
*100% Coincident factor used

When comparing the Central VI forecast with the overall Vancouver Island forecast, similar relative trends are witnessed. This strong association between CVI and overall VI is due to the fact that a large percent of the VI load is made up of the CVI load.

The QLC conversion is required to reduce the likelihood of load curtailment in the event of an outage of 1L115 or 1L116.

The scope of the project includes the following:

(a) Addition of fault limiting reactors on all 25 kV feeders;

(b) Addition of two Capacitive Voltage Transformers (CVTs);

(c) Upgrade of ground grid to lower ground resistance; and

(d) Protection and control modifications.

Justification

The existing configuration of QLC causes the flow on 1L115 and 1L116 to be unbalanced since QLC can only be supplied from either 1L115 or 1L116. Therefore, the thermal capability of the DMR - JPT path (1L115/116) cannot be maximized. When an overload is detected on either of these circuits, a RAS opens these circuits at the JPT end in order to prevent damage to the circuits. This results in a capacity constraint in the region during the heavy winter period. Balancing the flow on 1L115/116 will decrease the likelihood that the RAS will need to operate.

The CVI Project, planned to be in service in October 2010, will reduce the flow on 1L115/116, thus reducing the overloading likelihood. However, the present situation needs to be mitigated with an interim solution. In addition, when this reconfiguration is complete, QLC will be supplied by both 1L115 and 1L116 simultaneously, improving reliability of supply to the station. The preferred option is to convert QLC to a Jones type substation. This type of station configuration would allow QLC to be served by both 1L115 and 1L116 simultaneously; thus balancing the flow on these circuits. A probabilistic reliability assessment was completed for this option. The table below indicates the reduction of EENS after the completion of the reconfiguration project until CVI goes in service.

Table 5-13. EENS Before and After Reconfiguration

		2008/2009 (MWh/yr)	2009/2010 (MWh/yr)
1	Before Reconfiguration	4,595	5,218
2	With Reconfiguration	3,732	4,254
3	EENS Improvement	863	964

The EENS reduction was translated to a customer damage cost of $15.1M and used in a benefit/cost analysis. The analysis considered the two-year period between now and when CVI is planned to be in service (October 2010). Assuming that this project will cost approximately $1.6M, the benefit/cost ratio is 9.4, which indicates that this project is strongly economically justified.

Discussion of Alternatives

Retaining the existing system configuration would result in a high EENS (this is the second highest level of EENS identified in this Capital Plan). The high EENS is mainly a result of QLC being served from one of the two 138 kV circuits, which causes unbalanced loading on the circuits and reduces power transfer capability of the circuits by approximately 45 MW.

Since the benefit/cost ratio is 9.4, which indicates that this project is strongly economically justified, retaining the existing system configuration.

Project Risks / Impacts

The execution risk is low since all of the work required for this project is well understood and the equipment is easily available. The risk of delay is low but, if the project is delayed until October 2010, the primary benefit from this project will be lost.

However, if this project is implemented it mitigates risks if the CVI Project experiences any delays and it also provides the long-term reliability of supply benefits.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

This project needs to be completed before CVI goes in service in 2010 since the project is intended to reduce the risk of overloading 1L115/116 prior to the in-service date of CVI.

5.5.3.1.3 Sidney Substation Transformer Cooling Upgrade

In-Service Date: July 2008 Priority Rating: 4

Total Capital Cost: $1.3M Estimate Accuracy: +15% / -10%

Transmission Capital Cost: $0.3M (20% of total)

SDA Capital Cost: $1.0M (80% of total)

Definition Phase: 100% complete

Description

Install 8 additional radiators and 12 fans to each transformer at Sidney Substation (SNY) to meet load growth.

Justification

Currently there are two 56 MVA 60-25 kV transformers at SNY. The load forecast for Sidney indicates that the firm capacity of SNY (65 MVA) presently does not meet peak load in winter 2006 (71 MVA) when there is an outage of one of the transformers. The load is expected to grow rapidly to 77.2 MVA by 2010/2011. Additional firm transformation capacity is required to meet peak load.

Table 5-14. Sidney Load Growth

Vancouver Island	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Area																		
Sidney	25	SNY	65.7	61.1	58.7	69.3	63.4	68.5	70.7	72.0	73.2	74.3	75.4	76.5	77.6	78.7	79.9	81.0
				-7.0%	-3.9%	18.1%	-8.5%	8.0%	3.2%	1.8%	1.7%	1.5%	1.5%	1.5%	1.4%	1.4%	1.5%	1.4%

Table 5-15. Vancouver Island Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Vancouver Island			1667.8	1759.8	1760.2	1838.8	1926.6	1971.2	2007.2	2045.6	2073.1	2094.1	2113.7	2133.8	2152.6	2172.3	2192.2	2212.4
				5.5%	0.0%	4.5%	4.8%	2.3%	1.8%	1.9%	1.3%	1.0%	0.9%	1.0%	0.9%	0.9%	0.9%	0.9%

Load transfers between the Keating Substation (KTG) and SNY are causing various load fluctuations, positive and negative, between the stations. These load transfers make it difficult to compare the load forecasts between Sidney and the overall Vancouver Island region and are the reason for the discrepancies seen. The long term trends past 2009/2010 are relatively similar.

The recommended solution is to install additional cooling (8 radiators and 12 fans) to each transformer to increase the firm transformation capacity to 87 MVA, which is sufficient for the forecast load growth beyond 2017.

<u>Discussion of Alternatives</u>

Option 1: Defer Upgrade

Present load and load growth cannot be supplied when one transformer is out of service.

Option 2: Replace transformers with 75 MVA units

This option would increase the firm capacity of the station to 100 MVA but the cost would be approximately $5.9M. Since this option is $4.6M more than the preferred option, replacing the transformers at SNY is not recommended

Option 3: Transfer load to Keating

Transferring load from SNY to KTG would require the construction of new feeders from KTG. Adding more feeders at KTG would advance the need to install more capacity (new feeder section and transformer replacements) at KTG. The planning level cost estimate for the feeder section addition and transformer replacements at Keating is $10.3M. Since this option is $9.0M more than the preferred option, this option is not recommended.

Option 4: Demand Side Management

The load served by SNY is mainly residential and commercial. DSM is not expected to reduce the peak load from 71 MVA (peak in winter 2006) to 65 MVA (firm transformation capacity) as it would require a drop of 6 MVA in a community that is experiencing growth. This is a significant reduction in use and unlikely to be achieved from residential and commercial DSM programs.

Project Risks / Impacts

Adding extra cooling to existing transformers is routine. No execution risks are expected.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

None.

5.5.3.1.4 Tumbler Ridge Substation Transformer Replacement

In-Service Date: August, 2009 — Priority Rating: 1

Total Capital Cost: $8.2M — Estimate Accuracy: ± 10%

Transmission Capital Cost: $0.2M (3% of total)

SDA Capital Cost: $5.0M (97% of total)

Definition Phase: 100% complete

<u>Description</u>

Replace the existing two Tumbler Ridge Substation (TLR) transformers, T1 – normal standby (15 MVA) and T2 (25 MVA), with two new 75 MVA transformers.

<u>Justification</u>

This project is driven by load growth. Tumbler Ridge is experiencing large spot load increases from energy sector-customers related to oil, gas, and coal exploration and development. In 2006 - 2008 demand from Wolverine Mine (Western Coal Co.), NEMI, Shell, and a potential pipeline project are expected to be connected. The mining load is expected to continue to grow due to the many recent customer inquiries.

The majority of the load is from energy-sector customers related to oil, gas, and coal extraction industries. The load is forecast to be 24.3 MVA in 2007/2008 and 25.5 MVA in 2017/2018. Further additional spot load increases up to 10 MVA may materialize over the next ten years. The 75 MVA transformers were chosen as it is the next standard 230-25 kV transformer size available. A 75 MVA firm substation capacity would provide sufficient additional capacity to satisfy ongoing local economic expansion.

BCTC has received notification of an additional spot load that would cause the existing station capacity to be exceeded prior to the transformer replacement in-service date, so some additional work to enable both T1 and T2 to be in service at the same time will be needed prior to the in-service date of the two new transformers.

Table 5-16. Tumbler Ridge Load Growth

Northern	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Substation																		
Tumbler Ridge	25	TLR	3.9	4.3	4.8	7.4	17.7	24.3	24.4	25.0	25.1	25.2	25.3	25.3	25.3	25.4	25.4	25.5
				10.3%	11.6%	54.2%	139.2%	37.3%	0.4%	2.5%	0.4%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%

Table 5-17. Northern Area Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Northern*			675.5	724.5	730.2	745.7	814.7	844.5	859.0	872.2	879.8	885.9	890.1	893.9	896.9	899.3	901.6	904.0
				7.3%	0.8%	2.1%	9.3%	3.7%	1.7%	1.5%	0.9%	0.7%	0.5%	0.4%	0.3%	0.3%	0.3%	0.3%

Comparing the Tumbler Ridge Load Forecast with the Northern Region Load Forecast relative large increases are shared in years 2003/2004, 2006/2007, and 2007/2008 between each forecast. However, notable discrepancies exist between these forecasts due to the high mining activity in the Tumbler Ridge area as outlined above, which may or may not be shared to the same extent in the rest of the Northern region.

Discussion of Alternatives

Option 1: Use of a mobile transformer

A new 230-25 kV mobile transformer would be purchased as a contingency plan for failure of either T1 (15 MVA) or T2 (25 MVA). The maximum size is about 20 MVA so it would have insufficient capacity to fully backup T2. The cost is about $4.0M. This option was rejected because it does not increase the firm capacity of the station or meet the long-term load growth requirements: forecasted load growth along with spot load is projected to exceed the station firm capacity limit by the end of the ten year period.

Option 2: Add a new third 25 MVA transformer (T3)

A third new transformer would be added. This option would increase the station firm capacity to 40 MVA at a preliminary cost of $4.0M. There is significant uncertainty regarding the cost of this option because the substation would need to be expanded by 7 meters onto adjacent terrain which is different in elevation. This option was rejected because of the uncertainty of the civil work cost which may cause the project costs to exceed the recommended option. In addition, forecast load together with potential spot load increases may reach close to the firm capacity by the end of the 10 year period. This option may not meet the 20-year long-term load growth needs due to the uncertainty of spot load growth.

Project Risks / Impacts

Decrease of economic activity in the area such that the load forecast is revised downward.

Stakeholder and First Nations Consultation

Limited stakeholder and First Nations impact as all work is internal to the existing substation or control facilities.

Related / Dependent Projects

None.

5.5.3.2 Future Station Expansions and Modifications

5.5.3.2.1 Future Station Expansions or Modifications by Region

The following list of station expansion or modification initiatives sets out future project considerations at an early stage of analysis, and would form the basis for future project approvals.

BCTC is considering potential station expansion or modification programs in the following regions, based on anticipated load growth and emerging constraints. Project approvals will be sought at a future date pending further assessment.

Table 5-18. Future Station Expansions or Modifications

Line Number	Region/Project	Estimated Cost
1	Fraser Valley	$36.0M
2	Metro Vancouver	$40.0M
3	North Central	$12.0M
4	North East	$18.0M
5	North Shore Coastal	$53.0M
6	North West	$18.0M
7	South Interior	$65.0M
8	Vancouver Island	$80.0M

5.5.3.2.2 McLellan Substation Capacity Increase

In-Service Date: October 2011

Capital Cost: $10.0M

Load growth is forecast to exceed the 200 MVA firm capacity of McLellan Substation (MLN) in 2010. Additional transformation capacity and feeder sections are required to serve area load growth.

5.5.3.2.3 North Vancouver Substation Upgrade

In-Service Date: October 2010

Capital Cost: $16.0M

Load growth has exceeded the firm capacity of North Vancouver Substation (NVR). BCTC is developing a plan to transfer load to neighbouring substations and upgrade the existing substation.

5.5.3.2.4 Richmond Area Reinforcement

In-Service Date: October 2010

Capital Cost: $10.0M

Steveston Substation (STV), Richmond Substation (RIM) and Cambie Substation (CAM) supply the bulk of load in the City of Richmond. All three substations are heavily loaded. By 2010 the forecasted load demand at STV will exceed the station firm capacity. The lowest cost reinforcement option to supply load growth in the Richmond area is to install an additional 230/25 kV 150 MVA transformer at STV to increase the station firm capacity.

5.5.4 Customer-Requested Projects

5.5.4.1 Kinder Morgan Canada (KMC) TMX-1

In-Service Date: March 2008 Priority Rating: Mandatory

Total Capital Cost: $8.8M Estimate accuracy: ± 30%

Description

The KMC TMX-1 project will add 13 MVA of load to the North Thompson System in March of 2008. The TMX-1 project follows the KMC TMPSE project which added 32.4 MVA in March 2007.

Below is a summary table that shows the load growth in the North Thompson area, including the large load increase in F2008

Table 5-19. North Thompson Load Growth

South Interior	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Area																		
North Thompson							148.3	161.6 9.0%	163.6 1.2%	165.4 1.1%	167.3 1.2%	169.4 1.2%	171.3 1.1%	173.3 1.1%	175.3 1.2%	175.8 0.3%	176.1 0.1%	176.3 0.1%

Table 5-20. South Interior Area Load Growth

Area	kV	STN	NORMALIZED ACTUAL LOAD					FORECAST										
			F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
South Interior*			849.5	907.7 6.8%	897.6 -1.1%	947.0 5.5%	1005.6 6.2%	1036.3 3.1%	1060.6 2.3%	1072.9 1.2%	1086.1 1.2%	1094.9 0.8%	1103.1 0.7%	1109.7 0.6%	1115.4 0.5%	1120.7 0.5%	1124.5 0.3%	1128.4 0.3%

The impact of the KMC TMX-1 and TMPSE projects are shown above. When comparing the load forecasts of the North Thompson Region with the South Interior region as a whole, very little similarities can be seen besides their relatively steady long term forecasts. Again due to the large spot load additions from the KMC projects outlined above, large increases witnessed in the North Thompson region for 2005/2006, 2006/2007, and 2007/2008, are not shared with the SI region as a whole.

To meet the additional load demand and system reliability requirements associated with the KMC TMX-1 Project, the following system upgrades and reinforcements will be required:

(a) Replace the undersized cable section of transmission line 1L206 (Savona Substation (SVA) to BKL) under the Thompson River with a higher-capacity cable at least equal to the rating of the overhead section of the circuit.

(b) Construct a tap approximately 1.0 km south of the Blue River Substation (BLU) tap on the transmission line 1L211 (Avola Substation (AVO) and Valemount

Substation (VLM)) to interconnect a 138 kV transmission line to be constructed by KMC to supply their Blue River Substation (BLE). Construct another tap approximately 32 km north of the BLU tap to interconnect a 138 kV transmission line to be constructed by KMC to supply their Chappell Substation (CPL). Both taps will include a disconnect switch in the new radial sections of the line to facilitate the interconnection to the KMC lines.

(c) Avola Substation (AVO) :Upgrade the three existing 6.0 MVAr, 138 kV capacitor banks to 3 - 12 MVAr, 138 kV capacitor banks by adding additional capacitor cans to the existing capacitor banks and replace one 138 kV capacitor bank circuit breaker (1CBCX1) with a breaker capable of independent-pole operation and point-on-wave closing control. Modify the 138 kV bus including the installation of the circuit breaker removed from the 1CBCX1 position to create a position for a second STATCOM and split the existing 24 MVAr STATCOM (consisting of 2 - 12 MVAr STATCOMs) into two STATCOMs and upgrade the two STATCOMs to facilitate 24 MVAr operation under winter peak load conditions. Modify the STATCOM controls and automatic capacitor bank switching scheme to ensure that both STATCOMs will provide equal VAr support when required and to facilitate control of the capacitor banks and voltage flicker due to capacitor bank switching via either STATCOM. Upgrade the three 138/3.111 kV, 12 MVA STATCOM transformers (including an on-site spare) to facilitate 24 MVA operation for each transformer under winter peak load conditions.

(d) Expand the existing RAS to facilitate KMC load shedding as required to prevent a system voltage collapse in the upper North Thompson 138 kV system during faults external to the radial system north of BKL.

Justification

These projects are required to meet new load demand (13 MW) due to the installation of two pipeline pumping stations in the upper North Thompson Valley by KMC which are planned to enter service on 1 March 2008. The VAr support facilities required at AVO are necessary to facilitate supply to all load in the North Thompson system under normal peak-load conditions and to avoid a potential voltage collapse in the

North Thompson system for several fault conditions in the system that supplies the radial North Thompson system.

Discussion of Alternatives

Option 1: Deferring the Project

Deferring the project is not an option. The existing system does not have the capacity required to supply the TMX-1 load additions that BC Hydro has nominated as load increase in a NITS submission and has contracted with BCTC to supply it in accordance with the OATT.

Option 2: Non-wires Options:

Non-wires solutions are not practical. There is insufficient time available to implement either a DSM project or to construct generation and meet the in-service date required by KMC (1 March 2008). Further, there isn't sufficient load in the North Thompson system to implement an effective DSM project and, if the generator is a run-of-the-river hydroelectric development, it may not be available during the winter peak load period (the critical load period) due to watershed freeze-up.

Option 3: Wires Options

There is insufficient time available to implement a major system reinforcement project (such as an additional transmission line) to meet the required in-service date. The only other options to provide the system voltage support required would be to install additional capacitor banks and/or STATCOMs to provide the necessary VAr support. However, upgrading the existing facilities to meet the requirements necessary for the critical peak load period is the most economic option available to provide that VAr support.

Several options have been identified as a means to reinforce the North Thompson system, however, no planning studies have been undertaken to identify a preferred means of reinforcement. These studies are planned to be undertaken as part of the North Thompson 138 kV Reinforcement Project (see Section 5.5.2.4.18).

Project Risks / Impacts

Risks identified for this project are the tight project schedule. This will be mitigated by monitoring the progress of the project closely to ensure the project schedule is being maintained. The impact of a late completion date is that KMC may need to operate the pipeline at reduced capacity during peak load periods until the project is completed; however, as the winter peak load period will essentially be over by the time this project is scheduled to enter service, any operating impacts should be minimal.

The cable construction under the Thompson River represents a, cost and schedule risk. Equipment ordering and delivery is expected to have a low risk, although equipment delivery times and costs are increasing due to high demand for electrical equipment. KMC is aware of the risk and is prepared to provide the funding necessary to BC Hydro to facilitate equipment orders that will ensure the project schedule will be met.

Interconnections of KMC load fall under the BC Hydro tariff and BCTC is being used as a third party to plan, design, and construct the interconnection. BC Hydro will collect the CIA money for Direct Assignment costs and will also require the Customer to provide a Letter of Credit for the Network Upgrades. The customer is required to pay actual costs for the Direct Assignment and, if the Network Upgrades increase, then BC Hydro will ensure the Letter of Credit reflects this. Future Customer-Requested Projects

There are no identified future customer-requested projects.

5.5.5 Generation Interconnections

Generation interconnection projects involve the design and construction of facilities that are required to connect and integrate generation facilities to the existing transmission system. Typical work required for generation interconnections includes the construction of tap lines or a three-breaker ring bus substation, communication equipment, and protection coordination studies with associated setting changes.

Typical work required to integrate the generator into the regional network includes reinforcement of existing transmission lines and conversion of existing lines to higher voltage.

Under the grandfathered Interconnection Process which is applicable to the F2006 CFT and prior projects, generators pay for the facilities that are for the sole use and benefit of their project, and provide security for the facilities that are for the benefit of other parties as well as the generation project. Under the current Standard Generator Interconnections Procedures tariff, generators pay for only a few, if any, of the interconnection facilities, but they are required to post security for the remaining majority if not all of the interconnecting facilities.

In Order G-69-07, the Commission accepted BCTC's proposal to identify an amount for the interconnection of generation projects based on a forecast of capital needed for the upcoming year but that BCTC would not seek approval for these expenditures but would rely instead on the requirements of the OATT as the authority for proceeding with generation interconnections. As a result BCTC is proceeding with the East Toba and Montrose Creek Hydro Electric Project and the Savona ERG IPP, under the OATT, and there are no generation interconnection projects submitted for approval in this Capital Plan.

5.5.5.1 Future Generation Interconnection Projects

In-Service Date(s): Various Dates

Estimated Capital Cost: $934M

This amount represents the forecast of capital needed in future years for generation related projects. As set out in Section 5.5.5, these projects will be dealt with through the OATT and will proceed when a Facilities Agreement is signed.

5.6 Projects Attributable to Generation Additions (Directive 23)

The projects shown in Table 5-21 are attributed directly to specific generation additions.

Table 5-21. Projects Attributed to Generation Additions

Line Number	Project	Attributed Generation
1.	Ashton Creek Shunt Capacitors	See Table 5-22
2.	GMS Generation shedding	Potential Generators and NERC Reliability Compliance
3.	RAS for Bridge River	Potential Generators and NERC Reliability Compliance
4.	RAS for Rev Unit 5 Shedding	Revelstoke G5

The Ashton Creek 500 kV Shunt Capacitors project provides transfer capability for the following generation as shown in Table 5-22.

Table 5-22. New Generation Resources Attributed to Ashton Creek Shunt Capacitors (note 1)

Line Number	Generation Plant /Project Name	Expected In-Service Date	Winter Dependable Capacity (MW)	Maximum Continuous Rating (MW)	Notes
1	Revelstoke Unit 5	2010 August	500	500	BC Hydro
2	Brilliant Expansion	2007 (note 2)	0	127/144	IPP in CFT 2006
3	Canada - Glacier/Howser/East	2010	22.6	108.6	IPP in CFT 2006

Note 1: Originally from Amended LTAP in 2006 IEP.

Note 2: Brilliant Expansion entered service in summer 2007.

There is potential for generation projects in the South Interior East beyond 2010, which could use the remaining pre-contingency ATC of the Ashton Creek Shunt Capacitors. However this generation would have to be curtailed after the outage to be within the post contingency TTC.

5.7 Projects Proposed to avoid Generation Shedding (Directive 1)

In the Commission's F2008 Capital Plan decision, the Commission directed BCTC to identify projects that are being proposed to avoid generation shedding for first contingency events and to identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for first contingency events. This is from Order G-69-07, page 14, Directive 1.

The proposed projects in this Capital Plan that are being planned to avoid generation shedding are listed in the table below.

Table 5-23. Projects That Avoid Generation Shedding

	Proposed Projects	Key Drivers	Avoidable by N-1 Generation Shedding	Comments
1	Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors	Voltage stability limitations; Resource additions in South Interior	Yes	Generation Shedding was considered as an option to the reinforcements but was not selected as the preferred option. The project is described in Section 5.5.1.1.1

6.0 SUSTAINING CAPITAL PORTFOLIO

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

In the Commission's Decision on BCTC's F2008 Capital Plan, the Commission directed BCTC to reduce Sustaining Capital expenditures for F2008 and future years until changes in the trends of reliability indices or asset health assessments suggest otherwise. BCTC believes that the currently approved Sustaining Capital funding level is not adequate to address the present rate at which the transmission assets are deteriorating, and to ensure the safe, reliable operation of the transmission system.

Although BCTC has a Sustaining Investment Model that illustrates long-term capital requirements and impacts on system reliability, BCTC does not have evidence to directly correlate short-term trends of reliability to capital expenditures. However, BCTC continues to improve the Sustaining Investment Model as discussed in Appendix H, Response to Item 10(g).

To guide Sustaining Capital decisions, BCTC uses asset health assessments (asset condition and asset performance) to justify the refurbishment/replacement of transmission assets on an asset-class or specific asset basis. BCTC believes this Sustaining Capital Plan includes appropriate asset health and reliability evidence to justify an increase in Sustaining Capital expenditures. Accordingly, BCTC is respectfully requesting an increase to the currently allowed Sustaining Capital expenditures for F2009 and a further increase in F2010. BCTC considers the requested expenditures necessary to maintain the transmission system to acceptable levels of reliability, safety, and environmental performance, and is consistent with the findings of the UMS Report included as Appendix I of this Capital Plan and the Sustaining Investment Model.

Where appropriate, the investment justifications for the Sustaining Capital programs and projects identified in this Capital Plan are supported by statistical evidence illustrating deteriorating asset health and performance assessments. Decision-making that forms the Sustaining Capital portfolio considers other inputs in addition to system reliability statistics, including the accumulated experience of management, industry standards and practices, manufacturer recommendations and consultation.

BCTC uses a number of tools and methods to support data collection, synthesis, and analysis to enable efficient and effective capital planning. Some examples of tools that are used by BCTC include Indus Passport (asset management system for Stations), Oracle and STARR (asset management for lines and cables), IMAX (data collection system); DOBLE (analysis of insulation testing results), LabSys (gas in oil analysis), and Meridium (asset performance analysis). The tools that are used are supported by industry-recognized analysis methodologies including Present Value (financial justification), Mean Time Between Failure (asset performance analysis), Asset Health Assessments (asset condition), and Root Cause Analysis (asset failures). The specific tools and methods that are used to identify proposed transmission infrastructure capital investments are specific to each case.

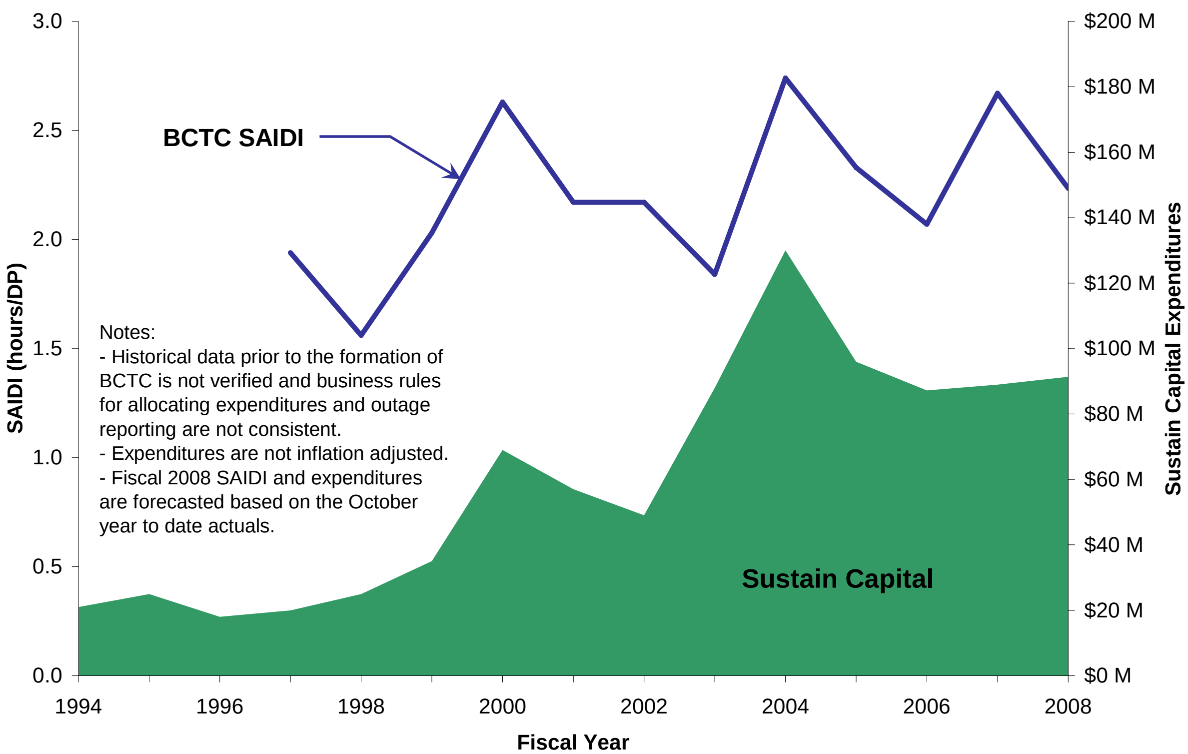
As a means of assessing overall asset health, BCTC completed an initial Base Line Audit of the transmission system in 2005. The Base Line Audit measured asset health across thirty-three asset classes to determine asset condition. The Base Line Audit concluded that there are numerous assets within the transmission system that are in poor or very poor condition.

In lieu of conducting another baseline Audit which would rely on very similar data to the initial Audit, BCTC and BC Hydro have foregone the Asset Baseline Study update that was supposed to take place this year and have instead, focused more resources on converting data to electronic format, automating data capture, and collecting missing asset health data. It will still be a number of years before BCTC has sufficiently accurate data in most asset classes to undertake a new comprehensive Asset Health Study that significantly improves the value of the original Base Line Audit.

BCTC recognizes the value that a direct correlation between transmission system reliability and Sustaining Capital investments would provide to BCTC, the Commission, and other stakeholders. However, given the relative size of the annual Sustaining Capital Portfolio budget of $112.9 million in F2009, which is approximately 1 percent of assets, BCTC submits that the correlation demonstrating annual or even short-term improvements and/or deterioration of system reliability is difficult to illustrate. On an annual basis, the correlation of reliability and the need to replace assets is evidenced by increasing equipment failures and corrective activity on an asset by asset basis that may or may not directly impact SAIDI, but will impact transmission system integrity.

Figure 6-1 illustrates a general increase in System Average Interruption Duration Index (SAIDI) in hours per delivery point (DP), which is a measure of system reliability. The majority of the Sustaining Capital expenditures in this Capital Plan address the refurbishment or replacement of system assets required to maintain targeted levels of system reliability.

Figure 6-1. Historical SAIDI and Sustain Capital Expenditures



BCTC attempts to maintain transmission system assets to meet original planning design criteria based on N-1 contingency state. If funding restraints result in BCTC not being able to maintain the transmission system at its design criteria, assets that are removed from service to preserve a safe, environmentally stable state until a replacement can be installed or the asset can be refurbished, will result in the loss of the N-1 contingency level of reliability. For example, Cheekeye and Mica 500 kV air-blast circuit breakers did not meet the original design criteria and had to be taken out of service for several weeks until replacement circuit beakers could be installed, resulting in operating the system in an N-0 condition for an extended period of time.

The currently-approved Sustaining Capital funding levels are lower than requested, with the result of delaying the timely attention to meet transmission system asset needs. Even at an increased funding level, there is currently a backlog of work which would take a number of years to address, positioning the system for potential system outages, or severe restrictions in generation.

In developing the F2009 to F2018 Sustaining Capital plan, BCTC has considered the following key factors:

(a) A large number of assets were refurbished in the 1990s as an urgent remedy to a maintenance backlog caused by insufficient funding of maintenance programs over a long period. For example, the majority of 230 kV and 500 kV air-blast circuit breakers that were 20 years or older were refurbished in the 1990s. Due to the urgency of that program, refurbishment was the preferred alternative, rather than addressing issues on a planned annual basis with appropriate funding. Additionally, the assets were still relatively new at that time. This action resulted in creating a large number of assets that now all require capital investment in F2009 and F2010, and beyond.

(b) More transmission assets that were installed in the 1960s are now reaching end-of-life condition, having deteriorated through use and age. Assets such as Air-blast Circuit Breakers, Pin and Cap Insulators, and Surge Arrestors now require attention in this Sustaining Capital plan, and will result in an even higher investment level required in the long-term.

(c) In developing its Sustaining Capital plans, BCTC recognizes that all existing assets will require programs to address end-of-life condition and programs will also have to be developed to address issues that have yet to be defined, including programs associated with spacer dampers, bridges, access roads, corrosion, and other known risks. The scope of these projects and the impact they will have on the Capital Plan in future years is unknown at this time but, as an example, there are approximately three hundred thousand spacer dampers located mid-span on transmission lines that have deteriorated and now have the potential of causing serious damage to the transmission line conductors. These will require replacement within the next decade. This project is currently being studied and a program is being designed to address this looming issue. Other examples are the condition assessment and remediation strategy associated with transmission tower grillages and pole anchors. Tower grillages are buried support structures for transmission towers that are subject to deterioration due to conditions such as ground water and soil acidity. BCTC is beginning to study this issue and will develop a program to provide necessary upgrades. However, this is another example of a program that can have a significant impact on future Capital Plan expenditures.

(d) Finally, without attempting to be exhaustive, there are a number of risks that threaten the integrity of the transmission system. These include fire, flood, adverse weather, seismic, security, safety and environment hazards that need to be addressed to enable the transmission system to provide long-term safe, reliable, and secure service.

BCTC believes that the above issues cannot be adequately addressed within the currently-approved funding levels.

BCTC is proposing this Sustaining Capital plan to ensure a long-term investment strategy for the continued reliability of the transmission system. The proposed Sustaining Capital plan provides for the minimum replacement or refurbishment expenditures which are necessary for system reliability and for minimizing outage impacts to customers.

Much of the transmission system was built in the 1960s and 1970s and is now reaching between 40 to 50 years of age. The transmission system was designed based on N-1 planning criteria that use redundancy to ensure high system reliability. The system has generally been well maintained and has required an absolute minimum level of Sustaining Capital investment to maintain an acceptable level of reliability. However, assets are showing signs of deterioration from both usage and age. BCTC has a comprehensive maintenance program, but to remain effective this requires spare parts, original equipment manufacturer support, and skilled resources, all at reasonable cost. BCTC realizes that as the transmission assets are aging and becoming more expensive to maintain, there is also decreasing access to spare parts and technical expertise that is limiting BCTC's abilities to repair at reasonable costs. The result is that as the transmission system ages, higher levels of Sustaining Capital investments are required to sustain the system as it was designed.

As stated above, the trend of the transmission system assets is moving to a more deteriorated state that requires capital refurbishment/replacement programs to ensure asset reliability. Reliability of these assets, in absolute terms relative to SAIDI, is masked because most assets have redundancy according to the N-1 planning criteria, which minimizes the impact of asset failure on customers. However, equipment failure evidence is indicating assets are deteriorating and reliability will eventually be impacted more significantly. In addition, failure to address transmission system risks has no immediate impact until an event occurs. For example, a fire at Cathedral Square which could occur as a result of not addressing an existing fire risk could cause a large outage to downtown Vancouver for an extended period of time. Such an event could be prevented with the risk mitigation project that is proposed in the F2009 Sustaining Capital Plan.

In BCTC's view, successful planning requires not only the appropriate level of funding, but also a well thought out implementation plan. BCTC develops an implementation plan that balances the capacity of manufacturers and service providers to deliver equipment and services over the long-term to the need to maintain an appropriate level of reliability, and all at reasonable cost. To accomplish this, the Sustaining Capital plan must be considered over a planning period longer than two years to ensure that equipment is replaced according to the implementation plan, and not being backlogged to future periods due to resource constraints, including funding levels, that limit the ability to execute implementation.

BCTC believes that a backlog of transmission system asset needs is not being addressed within the currently approved capital spending levels. Even at the proposed spending level in this Capital Plan, a deferral of currently identified projects to future years is required (Section 6.3.1.4 below). Serious threats to reliability, safety and the environment may occur when programs are constantly deferred into the future or are not adequately funded. In addition, there is concern that an increasing number of deteriorating assets have to be addressed now and that this deterioration rate will continue to increase in the future.

6.1 Sustain Capital Portfolio Table

For planning and management purposes, the Sustaining Capital Portfolio is divided into 11 programs:

(a) Stations:

i. Auxiliary Equipment;

ii. Circuit Breakers;

iii. Other Power Equipment;

iv. Stations Risk Mitigation;

v. Protection and Control; and

vi. Telecommunications.

(b) Lines:

i. Cable Sustainment;

ii. Overhead Lines Life Extension;

iii. Overhead Lines Performance Improvements;

iv. Overhead Lines Risk Mitigation; and

v. Right-of-Way Sustainment.

Table 6-1. Sustaining Capital Portfolio Table

Sustaining Capital Portfolio

$'000 (Escalated)

#	STATIONS	Page	IS Date	Total Project	Prior Years	F2009 Plan	F2010 Plan	F2011 Plan	F2012 Plan	F2013 Plan	F2014 Plan	F2015 Plan	F2016 Plan	F2017 Plan	F2018 Plan
	Auxiliary Equipment														
	For Approval														
1	Annual Program	206				6,697	7,601								
2	Future Program	206						7,508	8,879	8,566	8,948	9,862	9,492	9,778	10,086
3	Total for Auxiliary Equipment					6,697	7,601	7,508	8,879	8,566	8,948	9,862	9,492	9,778	10,086
	Circuit Breakers														
	For Approval														
4	Annual Program	215				19,515	24,147								
5	Horsey GIS Replacement Program	226	Mar 2010	9,235		150	2,205	6,880							
6	MCA- GIS Breaker Replacement Project	224	Jul 2008	11,727	6,144	5,583	-	-							
7	Future Program	215						26,945	31,296	33,452	36,961	40,651	43,200	45,865	48,651
8	Total for Circuit Breakers				6,144	25,248	26,352	33,825	31,296	33,452	36,961	40,651	43,200	45,865	48,651
	Other Power Equipment														
	In Progress														
9	Cathedral Square - Relocation of 2L31/32 Line Terminations	236	Dec 2008	11,692	689	4,136	6,866								
	For Approval														
10	Annual Program	229				6,827	8,638								
11	Future Program	229						8,584	7,417	6,308	7,751	6,693	7,558	7,921	8,159
12	Total for Other Power Equipment				689	10,963	15,505	8,584	7,417	6,308	7,751	6,693	7,558	7,921	8,159
	Protection and Control														
	For Approval														
13	Annual Program	249				11,740	10,672								
14	Third Party Requested Projects	258				1,219	1,179	1,215	1,252	1,289					
15	Future Program							10,098	11,098	12,788	13,123	16,041	16,505	17,666	9,289
16	Total for Protection and Control					12,959	11,851	11,313	12,350	14,077	13,123	16,041	16,505	17,666	9,289
	Risk Mitigation														
	For Approval														
17	Annual Program					7,792	7,829								
18	Murrin - Substation Reconfiguration and Seismic Upgrade		Sep 2012		89	500	1,000								
	Future														
19	Annual Program							9,518	8,706	9,559	8,522	8,778	9,040	9,310	9,579
20	Murrin - Substation Reconfiguration and Seismic Upgrade		Sep 2012	45,089				15,000	15,000	13,500					
21	Total for Risk Mitigation				89	8,292	8,829	24,518	23,706	23,059	8,522	8,778	9,040	9,310	9,579
	Telecommunications														
	In Progress														
22	Lower Mainland Network Robustness	269	Mar 2009	9,784	7,684	2,100									
	For Approval														
23	Annual Program	258				5,396	5,608								
24	Future Program	258						4,958	6,637	7,362	6,325	5,920	6,178	6,397	6,590
25	Total for Telecommunications				7,684	7,496	5,608	4,958	6,637	7,362	6,325	5,920	6,178	6,397	6,590
26	**TOTAL Stations**				**14,606**	**71,656**	**75,744**	**90,706**	**90,286**	**92,824**	**81,630**	**87,944**	**91,972**	**96,937**	**92,354**

Table 6-1. Sustaining Capital Portfolio Table (continued)

Sustaining Capital Portfolio
$'000 (Escalated)

		Page	IS Date	Total Project	Prior Years	F2009 Plan	F2010 Plan	F2011 Plan	F2012 Plan	F2013 Plan	F2014 Plan	F2015 Plan	F2016 Plan	F2017 Plan	F2018 Plan
	TRANSMISSION														
	Cable Sustainment														
	For Approval														
27	Annual Program	270				4,961	5,838								
28	Future Program	270						7,511	6,555	6,751	6,515	7,420	7,842	8,215	8,461
29	Total for Cable Sustainment					4,961	5,838	7,511	6,555	6,751	6,515	7,420	7,842	8,215	8,461
	OH Lines Life Extension														
	For Approval														
30	Annual Program	278				12,712	16,017								
31	Future Program	278						19,202	19,926	21,136	22,522	23,454	25,839	25,980	26,758
32	Total OH Lines Life Extension					12,712	16,017	19,202	19,926	21,136	22,522	23,454	25,839	25,980	26,758
	OH Lines Performance Improvement														
	For Approval														
33	Annual Program	290				4,515	5,355								
34	Future Program	290						2,867	3,543	3,041	3,132	3,227	2,658	2,738	2,820
35	Total OH Lines Performance Improvement					4,515	5,355	2,867	3,543	3,041	3,132	3,227	2,658	2,738	2,820
	OH Lines Risk Mitigation														
	For Approval														
36	Annual Program	292				9,882	9,979								
37	Future Program	292						8,987	9,687	10,191	10,559	10,362	11,203	12,225	12,873
38	Total for OH Lines Risk Mitigation					9,882	9,979	8,987	9,687	10,191	10,559	10,362	11,203	12,225	12,873
	ROW Sustainment														
	For Approval														
39	Annual Program	302				6,920	8,137								
40	Third Party Requested Projects	309				2,205	2,315								
	Future Approval														
41	Annual Program	302						8,742	8,997	9,270	9,546	9,835	10,131	10,437	10,888
42	Third Party Requested Projects	309						2,408	2,480	2,554	2,631	2,710	2,791	2,875	2,961
43	Total for ROW Sustainment					9,125	10,452	11,150	11,477	11,824	12,177	12,545	12,922	13,312	13,849
44	**TOTAL Transmission**					**41,196**	**47,641**	**49,717**	**51,188**	**52,943**	**54,905**	**57,008**	**60,464**	**62,470**	**64,761**
45	**TOTAL SUSTAINING PORTFOLIO**				**14,606**	**112,851**	**123,385**	**140,422**	**141,473**	**145,767**	**136,535**	**144,952**	**152,436**	**159,407**	**157,115**

6.2 Historical and Trend Explanations

Table 6-2. Sustaining Capital Portfolio History and Trends

	Sustaining Capital Portfolio ($M)	F2005 Actual*	F2006 Actual*	F2007 Actual	F2008 Forecast	F2009 Plan	F2010 Plan	F2011 Plan	F2012 Plan	F2013 Plan	F2014 Plan	F2015 Plan	F2016 Plan	F2017 Plan	F2018 Plan
	Stations														
1	Auxiliary Equipment	4.8	5.3	5.2	4.3	6.7	7.6	7.5	8.9	8.6	9.0	9.9	9.5	9.8	10.1
2	Circuit Breakers	9.9	17.3	11.6	18.9	25.3	26.4	33.8	31.3	33.5	37.0	40.7	43.2	45.9	48.7
3	Other Power Equipment	9.2	1.3	5.5	3.2	11.0	15.5	8.6	7.4	6.3	7.8	6.7	7.6	7.9	8.2
4	Protection and Control	8.6	8.7	7.7	9.5	13.0	11.9	11.3	12.4	14.1	13.1	16.0	16.5	17.7	9.3
5	Risk Mitigation	5.0	4.9	5.2	8.2	8.3	8.8	24.5	23.7	23.1	8.5	8.8	9.0	9.3	9.6
6	Telecommunications	11.2	10.8	8.3	10.6	7.5	5.6	5.0	6.6	7.4	6.3	5.9	6.2	6.4	6.6
7	**TOTAL Stations**	48.7	48.3	43.5	54.6	71.7	75.7	90.7	90.3	92.8	81.6	87.9	92.0	96.9	92.4
	Transmission														
8	Cable Sustainment	9.9	6.4	2.9	3.9	5.0	5.8	7.5	6.6	6.8	6.5	7.4	7.8	8.2	8.5
9	OH Lines Life Extension	15.8	16.1	20.1	11.6	12.7	16.0	19.2	19.9	21.1	22.5	23.5	25.8	26.0	26.8
10	OH Lines Performance Improvement	0.0	5.0	6.4	3.8	4.5	5.4	2.9	3.5	3.0	3.1	3.2	2.7	2.7	2.8
11	OH Lines Risk Mitigation	7.2	6.4	6.0	8.6	9.9	10.0	9.0	9.7	10.2	10.6	10.4	11.2	12.2	12.9
12	Right-of-Way Sustainment	6.1	5.5	9.8	9.1	9.1	10.5	11.2	11.5	11.8	12.2	12.6	12.9	13.3	13.9
13	**TOTAL Transmission**	39.0	39.4	45.4	36.8	41.2	47.7	49.7	51.2	52.9	54.9	57.0	60.5	62.5	64.8
14	**TOTAL SUSTAIN PORTFOLIO (a)**	**87.7**	**87.7**	**88.8**	**91.5**	**112.9**	**123.4**	**140.4**	**141.5**	**145.8**	**136.5**	**145.0**	**152.4**	**159.4**	**157.1**
15	**Adjustment for Inflation**	3.5	1.8	-	(5.2)	(11.5)	(17.8)	(24.9)	(28.5)	(32.7)	(33.7)	(39.0)	(44.2)	(49.6)	(52.0)
16	**TOTAL SUSTAIN PORTFOLIO (a)*(b) (in constant F2007 $)**	**91.2**	**89.5**	**88.8**	**86.3**	**101.4**	**105.6**	**115.5**	**113.0**	**113.1**	**102.8**	**106.0**	**108.2**	**109.9**	**105.1**
17	**Annual Inflation Rate****	2.0%	2.0%	2.0%	6.0%	5.0%	5.0%	4.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
18	**Adjustment Factor (F2007 Base) (b)**	104%	102%	100%	94%	90%	86%	82%	80%	78%	75%	73%	71%	69%	67%

Emergency Capital Projects and Third Party Funded Projects Included Above

	Commission Category	F2005 Actual***	F2006 Actual	F2007 Actual	F2008 Forecast*	F2009 Forecast*	Project Name	BCUC Approval
19	Circuit Breakers		0.2		-	-	Walters 230kV CB Replacement of B2B2 230 kV Circuit Breaker	L-70-05
20	Circuit Breakers		-	-	0.4	-	BUT 2CB1 Failed Circuit Breaker Replacement	
21	Other Power Equipment		0.2	2.5	-	-	Selkirk - T1B Emergency Replacement	L-70-05
22	Protection & Control		-	-	1.0	1.0	PLC 984 Replacement at Williston, Ingledow, and Meridian	
23	Station Auxiliary Equipment		-	-	0.8	0.5	Emergency Drop-in Substation Control Building for Fraser Flood	
24			**0.4**	**2.5**	**2.2**	**1.5**		
25	Third Party Funded Projects (CIA)		**0.6**	**4.9**	**3.0**	**2.2**	Various Projects with Third Party Contributions	
26	**Total**		**1.0**	**7.4**	**5.2**	**3.7**		

* Sustain F2005 and F2006 Actuals adjusted for misapplied accrual of $1.1M
** F05 to F07 Source: Statistics Canada Electric Utility Construction Price Indexes. For F08 onwards, rates are based on MMK Report
*** F05 not available. Emergency Expenditures tracked separately effective F2006

Table 6-2 shows the historical and proposed Sustaining Capital investments for the period F2006 to F2018. The capital expenditure forecast for years F2009 to F2018 are revised from the F2008 Capital Plan. The general trend in Sustaining Capital expenditures is discussed below. Specific changes to the proposed Sustaining Capital plan are discussed in Section 6.3 and Section 6.5.

BCTC is forecasting Sustaining Capital expenditures to increase from $91.5 million in F2008 (Forecast) to $157.1 million by F2018. In constant F2007$, the reference value relied on by the Commission in its F2008 Capital Plan decision, the trend includes a step increase of $15.1 million from $86.3 million in F2008 (Forecast) to $101.4 million in F2009 to address new projects or increasing activity in existing projects. BCTC forecasts capital expenditures to continue to increase in F2010 to $105.6 million and to $115.5 million by F2011 in constant F2007$, and then gradually decrease, with some year-over-year variability, back to F2010 levels by F2018. Table 6-3 provides a comparison of the F2009 Capital Plan to the F2007$ reference value.

In general, excluding inflation, the increases in Sustaining Capital expenditures are required to accommodate increasing activity to:

(a) Maintain system reliability to design criteria (address deteriorating asset health and asset performance);

(b) Address unacceptable risks (e.g., life-safety, seismic, fire/explosion, weather, etc.); and

(c) Address upgrades required to the transmission system infrastructure to enable contractual commitments to Third-parties.

In constant F2007$, the step increase of $15.1 million from F2008 (forecast) to the proposed F2009 expenditure of $101.4 million, and subsequent increase to F2018 is required to address three key issues:

(a) A large investment of approximately $4.1 million in F2009 and $6.9 million in F2010 for Cathedral Square substation fire risk mitigation project (refer to Section 6.5.1.3.4) to mitigate the risk of life safety hazards associated with CO_2 equipment currently installed in Cathedral Square substation and to relocate the oil-filled cable terminations (fire hazards in the GIS Room) and replace with non-oil filled cables terminations (no fire risk);

(b) A significant and accelerated investment required to replace 500 kV and 230 kV Air-Blast Circuit Breakers and 500 kV Circuit Switchers by 2014 (refer to Section 6.5.1.2.1), resulting in an additional $6.0 million and $4.5 million in expenditures in F2009 and F2010, respectively; and

(c) A very large investment of approximately $45.0 million to mitigate unacceptable system reliability risks due to a seismic hazard at Murrin substation (refer to Section 6.5.1.4.6). The Murrin Project is spread over F2009 to F2013, with project definition ($0.5 million) and site preparation ($1.0 million) needed in F2009 and F2010 respectively, and construction in F2011 to F2013 at approximately from $12 million to $15 million per year.

The remainder of the increase is required to address an increase in refurbishment and replacement activity across most transmission infrastructure asset classes to address the aging demographics and forecast need for infrastructure refurbishments and/or replacements to ensure safe and reliable operation of the transmission system, as well as to address other known risks.

The proposed Sustaining Capital Plan is based on the best information available at this time and may be subject to change in the future Capital Plans to address unanticipated risks or unanticipated deterioration of asset health and performance.

6.3 Changes from Previous Plan

Table 6-3 provides a breakdown of the approved Sustaining Capital funding level pursuant to Commission Orders G-69-07 (F2008 Capital Plan) and G-91-05 (F2006 Capital Plan). Table 6-3 also shows expected Third-party requested projects, and additional funding proposed in F2009 and F2010 compared to previous Capital Plan approvals.

Table 6-3. Reconciliation of F2009 Capital Plan Portfolio Expenditures to Approved F2007 Level

	Sustaining Capital Portfolio ($M)	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
1	F2007 level - per G-67-06*	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
2	Third Party Requested Projects (unescalated)	3.1	3.0	3.0	3.0	3.0	2.0	2.0	2.0	2.0	2.0
3	Other changes in work	15.2	19.5	29.5	26.9	27.0	17.7	20.9	23.1	24.8	20.0
4	**Subtotal Sustain Portfolio before Inflation**	**101.4**	**105.6**	**115.5**	**113.0**	**113.1**	**102.8**	**106.0**	**108.2**	**109.9**	**105.1**
5	Adjustment for Inflation $ (from F2007)**	11.5	17.8	24.9	28.5	32.7	33.7	39.0	44.2	49.6	52.0
6	**F2009-2018 Capital Plan**	**112.9**	**123.4**	**140.4**	**141.5**	**145.8**	**136.5**	**145.0**	**152.4**	**159.4**	**157.1**

* Order G-91-05 Directive 35 stated that the 15 percent reduction applied to the F2007 should apply to future year's forecasts until changes in the trends the reliability indices or asset health assessments suggest the need for change. Order G-69-07 Directive 32 reiterated the $83.1m, excluding Third Party funded expenditures, when expressed in F2007 dollars.

** F05 to F07 Source: Statistics Canada Electric Utility Construction Price Indexes. For F08 onwards, rates are based on MMK Report

6.3.1 Explanation for Variance from F2008 Sustaining Capital Portfolio

In its F2008 Capital Plan Decision, the Commission re-confirmed its F2006 Capital Plan Decision that it considers the Sustaining Capital expenditures should be $83.1 million for F2008 and F2009 (excluding Third-party funded expenditures) when expressed in constant F2007 dollars (unless reliability indices or asset health assessments suggest the need for further changes). In addition, the Commission directed BCTC to use an inflation factor of 2 percent for each of F2008 and F2009. In nominal dollars, including inflation and Third-party funded projects, the Commission approved $87.7 million for F2008 and $88.5 million for F2009 as shown in Table 6-4 below.

Table 6-2 illustrates that BCTC is forecasting actual F2008 Sustaining Capital expenditures of $91.5 million, $3.8 million more than the approved funding of $87.7 million (approved funding of $83.1 million, plus inflation of 2 percent, plus approved Third-party funded projects of $3.0 million) for the same period. The variance of $3.8 million is explained by the need to address emergency capital requirements during F2008 of $2.2 million (Burrard Thermal 2CB1 for $0.4 million; Emergency Drop-in Control Building for Fraser River Flood for $0.8 million, and Programmable Logic Controller Replacement for $1.0 million), and $1.6 million in carried forward expenditures from F2007 to F2008 due to changes in project schedule for the Mica Gas Insulated Switchgear Replacement project.

Table 6-4 illustrates the Commission approved funding for F2008 and F2009, as well as the forecast expenditures for F2008 and the BCTC proposed expenditures for F2009 and F2010. These are expressed in nominal and Real (F2007$) amounts.

Table 6-4. Sustaining Capital Expenditures – Continuity Schedule

	($millions)	F2008 Approved (note 1)	F2008 Forecast (note 2)	F2009 Approved (note 1)	F2009 Forecast	F2010 Forecast
1	Nominal	87.7	91.5	88.5	112.9	123.4
2	Real (F2007$)	86.0	86.3	85.0	101.4	105.6

Note 1: Approved amounts are from page 83 of F2008 Capital Plan Decision

Note 2: Nominal expenditure includes carry-forward for Mica GIS $1.6 million; Emergency Capital of $2.2 million; Third Party expenditures of $3.0 million.

As shown in Table 6-4, the proposed increase in F2009 Sustaining Capital over the forecasted F2008 capital expenditure is $21.4 million in nominal terms. The proposed F2009 increase over the Commission-approved F2008 capital expenditure is $25.2 million. This variance is composed of:

(a) An incremental increase of $5.4 million for inflation calculated at 5 percent as discussed in Section 2.2.10 and Section 9.31;

(b) An incremental increase of $0.1 million for additional Third-party requested projects as discussed in Section 6.3.1.1;

(c) An incremental increase of $2.1 million for forecast carry-forwards related to the Protection and Control Replacement project, the Lower Mainland Robustness project, and the Emergency Drop-in Control Building project. These projects were scheduled to be completed in F2008 but are now forecast to be completed in early F2009; and

(d) An incremental increase of $13.8 million which is required to address changes in Other Work to address system reliability issues and other unacceptable risks as discussed in Section 6.3.1.2.

In turn, the proposed Sustaining Capital expenditure of $123.4 million in F2010 is an incremental increase of $10.5 million in nominal terms over the proposed F2009 expenditures of $112.9 million. This increase consists of:

(a) An incremental increase of $5.9 million for inflation calculated at 5 percent; and

(b) An incremental increase of $4.6 million which is required to address changes in Other Work to address system reliability issues and other unacceptable risks.

6.3.1.1 Third-Party Requested Projects

During the year BCTC received new Third-party Requested projects that were not previously identified. Third-party requested projects are those projects for which BCTC enters into an agreement with a Third-party who will benefit from the modification or enhancement to the transmission system infrastructure. The changes are associated with the following projects:

(a) Voltage and VAR Optimization $0.9 million in each of F2009 and F2010 (refer to Section 6.5.1.5.7);

(b) Protection, Control and Metering (PCM) Upgrades of $0.2 million in each of F2009 and F2010 (refer to Section 6.5.1.5.8); and

(c) Right-of-Way Sustainment – Third-party $2.2 million and $2.3 million for F2009 and F2010 respectively (refer to Section 6.5.2.6).

Transmission capital expenditures required to implement Third-party projects are included in the Sustaining Capital plan. Where these projects are not related to BC Hydro, funding is fully recovered by a Contribution In Aid of Construction (CIAC) provided by the Third-party. The exception is Third-party requests from the Minister of Transportation (MoT), where BCTC is paid $400 per pole relocation on MoT rights of way (ROW). In this instance, BCTC is given free access to the revised ROW to relocate its poles.

Excluding inflation BCTC forecasts an incremental increase of $0.1 million for F2009 for Third-party requested work. BCTC forecasts no incremental increase for F2010.

6.3.1.2 Other Changes in Work F2009 and F2010

During the year, BCTC has identified additional Sustaining Capital requirements that it believes must be addressed in F2009 and F2010 to mitigate system reliability risks associated with asset condition and performance, and other risks (seismic, life-safety, environment, weather, security).

Table 6-5 illustrates the proposed F2009 expenditures and presents the change over F2008. In addition, the table illustrates the proposed incremental increase for F2010 and presents the change over the proposed F2009 plan.

Table 6-5. Comparison of Program Expenditures for F2009, F2009, and F2010

	Program Name	F2008 Forecast Capital Expenditures ($ millions)	F2009 Plan Capital Expenditures ($ millions)	Variance F2009 vs. F2008 Increase/ (Decrease) ($ millions))	F2010 Forecast Capital Expenditures ($ millions)	Variance F2010 vs. F2009 Increase/ (Decrease) ($ millions)	Section
		(a)	(b)	(b)-(a)	(c)	(c)-(b)	
1	Stations – Auxiliary Equipment	4.3	6.7	2.4	7.6	0.9	6.5.1.1
2	Stations – Circuit Breakers	18.9	25.3	6.3	26.4	1.1	6.5.1.2
3	Stations – Other Power Equipment	3.2	11.0	7.7	15.5	4.5	6.5.1.3
4	Stations – Risk Mitigation	8.2	8.3	0.1	8.8	0.5	6.5.1.4
5	Stations – Protection and Control	9.5	13.0	3.5	11.9	(1.1)	6.5.1.5
6	Stations – Telecommunications	10.6	7.5	(3.1)	5.6	(1.9)	6.5.1.6
7	Lines – Cables Sustainment	3.9	5.0	1.1	5.8	0.9	6.5.2.1
8	Lines – OH Life Extension	11.6	12.7	1.2	16.0	3.3	6.5.2.2
9	Lines – OH Lines Performance Improvement	3.8	4.5	0.8	5.4	0.8	6.5.2.3
10	Lines – OH Risk Mitigation	8.6	9.9	1.3	10.0	0.1	6.5.2.4
11	Lines – ROW Sustainment	6.1	6.9	0.8	8.2	1.2	6.5.2.5
11	Lines – ROW Sustainment (3rd Party)	3.0	2.2	(0.8)	2.3	(0.1)	6.5.2.6
12	Net Increase in Total Capital Expenditures	91.5	112.9	21.4	123.4	10.5	

To accommodate the proposed increase to Sustaining Capital expenditures, at a portfolio level BCTC has endeavored to re-prioritize the funding levels between programs by reducing project activities in a given year and/or by deferring projects to future years. The remaining funding allocation within each program illustrates the minimum expenditure required to address the highest priority project work, and still leaves deferred projects and a backlog of work that needs attention. This strategy is illustrated in Table 6-5 where BCTC has re-allocated funding in F2009 and F2010 from the Telecommunications program to the Circuit Breaker program.

Of the $21.4 million increase for F2009 and the $10.5 million increase for F2010 in nominal terms, the majority of the expenditure increase is explained by the need to address increases in activity for the following projects:

(a) Increase of $6.0 million in F2009 and an increase of $4.5 million in F2010 for the 500 kV and 230 kV Air-Blast Circuit Breaker and 500 kV Circuit Switcher Replacement project (refer to Section 6.5.1.2.1);

(b) Increase of $2.0 million in F2009 for the Pin and Cap Insulator Replacement project (refer to Section 6.5.1.1.1);

(c) Increase of $1.3 million in F2009 for the 230 kV Bulk Oil Breaker Replacement project (refer to Section 6.5.1.2.11);

(d) Increase of $1.9 million in F2009 for the Surge Arrestor Replacement project (refer to Section 6.5.1.3.2);

(e) Increase of $3.7 million in F2009 and a further increase of $2.7 million in F2010 for the Cathedral Square 2L31/32 Line Termination Relocation project (refer to Section 6.5.1.3.4);

(f) Increase of $1.3 million in F2009 for VIT SC4 Refurbishment project (refer to Section 6.5.1.3.5);

(g) Increase of $2.5 million in F2009 for the Protection and Control Replacements project (refer to Section 6.5.1.5.1);

(h) Increase of $1.5 million in F2009 for the Chapman's Fibre Optic Cable Replacement project (refer to Section 6.5.1.6.1); and

(i) Increase of $3.4 million in F2010 for VIT PCB Equipment Replacement project (refer to Section 6.5.1.3.7).

Section 6.5 of the document describes the programs and related projects which make up the Sustaining Capital portfolio. Each program is summarized, along with key drivers and issues, and the proposed capital expenditures for F2009 and F2010 are presented, as well as the year-over-year change. In addition, the key projects that make up the change are identified.

Within programs, a description is provided for each project. Project descriptions provide an overview of the project, the key issues being addressed, overview of the investment justification, and scope of work planned for F2009 and F2010. Where a project is new to this Capital Plan, or if a significant change has occurred from the F2008 Capital Plan, a forecast expenditure level is provided.

6.3.1.3 Deferred Work

Every year, BCTC determines a number of Sustaining Capital projects that are required for system reliability, safety improvements, environmental protection, efficiency, and deteriorating asset health. All identified projects are prioritized; if they meet prioritization model criteria as set out in Section 4.7.3.4 of the Capital Plan, and then form part of the Capital Plan. The remaining projects that do not score highly on the prioritization model are deferred and/or reduced in scope and will enter the Capital Planning process in later periods. Table 6-6 provides details of those projects that did not meet the prioritization criteria.

Table 6-6. Projects Not Assigned

	Projects that are Reduced in Scope or Deferred to future years	
	Project Name	**Reduced in Scope / Deferred to Future Years**
1	<230 kV Circuit Breaker Replacements at BR1, SCA, KGH, SEC, CMX, CRD, SYH	Reduced in Scope
2	Horsey GIS Replacements	Deferred
3	High Voltage Dehydrating Breathers on Transformers	Reduced in Scope
4	Leased Line Entrance Protection Replacements	Reduced in Scope
5	Tone and Test Equipment Replacements	Reduced in Scope
6	Point to Multi-point Radio	Deferred
7	CADD Modeling of Transmission System	Deferred
8	STER Conductor Inventory Reduction	Deferred
9	Line Post Insulator Replacements	Reduced in Scope
10	Overhead Transmission Structural Corrosion Program – 138/230/287 kV	Deferred
11	Overhead Transmission Structural Corrosion Program – 360 kV	Deferred
12	Steel Pole Painting	Deferred
13	Reconductoring/High Strength Conductor	Deferred
14	Long Span Crossing Refurbishment	Deferred
15	69 kV Lattice Steel Replacement	Deferred
16	230 kV Lattice Steel Replacement Program	Deferred
17	500 kV Polymer Insulator Replacements	Deferred
18	Restore Rating of 60L27/30	Deferred
19	Replace 60L93/94	Deferred

6.4 Optimization Results

Table 6-7. Sustaining Capital Optimization Results

				Value Scores							Risk Criteria Scores							
	Quadrant		BCUC Category	Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Value Score	Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Risk Score	Projects Deemed Mandatory
1	1	F2009-S-3679-230kV CB Replacements Double Pressure BUT2CB9 CSN2CB4 MUR2CB125	Circuit Breakers	-0.21	0.61	0.00	0.63	0.00	0.11	**1.15**	10	25	0	15	0	15	25	
2	1	F2009-S-5650-12kV Reactor CB Replacements MSA 12CB2 CBK 12CB16 17	Circuit Breakers	-0.22	0.61	0.00	0.78	0.00	0.00	**1.18**	2	15	0	25	0	0	25	
3	1	F2010-S-5670-230kV CB Replacements Double Pressure BUT2CB10 11 12 14 16	Circuit Breakers	-0.19	0.61	0.00	0.63	0.00	0.11	**1.16**	10	25	0	15	0	15	25	
4	1	F2009-S-3483-500kV CB Replacements ING 5CB3 4 7 8 11	Circuit Breakers	0.30	0.00	0.00	0.78	0.00	0.00	**1.07**	6	0	0	20	0	0	20	
5	1	F2009-S-3593-500kV Airblast CB Replacement NIC 5CB6 16 DMR 5CB4 14	Circuit Breakers	0.25	0.00	0.00	0.68	0.00	0.00	**0.93**	9	0	0	20	0	0	20	
6	1	F2010-S-5640-Airblast 230 kV Replacements ING 2CB5 12 18 19 GLN 2CB1 2	Circuit Breakers	0.49	0.00	0.00	0.73	0.00	0.00	**1.22**	15	0	0	20	0	0	20	
7	1	F2010-S-5660-500kV CB Replacements ING 5CB5 6 9 10 12	Circuit Breakers	0.35	0.00	0.00	0.78	0.00	0.00	**1.12**	6	0	0	20	0	0	20	
8	1	F2010-S-5690-Future 500 kV CB Replacement (F2010)	Circuit Breakers	0.22	0.00	0.00	0.78	0.00	0.00	**1.00**	6	0	0	20	0	0	20	
9	1	F2009-S-3669-Replacement of Bulk Oil CB BUT 2CB3 4 7 CBK 8 10 CKY 2CB3	Circuit Breakers	-0.46	0.61	0.00	0.70	0.00	0.00	**0.86**	0	15	0	15	0	0	15	
10	1	F2009-S-5680-Under 230 kV CB Replacement BR160CB1 SCA 1CB1 Etc	Circuit Breakers	-0.38	0.61	0.00	0.68	0.00	0.00	**0.92**	0	15	0	15	0	0	15	
11	1	F2009-S-5684-Spare 230kV 138 kV 69 kV CB	Circuit Breakers	-0.20	0.61	0.00	0.68	0.00	0.00	**1.09**	0	15	0	15	0	0	15	
12	1	F2009-S-5686-HSY GIS Replacement F2009 Portion	Circuit Breakers	-0.44	0.61	0.00	0.41	0.00	0.00	**0.58**	2	15	0	10	0	0	15	
13	1	F2009-S-5695-GIS Betterment (F2009)	Circuit Breakers	-0.32	0.61	0.00	0.38	0.00	0.00	**0.67**	2	15	0	10	0	0	15	
14	1	F2010-S-5610-Future 230 kV CB Replacement (F2010)	Circuit Breakers	-0.51	0.61	0.00	0.70	0.00	0.00	**0.80**	0	15	0	15	0	0	15	
15	1	F2010-S-5630-Replacement of Bulk Oil CB BUT 2CB2 5 10	Circuit Breakers	-0.46	0.61	0.00	0.70	0.00	0.00	**0.86**	0	15	0	15	0	0	15	
16	1	F2010-S-5681-Under 230 kV CB Replacement Future F2010	Circuit Breakers	-0.37	0.61	0.00	0.68	0.00	0.00	**0.92**	0	15	0	15	0	0	15	
17	1	F2010-S-5687-HSY GIS Replacement F2010 Portion	Circuit Breakers	-0.55	0.61	0.00	0.41	0.00	0.00	**0.48**	6	15	0	10	0	0	15	
18	1	F2010-S-5696-GIS Betterment (F2010)	Circuit Breakers	-0.32	0.61	0.00	0.38	0.00	0.00	**0.68**	2	15	0	10	0	0	15	
19	2	F2009-S-3598-500kV Circuit Switcher Replacements	Circuit Breakers	-0.44	0.00	0.00	0.74	0.00	0.00	**0.29**	0	0	0	20	0	0	20	
20	1	F2009-S-3601-VIT Synchronous Condenser Overhaul (SC4)	Other Power Equipment	-0.19	0.62	0.00	0.71	0.00	0.00	**1.14**	0	25	0	20	0	0	25	
21	1	F2009-S-3227-Life Extension of 500 230 kV Disconnect Switches	Other Power Equipment	0.39	0.00	0.00	0.66	0.00	0.00	**1.05**	0	0	0	20	0	0	20	
22	1	F2009-S-3296-Transformer Electronic Temperature Monitor (ETM) Upgrade	Other Power Equipment	0.46	0.00	0.00	0.64	0.00	0.00	**1.11**	0	0	0	20	0	0	20	
23	1	F2009-S-3424-SEL (Selkirk) T1 Spare - Approved	Other Power Equipment	-0.48	0.03	0.04	0.65	0.13	0.00	**0.37**	2	0	5	20	8	0	20	
24	2	F2010-S-5540-Surge Arrester Replacement Program	Other Power Equipment	-0.43	0.00	0.00	0.66	0.00	0.11	**0.34**	0	0	0	20	0	4	20	
25	1	F2010-S-5692-Life Extension of 500 230 kV Disconnect Switches	Other Power Equipment	0.44	0.00	0.00	0.66	0.00	0.00	**1.09**	0	0	0	20	0	0	20	
26	1	F2010-S-5700-Transformer Electronic Temperature Monitor (ETM) Upgrade	Other Power Equipment	0.45	0.00	0.00	0.64	0.00	0.00	**1.10**	0	0	0	20	0	0	20	
27	1	F2010-S-5010-CSQ - Relocation of 2L31 32 Line Termination and CO2	Other Power Equipment	-0.46	0.00	0.00	0.57	0.13	0.22	**0.46**	10	0	0	15	10	10	15	
28	2	F2010-S-3602-VIT PCB Filled Equipment Removal and Replacement	Other Power Equipment	-0.47	0.00	0.00	0.00	0.00	0.11	**-0.36**	0	0	0	0	0	25	25	M
29	2	F2009-S-5590-Surge Arrester Replacement Program	Other Power Equipment	-0.45	0.00	0.00	0.66	0.00	0.11	**0.32**	0	0	0	20	0	4	20	
30	2	F2009-S-3251-CSQ - Relocation of 2L31 32 Line Termination and CO2	Other Power Equipment	-0.66	0.00	0.00	0.57	0.13	0.22	**0.26**	10	0	0	15	10	10	15	
31	3	F2009-S-5720-Maintenace Free Dehydrating Breathers on Transformers	Other Power Equipment	0.45	0.00	0.00	0.00	0.00	0.00	**0.45**	5	0	0	0	0	0	5	
32	3	F2010-S-5730-Maintenace Free Dehydrating Breathers on Transformers	Other Power Equipment	0.44	0.00	0.00	0.00	0.00	0.00	**0.44**	5	0	0	0	0	0	5	
33	1	F2009-S-3210-500kV Line Protection Replacement (Stage 7)	Protection & Control	0.42	0.07	0.00	0.85	0.09	0.00	**1.42**	5	15	0	25	20	0	25	
34	1	F2009-S-3220-Transformer Gas Relay Replacements (Stage 4)	Protection & Control	0.42	0.06	0.00	0.85	0.09	0.00	**1.42**	5	15	0	25	12	0	25	
35	1	F2009-S-3267-Transformer LTC Control SVC Relay Replacement (Stage 2)	Protection & Control	0.34	0.06	0.00	0.85	0.09	0.00	**1.33**	5	15	0	25	12	0	25	
36	1	F2010-S-5100-500kV Line Protection Replacement (Stage 8)	Protection & Control	0.43	0.07	0.00	0.85	0.09	0.00	**1.44**	5	15	0	25	20	0	25	
37	1	F2010-S-5104-Transformer Gas Relay Replacements (Stage 5)	Protection & Control	0.42	0.06	0.00	0.85	0.09	0.00	**1.42**	5	15	0	25	12	0	25	
38	1	F2010-S-5105-Transformer LTC Control SVC Relay Replacement (Stage 3)	Protection & Control	0.33	0.06	0.00	0.85	0.09	0.00	**1.33**	5	15	0	25	12	0	25	
39	1	F2009-S-3217-Minor Capital (P&C)	Protection & Control	-0.21	0.00	0.00	0.73	0.00	0.00	**0.52**	0	0	0	20	0	0	20	
40	1	F2009-S-3218-Under 500kV Line Protection Replacement (Stage 9)	Protection & Control	0.58	0.15	0.00	0.77	0.09	0.00	**1.59**	10	15	0	20	12	0	20	

Table 6-7. Sustaining Capital Optimization Results (continued)

	Quadrant		BCUC Category	Value Scores: Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Value Score	Risk Criteria Scores: Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Risk Score	Projects Deemed Mandatory
41	1	F2009-S-3223-Transformer Current Relay Replacement (Stage 3)	Protection & Control	0.51	0.06	0.00	0.77	0.09	0.00	**1.42**	5	15	0	20	12	0	20	
42	1	F2009-S-3264-SCADA RTU Remote Control (Stage 4)	Protection & Control	-0.25	0.01	0.00	0.84	0.00	0.00	**0.60**	0	0	0	20	0	0	20	
43	1	F2010-S-5101-Minor Capital (P&C)	Protection & Control	-0.21	0.00	0.00	0.73	0.00	0.00	**0.52**	0	0	0	20	0	0	20	
44	1	F2010-S-5102-SCADA RTU Remote Control (Stage 5)	Protection & Control	-0.30	0.01	0.00	0.84	0.00	0.00	**0.56**	0	0	0	20	0	0	20	
45	1	F2010-S-5103-Transformer Current Relay Replacement (Stage 4)	Protection & Control	0.51	0.06	0.00	0.77	0.09	0.00	**1.42**	5	15	0	20	12	0	20	
46	1	F2010-S-5106-Under 500kV Line Protection Replacement (Stage 10)	Protection & Control	0.57	0.15	0.00	0.77	0.09	0.00	**1.58**	10	15	0	20	12	0	20	
47	4	F2009-S-5000-Protection Control Metering (PCM) - TLOB Portion	Protection & Control	-0.21	0.00	0.00	0.00	0.00	0.00	**-0.21**	0	0	0	0	0	0	0	M
48	4	F2009-S-5002-Voltage & Var Optimization VVO - Phase 2 - TLOB Portion	Protection & Control	-0.14	0.00	0.00	0.00	0.00	0.00	**-0.14**	0	0	0	0	0	0	0	M
49	4	F2009-S-5003-Voltage & Var Optimization VVO - Phase 3 - TLOB Portion	Protection & Control	-0.34	0.00	0.00	0.00	0.00	0.00	**-0.34**	0	0	0	0	0	0	0	M
50	4	F2010-S-5004-Protection Control Metering (PCM) - TLOB Portion	Protection & Control	-0.20	0.00	0.00	0.00	0.00	0.00	**-0.20**	0	0	0	0	0	0	0	M
51	4	F2010-S-5006-Voltage & Var Optimization VVO - Phase 3 - TLOB Portion	Protection & Control	-0.34	0.00	0.00	0.00	0.00	0.00	**-0.34**	0	0	0	0	0	0	0	M
52	1	F2009-S-3684-Stations Access	Station Auxiliary Equipment	-0.13	0.00	0.00	0.46	0.18	0.40	**0.91**	3	0	0	25	6	16	25	
53	1	F2010-S-5200-Air Compressor Replacements	Station Auxiliary Equipment	-0.25	0.61	0.00	0.78	0.00	0.00	**1.14**	0	15	0	25	0	0	25	
54	1	F2010-S-9987-Stations Access	Station Auxiliary Equipment	-0.20	0.00	0.00	0.46	0.18	0.40	**0.84**	3	0	0	25	6	16	25	
55	1	F2009-S-3083-Battery Bank Replacements	Station Auxiliary Equipment	-0.28	0.00	0.00	0.84	0.00	0.09	**0.65**	0	0	0	20	0	4	20	
56	1	F2009-S-3084-Minor Capital (Station Auxiliary Equipment)	Station Auxiliary Equipment	-0.37	0.00	0.00	0.73	0.00	0.00	**0.36**	5	0	0	20	0	0	20	
57	1	F2009-S-3111-Pin & Cap Replacements	Station Auxiliary Equipment	-0.40	0.00	0.00	0.83	0.00	0.09	**0.51**	5	0	0	20	0	3	20	
58	1	F2010-S-5201-Battery Bank Replacements	Station Auxiliary Equipment	-0.28	0.00	0.00	0.84	0.00	0.09	**0.65**	0	0	0	20	0	4	20	
59	1	F2010-S-5207-Minor Capital (Station Auxiliary Equipment)	Station Auxiliary Equipment	-0.37	0.00	0.00	0.73	0.00	0.00	**0.36**	5	0	0	20	0	0	20	
60	1	F2010-S-5208-Pin & Cap Replacements	Station Auxiliary Equipment	-0.39	0.00	0.00	0.83	0.00	0.09	**0.52**	5	0	0	20	0	3	20	
61	1	F2009-S-3110-Roofing Replacements	Station Auxiliary Equipment	-0.21	0.00	0.00	0.61	0.00	0.09	**0.48**	5	0	0	15	0	9	15	
62	1	F2009-S-3117-Facilities Upgrade	Station Auxiliary Equipment	-0.23	0.00	0.00	0.63	0.00	0.09	**0.48**	5	0	0	15	0	15	15	
63	1	F2010-S-5202-Facilities Upgrade	Station Auxiliary Equipment	-0.19	0.00	0.00	0.63	0.00	0.09	**0.53**	5	0	0	15	0	15	15	
64	1	F2010-S-5209-Roofing Replacements	Station Auxiliary Equipment	-0.25	0.00	0.00	0.61	0.00	0.09	**0.45**	5	0	0	15	0	9	15	
65	2	F2010-S-5520-Station Ground Grid Upgrade	Station Auxiliary Equipment	-0.23	0.00	0.00	0.31	0.00	0.22	**0.29**	0	0	0	10	0	20	20	
66	4	F2009-S-3197-Station Ground Grid Upgrade	Station Auxiliary Equipment	-0.24	0.00	0.00	0.31	0.00	0.22	**0.29**	0	0	0	10	0	5	10	
67	1	F2009-S-5001-Security Upgrade	Station Risk Mitigation	0.54	0.63	0.00	0.00	0.00	0.13	**1.31**	10	25	0	0	0	20	25	
68	1	F2010-S-5005-Security Upgrade	Station Risk Mitigation	0.52	0.63	0.00	0.00	0.00	0.13	**1.28**	10	25	0	0	0	20	25	
69	1	F2009-S-3120-Fire Protection Upgrade	Station Risk Mitigation	-0.22	0.00	0.00	0.48	0.16	0.11	**0.53**	10	0	0	20	12	15	20	
70	1	F2010-S-5203-Fire Protection Upgrade	Station Risk Mitigation	-0.22	0.00	0.00	0.48	0.16	0.11	**0.53**	10	0	0	20	12	15	20	
71	1	F2009-S-3145-Gravel Replacement	Station Risk Mitigation	-0.19	0.00	0.00	0.59	0.00	0.11	**0.51**	0	0	0	15	0	10	15	
72	1	F2010-S-5204-Gravel Replacement	Station Risk Mitigation	-0.21	0.00	0.00	0.59	0.00	0.11	**0.49**	0	0	0	15	0	10	15	
73	2	F2009-S-5220-Oil Spill Containment	Station Risk Mitigation	-0.37	0.00	0.00	0.00	0.09	0.22	**-0.06**	12	0	0	0	16	16	16	
74	2	F2010-S-5206-Oil Spill Containment	Station Risk Mitigation	-0.36	0.00	0.00	0.00	0.09	0.22	**-0.06**	12	0	0	0	16	16	16	
75	3	F2009-S-2540-Above Ground Storage Tank Replacements	Station Risk Mitigation	-0.22	0.00	0.00	0.28	0.09	0.22	**0.37**	2	0	0	10	8	8	10	
76	4	F2009-S-5595-Substations Seismic Structural Upgrade	Station Risk Mitigation	-0.27	0.37	0.00	0.00	0.07	0.17	**0.34**	0	0	0	0	0	0	0	
77	4	F2010-S-5530-Substations Seismic Structural Upgrade	Station Risk Mitigation	-0.27	0.37	0.00	0.00	0.07	0.17	**0.34**	0	0	0	0	0	0	0	
78	4	F2009-S-3359-Murrin Reconfiguration and Seismic Structural Upgrade	Station Risk Mitigation	-0.51	0.37	0.00	0.00	0.17	0.17	**0.21**	0	0	0	0	0	0	0	
79	4	F2009-S-5591-Seismic Upgrade of Telecom Microwave Buildings	Station Risk Mitigation	-0.14	0.00	0.00	0.00	0.07	0.17	**0.10**	0	0	0	0	0	0	0	
80	4	F2010-S-5510-Seismic Upgrade of Telecom Microwave Buildings	Station Risk Mitigation	-0.17	0.00	0.00	0.00	0.07	0.17	**0.07**	0	0	0	0	0	0	0	
81	1	F2009-S-3616-Chapman Telecommunication Replacement	Telecommunications	-0.32	0.14	0.05	0.73	0.00	0.00	**0.60**	5	0	5	25	0	0	25	
82	1	F2009-S-3095-Minor Capital (Telecom Equipment)	Telecommunications	-0.19	0.00	0.00	0.73	0.00	0.00	**0.55**	0	0	0	20	0	0	20	
83	1	F2009-S-3099-Leased Line Entrance Protection	Telecommunications	-0.36	0.00	0.00	0.65	0.00	0.22	**0.51**	0	0	0	20	0	10	20	
84	1	F2009-S-3107-Power Line Carrier Replacements	Telecommunications	-0.34	0.00	0.00	0.77	0.00	0.00	**0.43**	0	0	0	20	0	0	20	

Table 6-7. Sustaining Capital Optimization Results (continued)

				Value Scores							Risk Criteria Scores							
	Quadrant		BCUC Category	Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Value Score	Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Risk Score	Projects Deemed Mandatory
85	1	F2009-S-3123-Microwave Fire Protection Upgrade	Telecommunications	-0.19	0.00	0.00	0.48	0.16	0.11	**0.56**	5	0	0	20	3	5	20	
86	1	F2009-S-3670-Telecom Battery-Charger Replacements	Telecommunications	-0.24	0.00	0.00	0.84	0.00	0.09	**0.69**	0	0	0	20	0	4	20	
87	1	F2010-S-3093-Telecom Battery-Charger Replacements	Telecommunications	-0.23	0.00	0.00	0.84	0.00	0.09	**0.70**	0	0	0	20	0	4	20	
88	1	F2010-S-3096-Minor Capital (Telecom Equipment)	Telecommunications	-0.19	0.00	0.00	0.73	0.00	0.00	**0.55**	0	0	0	20	0	0	20	
89	1	F2010-S-3100-Leased Line Entrance Protection	Telecommunications	-0.36	0.00	0.00	0.65	0.00	0.22	**0.51**	0	0	0	20	0	10	20	
90	1	F2010-S-5205-Microwave Fire Protection Upgrade	Telecommunications	-0.24	0.00	0.00	0.48	0.16	0.11	**0.51**	5	0	0	20	3	5	20	
91	1	F2009-S-3600-Lower Mainland Radio SUPY Replacement	Telecommunications	-0.20	0.16	0.00	0.55	0.00	0.00	**0.51**	0	0	0	15	0	0	15	
92	2	F2009-S-3668-Teleprotection Tone and Test Panel Equipment Replacement	Telecommunications	-0.35	0.13	0.00	0.54	0.00	0.00	**0.32**	0	15	0	15	0	0	15	
93	2	F2010-S-5300-Teleprotection Tone and Test Panel Equipment Replacement	Telecommunications	-0.35	0.13	0.00	0.54	0.00	0.00	**0.32**	0	15	0	15	0	0	15	
94	4	F2009-S-5310-Lower Mainland Robustness (F2009 Stage) - Approved	Telecommunications	-0.42	0.00	0.00	0.26	0.08	0.00	**-0.08**	3	0	0	10	3	0	10	
95	4	F2010-S-5302-Nelway-Metaline Radio Upgrade	Telecommunications	-0.35	0.00	0.05	0.00	0.06	0.00	**-0.24**	0	0	5	0	0	0	5	M
96	1	F2009-S-3135-Replace 60L93 and 60L94	Cables	-0.42	0.00	0.00	0.73	0.15	0.22	**0.67**	1	5	0	25	0	5	25	
97	1	F2009-S-3113-Oil containment at cable terminating stations	Cables	-0.32	0.00	0.00	0.46	0.15	0.22	**0.51**	0	0	0	20	0	5	20	
98	1	F2009-S-3551-Partial Discharge Measurement System	Cables	-0.46	0.00	0.00	0.46	0.15	0.22	**0.36**	0	0	0	20	0	5	20	
99	1	F2009-S-3552-Stop Joint Explosion Protection	Cables	-0.21	0.19	0.00	0.66	0.15	0.22	**1.00**	0	3	0	20	0	5	20	
100	1	F2009-S-3570-5L29 31 Armour corrosion protection	Cables	-0.02	0.00	0.00	0.46	0.15	0.22	**0.80**	5	0	0	20	0	5	20	
101	1	F2009-S-3571-2L51 Cable Restoration	Cables	-0.31	0.02	0.00	0.46	0.15	0.22	**0.53**	0	0	0	20	0	5	20	
102	1	F2009-S-3572-Cables - Spare Program	Cables	-0.28	0.59	0.00	0.12	0.15	0.00	**0.58**	0	20	0	15	0	0	20	
103	1	F2009-S-3573-2L31 Cable Restoration	Cables	-0.23	0.01	0.00	0.46	0.15	0.22	**0.60**	0	0	0	20	0	5	20	
104	1	F2009-S-3576-Oil containment at cable manholes	Cables	-0.28	0.00	0.00	0.46	0.15	0.19	**0.52**	0	0	0	20	0	10	20	
105	1	F2010-S-7100-Cables - Spare Program	Cables	-0.25	0.59	0.00	0.12	0.15	0.00	**0.60**	0	20	0	15	0	0	20	
106	1	F2010-S-7102-Stop Joint Explosion Protection	Cables	-0.21	0.19	0.00	0.66	0.15	0.22	**1.00**	0	3	0	20	0	5	20	
107	4	F2010-S-7700-Cable Future (F2010)	Cables	-0.40	0.02	0.00	0.46	0.00	0.00	**0.07**	0	0	0	10	0	0	10	
108	4	F2009-S-3574-Restore Rating of 60L27 and 60L30 Cable Sections	Cables	-0.37	0.00	0.00	0.00	0.15	0.00	**-0.23**	1	0	0	0	0	0	1	
109	1	F2009-S-3540-Multiple circuits - Transmission Recurring Capital Project - F2009	OH Life Extension	0.60	0.00	0.00	0.73	0.20	0.16	**1.70**	16	0	0	25	8	15	25	
110	1	F2009-S-3556-OCAS - Crossing Markers	OH Life Extension	-0.28	0.00	0.00	0.73	0.15	0.11	**0.71**	3	0	0	25	5	5	25	M
111	1	F2009-S-3557-Marker Balls - Crossing Markers	OH Life Extension	-0.23	0.00	0.00	0.73	0.15	0.11	**0.76**	3	0	0	25	5	5	25	M
112	1	F2009-S-3560-500kV Polymer Replacement Program	OH Life Extension	-0.19	0.00	0.00	0.73	0.26	0.40	**1.20**	0	0	0	25	4	5	25	
113	1	F2009-S-3561-Insulator replacements	OH Life Extension	-0.22	0.00	0.00	0.73	0.26	0.40	**1.17**	0	0	0	25	4	5	25	
114	1	F2010-S-7010-Marker Balls - Crossing Markers	OH Life Extension	-0.28	0.00	0.00	0.73	0.15	0.11	**0.71**	3	0	0	25	5	5	25	M
115	1	F2010-S-7012-OCAS - Crossing Markers	OH Life Extension	-0.28	0.00	0.00	0.73	0.15	0.11	**0.71**	3	0	0	25	5	5	25	M
116	1	F2010-S-7302-500kV Polymer Replacement Program	OH Life Extension	-0.19	0.00	0.00	0.73	0.26	0.40	**1.20**	0	0	0	25	4	5	25	
117	1	F2010-S-7308-Insulator replacements	OH Life Extension	-0.30	0.00	0.00	0.73	0.26	0.40	**1.09**	0	0	0	25	4	5	25	
118	1	F2010-S-8006-Multiple circuits - Transmission Recurring Capital Project	OH Life Extension	-0.41	0.00	0.00	0.73	0.16	0.16	**0.64**	16	0	0	25	8	15	25	
119	1	F2009-S-3169-Spacer Damper Replacement	OH Life Extension	-0.17	0.00	0.00	0.58	0.25	0.24	**0.90**	0	0	0	20	0	0	20	
120	1	F2009-S-3522-Overhead Transmission Structural Corrosion Protection - 500kV Tower Painting	OH Life Extension	0.59	0.00	0.00	0.44	0.10	0.16	**1.29**	6	0	0	20	9	12	20	
121	1	F2009-S-3533-Overhead Transmission Structural Corrosion Protection - 360kV Tower Painting	OH Life Extension	0.48	0.00	0.00	0.65	0.11	0.16	**1.41**	6	0	0	20	9	12	20	
122	1	F2009-S-3534-Overhead Transmission Structural Corrosion Protection - Grillage Refurbishment	OH Life Extension	-0.13	0.00	0.00	0.65	0.11	0.19	**0.82**	9	0	0	20	9	10	20	
123	1	F2009-S-3537-Overhead Transmission Structural Corrosion Protection - Grillage Refurbishment - First Towers out of Substation	OH Life Extension	-0.07	0.00	0.00	0.65	0.10	0.27	**0.95**	6	0	0	20	6	6	20	
124	1	F2009-S-3539-Overhead Transmission Structural Corrosion Protection - Steel Pole Painting - F2009	OH Life Extension	0.35	0.00	0.00	0.65	0.11	0.16	**1.27**	4	0	0	20	9	12	20	
125	1	F2010-S-7020-Spacer Damper Replacement	OH Life Extension	-0.34	0.00	0.00	0.58	0.25	0.24	**0.73**	0	0	0	20	0	0	20	
126	1	F2010-S-8007-Overhead Transmission Structural Corrosion Protection - 360kV Tower Painting	OH Life Extension	-0.11	0.00	0.00	0.65	0.17	0.24	**0.95**	6	0	0	20	9	12	20	

Table 6-7. Sustaining Capital Optimization Results (continued)

				Value Scores							Risk Criteria Scores							
	Quadrant		BCUC Category	Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Value Score	Financial	Reliability	Market Efficiency	Asset Condition	Relationships	Environment & Safety	Overall Risk Score	Projects Deemed Mandatory
127	1	F2010-S-8008-Overhead Transmission Structural Corrosion Protection - 500kV Tower Painting	OH Life Extension	-0.28	0.00	0.00	0.65	0.18	0.32	**0.87**	6	0	0	20	9	12	20	
128	1	F2010-S-8010-Overhead Transmission Structural Corrosion Protection - Grillage Refurbishment - First Towers out of Substation	OH Life Extension	-0.13	0.00	0.00	0.65	0.16	0.24	**0.93**	4	0	0	20	6	6	20	
129	1	F2010-S-8011-Overhead Transmission Structural Corrosion Protection - Grillage Refurbishment	OH Life Extension	-0.15	0.00	0.00	0.65	0.16	0.19	**0.85**	9	0	0	20	9	10	20	
130	1	F2010-S-8012-Overhead Transmission Structural Corrosion Protection - Steel Pole Painting	OH Life Extension	-0.14	0.00	0.00	0.65	0.16	0.24	**0.90**	6	0	0	20	9	12	20	
131	1	F2010-S-8004-Civil Protective works	OH Life Extension	-0.31	0.00	0.00	0.61	0.19	0.30	**0.78**	9	0	0	15	10	16	16	
132	1	F2009-S-3532-Overhead Transmission Structural Corrosion Protection - 138,230,287kV Tower Painting	OH Life Extension	0.53	0.00	0.00	0.57	0.11	0.32	**1.53**	9	0	0	15	0	12	15	
133	1	F2009-S-3545-230kV Lattice Steel Tower Replacement Program	OH Life Extension	-0.15	0.00	0.00	0.53	0.11	0.22	**0.70**	6	0	0	15	9	10	15	
134	1	F2009-S-3546-69kV Lattice Steel Tower Replacement Program	OH Life Extension	-0.15	0.00	0.00	0.55	0.15	0.32	**0.86**	6	0	0	15	6	6	15	
135	1	F2009-S-3553-Circuit Refurbishments	OH Life Extension	-0.38	0.00	0.00	0.49	0.23	0.40	**0.75**	0	0	0	15	4	4	15	
136	1	F2009-S-3559-Disconnect Switch - 69kV and 138kV	OH Life Extension	-0.28	0.00	0.00	0.64	0.25	0.27	**0.88**	0	0	0	15	4	4	15	
137	1	F2009-S-3562-Long Span Crossing Refurbishment Program	OH Life Extension	-0.34	0.00	0.00	0.40	0.26	0.24	**0.57**	1	0	0	15	0	0	15	
138	1	F2010-S-7000-Disconnect Switch - 69kV and 138kV	OH Life Extension	-0.28	0.00	0.00	0.64	0.25	0.27	**0.88**	0	0	0	15	4	4	15	
139	1	F2010-S-7030-Circuit Refurbishments	OH Life Extension	-0.40	0.00	0.00	0.49	0.23	0.40	**0.73**	0	0	0	15	4	4	15	
140	1	F2010-S-7304-Long Span Crossing Refurbishment Program	OH Life Extension	-0.34	0.00	0.00	0.40	0.26	0.24	**0.56**	1	0	0	15	0	0	15	
141	1	F2010-S-8002-69kV Lattice Steel Tower Replacement Program	OH Life Extension	-0.16	0.00	0.00	0.55	0.19	0.32	**0.90**	6	0	0	15	6	6	15	
142	1	F2010-S-8003-230kV Lattice Steel Tower Replacement Program	OH Life Extension	-0.16	0.00	0.00	0.53	0.17	0.22	**0.76**	6	0	0	15	6	6	15	
143	3	F2009-S-3548-Single Wood Cross arm with line posts replacement program	OH Life Extension	-0.11	0.00	0.00	0.42	0.17	0.16	**0.63**	12	0	0	5	9	2	12	
144	3	F2010-S-8009-Overhead Transmission Structural Corrosion Protection - 138,230,287kV Tower Painting	OH Life Extension	-0.21	0.00	0.00	0.51	0.18	0.26	**0.74**	9	0	0	10	0	12	12	
145	3	F2010-S-8014-Single Wood Cross arm with line posts replacement program	OH Life Extension	-0.16	0.00	0.00	0.42	0.13	0.16	**0.55**	12	0	0	5	9	2	12	
146	3	F2009-S-3538-Transmission Minor Capital - F2009	OH Life Extension	-0.17	0.00	0.00	0.31	0.15	0.14	**0.42**	5	0	0	10	8	10	10	
147	3	F2009-S-3547-Guy and Anchor rod replacement program	OH Life Extension	-0.07	0.00	0.00	0.49	0.11	0.32	**0.86**	6	0	0	10	4	10	10	
148	3	F2010-S-8005-Guy and Anchor rod replacement program	OH Life Extension	-0.15	0.00	0.00	0.49	0.16	0.32	**0.83**	6	0	0	10	4	10	10	
149	3	F2010-S-8018-Transmission Minor Capital	OH Life Extension	-0.17	0.00	0.00	0.51	0.15	0.14	**0.63**	3	0	0	10	8	10	10	
150	4	F2009-S-3563-Reconductoring Program Using High Strength Conductor	OH Life Extension	-0.37	0.00	0.00	0.00	0.24	0.00	**-0.12**	0	0	0	0	0	0	0	
151	3	F2009-S-3554-Arcing Horns - 500kV, 230kV, 138kV	OH Performance Improvements	0.39	0.02	0.00	0.00	0.00	0.11	**0.52**	5	0	0	0	0	4	5	
152	3	F2010-S-7200-Arcing Horns - 500kV, 230kV, 138kV	OH Performance Improvements	0.38	0.02	0.00	0.00	0.00	0.11	**0.51**	5	0	0	0	0	4	5	
153	4	F2009-S-7970-Surge Arrester	OH Performance Improvements	-0.32	0.04	0.00	0.00	0.13	0.00	**-0.15**	0	10	0	0	3	0	10	
154	4	F2010-S-7980-Surge Arrester	OH Performance Improvements	-0.32	0.04	0.00	0.00	0.13	0.00	**-0.15**	0	10	0	0	3	0	10	
155	1	F2009-S-3542-Second Narrows Crossing Tower seismic withstand upgrade	OH Risk Mitigation	-0.24	0.00	0.00	0.70	0.17	0.11	**0.73**	0	0	0	20	6	10	20	
156	1	F2009-S-3544-2L056 Knight Street Crossing Tower Seismic upgrade	OH Risk Mitigation	-0.08	0.00	0.00	0.68	0.14	0.09	**0.83**	0	0	0	20	6	10	20	
157	1	F2010-S-7202-Bonding Program	OH Risk Mitigation	-0.25	0.00	0.00	0.16	0.32	0.24	**0.48**	0	0	0	15	4	20	20	
158	1	F2010-S-8001-2L056 Knight Street Crossing Tower Seismic upgrade	OH Risk Mitigation	-0.25	0.00	0.00	0.47	0.15	0.11	**0.48**	0	0	0	20	6	10	20	
159	1	F2010-S-8013-Second Narrows Crossing Tower seismic withstand upgrade	OH Risk Mitigation	-0.31	0.00	0.00	0.47	0.15	0.11	**0.42**	0	0	0	20	8	10	20	
160	1	F2009-S-3541-Civil Protective works - F2009	OH Risk Mitigation	-0.30	0.00	0.00	0.61	0.19	0.30	**0.79**	9	0	0	15	10	16	16	M
161	2	F2009-S-3517-Transmission System - Ice Hazard Risk Reduction Program	OH Risk Mitigation	-0.31	0.00	0.00	0.40	0.16	0.11	**0.36**	5	0	0	15	0	5	15	
162	1	F2009-S-3566-Copper Conductor Replacement	OH Risk Mitigation	-0.16	0.00	0.00	0.58	0.24	0.24	**0.90**	2	0	0	15	0	5	15	
163	1	F2009-S-3567-OHGW Refurbishment Program	OH Risk Mitigation	-0.16	0.00	0.00	0.47	0.17	0.07	**0.55**	0	0	0	15	0	0	15	
164	1	F2010-S-7420-Copper Conductor Replacement	OH Risk Mitigation	-0.28	0.00	0.00	0.58	0.24	0.24	**0.79**	2	0	0	15	0	5	15	
165	1	F2010-S-7440-OHGW Refurbishment Program	OH Risk Mitigation	-0.20	0.00	0.00	0.47	0.17	0.07	**0.51**	0	0	0	15	0	0	15	
166	1	F2010-S-8019-Transmission System - Wind and Ice withstand Program	OH Risk Mitigation	-0.32	0.00	0.00	0.42	0.16	0.16	**0.42**	5	0	0	15	0	5	15	
167	2	F2009-S-3543-Tower Climbing Barrier and Signage program	OH Risk Mitigation	-0.15	0.00	0.00	0.00	0.13	0.11	**0.09**	12	0	0	0	16	20	20	M
168	2	F2009-S-3555-Bonding Program	OH Risk Mitigation	-0.41	0.00	0.00	0.16	0.32	0.24	**0.32**	6	0	0	15	4	20	20	
169	2	F2010-S-8017-Tower Climbing Barrier and Signage program	OH Risk Mitigation	-0.16	0.00	0.00	0.00	0.13	0.11	**0.08**	12	0	0	0	16	20	20	M

Table 6-7. Sustaining Capital Optimization Results (continued)

	Quadrant		BCUC Category	Value Scores: Financial	Value Scores: Reliability	Value Scores: Market Efficiency	Value Scores: Asset Condition	Value Scores: Relationships	Value Scores: Environment & Safety	Overall Value Score	Risk Criteria Scores: Financial	Risk Criteria Scores: Reliability	Risk Criteria Scores: Market Efficiency	Risk Criteria Scores: Asset Condition	Risk Criteria Scores: Relationships	Risk Criteria Scores: Environment & Safety	Overall Risk Score	Projects Deemed Mandatory
170	3	F2009-S-3565-Automatic Splice Replacement Program	OH Risk Mitigation	-0.20	0.00	0.00	0.47	0.27	0.24	**0.78**	2	0	0	10	0	5	10	
171	3	F2010-S-7400-Automatic Splice Replacement Program	OH Risk Mitigation	-0.20	0.00	0.00	0.47	0.27	0.24	**0.78**	2	0	0	10	0	5	10	
172	4	F2009-S-3549-STER conductor inventory reduction program	OH Risk Mitigation	-0.15	0.00	0.00	0.00	0.00	0.00	**-0.15**	12	0	0	0	4	0	12	
173	4	F2009-S-3550-STER tower and equipment replacement program	OH Risk Mitigation	-0.11	0.00	0.00	0.00	0.05	0.00	**-0.05**	12	0	0	0	4	0	12	
174	4	F2010-S-8015-STER conductor inventory reduction program	OH Risk Mitigation	-0.27	0.00	0.00	0.00	0.06	0.00	**-0.21**	12	0	0	0	4	0	12	
175	4	F2010-S-8016-STER tower and equipment replacement program	OH Risk Mitigation	-0.27	0.00	0.00	0.00	0.13	0.00	**-0.14**	12	0	0	0	4	0	12	
176	4	F2009-S-3558-Restore Ratings for Nominal Circuits	OH Risk Mitigation	-0.31	0.00	0.00	0.00	0.22	0.24	**0.15**	0	0	0	0	9	8	9	
177	4	F2010-S-7300-Restore Ratings for Nominal Circuits	OH Risk Mitigation	-0.25	0.00	0.00	0.00	0.22	0.24	**0.21**	0	0	0	0	9	8	9	
178	4	F2009-S-3564-2m Line Post Insulator Replacement Program	OH Risk Mitigation	-0.18	0.00	0.00	0.12	0.07	0.09	**0.10**	0	0	0	5	0	0	5	
179	4	F2010-S-7306-2m Line Post Insulator Replacement Program	OH Risk Mitigation	-0.18	0.00	0.00	0.12	0.07	0.09	**0.10**	0	0	0	5	0	0	5	
180	1	F2009-S-3605-ROW Access Program Definition	ROW Sustainment	-0.08	0.00	0.00	0.46	0.20	0.40	**0.99**	6	0	0	25	16	20	25	
181	1	F2009-S-3607-Bridge Program	ROW Sustainment	-0.17	0.00	0.00	0.46	0.19	0.38	**0.85**	5	0	0	25	12	20	25	
182	1	F2009-S-3608-Helipad Program	ROW Sustainment	0.39	0.00	0.00	0.46	0.12	0.11	**1.09**	5	0	0	25	6	10	25	
183	1	F2009-S-3613-Road Remediation	ROW Sustainment	-0.23	0.00	0.00	0.46	0.19	0.40	**0.82**	5	0	0	25	12	20	25	
184	1	F2010-S-9976-ROW Access Program Definition	ROW Sustainment	-0.14	0.00	0.00	0.46	0.20	0.40	**0.92**	6	0	0	25	16	20	25	
185	1	F2010-S-9978-Bridge Program	ROW Sustainment	-0.18	0.00	0.00	0.46	0.19	0.38	**0.85**	5	0	0	25	12	20	25	
186	1	F2010-S-9979-Helipad Program	ROW Sustainment	0.37	0.00	0.00	0.46	0.12	0.11	**1.06**	5	0	0	25	6	10	25	
187	1	F2010-S-9983-Road Remediation	ROW Sustainment	-0.18	0.00	0.00	0.46	0.19	0.40	**0.87**	5	0	0	25	12	20	25	
188	2	F2009-S-3606-LiDAR Survey of Transmission System	ROW Sustainment	-0.25	0.00	0.00	0.25	0.07	0.11	**0.18**	0	0	0	20	2	5	20	
189	2	F2009-S-3609-5L030 5L032 McNab Creek Road License	ROW Sustainment	-0.19	0.00	0.00	0.42	0.02	-0.08	**0.17**	3	0	0	20	2	0	20	
190	2	F2009-S-3610-Highway Relocations	ROW Sustainment	-0.25	0.00	0.00	0.00	0.06	0.11	**-0.09**	15	0	0	0	20	5	20	M
191	2	F2009-S-3611-Deficient Rights Program	ROW Sustainment	-0.43	0.00	0.00	0.00	0.25	0.00	**-0.18**	15	0	0	0	20	0	20	M
192	2	F2009-S-3612-Miscellaneous Rights Acquisitions	ROW Sustainment	-0.37	0.00	0.00	0.00	0.07	0.00	**-0.30**	15	0	0	0	20	0	20	M
193	2	F2010-S-9977-LiDAR Survey of Transmission System	ROW Sustainment	-0.32	0.00	0.00	0.25	0.07	0.11	**0.11**	0	0	0	20	2	5	20	
194	2	F2010-S-9980-Highway Relocations	ROW Sustainment	-0.34	0.00	0.00	0.00	0.06	0.11	**-0.17**	15	0	0	0	20	5	20	M
195	2	F2010-S-9981-Deficient Rights Program	ROW Sustainment	-0.46	0.00	0.00	0.00	0.25	0.00	**-0.21**	15	0	0	0	20	0	20	M
196	2	F2010-S-9982-Miscellaneous Rights Acquisitions	ROW Sustainment	-0.38	0.00	0.00	0.00	0.07	0.00	**-0.30**	15	0	0	0	20	0	20	M
197	2	F2009-S-3615-Third Party Funded Projects	ROW Sustainment	-0.15	0.00	0.00	0.00	0.08	0.00	**-0.07**	15	0	0	0	10	0	15	M
198	2	F2010-S-9985-Third Party Funded Projects	ROW Sustainment	-0.18	0.00	0.00	0.00	0.08	0.00	**-0.09**	15	0	0	0	10	0	15	M
199	3	F2009-S-3681-EGIS - PowerGrid - TM	ROW Sustainment	-0.10	0.00	0.00	0.47	0.06	0.15	**0.58**	4	0	0	10	0	6	10	
200	3	F2010-S-9986-EGIS - PowerGrid - TM	ROW Sustainment	-0.10	0.00	0.00	0.47	0.06	0.15	**0.58**	4	0	0	10	0	6	10	
201	4	F2009-S-3614-Access Rights Acquisitions	ROW Sustainment	-0.20	0.00	0.00	0.00	0.23	0.00	**0.03**	1	0	0	0	2	0	2	
202	4	F2010-S-9984-Access Rights Acquisitions	ROW Sustainment	-0.22	0.00	0.00	0.00	0.23	0.00	**0.02**	1	0	0	0	2	0	2	
203	4	F2009-S-3568-PLS-CADD Line Modelling of Transmission System	ROW Sustainment	-0.21	0.00	0.00	0.00	0.00	0.00	**-0.21**	0	0	0	0	0	0	0	
204	4	F2010-S-7500-PLS-CADD Line Modelling of Transmission System	ROW Sustainment	-0.21	0.00	0.00	0.00	0.00	0.00	**-0.21**	0	0	0	0	0	0	0	

6.5 Sustaining Capital Portfolio Descriptions

The Sustaining Capital portfolio is described by program and project in the following sections. BCTC requests that the Commission approve the full annual Sustaining Capital forecast of expenditures as shown in Table 6-1 for F2009 and F2010, and not provide project by project approvals. As such, BCTC will work towards achieving the total Sustaining Portfolio suite of projects listed here within the general level of expenditure approved by the Commission.

All programs and projects have been prioritized. The prioritization process includes an evaluation of the risk of deferral. BCTC believes that the programs and projects presented are required as the minimum expenditure necessary to address deteriorating asset condition and performance, address unacceptable risks, and address Third-party requested projects.

6.5.1 Stations

BCTC is forecasting Sustaining capital expenditures related to Stations totaling $71.7 million in F2009, and $75.7 million in F2010. The programs and projects that make up the Stations work are discussed in the following sections.

6.5.1.1 Auxiliary Equipment

Station auxiliary equipment includes any station equipment used to support the power delivery system, including station cables, bus-work and insulators, steel structures, equipment foundations, grounding systems, station power supplies, batteries and chargers, air compressors and dryers, buildings and HVAC equipment, perimeter fences, drainage systems, and gravel. Station auxiliary equipment does not include circuit breakers, transformers or other power equipment.

The Key Drivers for the Auxiliary Equipment Program are:

(a) Maintain System Reliability (Asset Health), and

(b) Manage Risks (Safety).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Auxiliary Equipment program as shown in Table 6-8 below.

Table 6-8. Annual Forecast of Auxiliary Equipment Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$4.3 million	$6.7 million	$2.4 million	$7.6 million	$0.9 million

Generally, the increase in the Auxiliary Equipment Program from forecast F2008 to F2009 is driven by increased activity associated with Pin and Cap Insulator Replacements, and higher expenditures in Minor Capital. All other projects in the Auxiliary Equipment Program are proposed to remain effectively unchanged after providing for inflation. The increase in Auxiliary Equipment from F2009 to F2010 of $0.9 million is mainly due to inflation of 5 percent plus the reintroduction of the Compressor Replacement project that was included in the F2006 Capital Plan, but not included in F2008 Capital Plan as discussed below.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.1.1.1 Pin and Cap Insulator Replacements

This project was included in the previous capital plan. Compared to the F2008 forecast level of activity that resulted in capital expenditures of $0.5 million, BCTC is forecasting an increase in expenditure levels for F2009 of $2.0 million. This project is also included in the F2010 Capital Plan at approximately the same activity level as forecast for F2009, and is expected to continue for the 10-year planning period and beyond.

Pin and cap insulators were installed in stations from the 1950s to the 1970s. They have a metal stud base mortared together with one or more porcelain skirts. Changing weather (temperature and humidity) expands and contracts the mortar, allowing water to penetrate and crack the porcelain skirts. This type of failure has resulted in approximately thirty known system faults in the last ten years. Ongoing failures pose a risk to the transmission system by damaging adjacent equipment which is exposed to high fault levels.

The weakness of this type of insulator was recognized by the utility industry in the1970s. Pin and cap insulators are no longer manufactured and utilities have been replacing them with post-type insulators. A program was introduced at BC Hydro over 20 years ago to replace pin and cap insulators with post type insulators.

In 2005, BCTC experienced 20 pin and cap insulator failures. In 2006, there were 25 pin and cap insulator failures. Two explosive pin and cap failures have been associated with ‘near miss’ life-safety incidents in each of 2005 and 2006. Failures will continue to occur until all pin and cap insulators have been replaced.

In its Decision relating to the F2006 Update Capital Plan, the Commission directed BCTC to reduce Sustaining Capital expenditures. In order to comply with the Decision, BCTC suspended activity on Pin and Cap Insulator Replacements midway through F2007. As a result, BCTC is increasing expenditures on the replacement of Pin and Cap Insulators in F2008 to approximately $0.5 million.

In F2008, insulator replacements at eight 60 kV to 230 kV switchyards are being undertaken. By the end of F2008 over 4,200 pin and cap insulators will have been replaced under this project since 1982. However, almost 21,000 of these insulators in over 150 stations still remain on the transmission system.

Pin and cap insulators are replaced based on asset condition, mounting position, and criticality. Whenever possible the pin and cap insulators are replaced in conjunction with other planned work at substations to reduce costs associated with the work and to take advantage of planned outages. Replacement priority is given to insulators associated with disconnect switches (because they pose a risk to the operator of the switch), and those found to be in poor condition based on inspection. Insulators are inspected as part of station inspections which occur every three to six months. However, many more failed pin and cap insulators go undetected until the insulator is replaced.

As indicated in the F2008 Capital Plan, it is necessary for the work on this project to return to its forecast level in the F2007 Update Capital Plan for F2009 and F2010. However, even at this forecast level of activity, based on approximately 21,000 pin and cap insulators still in use, it will take approximately 23 years to complete the project.

6.5.1.1.2 Roofing Replacements

This project was included in the previous capital plan and there is no change to the F2009 forecast level of activity. This project is also expected to be part of the F2010 Capital Plan at the same activity level as forecast for F2009. Generally, nine or ten roofs are replaced each year under this project and will continue to be replaced at this rate through the 10-year planning period and beyond.

Roofs provide safe and secure enclosures for control systems at station and microwave sites. Roofing replacements are required when roofs reach their end of service life as a result of failures or normal wear and tear. Roofing is replaced on a priority basis to ensure the reliability and safety of the electrical system. Work includes removing the existing roof and metal flashings, installing a new roof membrane system and flashings, and if required, additional strengthening for seismic upgrading. In some cases roofs can be repaired, however failure to replace a roof that is at the end of its operational life puts sensitive electrical equipment at risk of damage and is not considered cost effective. Emergency replacement of roofing results in additional cost because of emergency procurement of materials and labour and because of reduced access to remote areas during inclement weather.

Roofing inspections performed by out-sourced roofing professionals to determine the state of existing roofs at the 291 sites are ongoing. From this assessment, work is prioritized based on the age and condition of the roof. It is expected that this program will continue indefinitely.

6.5.1.1.3 124 Volt Battery Bank Replacements

This project was included in the previous capital plan and there is no change to the F2009 forecast activity level. This project is also forecast to be part of the F2010 Capital Plan at the same activity level as forecast for F2009, and is expected to continue for the 10-year planning period.

Batteries are required for emergency operation of switchgear, relays, telecommunications equipment, emergency lighting, motors, inverters, and other devices. Batteries provide energy to circuit breakers during an outage, allowing the protection to function. Without batteries, there would be no emergency power at substations when a power outage occurs. Based on historical results, the average battery life is twenty-five years. Batteries are inspected yearly and are load tested after eighteen years of life.

BCTC has over 220 stations that use 124 Volt batteries. Six to nine battery banks are replaced each year with priority given to leaking or cracked batteries, those with a known failure rate, and those that have failed the load test. Replacement of failing batteries and chargers is required to ensure that there are no safety incidents, no loss of station control protection, no customer outages, and no equipment damage resulting from loss of battery power.

6.5.1.1.4 Gravel Replacements

This project was included in the previous capital plan and there is no change to the F2009 forecast activity level. This project is also part of the F2010 Capital Plan at the same activity level as forecast for F2009. BCTC expects to replace gravel at eight to ten stations each year under this project, and it is expected to continue for the 10-year planning period, and beyond.

Clean station gravel surfaces are designed to provide worker safety and meet insulation, clearance, and fire containment specifications. Vegetation growth is unacceptable in stations as it compromises the insulation provided by clean gravel for worker safety. Clean gravel inhibits vegetation growth, provides fire containment, and prevents risk of fire spread attributed to vegetation growth. Clean gravel can reduce the need for herbicides by up to 50 percent.

There are 291 stations, all of which have gravel surfaces. Over time, the gravel can be absorbed into the ground or become overgrown with vegetation and require replacement.

The normal life of a gravel surface is thirty years. Sites are identified through station inspections that are conducted every three to six months and prioritized based on condition and risk of safety issues.

6.5.1.1.5 Facility Upgrades

This project was included in the previous capital plan and there is no change to the F2009 forecast activity level. This project is also part of the F2010 Capital Plan at the same activity level as forecast for F2009. BCTC expects to address three to four stations each year under this project, and expects to continue at this level for the 10-year planning period and beyond.

Facility upgrades include work to replace or upgrade station fencing and drainage. Station perimeter fencing provides public safety and facility security. Failure to replace or upgrade facility fences could lead to increased equipment theft resulting in financial loss, negatively impact public and employee safety, and result in equipment and/or customer outages. Drainage ditches and culverts protect against flooding. Failure to upgrade drainage ditches and culverts could lead to station flooding resulting in outages.

The cost of facility upgrades ranges from $50,000 to $250,000 per station, depending on the size of the station and the work required. Facility upgrades are based on field inspections which are completed on all stations every three to six months depending on the risk associated with the station. The work level for this project is based on historical experience.

6.5.1.1.6 Auxiliary Equipment Minor Capital

This project was included in the previous capital plan. BCTC is forecasting incremental increases to activity for this project starting in F2009 to address increasing failures of equipment that are also becoming more expensive over time. This project is also part of the F2010 Capital Plan, and is forecast to have approximately the same level of replacements as F2009, at approximately the same cost. This project occurs every year to deal with unplanned equipment failures, and is expected to continue for the 10-year planning period and beyond.

The Minor Capital program has been based on historical experience in the past and is used to replace failing substation equipment that is not funded through other projects but is essential for continued operation of the system. An example is replacement of a failing HVAC unit for a station control building. Reasons for replacement include normal wear and tear, end-of-life of the equipment, and equipment failure. Minor Capital funding is generally used to address asset refurbishment/replacement where an asset is run to failure such that failure poses acceptable risk to transmission system reliability, safety, or environment. BCTC closely monitors Minor Capital expenditures to identify asset classes that may need refurbishment/replacement projects established.

Recently, BCTC has been experiencing increasing failures of equipment that are normally funded by Minor Capital, such as Current Voltage Transformers, Current Transformers, and Heating Ventilation and Air Conditioning (HVAC) Systems. Figure 6-2 provides the number of pieces of equipment replaced over the past four fiscal years. Evident from this graph is that the number of pieces of failed equipment that were replaced increased significantly in F2005 and have remained relatively constant since then. Figure 6-3 provides historical expenditures related to the number of pieces replaced and funded by Minor Capital, indicating that pieces of failed equipment being replaced are increasing in value over time.

Figure 6-2. Minor Capital Failed Equipment Replaced from F2004 to F2007

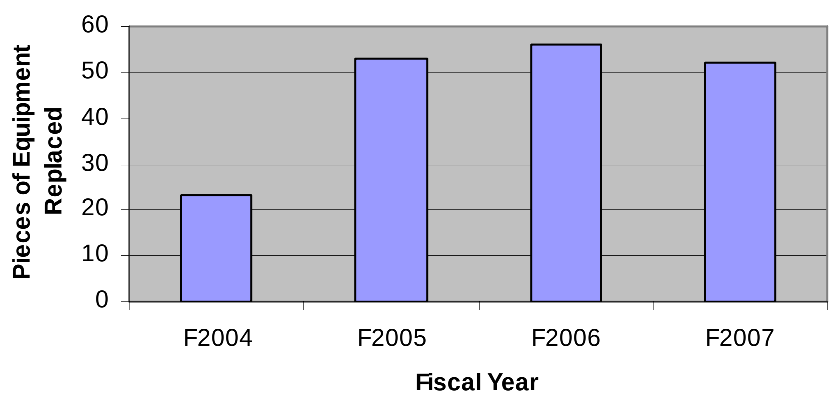
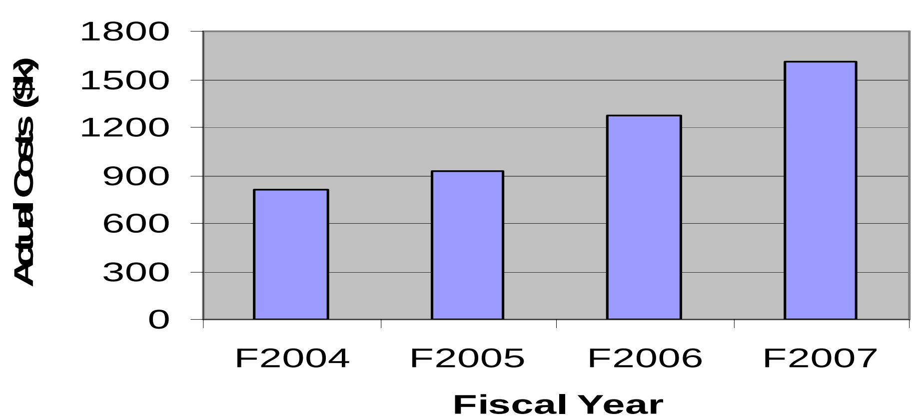


Figure 6-3. Minor Capital Spending F2004 to F2007



6.5.1.1.7 Grounding Upgrades

This project was included in the previous capital plan and there is no change to the F2009 forecast activity level. This project is also part of the F2010 Capital Plan and is forecast to have the same level of activity as F2009, and is expected to continue for the 10-year planning period and beyond.

Ground grids consist of interlaid copper wire that is laid underneath each station to provide low ground resistance. This allows for quick response from protection equipment and fast clearing of distribution faults to ensure safe conditions for crews and the public.

BCTC initiated a project in F2008 to measure and mitigate step and touch potentials at four substations per year. This is an ongoing project and is prioritized for stations which are recognized as having the highest risk. Four substations were completed in F2008 and four stations are planned for F2009. Early learnings from this project indicate that the work required varies from minor upgrades to more comprehensive upgrades costing up to $60,000 per station.

Failure to upgrade station grounding could lead to a step and touch potential that is outside of current IEEE and BC Hydro standards and poses a safety risk to substation workers and the public. This project will upgrade the identified deficient stations as well as identify and prioritize four other high-risk stations to be upgraded in F2010.

6.5.1.1.8 Station Structural Corrosion Protection

This project was included in the previous capital plan, however, there is no further activity planned for F2009 and F2010. BCTC completed Corrosion Protection for Horne Payne and Walters substations in F2007. Cost for the project was found to be too expensive relative to the benefit to continue with the project.

Substation steel structures provide support for critical substation equipment and must be maintained in acceptable condition to ensure station reliability. Lessons learned from the past project indicate that application of corrosion protective coatings can be logistically difficult to execute and expensive due to required planned outages. As a result, BCTC is evaluating the feasibility of the approach, and is deferring future activity in light of potential replacement of the remaining substations, such as North Vancouver substation, due to growth.

6.5.1.1.9 Vancouver Island Terminal (VIT) and Arnott (ARN) Cross Contamination Issues

This project was included in the previous capital plan and was completed in F2008. There is no forecast activity planned for F2009 and F2010.

6.5.1.1.10 Air Compressor Replacements

The Air Compressor Replacement project was included in the F2006 to F2015 Capital Plan. The project was required to replace air compressors that enable the function of Air Blast Circuit Breakers and other substation power equipment. Air compressor systems are used to supply dry high-pressure air to circuit breakers and to support other critical station systems. Subsequently, a project was initiated to replace Air Blast Circuit Breakers with SF_6 Circuit Breakers which do not require high-pressure air (i.e. air compressors) to operate. Therefore, the Air Compressor Replacement Project was temporarily suspended.

The Project is now required to address the replacement of failing air compressors in cases when repair is not a cost-effective alternative, and when the failing air compressors are not planned to be removed from service under the Air-Blast Circuit Breaker Replacement Project. This Project is planned for F2010 at a forecast expenditure level of $0.5 million. The activity is expected to continue for the 10-year planning period and beyond.

The air compressor systems that require replacement are coordinated with the Circuit Breaker program as described below in Section 6.5.1.2.

6.5.1.2 Circuit Breakers

High voltage circuit breakers are used to isolate sections of the power system and to interrupt high currents under fault conditions. They are the ultimate protection device on the transmission system and must be capable of reliably interrupting both load currents and fault currents in a timely manner. The transmission system currently employs over 1000 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 12 kV to 500 kV), arc extinguishing medium (air magnetic, air-blast, vacuum, minimum or bulk oil, SF_6 gas or SF_6 and other gas mixtures), types of circuit breakers (live tank, dead tank or Gas Insulated Switchgear), and vintages and brands.

The Key Drivers for the Circuit Breaker Program are:

(a) Maintain System Reliability (Asset Health, Asset Performance); and

(b) Manage Risks (Safety).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Circuit Breaker program as shown in Table 6-9.

Table 6-9. Annual Forecast of Circuit Breaker Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$18.9 million	$25.3 million	$6.4 million	$26.4 million	$1.1 million

Generally, the increase in the Circuit Breaker Program from forecast F2008 to F2009 of $6.4 million is driven by increased activity associated with 500 kV and 230 kV Air Blast Circuit Breaker and 500 kV Circuit Switcher Replacements Project. All other projects in the Circuit Breaker Program are proposed to remain effectively unchanged after providing for inflation. The increase in Circuit Breakers from F2009 to F2010 of $1.1 million is mainly due to the allowance for inflation of 5 percent, with all other projects effectively remaining unchanged.

BCTC identified failures of four circuit breakers and one circuit switcher at Burrard, Minette, Rosedale and Dunsmuir substations, which is a higher failure rate than expected, and is indicative of an accelerated degradation of asset performance. Analysis indicates that various circuit breaker classes are at end-of-life and mean-time-between-failure (MTBF) and corrective action rates are decreasing significantly, from 4,297 days to approximately 300-400 days. BCTC uses a database management tool called Meridium to determine MTBF rates, and other useful statistics that are used to manage replacement or refurbishment decisions, for various classes of equipment. BCTC transmission system planning standards for single contingencies (N-1), are to maintain the system at an MTBF (actual category performance) that is greater than three years (>1095 days).

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program. BCTC may revisit this format in future years.

6.5.1.2.1 500 kV & 230 kV Air-Blast Circuit Breaker and 500 kV Circuit Switcher Replacements

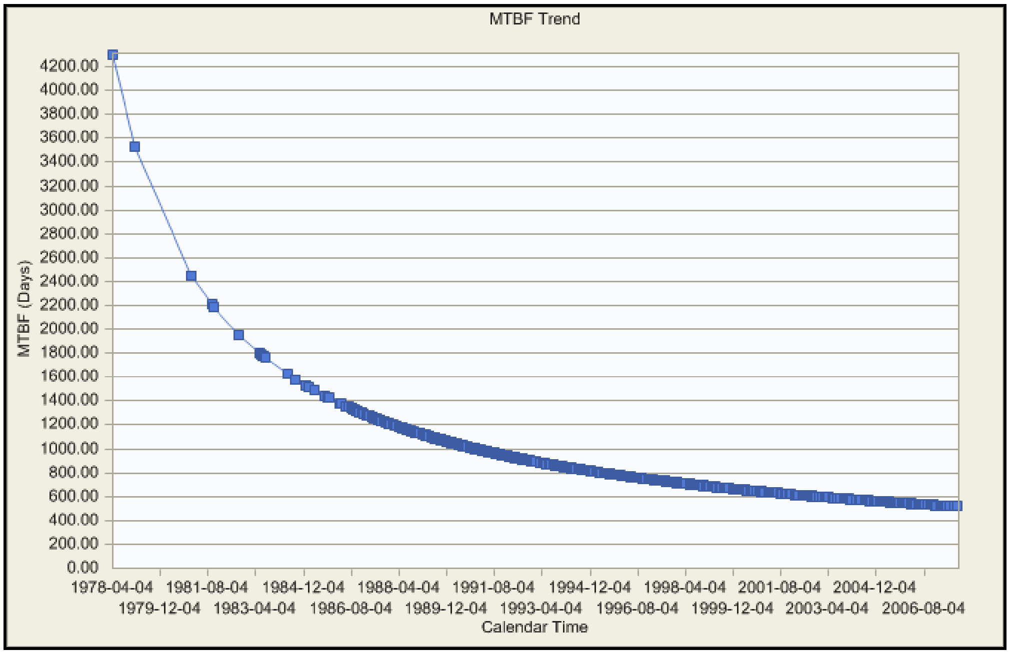
This project was included in the previous Capital Plan. The forecast activity level for F2009 is increasing compared to F2008 activity, resulting in additional expenditures of $6.0 million. BCTC also requires an additional $4.5 million of funding as part of the F2010 Capital Plan to meet the replacement of all air-blast circuit breakers by F2014.

(a) 500 kV & 230 kV Air Blast Circuit Breakers

The reliability of circuit breakers is essential to system operations, and the loss of certain critical circuit breakers could lead to widespread power outages. BCTC has approximately 170 air-blast circuit breakers that are due for replacement by F2014.The circuit breakers are approaching an average service life of 40 years, and are currently exhibiting deteriorating asset condition.

Figure 6-4, from BCTC's Meridium database management system, provides the actual MTBF for 500 kV Air-Blast Circuit Breakers for the period from January 1975 to November 2007. Results are based on an initial MTBF of 4297 days, and have declined to approximately 516 days between expected failures. The results indicate that these Circuit Breakers do not meet BCTC minimum reliability criteria, and are expected to continue to deteriorate over time. BCTC is of the opinion that it is now appropriate to replace the 500 kV Air Blast circuit breakers between F2009 and F2014.

Figure 6-4. MTBF of 500 kV Air Blast Circuit Breakers



Air-blast circuit breakers rely on compressed air as an arc-extinguishing and insulating medium and require associated air compressor equipment to function. Most use very high-pressure air to operate (1800 to 3600 psi).

Air-blast circuit breakers are configured with large masses supported on long vertical porcelain insulators, making stability a concern in seismically active areas. None of BCTC's circuit breakers currently in service meet seismic requirements, and a seismic event of significant magnitude would disable most of the 500 kV and 230 kV transmission systems in the Lower Mainland. As an example, a seismic event affecting Ingledow substation could result in rolling black-outs to the southern Lower Mainland and Fraser Valley, and loss of transfer capability (2,850 MW) to the United States for up to one year.

In addition, several air-blast circuit breaker explosive failures (i.e., Ingledow 5CB10, Williston 5CB2 & 5CB5, and Cranbrook 5CB13) have occurred in the past 6 years. At failure, porcelain shards were spread over a radius of 30 meters, creating a life-safety hazard to personnel and damaging nearby equipment.

To address these issues, BCTC has assessed two alternatives. The first alternative calls for a major refurbishment of the circuit breakers. BCTC undertook a major life-extension refurbishment approximately 20 years ago to extend the useful life of the breakers to 2014. However, only one major life-extension refurbishment is economically and technically feasible on these circuit breakers, leaving replacement as the only option at this time. To replace the fleet of 500 kV Air- Blast Circuit Breakers by 2014, BCTC needs to undertake a replacement program of approximately 24 units per year to meet that date. Given the criticality of these circuit breakers, BCTC is examining options to accelerate the replacement project, which may require additional capital expenditures in future Capital Plans.

Replacement of the air-blast circuit breakers also provides an opportunity to remove maintenance intensive air-compressor systems as the replacement SF_6 Circuit Breakers do not required high-pressure air to operate and therefore air-compressor maintenance costs are eliminated.

For those circuit breakers which are no longer supported by the Original Equipment Manufacturers or spare parts are cost-prohibitive, refurbishment is not an alternative and the circuit breaker must be replaced. Where there is OEM support or available spare parts the decision to perform a one-time refurbishment or asset replacement is assessed on a case-by-case basis.

On average, this project will need to address the replacement of 24 circuit breakers per year. This volume of activity is required to balance resources while minimizing impacts to the transmission system so that all the circuit breakers are replaced prior to failure. Circuit breaker replacement is prioritized based on asset condition as determined by inspections. Activity planned for F2009 includes replacements at the following substations: Ingledow, Nicola, Dunsmuir, and Williston substations. Planned activity for F2010 includes replacements at Ingledow (5 breakers), and Glenannan substations.

As a result of the issues associated with air-blast breakers, BCTC started the project in 2004 to gradually remove all air-blast circuit breakers and their associated compressor equipment from the system. The air-blast circuit breakers are being replaced with proven and reliable low-maintenance SF_6 circuit breakers. The type of SF_6 breakers that BCTC uses for replacements were first installed in the early 1990s. To date, approximately 65 of these breakers have been installed on the transmission system and there have not been any failures.

To minimize replacement costs, most of the existing foundations and control wiring circuits will be re-used. Additionally, as the air-blast breakers are phased out, the supporting air systems will be removed and this will reduce annual maintenance costs by approximately $70,000, and eliminate the need to replace air compressors that are estimated to cost between $0.4 million and $1.0 million. Finally, the new replacement circuit breakers alleviate the existing seismic risk of the existing air-blast circuit breakers.

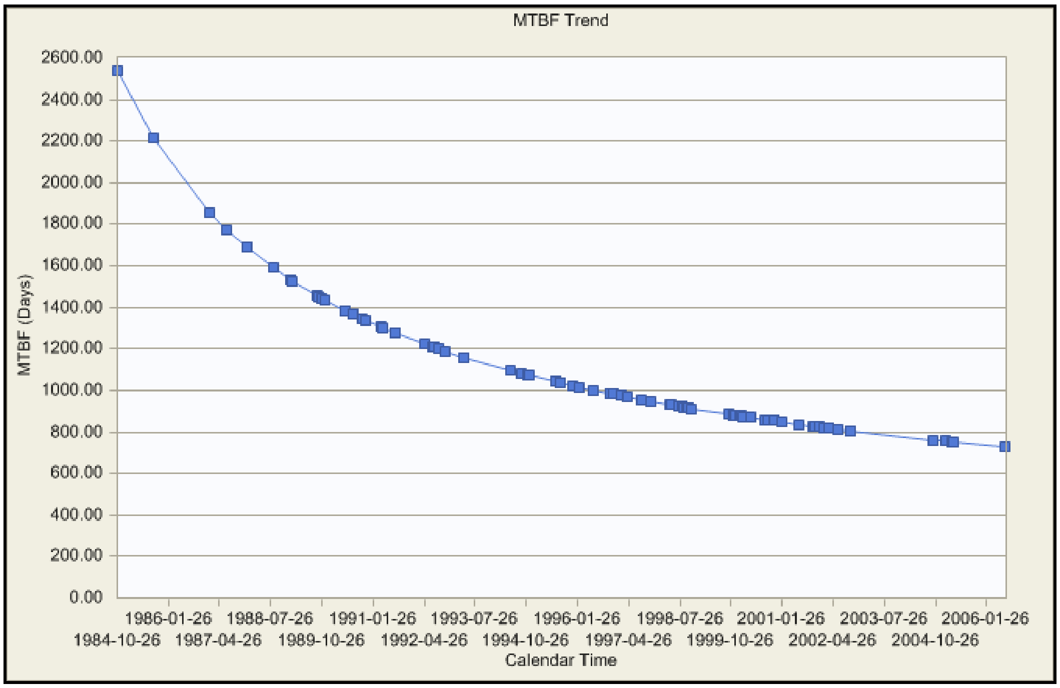
The replacement 230 kV SF_6 breakers are equipped with bushing type current transformers, which will also allow for the removal of the existing freestanding oil-insulated current transformers, of which some have failed and are close to end-of-life. The most recent failures occurred in October 2007 at Ingledow. Significantly, the life-safety risk associated with failure is reduced and, based on the experience with previously installed replacement SF_6 breakers, it is expected that reliability will be restored as well.

(b) 500 kV Circuit Switchers

There are 12 – 500 kV circuit switchers remaining in service on the transmission system. These circuit switchers were installed between 1975 and 1983, mostly as 500 kV reactor switching devices. In the 1970s the circuit switchers were considered a low-cost alternative to circuit breakers. Experience accumulated over the past 30 years indicates that 500 kV circuit switchers are not suitable for reactor switching applications because circuit switchers are prone to re-strikes during switching that represents a risk of reactor failure, impacting system transfer capability. Additionally, the circuit switchers no longer meet national and international standards (i.e., IEC, IEEE) as interrupting devices for reactor switching.

Figure 6-5 indicates that the 500 kV circuit switchers are reaching end-of-life condition, and will require replacement. Initial MTBF for the class was 2,538 days at installation, and has declined to approximately 727 days until failure, which is below BCTC's minimum reliability criteria.

Figure 6-5. MTBF for 500 kV Circuit Switchers



Frequent operations demanded by the system due to electricity trade have led to most of these units reaching or exceeding OEM recommended maximum number of operations. BCTC's strategy is to address circuit switcher issues by using spare parts. However, this strategy was not practical for 3 circuit switchers (Williston 5D34, Dunsmuir 5D51 and 5D54), which have failed due to high-use, and require replacement with circuit breakers.

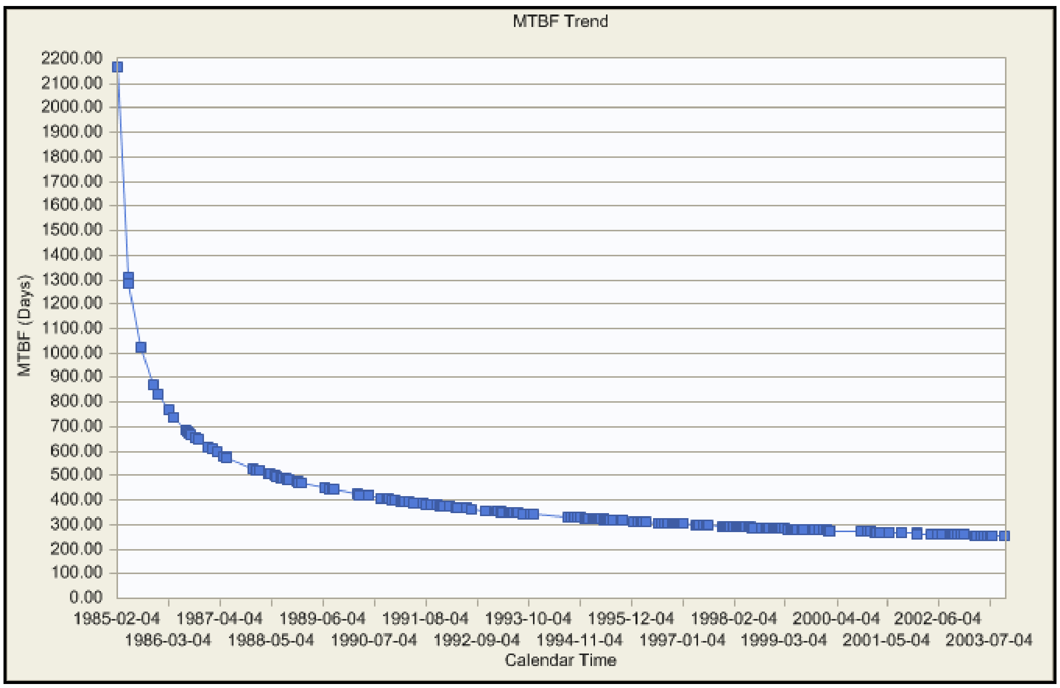
6.5.1.2.2 230 kV Double Pressure SF_6 Circuit Breaker Replacement

This project was included in the previous Capital Plan and there is no change to the F2009 forecast activity level. This project is also part of the F2010 Capital Plan and is forecast to have the same level of activity as F2009. This project is expected to continue until F2015.

ITE type GA and Westinghouse type SF_6 circuit breakers, which are first-generation double-pressure SF_6 technology, were installed in the 1950s and 1960s. These circuit breakers are in poor condition and have poor reliability and need to be replaced.

Figure 6-6 provides the MTBF for 230 kV Double Pressure SF_6 Circuit Breakers. The observed period is from January 1985 to November 2007, indicating an initial MTBF of 2,171 days between failures at installation, declining to approximately 253 days between expected failures currently. This is unacceptable and leads to increased OMA costs for repair.

Figure 6-6. MTBF for 230 kV Double Pressure SF_6 Circuit Breakers



The original double-pressure SF_6 breakers are also subject to significant gas leaks, requiring costly repairs, which are short-term solutions to the problem. The average cost of repair is approximately $80,000 per failure. Additionally, SF_6 is a major greenhouse gas with the same effect as releasing over 23,000 times its volume in CO_2. Most governments and utilities are taking steps to reduce or eliminate SF_6 leaks. BCTC supports the CEA/Environment Canada Memorandum of Understanding to control and minimize SF_6 gas releases. By comparison, the modern SF_6 'dead-tank' type circuit breakers have predicted mean-time-between-failure rates of about twenty years and none of the more than thirty 230 kV circuit breakers of this type on the system have failed or leaked since being installed beginning in 1995.

An analysis was conducted that compared the cost of refurbishment against the cost of replacement. Results show that replacement is preferred as it is the least cost alternative. Therefore, a total of three SF_6 breakers will be replaced in F2009 and five in F2010 and the remaining thirty-two double-pressure SF_6 breakers will be replaced by F2015. Circuit breaker replacement is prioritized by SF_6 gas leakage rate and failure.

6.5.1.2.3 12/25/60/138 kV Reactor Circuit Breaker

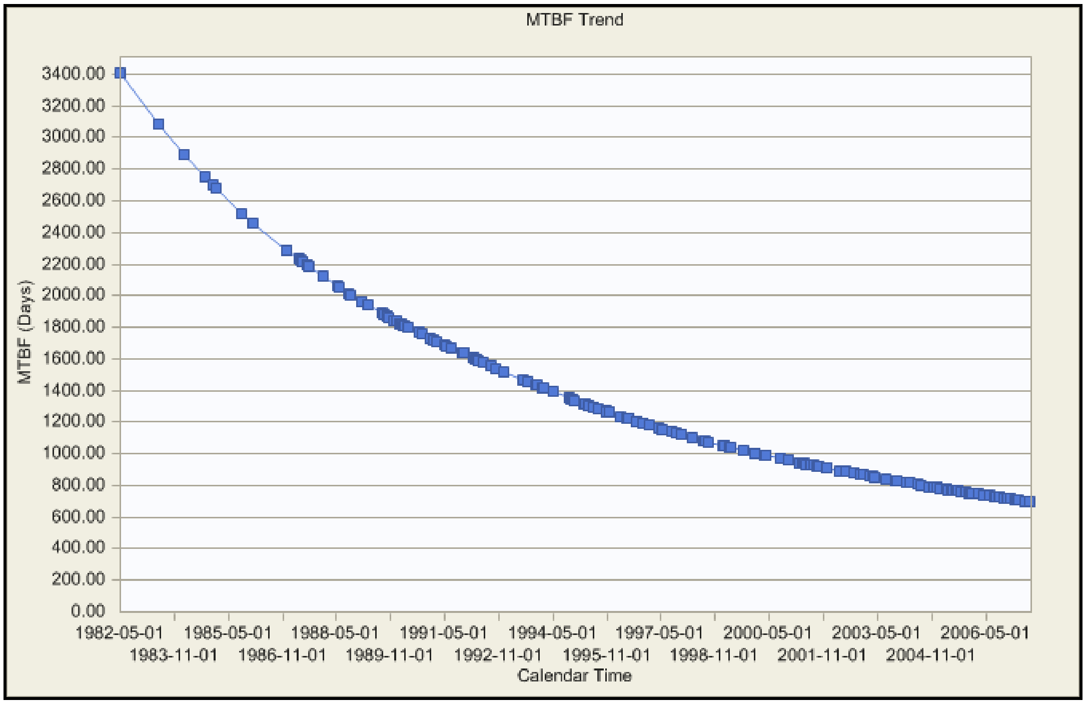
This project was included in the previous Capital Plan and there is no change to the F2009 forecast activity level. BCTC has no planned activity for F2010.

Reactor circuit breakers are used to switch shunt reactors to regulate system voltages, and there are approximately twenty-five reactor circuit breakers in use in the transmission system. A strong predictor of end-of-life for these breakers is the cumulative number of switching operations they have completed. Therefore, these values are continuously monitored and replacement or refurbishment is planned when the number of operations approaches 10,000.

Three reactor switching circuit breakers were completed in F2008 (Kelly 12CB2, Meridian 12CB31, Kidd2 12CB1). Three additional reactor switching circuit breakers have been identified as being in poor condition, are reaching the maximum number of recommended operations, and require replacement in F2009 (Malaspina 12CB2, Cranbrook 12CB16 and 12CB17).

MTBF is declining as shown in Figure 6-7. MTBF for this type of circuit breaker at installation is over 4,900 days, but has decreased to 695 days to next failure, which is an unacceptable level of reliability for these types of equipment, based on BCTC's minimum reliability criteria.

Figure 6-7. MTBF for 12 kV Grid Reactor Circuit Breakers



Previously, the reactor circuit breakers were replaced on failure with standard spare breakers. However, accumulated experience has proven that regular spare breakers are not suitable for this demanding application and there was a need to standardize on 60 kV (special type-tested units) breakers for 12 kV reactor switching. Refurbishment was also considered for each of the breakers; however, due to high maintenance costs and a lack of spare parts, this alternative was rejected. It is expected that replacement of these breakers will lead to some reduction in maintenance costs as the breakers used for replacement are expected to demonstrate improved performance.

6.5.1.2.4 Vancouver Island Terminal (VIT) Synchronous Condenser Circuit Breaker Replacement

This project was included in the previous Capital Plan and there is no activity planned for F2009 or the remainder of the 10-year plan as this project was completed in F2008.

6.5.1.2.5 Spare Circuit Breaker Purchase

This project was included in the previous Capital Plan and there is no change in activity planned for F2009. There is no activity currently planned for F2010, but there may be a requirement for additional funds depending on usage of the spares.

There are over three hundred 230 kV circuit breakers in the system. Most of these were installed in the late 1960s and early 1970s and some of these breakers are close to the end-of-life. The average lead-time to order a circuit breaker is eight months.

To minimize system reliability risks, knowing that there are long procurement lead-times, BCTC plans to acquire a second 230 kV spare circuit breaker. Currently, BCTC is experiencing a failure rate of two per year for 230 kV circuit breakers.

6.5.1.2.6 Independent Pole Operating Breakers

This project was included in the previous Capital Plan for F2009 but has been cancelled and there is no planned activity for F2009 or F2010. The required features of this project are incorporated into existing Protection and Control and Circuit Breaker replacement programs as a design standard.

6.5.1.2.7 Mica Gas Insulated Switchgear Replacement

This project was included in the previous Capital Plan and there is no change in activity planned for F2009. There is no activity planned for F2010 as the project will be complete in F2009.

The Mica Generating Station was built and commissioned in 1976 and has approximately 1800 MW of installed power or 17 percent of BC Hydro's total installed generation. It is considered vital to the BC Hydro system.

The Gas Insulated Switchgear (GIS) was installed at the station in 1975 and, at the time, was prototype equipment in its voltage class. The four existing ITE GB-type breakers use outdated double-pressure technology and have six break/pole and closing resistors with compressed-air mechanisms that are maintenance intensive.

The justification for the full project was based on the need to address the following issues:

(a) Problems with 5CB7 resulted in frequent trips of 5L72.

(b) Operating restrictions as a result of breaker inadequacies.

(c) The original manufacturer (ITE) no longer exists, and while parts are still available, they are very expensive.

(d) Several of the disconnect switches are no longer operational, and some of the operating rods exhibit high levels of partial discharge.

(e) The Mica GIS provides the largest amount of SF_6 gas leakage in the entire BC Hydro system. SF_6 is a greenhouse gas that has more than 23,000 times the effect than CO_2. Numerous attempts to eliminate the leaks have only been partially successful.

(f) The circuit breakers also suffer from various other defects, and their reliability is considerably lower than what is required for switchgear serving a major generating station, such as Mica.

(g) The circuit breakers are difficult and costly to maintain. An estimate for partial refurbishment of one circuit breaker (5CB10) came to $500,000. Refurbishing the adjacent disconnects would add another $200,000.

All four circuit breakers and associated disconnects are being replaced by F2009. The risk of these circuit breakers restricting generation at Mica is not acceptable as it can result in the loss of 1800 MW of generation. In addition, replacement of the circuit breakers will allow lifting some of the existing operating restrictions on switching 5L71 and 5L72, mitigate the risk of SF_6 gas leaks (the new equipment is guaranteed for less than 0.5 percent gas leaks per year), and reduce maintenance costs.

The F2008 implementation phase of the project addressed replacement of two of the four 500 kV GIS circuit breakers and associated equipment. The F2009 phase of the project will address the remaining two 500 kV GIS circuit breakers.

6.5.1.2.8 Gas Insulated Switchgear (GIS) Betterment

This project was included in the previous Capital Plan and there is no change to forecast activity levels for F2009 or F2010. This project is expected to be complete in F2010.

GIS installations at Peace Canyon, Sperling, and Ashton Creek were commissioned between 1977 and 1979. These stations are critical to support the power system. They have been in service without any major interruption since their in-service date, and most of the equipment is still in fair condition. However, the hydraulic mechanisms which are a major component of the circuit breaker are starting to deteriorate, due to the aging of seals and gaskets, and wear of mechanical parts.

Maintain-on-failure is not an acceptable alternative due to the very long lead-time (approximately 9 months) for delivery of spare parts and due to deteriorating reliability.

Refurbishment was chosen over replacement because the cost of replacement was found to be nearly eight times higher than the cost of refurbishment and refurbishing does not require extensive outages. Refurbishing the hydraulic mechanisms is expected to extend the circuit breaker life expectancy by up to 25 years.

6.5.1.2.9 Horsey GIS Replacement Program

This project was included in the previous Capital Plan and there is a change in scope for F2009, deferring much of the activity and cost of the project to F2010, with completion expected in F2011.

Although the F2008 and F2009 expenditures associated with this project were previously approved, the cost of replacement was found to be excessive. The project is being reviewed to determine the best option, and will be addressed in a future Capital Plan.

The deterioration of the Horsey GIS needs to be addressed to ensure continued supply to downtown Victoria and mitigate environmental risks related to SF_6 gas leaks.

BCTC requires definition funding in F2009 of approximately $0.2 million to establish the project that will mitigate the deterioration of the GIS equipment at Horsey station. Funding requests in F2010 will address the implementation phase of the project for F2010 and F2011.

6.5.1.2.10 60 kV to 138 kV Circuit Breaker Replacement

This is a new project that will be initiated in F2009. BCTC is forecasting an expenditure of $0.5 million in each of F2009 and F2010. The project is expected to continue for the 10-year planning period and beyond, at higher activity levels.

The project will replace three to four high-priority breakers in the first two years and is required to address system reliability risk related to increasing failures and lack of support by the original equipment manufacturer. The project will be accelerated starting in F2011 to $4.0 million per year (30 breakers per year), over the next 20 years, for the replacement of approximately 650 remaining circuit breakers showing excessive deterioration.

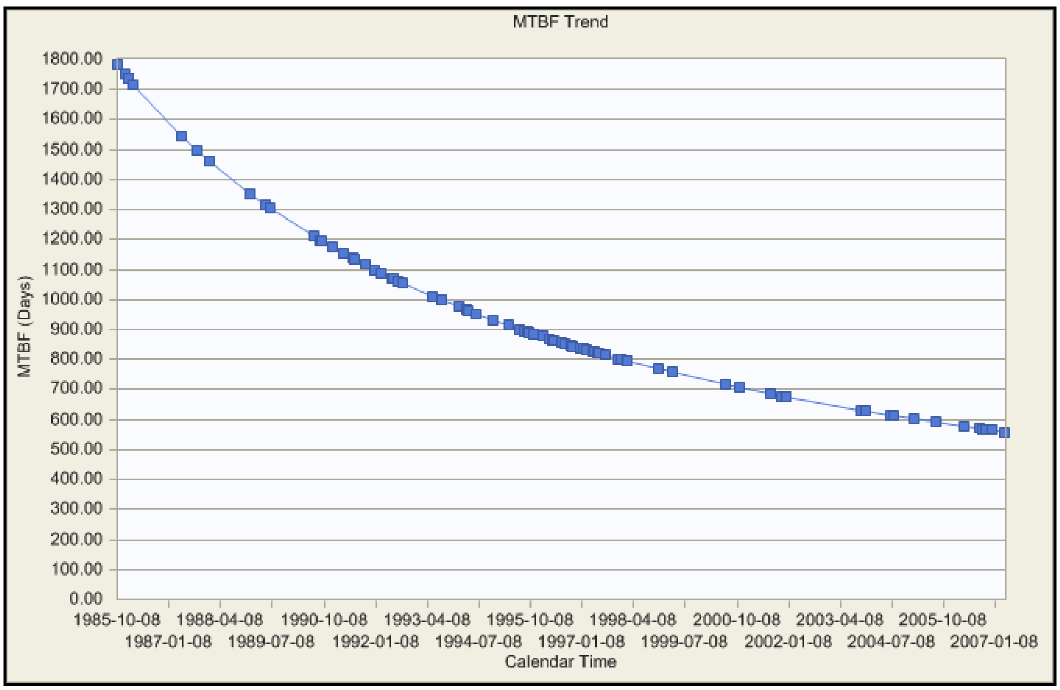
The asset condition of 60 kV and 138 kV circuit breakers are deteriorating and some breakers are at end-of-life. Over the past year, BCTC has experienced an increasing number of circuit breaker failures (e.g. Strathcona 1CB6 and 1CB8, VIT 1CB3, Keogh 1CB6 and 1CB8, Vernon Terminal 1CB13). Prior to this, BCTC had not experienced any significant failures that required replacement. Most of these breakers are in the range of 40 to 50 years old. As a result, a number of 60 kV and 138 kV breakers require urgent major refurbishment or replacement due to their condition. BCTC conducts an assessment to determine the most effective alternative to either refurbish or replace on a case-by-case basis. Where possible, BCTC deploys a strategy to re-use parts from circuit breakers that are no longer in service to refurbish existing circuit breakers and minimize capital expenditures. This work is prioritized based on asset condition.

6.5.1.2.11 230 kV Bulk Oil Circuit Breaker Replacement

This is a new project that will be initiated in F2009 at a forecast level of expenditure of $2.6 million. The project is also planned for F2010 at a forecast level of expenditure of $2.8 million, and is expected to continue until all circuit breakers are replaced, in approximately four years.

There are twenty-one 230 kV bulk oil type circuit breakers with an average age of 45 years old in the system. These circuit breakers are at, or near, end-of-life and are no longer supported by the OEM and replacement parts are no longer available for repair and refurbishment. In addition, the MTBF for 230 kV Bulk Oil Circuit Breakers is also declining, as shown in Figure 6-8. MTBF for this type of circuit breaker at installation is estimated to be 1,785 days, but has decreased to approximately 560 days to the predicted next failure by the Meridium planning tool, which is an unacceptable level of reliability for this type of equipment based on BCTC minimum reliability criteria. To minimize capital costs and maintain reliability, BCTC is deploying a strategy to salvage spare parts from circuit breakers when they are replaced.

Figure 6-8. MTBF for 230 kV Bulk Oil Circuit Breakers



These bulk-oil circuit breakers present a system reliability risk for the major stations serving the Lower Mainland.

BCTC proposes to replace six 230 kV bulk-oil circuit breakers in F2009, and six more in F2010. The approximate value of a replacement circuit breaker is $0.5 million. The remaining bulk-oil circuit breakers will be replaced on a priority basis over the next four years. The secondary benefit of replacement is that the new SF_6 circuit breakers, which have negligible SF_6 gas leakage.

Over the past twenty years, BCTC experienced 92 breaker failures in the 230/360 kV bulk oil circuit breaker class. Of the 92 failures experienced, most were able to be repaired. However, in the last year, there were three catastrophic failures (Burrard 2CB1 and Rosedale 3CB1 and 3CB2). As a result, BCTC has identified the following six breakers for replacement: Burrard 2CB1, Rosedale 3CB1 and 3CB2, Cranbrook 2CB8 and 2CB10, Cheekeye 2CB3. In 2007, catastrophic failure occurred at Burrard on 2CB1, which failed due to an internal component fault. This failure did not cause an outage but reduced system reliability for Burrard Thermal Generator (G1) and supply to the Lower Mainland for 2 months, until a replacement unit could be installed.

6.5.1.3 Other Power Equipment

Other Power Equipment consists of disconnect switches, surge arrestors, power transformers, instrument transformers, shunt reactors, shunt capacitors, synchronous condensers, HVDC systems, series capacitor stations, cable terminations, and load tap changers.

The Key Drivers for the Other Power Equipment program are:

(a) Maintain System Reliability (Asset Health, Asset Performance); and

(b) Manage Risks (Safety, Environment).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Other Power Equipment program as shown in Table 6-10 below.

Table 6-10. Annual Forecast of Other Power Equipment Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$3.2 million	$11.0 million	$7.8 million	$15.5 million	$4.5 million

Generally, the increase in the Other Power Equipment Program from forecast F2008 to F2009 of $7.8 million is driven by increased activity associated with the Cathedral Square 2L31/32 Line Termination relocation, Surge Arrestors, and Synchronous

Condensers at VIT and an allowance for inflation of 5 percent. The increase in Other Power Equipment from F2009 to F2010 of $4.5 million is mainly due to the replacement of PCB filled equipment at VIT, continuation of the Cathedral Square Line Termination relocation project started in F2009, and an allowance for inflation of 5 percent, with all other projects effectively remaining unchanged.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.1.3.1 Mechanical Transformer Electronic Temperature Monitor (ETM) Upgrades

BCTC is forecasting an increase to the F2009 activity level. This project is also part of the F2010 Capital Plan and is forecast at the same level of activity as F2009. This project is expected to continue for the 10-year planning period and beyond.

This project was included in the previous Capital Plan and it was noted by the Commission “that while it may be justifiable to install this new technology on new transformers, it may be too soon to embark on a comprehensive replacement program within the installed base.” (Refer to page 77 of the F2008 Capital Plan Decision).

BCTC proposes to replace existing mechanical temperature monitors with Electronic Temperature Monitors (ETMs), which are proven technology, more reliable and require less maintenance as outlined below. ETMs are a standard feature on all new transformers put into the system. BCTC respectfully submits that installation of ETMs will reduce transformer outage time and OMA costs which are presently required to recalibrate the mechanical temperature monitors for each transformer in the system on an eight year cycle. The ETMs are required for normal operation of transformers and to monitor temperatures when loads approach or exceed name-plate ratings.

BCTC’s implementation strategy was to install ETMs as a pilot project in F2008 and in F2009 and then roll-out the project in F2010 and beyond. BCTC is requesting that the project be accelerated in F2009 to minimize premature aging of heavily loaded transformers and to minimize maintenance work for mechanical gauges that would otherwise require costly calibration.

Temperature monitors on transformers provide several critical functions including:

(a) Monitoring and notifying the Control Centres when temperature limits are exceeded due to loading;

(b) Operating cooling equipment such as fans and pumps; and

(c) Indicating maximum temperatures over a period of time that may indicate equipment issues or affect planning needs (loads exceed capacity).

There are essentially three different methods used to measure the transformer winding temperatures:

(a) Direct Measurement (DM) – Using fibre-optic technology and an embedded sensor in the winding, the temperature of the winding can be read directly. This technology has been available for 20 years but has not been widely adopted in the industry due to its relatively high cost.

(b) Mechanical Sensing and Simulated measurement – Using a mechanical gauge (bourdon tube) to measure the top oil temperature, the winding temperature is simulated by placing the sensing bulb in a heated well wound with a heating coil through which a current proportional to the transformer load current passes. For a substantial period of time the bulk of the industry used this method and almost all of BCTC transformers use this method. Also, this system does not allow for remote monitoring from Control Centres and therefore BCTC considers this technology as no longer practical for the application.

(c) Electronic Temperature Monitors (ETMs) – Thermal sensors such as thermistors and resistance temperature detectors (RTDs) translate the thermal units into proportional electrical quantities and a current transformer measures the load current. An internal computer program calculates the winding temperature based on the top oil temperature and the measured load current. ETMs are accepted by the industry and standard equipment for new transformers.

There are approximately 200 transformers on the transmission system. Most station transformers currently use mechanical temperature monitors for indicating operating temperatures at site and controlling the cooling system. There are a number of problems associated with mechanical temperature monitoring devices and the prevalence of such problems has been increasing with age:

(a) The gauges are bourdon tube type with the pointer driven by expanding liquid inside the capillary tubes. The capillary tubes are prone to external damage resulting in liquid leakage. When this happens, the gauge is beyond repair;

(b) The gasket seals deteriorate over time and condensation can occur inside the gauge. Condensation ruins the micro-switches;

(c) After re-calibration, some gauges could be accurate in the lower portion of the temperature range but not the upper-portion, and vice-versa;

(d) The gauges are unable to provide transformer operating temperatures remotely to Control Centers; and

(e) Field-testing has shown that 50 percent of the monitors on these transformers are defective or grossly out of calibration. Testing and calibration of the mechanical monitors is very time consuming, causing the transformer to be taken out of service for an extended period during maintenance which leaves the station in a vulnerable state.

Today's new transformers have much tighter designs and loadings have increased, requiring more accurate temperature monitoring. Mechanical gauges are inherently not as accurate as the new ETMs.

ETMs that were installed on the system more than ten years ago are still in good condition which confirms that they are a proven technology. They have been widely adopted by other utilities. Additionally, these replacement gauges have a 'self-checking' capability so no routine maintenance or calibration is required.

Failure of the existing mechanical temperature monitors could lead to inefficient cooling, resulting in over-heating and reduced life to the fully loaded transformers. By providing accurate temperature readings, the ETM will allow the operation of the transformer to a higher capacity without overheating, and also provides the added benefit of extending transformer life.

A financial comparison between replacing with an ETM versus a mechanical temperature monitor indicates:

(a) Replacement with mechanical gauge including installation, material and calibration is approximately $9,000;

(b) Replacement with ETM including installation, and material (calibration not required) is approximately $10,000;

(c) The maintenance schedule and cost for a mechanical gauge is:

i. Maintenance every 8 years - $2,400; and

ii. Replacement of components (bulb or gauge) every 16 years - $4,100;

(d) There are no maintenance costs for an ETM as the unit is self monitoring and the failure rate extremely low.

The present value analysis based on total lifecycle costs, including periodic maintenance costs, indicate that replacement with an ETM is in the best interest of the ratepayer, not including the added benefit of extending the life of transformers, and the flexibility of operations related to overloading transformers in a controlled environment.

6.5.1.3.2 Surge Arrester Replacements and Additions Program

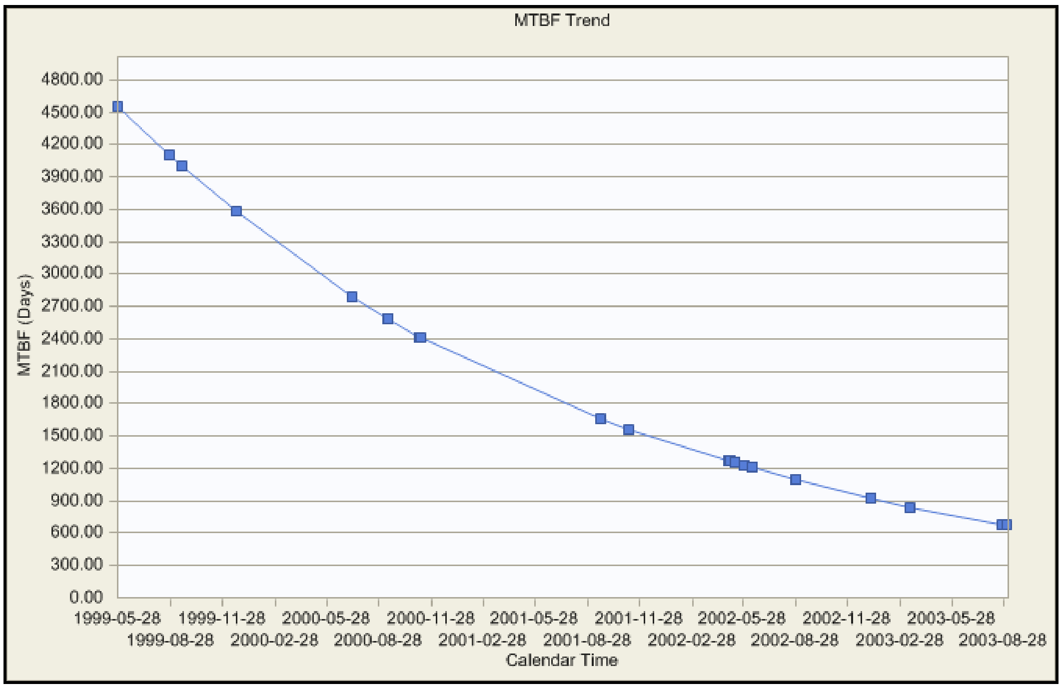
This project was included in the previous Capital Plan and there is an increase to the F2009 and F2010 forecast activity level. This project is expected to be complete in F2010.

Surge arrestors provide high energy, short-duration impulse and over-voltage protection resulting from lightning and routine switching operations affecting costly station equipment such as transformers, circuit breakers and reactors. The replacement cost of a 75 MVA transformer is approximately $1.5 million and is significantly higher than the replacement cost of the surge arrester that protects it, costing approximately $8,000 per unit.

The transmission system has over 2,600 surge arrestors from 60 kV up to 500 kV. As of the end of F2007, approximately 300 are the old Silicone Carbide (SiC) gap-type arrestors. The SiC gap-type arrestors have been identified as no longer being effective due to the aging of seals and gaskets, and gap erosion.

This project focuses on replacing the existing SiC gapped surge arrestors. The MTBF rate of this type of surge arrestor has decreased by approximately 85% from 4,550 days in 1999 to 670 days in 2003. Figure 6-9 provides the declining MTBF of the Surge Arrestors over the period.

Figure 6-9. MTBF for Surge Arrestors



The older Silicone Carbide gapped type arrestors are now considered to be ineffective and it is widely known within the utility industry that such gapped type surge arresters are failing, primarily due the seals, as anticipated by the manufacturers. Based on the results presented above, BCTC initiated a replacement project in 2004 that is continuing for the forecast period covered by this Capital Plan. To the end of F2007, there are still 300 SiC gap type surge arrestors in service, and BCTC plans to replace them by 2011.

This type of surge arrestors has also been known to explode violently from internal pressure, spraying porcelain shards over a large area. It is now generally accepted within the industry (DOBLE Engineering) that these SiC gapped surge arrestors have reached the end of their life and they no longer reliably perform the protective function for which they were designed.

Under the existing project, the gapped arresters are replaced with a more reliable and safer type of surge arrester of different and more effective technology (metal oxide Varistor). Priority is given to stations that are ranked in terms of criticality to the system. To reduce costs and shorten the lead-time for equipment delivery, BCTC has negotiated long-term supply contracts with multiple suppliers.

Acceleration of the project is required to provide appropriate surge protection for transformers, which is currently inadequate, exposing the transformers to potential electrical failure which could require costly transformer replacement.

6.5.1.3.3 Disconnect Switch Rebuild (230 kV and 500 kV)

This project was included in the previous Capital Plan and there is no change to the F2009 forecast activity level. This project is also part of the F2010 Capital Plan and is forecast at the same level of activity as F2009. The project is expected to continue for the 10-year planning period and beyond.

The project is required to address system reliability risks related to asset condition.

There are approximately 4,200 high voltage disconnect switches on the transmission system. Their primary function is to isolate apparatus and circuit elements from the power grid for maintenance and voltage control. The 230 kV and 500 kV disconnect switches are well designed units that are forty years old on average and have reached the end of their useful life. By refurbishing these disconnect switches and their related operating mechanisms, it is estimated that their life can be extended by approximately twenty years.

BCTC has targeted three additional 500 kV units for rebuild in F2009 at GMS generating station and six 230 kV disconnects in the Lower Mainland. The disconnect switches that are selected to be refurbished are in critical locations and, even with redundancy built into the system, the failure of a second switching device at the same substation could result in a loss of generation at GMS (for the 500 kV units) or a loss of supply to the Lower Mainland (for the 230 kV units).

It is expected that nine disconnect switches, annually, will be totally refurbished (including bearings, contacts, and mechanical drives) under this project.

6.5.1.3.4 Cathedral Square – Relocation of 2L31/32 Line Terminations

This project was included in the previous Capital Plan at $5.4 million. The project expenditure has increased to $11.7 million with expenditures of $0.7 million in prior years, $4.1 million in F2009, and $6.9 million in F2010.

The increase in expenditure is required to address changes in project costs that were identified in F2008 project definition. The project is required to address unacceptable life-safety risks and system reliability risks related to fire and explosion hazards within the station.

Cathedral Square (CSQ) is a critical transmission and distribution station constructed in the early 1980s serving approximately one-third of the downtown Vancouver load (148 MVA). CSQ substation has a number of unique features that create fire protection related challenges and risks: the substation is a multi-level underground substation, its design includes unique infrastructure components including 200 psi pressurized oil insulated 2L31/2L32 cables which terminate in the substation GIS room, and oil insulated transformers located within the underground transformer vaults.

The primary justification for this capital expenditure is to remove the Carbon Dioxide (CO_2) Fire Suppression System, which poses an unacceptable life-safety risk for employees and contractors working in the substation. The CO_2 fire suppression system contains 15,000 pounds of CO_2 gas, which when released causes a risk of fatality due to asphyxiation. In addition to the life safety risk, the oil pressurized pipe-type cables present an unacceptable system reliability and financial risk due to fire/explosion hazards within the station GIS room and transformer vaults and enclosures. These risks and mitigation recommendations are documented in a BC Hydro Engineering report entitled, “CO_2 Fire Protection System Safety Study” (Report No. E41). The identified life-safety risk significantly exceeds the industry-accepted Human Resources Canada Occupational Safety standard. In addition, depending on the severity of damage caused by fire (i.e., significant damage to GIS, transformers, and cables terminations), the consequences could be a disruption to service estimated to be between one and two years while the station is being rebuilt. BCTC estimates that the financial impact for the replacement cost of the station and damaged cables is approximately $100 million. During service disruption, a very small portion of the Downtown Vancouver load could be transferred to Dal Grauer and Murrin substations.

The risks identified at Cathedral Square are supported by a recent incident in Barcelona, Spain. In July, 2007 a fire occurred at an underground substation in Barcelona that is similar in size and configuration to CSQ with three 230 kV cables, GIS and three transformers. The fire was caused by overloading of an oil pressurized pipe-type cable similar to the cables feeding CSQ (2L31/32). The fire resulted in the complete loss of the Barcelona substation, and it is expected to be out of service for approximately one year.

The planned capital expenditure implements the infrastructure changes needed to mitigate the fire/explosion hazards and life-safety risks by implementing the following infrastructure upgrades:

(a) Remove the fire hazard from the substation GIS room by relocating existing pressurized oil insulated cable terminations for 2L31/2L32 circuits to a manhole to be constructed outside the substation. New non-oil cable terminations will be installed in the GIS room;

(b) Eliminate the life-safety risks by removing the high-volume (15,000 lbs) flooding CO_2 Fire Suppression System from the substation GIS room and transformer vaults & enclosures;

(c) Mitigate the fire hazard within the transformer vaults by installing a water-cycling sprinkler system; and

(d) Mitigate the fire/explosion hazard within the transformer enclosures by installing a low-volume inert N2 Fire Suppression System that does not pose a life-safety risk to workers.

In addition to the recommended solution described above, three other alternatives were considered and rejected. The rejected alternatives were:

(a) Do Nothing – this alternative was rejected because it does not address the unacceptable life-safety risks to employees and contractors working inside the substation, and it does not address the system reliability risks related to the fire/explosion hazards in the GIS Room due to the high probability of a failure of the fire protection system to operate, if required;

(b) Isolate the fire hazard in the GIS Room – this alternative was rejected because it was an unproven solution, and was not considered effective at mitigating the fire risks. The expenditures required to implement this alternative are approximately equal to the recommended solution; and

(c) Install a pressure sensitive cut-off value on oil filled pipe-type cables before entrance in to substation GIS Room (minimizing fuel to feed a fire) – this alternative was rejected as it was found to be technically infeasible as it placed an unacceptable risk to the integrity of the transmission cables (2L31/32).

6.5.1.3.5 VIT SC4 and SC3 Overhaul

This is a new project that will be initiated in F2009 at a forecast cost of $1.4 million. BCTC has no planned activity for F2010; however, the project will be completed in F2011 with a forecasted expenditure in F2011 of $1.5 million.

The project is required to address system reliability risks related to asset condition and requires refurbishment of synchronous condensers #3 and #4 at Vancouver Island Terminal (VIT).

Synchronous condensers are required to regulate system voltage in response to load swings. The assets form a critical component of the transmission infrastructure for Vancouver Island supply from the Lower Mainland. BCTC has determined that the synchronous condensers will be required to meet long-term Vancouver Island system needs independent of the High-Voltage Direct Current (HVDC) System.

Regular maintenance of synchronous motors requires periodic re-wedging (securing the winding to the stator core so that stator bars do not wear out prematurely due to unrestricted movement because of loose wedges) to extend asset life. This asset is due for a re-wedging procedure.

6.5.1.3.6 Dehydrating Breathers on Transformers

This is a new project that will be initiated in F2010 at a forecast cost of $0.6 million. The project is expected to continue for the 10-year planning period and beyond, and is required to address system reliability risks related to asset condition.

All station transformers currently use silica-gel breathers to keep moisture out of the transformer oil. Moisture in transformer oil can lead to failure. The silica-gel requires frequent replacement as it consumes the moisture before it enters the transformer. An analysis during 2006/7 shows that the replacement of silica-gel breathers with dehydrating breathers is more effective (lower moisture ingress).

BCTC proposes to replace the existing silica-gel breathers with dehydrating breathers which are proven technology and more reliable. The new breathers will increase the transformer life by ensuring minimal moisture enters the transformer.

The total cost for each new breather is approximately $10,000. The project will install 40 to 50 units each year.

6.5.1.3.7 VIT PCB Equipment Replacement

This is a new project that will be initiated and completed in F2010 at a forecast cost of $3.4 million. The project is required to address system environmental risks.

This project will remove from service the last remaining PCB-filled equipment at VIT Station and replace it with non-PCB equipment in accordance with the current Environment Canada proposed regulations. These proposed regulations require BCTC to remove the PCB filled equipment no later than 2010.

The capacitors at VIT are required for voltage and HVDC support to meet the transmission system long-term needs. The existing capacitors are near the end of their expected life. It is recommended that the replacement and disposal of PCB-filled capacitors at VIT Pole 1 high pass filter sections HP1CX1, HP1CX2, and VIT Pole 2 filter banks 13HF2CX1, 7HF2CX1, and 5HF2CX1 be completed in F2010 as per the federal regulations.

6.5.1.4 Stations Risk Mitigation

The Risk Mitigation program addresses the following risks: safety, seismic, environment, weather, and security. As an example, the Stations Risk Mitigation program implements substation infrastructure improvements to reduce system reliability, life-safety, and environmental risk caused by materials theft and vandalism.

Each risk is evaluated based on business impact (e.g. reliability, financial, environmental, safety, relationships) and probability of occurrence to determine the appropriate duration and magnitude of investment that is required to mitigate the risk to acceptable levels.

The Key Drivers for the Station Risk Mitigation program are:

(a) Manage Risks (safety, seismic, environment, weather, and security); and

(b) Maintain System Reliability.

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Stations Risk Mitigation program as shown in Table 6-11 below.

Table 6-11. Annual Forecast of Stations Risk Mitigation Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$8.2 million	$8.3 million	$0.1 million	$8.8 million	$0.5 million

Generally, there is no material change in the Stations Risk Mitigation Program forecast for F2009 compared F2008. Once inflation is taken into account, the small increase to Station Structural Seismic and Murrin Seismic planning projects is offset by small decreases within the remaining projects. The increase in Station Risk Mitigation program from F2009 to F2010 of $0.5 million is mainly due to the inclusion of an allowance for inflation of 5 percent, with the planned projects effectively remaining unchanged.

The following sections describe the projects which make up the Program. The description for each project includes an overview of the project, justification for the project, and changes in activity levels from the previous capital plan and planned activities for F2010.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.1.4.1 Security

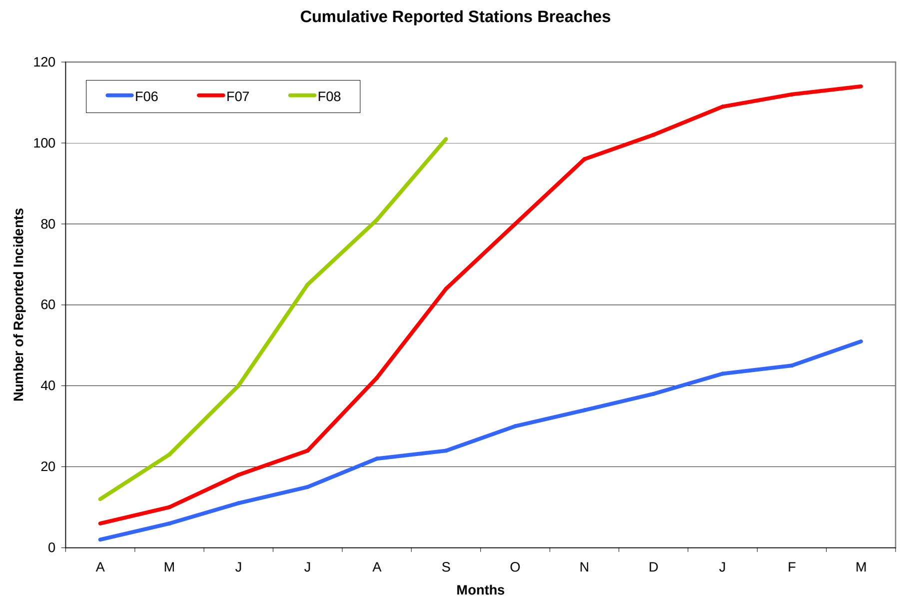
This project was included in the previous Capital Plan and there is a small decrease to the F2009 forecast activity level. This project is also included in the F2010 Capital Plan at the same level as F2009, and is expected to continue for the 10-year planning period and beyond.

The project is required to address life-safety and system reliability risks due to security incidents at stations and telecommunications sites. The small decrease in F2009 activity is planned while BCTC re-evaluates the effectiveness of portions of the project. The F2008 security upgrade project includes several security upgrades including expanded metal mesh, security signage, transformer neutral encasement, and a pilot closed circuit television (CCTV) security system at Wahleach substation. BCTC is assessing the effectiveness of these security measures to reduce security incidents.

Security systems include perimeter fencing, intrusion detection, and alarm systems which protect station assets from vandalism, theft, and protect the public from electrical hazards.

Over the past several years, BCTC has experienced a significant increase in number and frequency of security incidents (break-and-enter, vandalism, and thefts) at stations and communication sites throughout the Province. The following Figure illustrates the history of security incidents for F2006, F2007, and year-to-date F2008.

Figure 6-10. Security Incidents by Year



Security incidents result in increased costs to repair damaged infrastructure, replacement of stolen equipment, and increased costs for security guard services. Based on experience, the OMA cost of security incidents for F2008 is forecast to be in excess of $2.0 million, up from $31,000 in F2006.

At the present time, BCTC is deploying 24-hour security guards at each site that has experienced multiple break-ins until mitigation improvements are made. The OMA cost of a security guard per site is between $120,000 and $150,000 per year.

Theft of station equipment electrical safety grounds has resulted in increased life-safety risks for employees/contractors working in stations, as well as environmental incidents related to oil spills. The cutting of station and communication site perimeter fencing has resulted in an increased potential for public access to electrical hazards within these sites.

The theft of station transformer neutrals has resulted in equipment outages, customer-hours lost, and an increased risk to system reliability. In addition, there is a high risk to the public due to the potential over-voltages which could result in damage to customer equipment or fire.

To mitigate these risks, BCTC has identified a prioritized list of stations and telecommunications sites that require physical security infrastructure upgrades. Sites are prioritized based on criticality, security incident history, and financial loss. The project implements physical security infrastructure upgrades necessary to deter unauthorized access to sites, minimizing vandalism and theft. Infrastructure upgrades include the reinforcement of site perimeter fencing using expanded metal mesh; installation of security/electrical hazard signage; installation of station control room security entry alarms; and the installation of infrastructure necessary to secure and alarm critical microwave radio/fibre equipment at communication sites. Depending on the size of the stations, BCTC proposes to implement security upgrades to 8 to 10 stations per year.

6.5.1.4.2 Fire Protection

This project was included in the previous Capital Plan and there is no change to the F2009 forecast activity level. This project is also included in the F2010 Capital Plan at a small increase compared to F2009, and is expected to continue for the 10-year planning period and beyond.

The project is required to address system reliability and life-safety risks due to fire hazards.

Fire protection systems detect, report, and suppress fires at stations. Fire risk reduction is a priority at substations, where loss for an extended period of time would cause significant outages until repairs can be completed.

Older fire protection systems can also place personnel, contractors, emergency response personnel, and the general public at risk. In the past, Halon and Carbon Dioxide (CO_2) fire protection systems were considered to be the most effective systems. Today these systems are considered to be a risk to personnel, and regulatory changes require them to be removed for safety and environmental reasons.

Halon is a controlled substance due to its ozone-depleting properties and BCTC has adopted a policy of removing Halon from all sites where practical. Under the Montreal Protocol, endorsed by Canada in 1987, all Halon systems must be removed from service by 2010. Halon 1301 is also no longer manufactured in North America, and these systems cannot be recharged or properly maintained.

Halon-based systems will be removed by F2009 and replaced with Novec 1230 systems. Novec 1230 is an environmentally-friendly alternative to Halon that does not deplete ozone.

A Fire Risk Reduction Study was completed in F2005 that reviewed fifteen priority stations. These stations were selected based on their criticality, with 500 kV stations having the highest priority. Of these fifteen, six were identified for the fire risk reduction program based on the risk of damage to assets and life safety. Key life safety upgrades include addition of fire alarm and detection systems, emergency lighting, and self-illuminated exit signs. Fire risk reduction measures include installation of fire stopping, non-combustible cable trench covers, firewalls, and spill curbs.

A fire at Texada Island East substation in February 2007 resulted in $200,000 in damage. The fire also identified a high fire risk at the five cable terminal sites. These five substations will be addressed in F2009 with completion expected in F2010. Other stations will be evaluated to identify work in F2010 and beyond.

6.5.1.4.3 Oil Spill Containment

This project was included in the previous Capital Plan and there is no change to the F2009 forecast activity level. This project is also included in the F2010 Capital Plan at the same level of activity as in F2009, and is expected to continue for the 10-year planning period. This project is required to address environmental risks due to oil spill hazards.

Oil and diesel fuel is stored on site for use in various kinds of equipment including emergency diesel generators in critical transmission stations. There is in excess of 37 million litres of oil contained in transformers, circuit breakers and instrument transformers on the transmission system. Leaks could result in significant clean-up costs and fines. Oil spills of more than 100 litres are reportable to Environment Canada. Approximately two spills per year have occurred in the past. The goal of this program is to mitigate accidental spills by installing spill containment, oil/water separators, and oil stop valves, and replacing existing above-ground diesel tanks with double-walled tanks.

The project has two parts:

(a) Installation of Oil Containment

An internal risk framework for mitigating accidental oil spills at stations was developed in 1990. The framework considers the volume of oil, location, spill destination, oil type, and spill probability. Using these factors, a risk score was assigned to applicable stations. A higher risk score indicates a greater impact of an accidental oil spill and is used as a prioritization tool. Oil spills are a result of equipment failures. Oil spill mitigation measures include substation drainage, ditching, catch basins, oil water separators, and curbing.

Of the 291 stations on the system, 37 stations had oil containment work completed by the end of F2007. Work started at four substations in F2008 and will be completed in F2009. There are 101 remaining substations with risks that need to be addressed in future years. It is expected that stations with a lower risk will have a smaller scope of work, thereby allowing more stations to be addressed annually with the result that all priority stations with high risk will be addressed over the next 25 years.

(b) Replacement of Above-Ground Diesel Storage Tanks

Existing single-walled above-ground diesel storage tanks will be replaced with double-walled tanks to conform with the Canadian Council of Ministers of the Environment (CCME) Environmental Code of Practice, which requires that all above-ground fuel storage tanks have overfill prevention, secondary containment, and leak detection. The single-walled tanks, which are thirty years old and at the end of their operational life, have a medium-to-high risk of failure. An alternative option of upgrading existing spill prevention systems was rejected because there is a high risk the tanks cannot be modified because of their age or would subsequently leak due to their age. This is a two-year project to replace above-ground storage tanks at the five stations that do not meet the

CCME requirements. The total estimated capital cost for this project is $750,000 and it is expected to be completed by the end of F2009.

6.5.1.4.4 Stations Seismic Structural Upgrade

This project was included in the previous Capital Plan and there is an increase in planned activity level for F2009. This project is also included in the F2010 Capital Plan at similar levels of activity as F2009, and is expected to continue for the 10-year planning period and beyond. This project is required to address system reliability and life-safety risks due to seismic hazards in stations.

Much of coastal BC is in a high-risk seismic zone. In the event of a major seismic event, damage to the buildings and equipment in substations located in coastal areas could result in extended outages in affected areas. Substation buildings installed before the 1980s were not constructed to the present National Building Code 2005 seismic standards. BCTC currently uses this standard for new substation and telecommunication infrastructure.

This project covers the execution of seismic upgrades to Meridian, Atchelitz and Williston stations in F2009 which were previously defined in F2008. The definition work in F2008 identified the specific activity and expenditures required for execution in F2009 resulting in the need to increase the funding this project. In F2010, three additional stations will be prioritized and addressed. Seismic upgrades to microwave repeater sites are included in the Seismic Upgrades to Telecom Buildings project.

6.5.1.4.5 Seismic Upgrade to Telecom Buildings

This project was included in the previous Capital Plan and there is no change to the F2009 and F2010 forecast activity level. This project is expected to continue for the 10-year planning period and beyond, and is required to address system reliability and life-safety risks due to seismic hazards at telecommunications buildings.

Telecommunications buildings installed before the 1980s were not constructed to the present National Building Code 2005 seismic standards. Where infrastructure upgrades are required, BCTC prioritizes upgrades based on risk which considers life-safety and reliability.

BCTC has undertaken a separate initiative under the seismic category to address required seismic upgrades to address risks to telecommunication infrastructure. The consequence of seismic damage to microwave telecommunications buildings is unacceptable, as it would result in extended outages and reduced transfer capability on the transmission system.

Defined in F2008, this project covers the execution of seismic upgrades to Pocahontas, Bruce Peak, Bowen, Jarvis, Thyme, and Cottle Hill which will be completed by F2015. Starting in F2009, one telecommunication site will be completed each year.

6.5.1.4.6 Murrin Substation Reconfiguration and Seismic Upgrade

This project was included in the previous Capital Plan and there is a decrease in forecast activity level compared to what was approved in the F2008 Capital Plan ($3.3 million), due to a major project revision. BCTC is in the process of defining the revised project in F2008, F2009 and F2010, and will incur expenditures as outlined below. This project will also form part of the F2011 to F2013 Capital Plans and is expected to be completed in F2013.

This is a large and complex project and will require extensive definition. The preliminary capital cost estimate for this project is $45 million over the five year period from F2008 to F2013, with expected capital expenditures of $0.1 million in F2008, $0.5 million in F2009, $1.0 million in F2010, $15.0 million in F2011, $15.0 million in F2012, and $13.5 million in F2013.

The project is required to address unacceptable system reliability risks due to seismic hazards.

In the F2006 Capital Plan, $7.7 million was requested to build a seismic curtain wall to secure the Murrin Substation grounds in F2008. However, subsequent geotechnical studies concluded that this option is not technically feasible. More complex than previously assumed, the curtain wall would not provide appropriate confinement of the soil to prevent large settlement of the risk areas, thus would not prevent equipment damage in a seismic event. Consequently, the recommended solution for this project has been revised. The objective of the revised solution is to seismically secure and reinforce sufficient system equipment at Murrin Substation so that service could be maintained to downtown customers in a post-seismic event.

Murrin is a critical station which feeds approximately two-thirds of the Vancouver downtown load through itself and Dal Grauer. The 230 kV switch yard at Murrin station is located on seismically unstable land. If a significant earthquake occurs, there is a high likelihood that the 230 kV switch yard would be severely damaged. The consequence of this damage would be the loss of supply to serve critical downtown Vancouver load for many months.

BCTC requires approximately $0.5 million for Definition Phase funding in F2009 to scope, schedule and cost the revised project, and requires $1.0 million in F2010 to do site preparation. The proposed new solution is to relocate critical infrastructure components (e.g., 230 kV cables, circuit breakers, control systems, etc.) from the 230 kV switch yard to an area of the station site that is seismically stable. This solution calls for the construction of a building to house new 230 kV GIS and a control room. In addition, the 230 kV cables which are also at seismic risk need to be relocated. The scope, schedule, and cost estimates for execution are expected to be complete by the end of F2009.

6.5.1.4.7 Emergency Drop-in Substation Control Building

This is a new project that was initiated in F2008 as an emergency response to the Fraser River flood threat.

The construction of an Emergency Drop-in Control Building was initiated as a contingency to address the Fraser River Flood risk in F2008 at Chilliwack substation. It was identified that there was a high-probability that a flood would result in damage to the Control Building at this substation. The potential impact of a severely damaged Control Building necessitated the procurement of an emergency portable control building to decrease the restoration time for service and to minimize the disruption of service to customers.

Part of BCTC's strategy was to address the flood risk and subsequently to minimize stranded investment if the flood damage did not occur by re-deploying the Emergency Drop-in Control Building to an alternative substation.

After the flood risk subsided, Colwood substation was selected to receive the Drop-in Control Building because major infrastructure upgrades are planned in F2009/10 for Colwood substation that relate to both Growth and Sustaining issues. A total life-cycle analysis at Colwood identified that the Drop-in Control Building could be deployed at a lower cost than rebuilding the existing control building and its various components. The expenditure required to complete this project is $0.5 million in F2009 to account for the timing of placing the unit into service at Colwood.

Given that the potential flood was a 1-in-200 year event, BCTC does not expect to need to purchase another emergency control building.

6.5.1.5 Protection and Control

Protection and Control (P&C) assets consist of all protective relaying and control systems at the transmission stations. These systems are a supporting component of the primary circuit elements of the transmission system, and are required to preserve the life of the primary circuit elements and maintain the overall reliability of the system. P&C assets protect transmission equipment from damage due to electrical and mechanical faults, ensure stability and reliability of the transmission system, protect the public and personnel, and provide local and remote control and monitoring of transmission equipment.

P&C facilities at transmission stations incorporate a variety of equipment that measures voltage, current, and other data at key points in the switchyard and conveys that information to P&C equipment within a control building. Alarms are also an important component in substation monitoring, as they alert operators to abnormal conditions that require investigative or corrective action. Consolidating all P&C equipment in a station control building allows circuit breakers and disconnect switches to be operated from a single location for testing and maintenance purposes. The information is in turn transmitted to the system control centres via Remote Terminal Units (RTU) and telecommunication facilities. In general, stations are unmanned and operated remotely from the control centres.

The Key Drivers for the Protection & Control Equipment program are:

(a) Maintain System Reliability (Asset Health, Asset Performance);

(b) Manage Risks (Safety); and

(c) Third-party Requested Initiatives.

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Protection and Control program as shown in Table 6-12.

Table 6-12. Annual Forecast of Protection and Control Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$9.5 million	$13.0 million	$3.5 million	$11.9 million	($1.1) million

Generally, the increase in the Protection and Control program from forecast F2008 to F2009 of $3.5 million is driven by increased activity associated with Protection and Control Replacements and Voltage VAr Optimization projects. All other projects remain effectively unchanged once inflation is considered. BCTC is forecasting a decrease in expenditures for the Protection and Control program from F2009 to F2010 of $1.1 million, which is mainly due to a reduction in the Programmable Logic Controller replacement project, and a minor decrease in activity for Protection and Control Replacements. All other projects remain unchanged, after consideration of an allowance for inflation of 5 percent.

The following sections describe the projects which make-up the Program. The description for each project includes an overview of the project, justification for the project, and changes in activity from the previous Capital Plan submission, and planned activities for F2010.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.1.5.1 Protection and Control Replacements

These projects were included in the F2008 Capital Plan .There is no change to the F2009 forecast activity level; however, the expenditure in F2009 reflects an additional

$1.4 million to complete the project started in F2008. This project is also included in the F2010 Capital Plan at slightly lower activity level, and is expected to continue throughout the 10-year planning period.

Line and transformer P&C systems are used to protect and control electrical equipment, specifically transmission lines and station transformers, in the event of a system fault or where regulation of transmission and distribution supply voltage is required. Types of transformer P&C systems on the transmission system include Transformer Current Differential Protection Systems, Transformer Sudden Pressure Trip Gas Relay Protections and Transformer Load Tap Changer Voltage Control Systems.

The older existing line and transformer P&C systems are in poor condition, resulting in mis-operations. During the period from F2002 to F2006, mis-operation of protection systems accounted for more than 5% of the Customer Hours Lost and nearly 2.5% of SAIDI (System Average Interruption Duration Index). These systems have no manufacturer support, no available spare parts, and also require frequent calibration. The project goal is to reduce protection mis-operations by replacing the older, unsupported, protection systems with new ones. The removed protection systems are salvaged for critical spares until all the older protection systems have been replaced. The older existing protection systems have an estimated end-of-life of 35 years. About 30 percent of the 500 kV line protection systems and sixty percent of the under-500 kV systems are between 25 and 35 years of age, with the balance between new and 15 years of age. Protection systems are identified for replacement and prioritized based on performance, specifically their average number of mis-operations.

The P&C mis-operation reduction project includes:

(a) 500 kV Transmission Line P&C Systems

The project is required to address system reliability because of end-of-life issues resulting in unpredictable performance (i.e. mis-operation of the protective relay) which in the past has resulted loss of an inter-tie (i.e. Alberta), loss of major generation (i.e. Revelstoke and Mica Generation Stations), and loss of major customer load (i.e. Alcan).

Three 500 kV line electromechanical protective relaying systems are targeted for replacement each year. The new reliability-proven protection systems, which are microprocessor-based, digital relaying systems and have self-diagnostics and alarming, will enable extension of maintenance intervals from two to six years, resulting in OMA savings of approximately $1,000 per protection. A lifecycle cost analysis shows that an alternative option of refurbishing the relays has a NPV that is 1.2 times higher (less favourable) than replacing them.

Under this project, thirty 500 kV line electromechanical protective relaying systems will be replaced by the end of F2008. The remaining five systems are expected to be addressed over the next three fiscal years.

The planned expenditures for F2009 include a $1.2 million provision for a carry-forward of expenditures for work originally planned to be completed in F2008 but are now forecast to be complete in early F2009. The change in project schedule is related to resource constraints.

(b) Under 500 kV Transmission Line P&C systems

This project is required to address system reliability because of end-of-life issues resulting in unpredictable performance (i.e. mis-operation of the protective relay) which in the past have resulted in loss of major customer load (i.e. University of British Columbia and Triumph, Eburne Sawmills) and loss of major load (i.e. Lower Mainland).

Five to six under-500 kV line protection systems are targeted for replacement each year as they reach end-of-life condition and are no longer dependable. Replacing the old electromechanical relays with newer digital technology relays with fault location identification, system disturbance analysis capabilities, self-diagnostics and alarming, enables extension of maintenance intervals from three years to six years, resulting in approximately $500 per protection.

Under this project, 97 under-500 kV line electromechanical protective relaying systems will have been replaced by the end of F2008. The remaining 54 systems are expected to be addressed over the next ten fiscal years.

(c) Transformer Current Differential Protection System Replacements (Type HU Relaying)

There are approximately fifty autotransformer current differential protection systems on the transmission system. Six to nine of these systems are targeted for replacement each year. Replacing the old electromechanical relays with newer digital relays with self-diagnostics and alarming allows extension of the maintenance interval from three years to six years, reducing maintenance costs by half to approximately $500 per protection.

Under this project, sixteen electromechanical protective relaying systems will be replaced by the end of F2008. Approximately thirty-four additional system replacements are expected to be addressed over F2009 to F2013.

(d) Transformer Sudden Pressure Trip Gas Relay Protections (GE Model 11)

There are a number of station transformer sudden pressure gas relay tripping protections on the transmission system that have been identified as unreliable. Between four and six transformer protections have been targeted for replacement each year. Replacing the problematic GE Model 11 transformer Gas Relaying with digital protection systems with self-diagnostics and alarming enables extension of the maintenance interval from three to six years, reducing maintenance costs by approximately $500 per protection.

Under this project, eighteen transformer electromechanical protective relaying systems have been replaced by the end of F2008. The remaining fourteen systems are expected to be addressed by the end of F2011.

The project is required to address system reliability because of end-of-life and technical issues resulting in unpredictable performance (i.e. many mis-operations of the protective relay with 250 events recorded over a 12-year period) which in the past have resulted in loss of major generation (i.e. Revelstoke) and the loss of a major substation load (i.e. Como Lake Substation). Units that have not been replaced continue to experience mis-operations. As the replacements take place, overall system performance improves.

Sudden-pressure relays have operated incorrectly and tripped non-faulted transformers due to a variety of reasons including vibration from earthquakes or heavy construction equipment, water ingress into the relay or associated wiring, through faults, and transformer pump starting. Of real concern are the significant additional outages and system restoration delays that would result from sudden-pressure gas relay operations during a major earthquake

The relay is not appropriate for this application to detect internal transformer faults. BCTC has re-engineered the protection for transformers to be more effective, increasing reliability for the transmission system by eliminating the relay.

(e) Transformer Load Tap Changer Voltage Control Systems (SVC Relays)

The project is required to address system reliability because of to end-of-life and technical issues resulting in unpredictable voltage performance.

There are over 300 transformer load tap changer control systems on the transmission system, many with the Westinghouse Model SVC tap changer control relay. The LTC (Westinghouse Model SVC) has been identified as having a high failure rate which results in unacceptable voltage regulation to the customer. The high failure rate is due to an internal component of the LTC relay and there are no suitable replacement parts available to repair these units. In F2009 and F2010, approximately eight systems will be targeted for replacement.

6.5.1.5.2 Station SCADA Remote Supervisory/Telemetry System Refurbishments and Replacements

This project was in the F2008 Capital Plan and there is no change to the F2009 and F2010 forecast levels of activity. This project is expected to continue throughout the 10-year planning period and is required to address system reliability risks as a result of unpredictable performance and system operation requirements.

Station Supervisory Control and Data Acquisition (SCADA) systems provide control, metering, status and alarms for a variety of station equipment, such as transformers, lines and circuit breakers, which allow control centres to remotely operate, control and monitor the station equipment. There are approximately 130 Remote Terminal Units

(RTUs) and 170 older supervisory/telemetry systems installed in the 1960s and 1970s in approximately 200 transmission stations, out of the current of 291 stations.

The older supervisory/telemetry systems are prone to failure, no longer repairable or sustainable and are nearing or are past end-of-life and do not support the requirements of the special applications (e.g., state estimator, transient and voltage stability analysis applications) for the System Control Centre. Approximately 120 station installations have been identified as candidates for replacement. Of these, approximately 54 are no longer supported by original manufacturer and spare parts are not available.

Where there is no longer any OEM support, the older supervisory/telemetry systems will be replaced with new SCADA RTU technology. Continuing to refurbish and repair this equipment is not a cost-effective or sustainable alternative. The likelihood of defects or failures after refurbishment is high and would have a continuing negative impact on operational reliability, as the effectiveness of refurbishment is insufficient to resolve functional issues for more than 3 to 6 months. Removed original equipment will be selectively retained for critical spares until the remaining population is replaced.

The new replacement equipment will improve station operating performance by replacing old and ineffective equipment with equipment that will significantly increase data acquisition, allow for discrete alarms as opposed to the current grouped/masked alarms as well as correct key station telemetry blind spots.

Selection criteria have been developed to identify the most critical stations requiring replacement. The F2009 project will replace SCADA remote units at Deep Cove, Salmon Valley, and Beaverley substations. Substations will be prioritized for replacement in F2010 based asset condition, criticality, and SCMP needs. The program will be increased in F2011 to replace approximately six to eight systems per year due to increasing operational requirements.

6.5.1.5.3 Transmission Line Single Pole Trip & Reclose Retrofit Installations

This project was included in the F2008 Capital Plan. It has been deferred for F2009 and there is no planned activity for F2010. The project has been deferred because

Single Pole Trip & Reclose functionality is now integrated as part of the Line Protection Upgrade project.

6.5.1.5.4 P&C Minor Capital Add and Replace Program

This project was in the F2008 Capital Plan and there is no change to the F2009 and F2010 forecast levels of activity. This project is expected to continue for the 10-year planning period and beyond, and is required to address system reliability risks.

The Protection and Control Minor Capital project addresses system needs involving the addition of required P&C functionality or the replacement of failed components that are low cost ($5,000 to $150,000) and are not covered by existing P&C program initiatives. Examples of Minor Capital initiatives include Retrofit SCADA Remote Single-Pole Auto-Reclose On-Off Control, Dial-up Data Modern Fire-Wall Retrofits at 35 Critical Cyber Asset Stations to cyber secure remote access to Protective Relaying Settings & Controls, and Cable Overvoltage Protection and Control Scheme Replacement.

6.5.1.5.5 500 kV Digital Fault Recorder Replacements

This is a new project that BCTC intends to initiate in F2010 at a forecast expenditure of $0.7 million. The project is expected to continue for the remainder of the 10-year plan, and is required to address system reliability risks by replacing existing analysis tools which currently have limited capability to effectively diagnose system performance.

Digital fault recorders (DFR) are a critical diagnostic tools used to sustain system reliability. The current DFRs do not provide sufficient analysis data required to effectively address the increasing complexity of the power system.

The need for more sophisticated DFRs became evident during the analysis of a system fault that occurred at Williston substation on January 23, 2007 where the system separated and 982 MW of load was lost, affecting 67,000 customers for over 2 hours. The limited functionality and capability of the DFRs used to analyze the Williston event resulted in delayed restoration of the system of from one to two hours and extended the time to implement full corrective action to prevent a reoccurrence. The Williston event highlighted the following functional deficiencies, including: missing capability to see sufficient number of current and voltage analog quantities and sequence of events to perform adequate analysis, lack long-duration continuous capability, and lack the ability to interleave time-stamped events from multiple stations to see a system view of disturbance vs. a station view of a disturbance.

BCTC intends to define the project in F2009 and then initiate the replacement of 70 DFRs with approximately 14 units being replaced each year in 2010 and beyond.

6.5.1.5.6 Programmable Logic Controller Replacement

This is a new project that was initiated in F2008. BCTC is forecasting an expenditure of $1.0 million in F2009 and $0.3 million in F2010. The project is expected to continue throughout the remainder of the 10-year plan, and is required to address system reliability risks due to end-of-life and technical issues resulting in unpredictable performance.

Programmable Logic Controllers (PLCs) are industrial computers that are used to enable control and remedial action protection schemes at numerous critical transmission stations throughout the system. Due to the function PLCs perform to support the system, a mis-operation of a PLC can have cascading impact on the transmission system.

This project was initiated in response to a failure of a PLC (Model 984) at Williston station on January 23, 2007 that resulted in a significant system outage with subsequent loss of 982 MW of load affecting 67,000 customers for over 2 hours. The root cause of failure was identified as a faulty PLC module installed during manufacture of the original unit. The PLC984 has a hardware flaw which can only be addressed by replacement because the PLC is no longer supported by the OEM and replacement parts are no longer available. Failure to replace these units expeditiously presents an unacceptable system reliability risk and could cause sudden and unexpected loss of significant amounts of transmission.

In F2009, BCTC intends to complete the replacement of the PLC984s used for control and remedial action protection schemes at Ingledow, Williston, and Meridian, which are critical 500 kV stations. In future years, the project would address the replacement of the PLC984s at the remaining fourteen stations where PLC984s are installed, and will be prioritized based on criticality.

6.5.1.5.7 Voltage and VAR Optimization

This is a new project that BCTC intends to initiate in F2009. BCTC is forecasting an expenditure of $0.9 million in each of F2009 and F2010. The project is expected to continue to F2013, and is required to support a Third-party (BC Hydro) initiated project named Voltage and VAR Optimization (VVO). VVO is a BC Hydro energy conservation and savings initiative that derives energy savings by optimizing the substation supply voltage to customers. As an example, in F2008 BC Hydro is implementing VVO at Horsey, Esquimalt, and Goward Substations. The projected annual energy savings for the above stations is 13.1 GWh/y, which equates to $1.2 million in annual savings at $88/MWh (Utility and Total Resource Cost Tests).

To implement the project, Transmission and SDA infrastructure upgrades are required. The transmission infrastructure upgrades form small part of the total expenditure. The project is managed by BCTC.

6.5.1.5.8 Protection, Control, and Metering Upgrades

This is a new project that BCTC intends to initiate in F2009. BCTC is forecasting an expenditure of $0.2 million in each of F2009 and F2010. The project is expected to continue until F2013.

The transmission expenditure is required to support a Third-party (BC Hydro) initiated project named Protection, Control, and Metering Upgrade (PCM) project. PCM is a BC Hydro initiative which involves upgrades to SDA protection, control, and metering infrastructure to a number of operational and planning processes and to enhance worker safety protocols for employees working in Distribution functions.

To implement the project, Transmission and SDA infrastructure upgrades are required. The transmission infrastructure upgrades form a small part of the total expenditure. The project is managed by BCTC.

6.5.1.6 Telecommunications

BCTC operates an extensive telecommunications system to support power system protection, control and business requirements. A variety of telecommunications technologies are used, depending on technical requirements, economics, and WECC reliability requirements. These include microwave, powerline carrier, fibre-optic cable, copper pairs, leased line, and VHF/UHF radio. The primary purpose of the telecommunications system is for the protection of the transmission system. The communications infrastructure also provides:

(a) High speed protective relaying;

(b) Supervisory Control and Data Acquisition (SCADA);

(c) Automatic Generation Control;

(d) Remedial Action Schemes;

(e) Dispatch intercom;

(f) Wide Area Network for data traffic;

(g) Low-cost alternative for internal voice and data traffic;

(h) Internal telephone network;

(i) Mobile radio - crew dispatch and restoration co-ordination; and

(j) Call Center communications and routing.

The Key Driver for the Telecommunications program is:

(a) Maintain System Reliability (Asset Condition, Asset Performance)

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Telecommunications program as shown in Table 6-13.

Table 6-13. Annual Forecast Telecommunications Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$10.6	$7.5	($3.1)	$5.6	($1.9)

Generally, the decrease in expenditures for the Telecommunications Program from forecast F2008 to F2009 of $3.1 million is driven by a reduction in activity associated with Power Line Carrier Replacements, Fire Protection, and Lower Mainland Robustness projects partially offset by undertaking Chapman Fibre Optic Replacement. All other projects remain effectively unchanged once inflation is considered. BCTC is forecasting a further decrease in expenditures for F2010 of $1.9 million, which is mainly due to completion of Power Line Carrier Replacements, Chapman's Fibre Optic Replacement project, and Lower Mainland Robustness, partially offset by minor increases in activity for the Tone and Test program and Point to Multi-point project. All other projects remain effectively unchanged, after consideration of an allowance for inflation of 5 percent.

The following sections describe the projects which make-up the Program. The description for each project includes an overview of the project, justification for the project, and changes in activity levels from the previous Capital Plan and planned activities for F2010.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.1.6.1 Chapman (CHP) Fibre Optic Cable Replacement

This project was submitted as part of the F2008 Capital Plan and was not approved. BCTC is applying for reconsideration for this project. An expenditure of $1.6 million in F2009 is required to complete the project. In F2008, $0.25 million was incurred prior to receiving the Commission's Decision.

The project is required to enable circuit 5L41, one of the major 500 kV circuits that are part of the ILM grid, to continue to operate at its designed transmission capability with Chapman's (CHP) series capacitor bank in service. Loss of the CHP capacitor bank will result in a reduction in capacity of 400 MW from the Interior to Lower Mainland. Communications are required to provide protection of CHP and are currently provided by a fibre optic cable. Loss of this fibre optic cable will require CHP to be taken out of service and there is presently a high probability that the existing fibre optic cable could fail at any time.

CHP is a 500 kV series capacitor station in the eastern Fraser Valley used to maintain power transfer capability of the transmission system to the Lower Mainland. Loss of CHP capacitor station will not result in loss of circuit 5L41; however, it will result in reduction transfer capability (line loading) to the Lower Mainland. Communications at CHP are provided by a 31 km fibre-optic cable between CHP series capacitor station and the American Creek series capacitor station. The fibre optic cable enables protection, status indication, control, and alarm systems for CHP series capacitor station.

Over the years, this early-vintage cable has had a variety of problems with splices and terminations and is in poor condition. Between 1998 and December 2005, eighteen incidents required nearly $400,000 in maintenance costs to remediate. Further maintenance costs are expected to continue if the fibre optic cable is not replaced. In addition, because the fibre optic cable is strung at a low height on the transmission towers, significant vegetation management is needed with annual OMA costs of approximately $100,000 per year.

Loss of CHP could also result in a loss in trade benefits. In the event of a fibre optic cable failure, the estimated transmission revenue loss could be as high as $195,400 to BCTC (loss of 36,800 MWh of average import/export capacity @ $5.3 per MWh) and $2.2 million to the customer (loss of 36,800 MWh of customer loss @ $60 per MWh export and $30 per MWh import).

The fibre optic cable that was originally installed in 1998 was incorrectly designed for its environment of 500 kV corona and ultra-violet light exposure. These environmental effects have resulted in accelerated deterioration of the cable. Due to this deterioration, the cable is not expected to last past 2012. To mitigate the consequences of failure, the fibre optic cable must be replaced with either an appropriately designed fibre optic cable or a microwave radio link.

BCTC assessed three options for the fibre optic cable replacement. The first option was the replacement of the existing fibre optic cable with a new appropriately designed fibre optic cable at a cost of $2.7 million in F2012. The second option was the replacement of the fibre optic cable with a microwave radio link at a cost of $1.5 million in F2012. The third option was the replacement of the fibre optic cable with microwave radio in F2009. The preferred option is to replace the fibre optic cable with a microwave radio link in F2009.

BCTC has updated the PV calculation for each of the three options described above using the current PV model which includes a discount rate of 2.5 percent rather than the discount rate of 6 percent that was used in the previous calculation and submission.

Option 1 - Replace Fibre Cable with an appropriately designed fibre optic cable in F2012 has the following assumptions:

(a) Fibre cable is replaced in F2012 at a cost of $2.7 million;

(b) There is a removal charge of $93,000 in F2012;

(c) An extraordinary maintenance expense of $250,000 is required in F2009 to extend the life of the existing fibre optic cable to F2012. The extraordinary maintenance is required due to the current condition of the fibre optic cable. If the maintenance is not performed, the cable will only last to F2009. If BCTC performs the maintenance it would be possible to extend the life of the cable to F2012;

(d) Regular vegetation maintenance of $45,000 per year is required from F2009 and continue thereafter; and

(e) Regular corrective maintenance of $54,000 per year is required from F2009 to F2012, and then the corrective maintenance is expected to decrease to $17,000 per year thereafter because of the new fibre cable.

Option 2 - Replace Fibre Optic Cable with Microwave Radio in F2012 has the following assumptions:

(a) Fibre Optic cable is replaced in F2012 with microwave radio at a cost of $1.5 million;

(b) Converting to Microwave Radio requires a removal charge of $775,000 in F2012 (higher removal charge compared to Option 1) because an independent project is required to remove the fibre, which is not required with under Option 1 above;

(c) An extraordinary maintenance expense of $250,000 is required in F2009 to extend the life of the existing fibre optic cable to F2012;

(d) Regular vegetation maintenance of $45,000 per year is required from F2009 to F2012 (no vegetation maintenance is required with microwave radio); and

(e) Regular corrective maintenance of $54,000 per year is required from F2009 to F2012. Starting in F2013, regular maintenance of $10,000 per year is required for the microwave radio.

Option 3 - Replace Fibre Optic Cable with Microwave Radio in F2009 has the following assumptions:

(a) Fibre cable is replaced in F2009 with microwave radio at a cost of $1.5 million;

(b) Converting to Microwave Radio requires a removal charge of $775,000 in F2009 (higher removal charge compared to Option 1) because an independent project is required to remove the fibre, which is not required under Option 1 above; and

(c) Regular maintenance of $10,000 per year commencing in F2010 is required for the microwave radio.

Table 6-14 shows the results of the PV calculation.

Table 6-14. PV Calculation Results

Option	Description	PV ($000s)
Option 1	Replace Fibre Cable Like-for-Like in F2012	($4,142)
Option 2	Replace Fibre Cable with Microwave Radio in F2012	($1,368)
Option 3	Replace Fibre Cable with Microwave Radio in F2009	($ 923)

The conclusion of the PV analysis shows that Option 3 is the least-cost alternative.

This project will replace the existing fibre optic cable with a microwave radio solution in F2009 which will restore the integrity of the communication system supporting CHP.

6.5.1.6.2 24 Volt Battery/Charger Replacement

This project was in the F2008 Capital Plan and there is no change to the F2009 and F2010 forecast levels of activity. This project is expected to continue for the 10-year planning period and beyond, and is required to address system reliability risks.

24 Volt batteries and chargers are essential to the remote operation of stations. The 24 Volt batteries and chargers operate SCADA equipment, teleprotection and other devices. Battery life expectancy is from 5 to 15 years depending on the type of cells, environmental conditions, operating demand, and maintenance. Charger life expectancy is 30 years.

24 Volt batteries and chargers are inspected twice per year and tested yearly. Those batteries and chargers that have reached the end of their operational life can cause disabling of the telecommunication system and prevent monitoring and control of station equipment should they fail. If a battery or charger fails and a fault occurs, this can result in significant costs to replace damaged substation equipment. If critical station equipment is damaged, extended customer outages are also likely.

There are approximately 160 sets of 24 Volt batteries and three hundred 24 Volt chargers on the transmission system. Of these, 90 batteries and 30 chargers have been identified for replacement and prioritized on the basis of age and operating environment. On average, it costs approximately $35,000 to replace a set of batteries and chargers. Under this project, approximately eight batteries and nine chargers will be replaced each year.

6.5.1.6.3 Tone and Test Equipment Panel Replacements

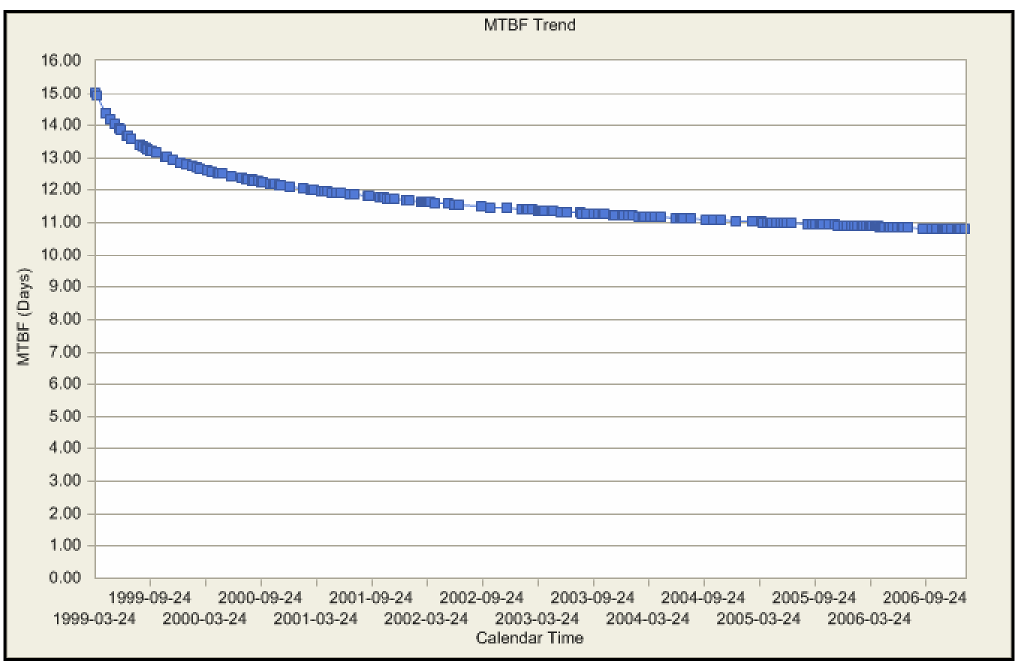
This project was in the F2008 Capital Plan and there is no change to the F2009 forecast activity level. BCTC is proposing to increase activity in this project in F2010. This project is expected to be complete in F2011, and is required to address system reliability risks.

Tone and test panel equipment provide the interface, testing and isolation functions between station protection equipment and the telecommunications system. Tone transmitters convert protection relay logic to a specific frequency allowing it to be carried over a telecommunications channel. Tone receivers convert the transmitted frequency to relay logic. Test panels are used to isolate protective relays and tone transmitters and receivers thereby allowing the testing of telecommunication channels without operating the relays.

There have been 233 tone and test panel failures between February 1999 and September 2006 requiring corrective action, and there is evidence that failures are continuing. The consequence of a loss of communications related to the failure of tone and test equipment reduces the functionality of the circuit and/or transformer protection. Failures result in slow tripping, no tripping, and inadvertent tripping of protection that could lead to equipment damage or unnecessary outages. The impact of failure is mitigated by redundancy (N-1 design).

As of February 1999 the MTBF for this equipment was 15.05 days and by September 2006 the MTBF had declined to 10.80 days. Figure 6-11 illustrates the MTBF for Tone and Test Equipment.

Figure 6-11. MTBF for Tone and Test Equipment



Analysis of the failure rates shows that this equipment has reached end-of-life. The units are no longer supported by the OEM and spare parts are no longer available. Decommissioned equipment has been used for spare parts in the past; however, there are no longer spare parts available to service existing units. Accordingly, replacement is the only viable option.

There are approximately 1,600 tone transmitters and receivers throughout the transmission system. Some tone transmitters are removed as part of P&C system upgrades as they are no longer required. The remaining units will be replaced within the scope of this project.

There is a need to increase activity in F2010 to address the unacceptable MTBF for this asset class.

6.5.1.6.4 Power Line Carrier Replacement

This project was in the F2008 Capital Plan and is expected to be completed in F2009. The project is required to address system reliability risks.

Power Line Carriers are used on 230 kV, 138 kV and 60 kV transmission lines for teleprotection, telemetry, alarms, remote control, and voice communications. There are ten Power Line Carrier terminals remaining in the system that will be replaced as part of this project in F2009.

The Power Line Carrier terminals have reached end-of-life and are no longer supported by the OEM and there are no spare parts available. Prior to this project there were 174 Power Line Carrier failures between April 1999 and September 2006. Decommissioned equipment has been used for spare parts, and in additional OEM spare parts are no longer available. Accordingly, replacement of the Power Line Carrier terminals is the only viable alternative.

Existing Power Line Carriers will be replaced with either new units or with fibre-optic, radio, or microwave alternatives as appropriate. The selection of technology is evaluated on a site by site basis, and is based the most cost-effective alternative.

6.5.1.6.5 Access Roads, Bridges, and Helipads Work for Microwave Stations

This project was in the F2008 Capital Plan and there is no change to the F2009 and F2010 forecast levels of activity. This project is expected to continue for the remainder of the 10-year planning period and beyond, and is required to address system reliability and life-safety risks.

Microwave stations provide an important link in power system communications, protection, and control systems. There are over forty mountaintop microwave repeater stations around the province. Roads, bridges, gates, culverts, and helipads are required to provide access to these remote microwave facilities.

Maintenance inspections have determined that a number of these assets are in poor condition. The sites have been inventoried and assessed in F2008 and, based on the results of this assessment the most critical sites will be addressed in F2009 and F2010. The project will address upgrades to roads, bridges, gates, culverts, helipads at approximately 10 sites per year.

Failure to do this work could result in loss of access to the microwave facilities, and the eventual loss of the ability through these facilities to remotely monitor and operate other system facilities. A portion of the cost of this work is shared with other users of the microwave facilities, primarily the Forest Service and BC Parks.

6.5.1.6.6 Telecommunications Minor Capital

This project was in the F2008 Capital Plan and there is no material change to the F2009 and F2010 forecast levels of activity. This project is expected to continue for the remainder of the 10-year planning period and beyond and is required to address system reliability risks.

Capital expenditures are incurred each year to add or replace failed minor equipment at telecommunications facilities, which are small cost items that are not assigned to specific projects and are difficult to predict. An example of a minor capital expenditure is the addition of a telephone connection between Control Centres. Failure to make these expenditures would impair operational efficiency and could result in the long-term degradation of transmission system reliability.

6.5.1.6.7 High Voltage Entrance Protection Replacement

This project was in the F2008 Capital Plan and there is no change to the F2009 forecast activity level. BCTC is intending to increase activity levels in F2010. The project is expected to continue to F2014. The project was previously planned to be complete in F2017 and has been accelerated, starting in F2010 to address safety risks for personnel working inside substations. The project is required to address system reliability and life-safety risks.

High Voltage Entrance Protection (HVEP) is used to provide ground protection for workers in substations. As an example, the majority of substations have telephone service wires and, in the event of an electrical fault at a station, there may be a hazard from Ground Potential Rise (GPR), which could cause electrical injuries to crews working on or near those telephone wires inside or outside the substation.

There are a number of substations on the transmission system that use old style reactors and isolating transformers for HVEP. Testing has shown that this equipment is not adequate in the event of a lightning strike or GPR resulting from an electrical fault. As well as the electrical hazard to personnel, GPR would likely damage the communication circuits with possible loss of valuable data.

A project to replace HVEP systems began in F2003. Sites selected for replacement are coordinated with the telephone and leased line service provider. The scope of this project addresses the remaining 40 sites. BCTC plans to replace six to eight HVEP systems per year.

6.5.1.6.8 Fire Protection

This project was in the F2008 Capital Plan and there is no material change to the F2009 and F2010 forecast levels of activity. This project is expected to be complete in F2011, and is required to address system reliability and life-safety risks due to fire hazards.

BCTC manages approximately forty microwave sites. Based on industry data, the risk of a fire at microwave sites is approximately one per year given the number of sites. Loss of a microwave station could result in the loss of transmission capacity, system reliability, and potentially system outages. In addition to the impact on system reliability, the potential financial impact of fire could be between $3.0 million and $4.0 million per site.

Because water is not available at microwave stations that are located on mountaintops and in remote areas, Halon and Carbon Dioxide (CO_2) fire protection systems were installed instead of water-based sprinkler systems. CO_2 Fire Protection Systems are used as a fire suppressant and must be disabled to prevent accidental asphyxiation by personnel before entering and while working. Due to a need to ensure the safety of workers and mitigate system reliability risks, the existing fire suppression systems need to be replaced or upgraded with Novec 1230 systems which do not pose life-safety or environmental risks. Novec systems use mixtures of nitrogen and oxygen which are effective at extinguishing fires and do not pose a life-safety risk.

To date, eighteen microwave sites have been addressed. The remaining seven sites with fire protection systems which need to be addressed are prioritized based on criticality and risk, and are scheduled to be completed by 2011.

6.5.1.6.9 Lower Mainland Network Robustness

Initiated in 2006, this project was in the F2008 Capital Plan. BCTC forecasts an increase in activity in F2009 to address carry-over expenditures from F2008. This project will be complete in F2009, and is required to address system reliability risks.

The project is required to improve the robustness of the telecommunications network thereby avoiding the potential loss of service and revenue from a single contingency failure of the network by decreasing the risk of a catastrophic failure. The investment specifically decreases risks associated with loss of the Microwave Control Centre (MCC) at Burnaby Mountain by relocating the MCC to a new site and linking other major sites in a configuration that will eliminate full reliance on the MCC. If the MCC is out of service under the current configuration, the telecommunications network could be disabled for up to six months. Such a loss would limit protection and control of the transmission system necessitating domestic load shedding and lost trade opportunities.

6.5.1.6.10 Point to Multipoint Radio

This is a new project that BCTC intends to undertake in F2010 at a forecast cost of $0.8 million.

The project is required to address system reliability risks.

Nine substations in the Lower Mainland use a single VHF point-to-multipoint radio system for supervisory control. This system was installed in the 1970s and has reached end-of-life and requires replacement. If the system is not replaced, there is a high probability the Control Centres will not have supervisory control and visibility of critical substation equipment required to operate the substation safely and reliably. BCTC experienced two long-duration (several months) substation failures due to interference of the old VHF technology. The consequence of failure of this system is potential extended outage duration for customers. The outages would be extended by the inability to initiate feeder/bus re-close after a fault within 90 seconds and would require dispatching crews that would take more than 1 hour to restore service.

The alternatives considered include the replacement of the existing VHF systems with a new UHF system or with new leased lines and new RTUs. The UHF point-to-multipoint replacement alternative is preferred as it is the least cost alternative.

6.5.2 Lines

BCTC is forecasting Sustaining Capital expenditures related to Lines totaling $41.2 million in F2009, and $47.7 million in F2010. The programs and projects that make up the Stations work are discussed in the following sections.

6.5.2.1 Cable Sustainment

Cables, both underground and submarine, are generally used where overhead lines are not feasible or where there is a particular siting reason to use cables. There are over 400 km of underground or submarine cables on the transmission system. Most of these circuits are located in Vancouver, Burnaby, Coquitlam and Victoria, and include 69 kV, 230 kV and 500 kV voltage levels.

The Key Drivers for the Cable Sustainment program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for F2010 within the Cable Sustain program as shown in Table 6-15.

Table 6-15. Annual Forecast Cable Sustain Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$3.9 million	$5.0 million	$1.1 million	$5.8 million	$0.8 million

Generally, the increase in expenditures for the Cable Sustainment program from forecast F2008 to F2009 of $1.1 million is driven by an increase in activity associated with Stop Joint protection and monitoring, partially offset by a decrease in activity associated with Oil Containment at Marine Cable Terminations. All other projects remain effectively unchanged once inflation is considered. BCTC is forecasting a further increase in expenditures for F2010 of $0.8 million, which is mainly due to initiation of cable replacements for 60L93 and 60L94, partially offset by completion of the Oil Containment at Marine Cable Terminations project, and the 2L51 Life Extension project. All other projects remain effectively unchanged, after consideration of an allowance for inflation of 5 percent per annum.

The following sections describe the projects which make-up the Cable Sustainment program. The description of each project includes an overview of the project, justification for the project, changes in activity from the previous Capital Plan and planned activities for F2010. Where applicable, certain projects are identified as Risk Mitigation or Life Extension.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.2.1.1 2L51 Life Extension

This project was initiated in F2006. The previous capital plan did not forecast any capital expenditures in F2008 or F2009; however, this Capital Plan includes an expenditure of $0.7 million to complete the project in F2009. Completion of the project was deferred to F2009 to allow other higher-priority project to proceed.

A 230 kV circuit (2L51) commissioned in 1975 connects Como Lake Substation in Coquitlam to Barnard Substation in Burnaby. The circuit supplies power to customers in the metropolitan area of the Lower Mainland. Circuit 2L51 is the longest (15 km) 230 kV underground cable circuit in the system and has one of the highest replacement costs, estimated in F2007 at $66.0 million.

Elements of the cable have deteriorated significantly. The purpose of this project is to extend the operational life of 2L51 and delay the replacement of the circuit.

Work required for the cable restoration includes replacement of cable bonding and grounding, thermal backfill upgrades, and repair of several identified oil leaks, which represents normal degradation. The Do Nothing option would lead to earlier replacement of the cable and would put the metropolitan Lower Mainland system at risk of outages. Comparing replacement with restoration shows that early replacement is less favourable than extending the cable life at this time.

6.5.2.1.2 5L29 and 5L31 Corrosion Protection

This project was initiated in F2006. The F2008 Capital Plan did not forecast any capital expenditures in F2008 or F2009; however this Capital Plan has included an expenditure of $0.2 million to complete the project in F2009. Completion of the project was deferred to F2009 to allow other higher-priority project to proceed.

There are two types of submarine cable systems in use on the transmission system, Alternating Current (AC) and High Voltage Direct Current (HVDC). The AC submarine cable system consists of two parallel 500 kV circuits of 37 km each (12 single phase cable sections) that supply Vancouver Island. With the completion of the VITR project, two 230 kV AC cable circuits will be installed that will also supply Vancouver Island from the Mainland. The HVDC cable system consists of five 300 kV DC cables, 32 km each, running from Arnott (ARN) to VIT.

Submarine cables 5L29 and 5L31 currently supply about 75 percent of Vancouver Island's power. The armour of the submarine cables is subject to corrosion and is therefore the weakest link. If the armour is allowed to deteriorate, the cables will be at the end of their operational life sooner because without healthy armour, the submarine cables become weaker mechanically and lose their ability to withstand tidal movement and other impacts such as anchors. Without adequate cable armouring it is also not possible to physically lift the cables from the ocean floor to perform maintenance or repair.

To extend the life of submarine cables 5L29 and 5L31, cathodic protection will be provided for the armour. The replacement cost of the submarine cables is estimated at $400 million. The do-nothing option leads to earlier replacement of the submarine cables, and would put Vancouver Island supply at risk. An analysis comparing the do nothing option with corrosion protection shows that the do nothing option is much less favourable than the recommended solution of corrosion protection.

6.5.2.1.3 5L29 and 5L31 Real Time Rating

This project was completed in F2007.

6.5.2.1.4 Oil Containment Installation at Submarine Cable Terminating Stations

This project was in the F2008 Capital Plan and there is a decrease in forecast activity level in F2009 to complete the project.

Cables contain oil as an insulating medium which is stored in large storage tanks at the cable terminating stations at both ends of the cable. The oil storage tanks are part of the submarine cable system and are needed to regulate oil pressure, which varies with the loading of the cable circuits.

There are ten cable-terminating stations on the transmission system with oil storage tanks with a capacity of up to 50,000 litres. Seven of these stations are submarine cable terminating stations near the ocean, increasing the risk that an accidental oil spill could result in significant environmental damage. In November 2005, an accidental oil spill at Cape Cockburn (one of the 500 kV submarine cable terminating stations) released an estimated 2,500 litres of insulating oil into Malaspina Strait.

To mitigate the risk of another spill, the terminating stations near the ocean were prioritized based on volume of oil and risk of spill, and a program was put in place to retrofit these with oil containment systems over a four-year period. In F2007, three stations were retrofitted. One site is being addressed in F2008, and the remaining sites are being addressed in F2009.

6.5.2.1.5 Cable Replacements for 60L93 and 60L94

This project was identified in the F2008 Capital Plan with activity in F2009 but has since been deferred to F2010. The F2010 expenditure is forecasted at $2.2 million.

Circuits 60L93 and 60L94 supply electricity to Chilliwack. The cable portions of these circuits were commissioned in 1978 as part of a project that replaced overhead circuits with underground cables.

A comprehensive condition assessment and lab analysis in 2006 concluded that these cables were approaching the end of their operational life and need to be replaced, as confirmed in Powertech Report 16550-06. An alternative option would be to replace the cables with an overhead line, but this would require acquisition of new rights-of-way at an estimated cost of $5.0 million. The recommended solution of replacing the cable is estimated to cost $2.2 million. BCTC is proposing to replace these cables in F2010.

6.5.2.1.6 Cable Emergency Preparedness

This is a project which BCTC initiated during F2008. The project is forecast to be completed by F2013 contingent upon cable and cable accessory delivery lead times. The forecast expenditure is $0.6 million for each of F2009 and F2010.

A wide range of cables are used in the system from different manufacturers, voltage classes, vintages (1950s to 2000s), insulating medium (gas or oil), and type (submarine, direct buried or in duct). Each class of cable needs its own spares because the cables are not interchangeable. The availability of spare cables and accessories is critical for emergency repairs for cables that serve high density load areas to minimize restoration time, as the lead-time required to order replacement cables is six to twelve months. With spare cables available on site, the restoration time is shortened to two weeks on average.

To eliminate the risks associated with the long lead-time for cable replacement and its potential impact on system availability in the event of a cable failure, a cable system spare review was initiated (under OMA) in F2007. As part of the review, a system-wide inventory of in-service as well as spare cables and accessories was completed and the required spares identified and prioritized based on condition and circuit criticality. The cable system spare review resulted in a list of the cables and accessories to be procured under this project. This project will replenish cable spares that have been used and not replaced. In addition, the project will increase spares in stock to address higher risks associated with deteriorating asset condition. The total amount of cable procured will be dependent upon the results of a competitive bidding process.

6.5.2.1.7 2L31 Cable Restoration – Life Extension

This project was initiated in F2007 and was included in the F2007 Update Capital Plan. However, work that was previously planned has been deferred to F2009 and was not included in the F2008 Capital Plan due to management changes and a review of priorities. BCTC forecasts that an expenditure of $0.3 million is required to complete this project in F2009.

Many 230 kV cables are installed in the downtown core of the City of Vancouver adjacent to other utilities, including steam pipes. Circuit 2L31 is installed in close proximity to a steam pipe, reducing the reliability of 2L31 as increased heat affects the cable negatively; the cable is therefore de-rated. A mitigation scheme has been developed that will insulate the cable from the heat. Circuit 2L31 is necessary to provide power to the downtown core and must operate as rated, especially in the case of a contingency event.

The recommended solution is to install an insulation system and temperature monitoring system to accurately manage this cable to its rating. The insulation will form a thermal barrier between the cable and the steam pipe thus mitigating the heat transfer to the cable and enabling up-rating of the cable.

6.5.2.1.8 Stop Joint Explosion Protection – Risk Mitigation

This is a new project that was initiated in F2008. It has a forecast expenditure level of $0.3 million in F2009, and will be completed in F2010 at a forecast cost of $0.1 million.

Typical cables with stop joints are approximately $45 million in value and are used to supply load to Downtown Vancouver, the west side of Vancouver, and Downtown Victoria, and require a high degree of reliability. Stop joints form part of the cable circuits. Cable stop joints tend to fail catastrophically when failure occurs, causing damage to the other cables in close proximity to the failed stop joint. Failure of a 2L64 stop joint in December 2005 and a 2L53 stop joint in December 2006 and the resulting effect on the remaining stop joints in the manhole has highlighted the need to install protection on all higher risk stop joints in the 230 kV cable system. The repair cost of failed stop joints was approximately $1.0 million per occurrence. The system was also at risk of widespread outage since it was operating in an N-0 state (where loss of another critical transmission circuit would result in customer outages) for several weeks. The manufacturers' analysis and investigation concluded that the 2L64 stop joint failed due to moisture ingress during construction and the 2L53 stop joint failed due to contamination in the insulating oil.

Implementation of this project will minimize the risk of fire and shrapnel damage to the adjacent stop joints that would result should future cable failures occur. Ballistic grade material "explosion-proof blankets" have been selected and installed between the phases in the 230 kV cable manholes prioritized based on circuit criticality. Thirty blankets will be installed in F2009 and 10 blankets will be installed in F2010. The timing of expenditures is scheduled to coordinate with required planned outages on the system.

6.5.2.1.9 Stop Joint Monitoring – Risk Mitigation

This is a new project that BCTC intends to initiate in F2009 at a forecast expenditure level of $1.5 million. This project will be completed in F2010 at a forecast cost of $1.7 million.

Stop joint monitoring is a critical function to support the reliable operation of the transmission system. Refer to Section 6.5.2.1.8 above.

Deterioration in transmission cable insulation transmits partial discharges that can be measured and monitored to predict an imminent failure, and has been proven to be a leading indicator of oil filled transmission cable failures per IEEE 400-2001 Guide for Field Testing and Evaluation of Insulation of Shielded Power Cables Systems).

Installation of partial discharge monitoring is considered to be industry best practice to protect valuable transmission infrastructure, mitigate safety and environmental risks, and provide early warning of pending failure.

Recently, partial discharge measurement has been used to establish a baseline for Circuit 2L53 following the December 2006 failure. The results have been favourable and a permanent partial discharge measurement system would allow BCTC to monitor the overall health of all oil filled cables and have the ability to predict imminent failures. BCTC is proposing that each of the 63 stop joints in the transmission cable system be fitted with the partial discharge detection equipment – half in F2009 and the remainder in F2010.

6.5.2.1.10 Manhole Oil Containment – Risk Mitigation

This is a new one-year project that BCTC intends to undertake in F2009 at a forecast expenditure level of $0.6 million.

Cables contain oil as an insulating medium which is stored in large storage tanks at the cable terminations in substations at both ends of the cable. The oil storage tanks are part of the cable system and are needed to regulate oil pressure, which varies with the loading of the cable circuits. Typically, manholes are connected to city sewer systems such that water that collects within them is drained out. On newer circuits such as 2L33 and 2L55, secondary cable fluid containment is provided in all manholes to minimize the risk of cable oil spills and subsequent discharge of oil to the sewer system. Older cable manholes do not have cable fluid containment and, if a leak occurs, it will result in an environmental incident.

BCTC has experienced annual reportable environmental incidents related to cable oil leaks that result in oil discharge to the storm and waste water systems. Examples are 2L55 and 2L53 in June 2007 as well as 2L64 in December 2005. Oil spillage is measured and monitored per corporate policy. Oil spillage on these circuits is an environmental incident that has been deemed unacceptable by BCTC.

There are eleven 230 kV circuits that contain stop joints and reservoir manholes. Of these, eight circuits (2L32, 2L39, 2L40, 2L45, 2L51, 2L53, 2L64 and 2L145) have no secondary containment. All circuits except 2L51 are in duct-bank systems where stop joints are racked and reservoir tanks stored inside manholes. The drains for these manholes are typically connected to the city sewer system. 2L51 is a direct buried cable where the stop joints are buried in joint bays and the reservoir tanks are stored in manholes located near the stop-joint bays. There are 5 stop-joint bays and 5 reservoir manholes in this circuit.

The recommended solution to potential environmental hazard oil spills is to install secondary containment in all manholes in F2009 and F2010. Since 2L51 is a direct buried cable, a more sophisticated solution will be required to install an oil containment system for that circuit.

6.5.2.2 Overhead Lines Life Extension

The overhead transmission network consists of conductor systems, metal support structures, wood poles, and associated equipment which includes spacer dampers, aircraft warning markers, and disconnect switches. The overhead network has a total of 18,000 km of transmission lines with a replacement value of approximately $6 billion. These circuits include approximately 22,000 metal support structures and approximately 100,000 wood poles.

The Key Driver for the Overhead Lines Life Extension program is:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Overhead Lines Life Extension program as shown in Table 6-16.

Table 6-16. Annual Forecast O/H Lines Life Extension Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$11.6 million	$12.7 million	$1.1 million	$16.0 million	$3.3 million

Generally, the increase in expenditures for the Overhead Lines Life Extension program from forecast F2008 to F2009 of $1.1 million is driven by an increase in activity associated a number of projects such as Circuit Refurbishments, Marker Ball Replacements, and Wood Pole replacements, partially offset by a decrease in activity associated with completion of the 60L129 Upgrade in F2008. All other projects remain effectively unchanged once inflation is considered. BCTC is forecasting a further increase in expenditures for F2010 of $3.3 million, which is mainly due to minor increases in activity in a number of programs, including Wood Pole Replacement, and an allowance for inflation of 5 percent.

The following sections describe the projects which make-up the Program. The description for each project includes an overview and justification, activity levels for F2009 and planned activity or F2010.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.2.2.1 Wood Pole Replacements

This project was in the F2008 Capital Plan and there is no change to the F2009 forecast activity level. This project is also part of the F2010 plan and although BCTC is not forecasting an increase in activity, a small increase in expenditures is expected in F2010. The project is expected to continue for the remainder of the 10-year planning period and beyond.

There are approximately 100,000 wood poles in the transmission system on 69 kV to 287 kV transmission structures. The average age of the transmission wood poles is 28 years with an expected mean life of 55 years. The condition of wood poles is assessed by applying the criteria detailed in the Wood Pole Test and Treat Maintenance Standards. A wood pole receives its first Test and Treat inspection (to assess and collect field data) on a routine basis once it is 25 years old and every 8 years thereafter. The field data is used to perform structural strength calculations to determine serviceability (also known as remaining life). Poles that do not meet the serviceability criteria as defined in the Wood Pole Strength Standard are deemed to be at end-of-life and scheduled for replacement. As the system ages, the failure rate has been increasing as the average age increases - this trend is predicted to continue for the foreseeable future.

The most recent lifecycle cost analysis shows that replacing the poles after they fail is 3 to 5 times less favourable than planned replacement through the Test and Treat program. The higher costs are related to outages, overtime, emergency sourcing of materials, damage to adjacent structures and/or equipment, and higher mobilization costs.

The number of poles replaced per year is dependent on the age demographic of the pole population and whether or not they were treated prior to installation. Each year, approximately 10 percent (10,000 poles) of the total transmission pole population (100,000 poles) are tested and treated and currently approximately 4 percent or 400 poles need to be replaced. In this Capital Plan, approximately 400 poles will be replaced in each of F2009 and F2010.

6.5.2.2.2 Aircraft Marker Crossings Refurbishment, Upgrade or Replacements

This project was in the F2008 Capital Plan and requires an increase in both the F2009 and F2010 forecast expenditure levels to address a backlog of marker crossings that are in a failed or failing state. The project is expected to continue throughout the remainder of the 10-year planning period, and is required to address Transport Canada regulations which require air-craft obstacles to be visibly marked.

Where transmission crossings over pipelines, railways and bodies of water pose a potential danger to aircraft, the crossings are marked to comply with Transport Canada catenary crossing regulations. These warning markers must be clearly visible to pilots.

There are 193 marked crossings on the transmission system. These markers need to be replaced when they fall off, or are faded and beyond repair. Because this is a regulatory requirement, there are no other options. BCTC could be subject to legal action if there was an aircraft accident near or at a transmission crossing.

All marker crossings are inspected at least once per year as part of annual overview inspections. Critical crossings, such as 500 kV and radial lines, are inspected more often — up to four times per year. The circuits and crossings that are most in need of work have been established and prioritized based on inspection results.

The average cost for marker replacement per crossing is $200,000. BCTC expects to replace up to eight marker crossings per year based on historical experience and it is anticipated that this level of work will remain relatively constant in future years. All actual replacements are based on need.

Transport Canada has recently approved a new technology OCAS (Obstacle Collision Avoidance System) – an active' radar-based system) as an alternative to traditional marker systems. The OCAS field unit is designed as a “sleeping system.” The only function in continuous operation is the radar which scans the area surrounding an obstacle. If a target is detected, the radar awakes the system and immediately tracks the aircraft and calculates its speed, heading and altitude. If a collision hazard exists, the pilot is warned by flashing lights and an audio warning transmitted over the VHF band. All flight movements and warning activations are monitored locally and transmitted to a national OCAS Control Center (OCC). The OCAS System can be accessed for operational and maintenance status at any given time through the OCC. The OCAS field unit is prepared for easy installation in remote locations. A solar energy system allows stand alone operations, enabling OCAS field units to be placed practically anywhere. The OCAS Field Units can be erected as stand alone units on a separate mast or mast mounted on the obstacle itself.

The OCAS system typically can be implemented for 50 to 75 percent of the traditional marker cost, but costs can vary depending on the location and accessibility of the installation.

BCTC will install both the OCAS system and traditional marker balls, as appropriate, in its F2009 and F2010 program. In certain locations the OCAS system is not effective and traditional marker balls will be used. BCTC works in collaboration with Transportation Canada to determine the appropriate solution on a case-by-case basis. The project will implement approximately six marked crossings in each of F2009 and F2010. The number of marker crossings implemented is a function of type, location, accessibility, and cost.

6.5.2.2.3 Circuit Refurbishments

This project was identified in the F2008 Capital Plan with expenditures forecast for F2009. During F2008 a study was completed under the OMA budget that identifies and prioritizes circuit refurbishments planned for F2009 and beyond. Forecast expenditures in F2009 are $1.3 million, and this remains unchanged in F2010. This project is expected to continue throughout the remainder of the 10-year planning period.

Circuit support structures need to be refurbished when they have deteriorated to the point where it is no longer economically to maintain them. Circuit support structures can include steel towers and wood poles with steel components.

Steel is progressively corroding, often at an accelerated rate if moisture and pollution are prevalent (such as in marine and industrial environments), resulting in loss of steel mass and corresponding reduction of strength. Wood pole decay is also accelerated in moist coastal areas. Circuits located in the marine environment on the coast or in areas of high pollution are especially susceptible to deterioration as these types of environments accelerate corrosion, which shortens the lifespan of the transmission assets.

As a maintenance activity in F2008, BCTC is assessing asset condition and determining the circuits that require refurbishment. BCTC will prioritize the circuits targeted for replacement in F2009 and F2010 based on asset condition, reliability, number of customers served, and OMA maintenance costs.

An alternative to these projects would be to continue to repair and replace components; however, this approach is no longer considered to be economic as running the circuits to failure results in significantly higher costs due to overtime, power outages, emergency sourcing of materials, damage to adjacent structures and/or equipment, and higher (repeated) mobilization costs.

6.5.2.2.4 Disconnect Switch (69 kV and 138 kV) Replacements

This project was in the F2008 Capital Plan and there is no significant change to the F2009 forecast activity level. This project is also part of the F2010 plan at the same forecast level of activity. The project is expected to continue throughout the remainder of the 10-year planning period and beyond.

Line disconnect switches are integral components of transmission lines that are used to isolate transmission circuits for quick restoration of forced outages (sectionalization) and for maintenance work.

An inventory and initial condition assessment completed in F2006 indicated that of the 314 disconnect switches on the transmission system, 46 had some form of deficiency. These were prioritized and the most critical deficiencies are being addressed first. Further work will be done to determine if some of the disconnect switches can be refurbished rather than replaced. However, refurbishment is not always a viable option as spare parts may no longer be available from the manufacturer and there may not be enough parts available from salvaged equipment. If the disconnect switches are replaced only after they fail, there will be lengthy, unplanned power outages that will also be more expensive to address due to the higher costs associated with emergency repairs. Without a functioning disconnect switch, crews are unable to isolate portions of the transmission lines to perform routine maintenance.

In addition to the inventory and assessment work completed in F2006, more intensive inspections are taking place in F2008 and a new switch maintenance standard has been introduced.

Eight switches are expected to be replaced in F2009 and it is expected that this level of work will need to increase in future years, which was confirmed by an update in F2008 of the F2006 condition assessment. In F2010, dependant on the ongoing condition assessment program, ten to twelve switches will be replaced. Work activity and cost are dependant on equipment rating and application. Switch replacement work is prioritized based on circuit criticality and with input from Real Time Operations.

6.5.2.2.5 Spacer-Damper Replacements

This project was identified in the F2008 Capital Plan with expenditures forecast for F2009. During F2008 a study was completed under the OMA budget that identifies and prioritizes Spacer-Damper Replacements planned for F2009 and beyond. BCTC forecasts minimal spending in F2009 of $0.3 million to accommodate F2009 forecast activity level. This project is also part of the F2010 plan and BCTC forecasts minor increases in forecast activity level. The project is expected to continue throughout the remainder of the 10-year planning period and beyond.

Conductor spacer-dampers are hardware components designed to maintain the shape of conductor bundles and to dampen vibration. Without spacer-dampers, the bundles would lose their shape, particularly in response to wind, and result in arcing or contact causing expensive damage to the conductors and potentially leading to catastrophic failure.

Spacer-dampers are designed as sacrificial components of overhead transmission lines that were intended to save the conductors. For typical overhead transmission lines, the conductors account for approximately one-third of the overall construction costs. Spacer-damper costs are insignificant compared to the conductor costs. There are over 300,000 spacer-dampers on the transmission system.

Spacer-dampers become stiff and inflexible when they reach the end of their operational life. The inability to flex will result in the spacer-dampers rubbing or abrading the conductor, which damages the strands. An analysis was completed comparing early replacement with run to failure (do nothing) which showed that early replacement is four times more favourable. The average replacement cost is $1,000 per spacer-damper.

A shortlist of spacers and spacer dampers that should be targeted for earliest replacements has been prepared, taking into consideration the following:

(a) Specific technical knowledge that has been acquired internationally on spacers and spacer dampers;

(b) Knowledge and experience specific to BC Hydro’s system; and

(c) The ages of the spacers and spacer-dampers, and environments in which they are located.

The following products, in the order indicated, should be among the earliest replacements:

(a) All remaining Alcan (spring-type) 2 bundle spacers (such as those found on 3L02);

(b) All remaining Hayes/Ohio Brass 2-bundle rigid spacers;

(c) The remaining Metalastik 4-bundle spacer dampers on circuit 5L12;

(d) Furukawa 4-bundle spacer dampers; and

(e) Gould 4-bundle spacer dampers.

The results of the above strategy and prioritization will determine the circuits targeted for spacer-damper replacement in F2009, F2010 and beyond. Additional sampling will occur in F2009 to further refine the prioritized list.

Spacer damper replacements have been done in the past, most recently on 5L52 in South Surrey in F2004, but not as part of an ongoing project.

6.5.2.2.6 Transmission Tower Corrosion Protection

This project was in the F2008 Capital Plan and there is no significant change to the F2009 and F2010 forecast levels of activity. This project is expected to continue throughout the remainder of the 10-year planning period and beyond.

Galvanized metal (Poles and Lattice Tower) structures are widely used throughout the transmission system. There are approximately 22,000 metal structures in the system. The steel is protected by the galvanizing for many years but, over time, the galvanizing deteriorates and exposes the raw steel. When the raw steel is exposed to air and humidity or chemicals, the result is rust or corrosion. Corroded steel loses thickness over time and ultimately weakens the structure.

The majority of steel lattice towers on the transmission system also have steelwork under each tower leg, called a grillage foundation. Other foundation types also exist, such as rock anchors, piles and concrete. Rust or corrosion has been identified on many metal structures on the system, especially in industrial or marine environments and BCTC has initiated a metal structure painting program.

BCTC plans to provide corrosion remediation and protection while corrosion is still at the early ‘surface corrosion’ stage rather than waiting until it reaches the ‘structural corrosion’ stage, which may result in the collapse of the structure if not addressed. The transition from surface to structural corrosion takes about ten years if remedial work is not completed.

The average life of transmission towers is 75 to 80 years. However, depending on ambient conditions such as humidity, temperature variations, ground water table and pollution, an opportunity exists at approximately 35 to 40 years of age to extend tower life by about 25 years if remedial corrosion protection work is performed. If this work is performed at approximately 25 to 30 year intervals, again depending on ambient conditions, the life of the tower can be significantly extended. Failure to remedy the corrosion early will result in much more costly remediation work once tower corrosion reaches an advanced stage. A lifecycle cost analysis shows that addressing the corrosion in its early stages has the lowest lifecycle cost. Delaying remediation until structural corrosion is present is 1.5 times less favourable than early remediation.

The focus of the work is on the 230 kV and 500 kV circuits feeding the Lower Mainland which is the highest priority. In future years, the project will include 138/230/287/360 kV transmission systems. The transmission towers needing work were identified by maintenance inspections and prioritized based on condition and line criticality. In addition, the program is refined as more detailed asset condition data is obtained.

6.5.2.2.7 Overhead Lines Minor Capital

This project was in the F2008 Capital Plan. There is no change to the F2009 and F2010 forecast levels of activity. This project is expected to continue throughout the remainder of the 10-year planning period and beyond.

The minor capital budget covers a variety of additions or improvements to overhead transmission components and assets that are not covered by other investments. These are grouped together for administrative efficiency. Examples include structural improvements such as reinforcement of bent tower steel members and tower number signs; and improvements to berms and riprap at tower sites. In most cases, if the deterioration were allowed to continue, more significant repair costs would be incurred later. The cost of unplanned repairs is generally 2 to 3 times that of planned repairs. The investment level is based on historical spending.

6.5.2.2.8 Insulator Replacements

This project was in the F2008 Capital Plan and there is a minor increase to the F2009 and F2010 forecast levels of activity. The F2008 project addressed replacements of a specific class of insulators manufactured by Canadian Ohio Brass. The F2009 project will begin to address the insulators made by Canadian Porcelain and this project will continue into F2010. This project is expected to continue throughout the remainder of the 10-year planning period and beyond.

There are over two million porcelain or toughened glass suspension insulators on the overhead transmission system. Generally, these insulators do not degrade significantly with age. However, insulators can experience severe degradation in areas of high lightning incidence or where there is significant urban or industrial pollution. It is also well documented that the quality and robustness of insulators can vary significantly between different manufacturers or from the same manufacturer in different years. Failure of insulators results in energized conductors falling to the ground resulting in reduced reliability and a public and employee safety issue. In addition, as insulating properties degrade, reliability is impacted due to flashover caused by switching surges or lightning.

BCTC has identified several manufacturers' models that have degraded over time, or have specific defects that have resulted in unexpected insulator failures and circuit outages. Over the past 4 or 5 years, the replacement of specific insulators manufactured by Canadian Ohio Brass has been targeted due to their catastrophic failure history. A similar problem exists with insulators made by Canadian Porcelain and these units will be addressed starting in F2009. In addition, a small number of vintage 230 kV and 500 kV Non Ceramic Insulators (NCI) installed on the system pose a significant risk. Other utilities have experienced many failures of similar products. Therefore, a program to remove the NCI's will be developed in F2009.

Pollution is causing degradation of the zinc corrosion protection on all suspension insulators in the Greater Vancouver/Fraser Valley area. It is anticipated that performance issues will become more frequent with these insulators in the next decade, and their replacement will have to be staged over multiple years in the future. The justification for insulator replacement will be based on circuit performance and targeted testing as part of BCTC's routine inspection and random sampling.

6.5.2.2.9 Long Span Crossing Refurbishment

This is a new project which BCTC proposes to commence in F2010, and is expected to continue throughout the remainder of the 10-year planning period. The capital expenditure required for this project is forecasted to be $0.1 million in F2010.

For the purposes of this program, a conductor span is considered a "Long Span" if it is greater than 500 meters and over a body of water. The design of long span crossings is unique since the conductor tensions are much higher than typical spans. As a result, conductor, tower and hardware specifications are unique. There are approximately 200 such crossings on the transmission system (the transmission system includes the highest number of long-span crossings in the world).

Long span crossings are assessed during regular inspections. Corrosion is a key factor in strength deterioration since most long span crossing are over bodies of salt water. Another factor that affects the condition of the components is vibration. High unplanned costs would result if the conductor span fails since it would fall in the ocean and would require unique equipment and resources to recover it from the sea bed.

The scope of this project in F2010 and beyond is to refurbish the components of long spans crossings that have been identified as requiring remediation through condition assessments. Delaying this project will result in further deterioration of the long span crossing components to the point where failure may occur, resulting in expensive repair and long outages. This project has not been required in the past as the degradation had not been considered significant.

6.5.2.2.10 Guy and Anchor Rod Replacement Program

This is a new project that BCTC proposes to begin in F2009 that was not previously identified. It is expected to continue for the remainder of the 10-year planning period and beyond. The capital expenditure required for this project is forecasted to be $0.1 million in F2009 and $0.2 million in F2010.

Anchor rods are steel rods attached to a buried anchoring device. Guyed transmission structures (guyed non-self-supporting, dead ends, light and heavy angles) require a mechanism to attach the guy wires. In certain transmission line arrangements, guying is required to support the structures. Hundreds of thousands of anchors rods and guy anchors are in service on the transmission system. Since the guy anchor, anchor rods and wood anchor slugs are buried in soil or rock, they are susceptible to corrosion causing weakening. Further, historically the anchor system has not been replaced when a pole is replaced (which was not industry practice because it was considered very costly) increasing the risk of failure.

Following a condition assessment, a program is required in F2009 and beyond to systematically replace guy anchors and anchors rods that have reached end-of-life or have deteriorated due to corrosion. Delaying this project will result in further deterioration of the guys and anchor rods to the point where failure may occur, resulting in expensive repair and long outages. This project has not been required in the past as the degradation had not been considered significant until now.

6.5.2.2.11 Single Wood Crossarm (with Line Posts) Replacement Program

This is a new project commencing in F2009 Capital Plan that was not previously identified. It is expected to continue for the remainder of the 10-year planning period. The capital expenditure required for this project is forecasted to be $0.3 million in each of F2009 and F2010.

The revised standard 69 kV line post construction requires the use of a strain plate and a double crossarm. In many cases across the province, line posts have been installed on a single crossarm. The wind and weight span on the insulator has caused the single crossarm to twist, crack or elongate the drilled holes.

The scope of this long term program is to replace all non-standard line post installations with standard construction (double crossarm with strain plate or post-tensioning if suitable). The consequences of delaying commencement of this program in F2009 and beyond will result in forced outages and the potential for energized conductors falling to the ground which represents a public safety risk, outages to customers, and a risk to the lines crew doing maintenance. An example of a recent failure includes 60L56/57 serving UBC that resulted in a fire in a residential neighborhood.

In addition, a potential crossarm failure may result in Transmission Line to Distribution Line (under-build) contact which represents a liability to BC Hydro due to claims from customers with damaged electronics and house wiring.

Until now, BCTC has dealt with this problem on a case by case basis, which is the most expensive means of correcting the problem. The age of the crossarms in conjunction with their condition assessment requires a replacement program, which is the most efficient way to deal with the problem. The number and seriousness of occurrences requires that a program be developed to systematically address all single wood cross arm deficiencies. Thirty crossarm replacements are expected in F2009. The results of the F2009 program will determine activity level in the future.

6.5.2.3 Overhead Lines Performance Improvements

Transmission lines may be deficient due to localized climate issues, which were not identified when the line was built, and require work to bring that section of the line back to the reliability level designed into the line as a whole. Examples of this are local unequal ice loading, lightning-prone sections, or salt fog on a short section of line. Currently, the focus of this program is on reducing lightning caused outages.

Transmission lines that traverse through seasonally dry high elevation areas are subject to repeated lightning strikes. The regions of Prince George, Kootenay and the Southern Interior are most affected by lightning strikes. Lightning strikes, and even switching operations in some cases, can cause power surges that may result in significant impacts, such as:

(a) Transmission line outages;

(b) Customer outages;

(c) Insulator damage; and,

(d) Damage to other transmission equipment.

On a system-wide basis, approximately 2 percent of the total System Average Interruption Duration Index (SAIDI) is caused by lightning.

The Key Drivers for the Overhead Lines Performance Improvements program are:

(a) Maintain System Reliability (Asset Condition, Asset Performance); and

(b) Risk Mitigation (Safety, Environment).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 Sustaining Capital initiatives within the Overhead Lines Performance Improvement program as shown in Table 6-17.

Table 6-17. Annual Forecast O/H Lines Performance Improvements Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$3.8 million	$4.5 million	$0.7 million	$5.4 million	$0.9 million

Generally, the increase in F2009 forecast expenditures for the Overhead Lines Performance Improvements program from forecast F2008 of $0.7 million, and the $0.9 million increase in forecast F2010, is driven by increases in activity associated with installations of Arcing Horns in each year. The annual increases also reflect an allowance for inflation of 5 percent in each year.

The following section describes the project that currently makes-up the Program.

6.5.2.3.1 Arcing Horn Installations

This is an existing project which was initiated in F2005 and will continue until the end of the 10-year capital planning period, diminishing over time. There are changes to activity levels in both F2009 and F2010. In F2009, BCTC is planning to increase the number of arcing horns installed on the 500 kV system. The project expands in scope in F2010 to address additional voltages (138 kV, 230 kV and 287 kV as well as 500 kV) and then decreases over time as all the vulnerable insulators that have been damaged by lightning strikes are replaced.

On every transmission structure in the province, there is an insulator string at each phase of the transmission lines. Every year, insulators are damaged by power surges resulting from lightning strikes and switching operations. These damaged insulators can prevent the line from being energized resulting in a sustained outage.

Arcing horns are a pair of conductors (usually steel) used to protect insulators or insulator strings from damage due to system overvoltage conditions. Arcing horns form a spark gap that enables any abnormal overvoltage to form an electrical arc. The hot arc then travels upwards, becomes increasingly longer as the wire climbs the horns, and is eventually extinguished as it approaches the top of the horns.

Under this program, arcing horns are added when the damaged insulators are replaced to prevent the power surge from traversing the insulators, thereby avoiding similar damage to the same insulator location in the future. Over time, the ongoing cost of insulator replacements will be reduced as increasing numbers of insulators are protected with arcing horns. An analysis was completed that shows that continuing to replace damaged insulators alone is 1.2 times less favourable than installing arcing horns when the insulators are replaced.

Insulators are inspected to identify deficiencies at minimum once per year during the annual overview inspections. On critical 500 kV and radial lines, overview inspections are more frequent - up to four times per year. It is expected that this project will continue until F2011 when it will begin to taper off as a significant amount of the lightning-prone insulators will have been addressed.

6.5.2.4 Overhead Lines Risk Mitigation

The Overhead Lines Risk Mitigation program addresses issues and potential events which could put the system at risk of a prolonged outage or pose safety concerns. The risk of forest fires sparked by pole-top fires is mitigated under this program as well as risks to the public safety and operating concerns associated with end-of-life overhead conductors and deficient transmission line-to-ground clearances. Civil protective work is included to ensure the long-term stability of transmission structures.

Potential low-probability high-consequence events, such as seismic and wind and ice storms, are also addressed by this program.

The Key Drivers for the Overhead Lines Risk Mitigation program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 as shown in Table 6-18.

Table 6-18. Annual Forecast O/H Lines Risk Mitigation Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$8.6 million	$9.9 million	$1.3 million	$10.0 million	$0.1 million

Generally, the increase in expenditures for the Overhead Lines Risk Mitigation program from forecast F2008 to F2009 of $1.1 million is driven by the introduction of a number of new small projects including Overhead Ground Wire Replacements, Autosplice replacements, Copper Conductor replacements, System Transmission Emergency Response (STER) Tower replacements and a Tower Barrier project. Increases in these new projects are partially offset by a reduction in the Seismic Withstand project. Each of the new projects described above is also forecast for F2010, and maintain the same activity levels as in F2009. All other projects remain effectively unchanged once inflation is considered.

The following sections describe the projects which make-up the Program. The description for each project includes an overview of the project, justification for the project, changes in activity from the previous Capital Plan submission, and planned activities for F2010.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.2.4.1 Bonding Installations

This project was in the F2008 Capital Plan and there is no change to activity forecast in F2009. There is a minor decrease in activity expected in F2010. This project is expected to be complete in F2012.

There are over 100,000 wood poles in the transmission system supporting overhead conductors. Pole top fires occur when insulators become contaminated and allow leakage current to travel on the wood parts of the pole, causing heat and subsequent fire. Bonding mitigates this issue.

On average, six pole-top fires occur annually, which can start forest fires, causing extensive damage to private and Crown lands, the transmission system, and which may result in personal injuries. BCTC could be responsible for the cost of fighting forest fires and resulting property damage. Pole-top fires are also a source of service interruptions. Their number and impact vary considerably from year to year depending on the weather; and have accounted for up to 25% of the SAIDI in the past.

A risk assessment was completed to identify the transmission circuits that are critical to the system and have the highest risk of initiating forest fires. A total of 107 - 69 kV and 138 kV transmission circuits were identified as high risk and prioritized. Installing electrical bonding is the only method to mitigate the risk of pole-top fires. Under this project, wood poles are assessed and, if they do not already have bonding, are bonded. BCTC plans to complete thirty circuits per year. Wood pole bonding began in F2006. The planned completion date for this project has been extended from F2010 to F2012 to address a more current assessment of fire risk zones. The change in fire risk zones resulted in a higher number of wood poles that require bonding. As of F2008, a total of 16,000 wood poles on the prioritized list remain to be bonded.

6.5.2.4.2 Civil Protective Works

This project was in the F2008 Capital Plan and there is no change to activity forecast in either F2009 or F2010. This project is expected to continue for the remainder of the 10-year planning period and beyond.

When transmission circuits and structures are routed and designed, reasonable measures are taken to mitigate the risks of river/stream erosion, rockslides, mudslides, avalanches, and natural wear and tear. However, these events do occur, and civil protective works after initial construction may be needed to prevent damage.

The objective of this project is to maintain system reliability and avoid the high costs of correcting forced outages. Typically it costs about twice as much to correct a problem after a forced outage than it does to proactively correct a problem before an outage has occurred.

The main activities comprising this project include:

(a) For structures subject to water erosion, surrounding them with protection at their base;

(b) For structures at risk of avalanche and debris, installing a berm to deflect material away from the base of structures; and

(c) For structures at risk of instability, making improvements to the foundation.

Specialized geotechnical inspections of the transmission system are carried out annually to identify and define the civil protective works required. For example, a structure that is in close proximity to a river is subject to erosion. Failure to protect such a structure may result in the erosion undermining the structure foundation and total structure collapse. BCTC's risk matrix of consequence and probability is then used to prioritize the civil protective works. The investment level is based on historical spending and is expected to remain constant in future years.

6.5.2.4.3 Clearances for Circuits

This project was in the F2008 Capital Plan and there is no change to activity forecast in either F2009 or F2010. This project is expected to continue throughout the remainder of the 10-year planning period.

The overhead transmission system must meet specific clearances to maintain the as-built circuit ratings, and for public safety. Safe electrical clearances are set by BCTC guidelines and the Canadian Standards Association (CSA) and are defined as distance between the lowest point of the conductors and the highest point of the ground profile. A detailed model of the line is created that identifies the most probable combination of factors that would result in potential clearance issues. These factors include the ambient and conductor temperatures and wind speed.

Each year, electrical clearance deficiencies on overhead transmission circuits are identified. Deficiencies are usually due to older construction practices, changes in land use under the transmission lines over the years resulting in a raised ground profile, or inaccuracies due to the difficulty in obtaining survey data during the original design or installation of older lines.

The objective of this project is to correct electrical clearance deficiencies as they are discovered. Methods typically include increasing pole heights, increasing conductor tension, or re-contouring the ground beneath the conductors. In most cases, there is no alternative to undertaking the work. Not undertaking the appropriate remediation will result in the line being de-rated for safety reasons with a consequential loss of transfer capability. This project will continue on an ongoing evaluation and correction basis, and involves a series of relatively small work projects. Spending is based on historical levels.

6.5.2.4.4 Seismic Withstand

This project was in the F2008 Capital Plan and BCTC is forecasting a decrease in activity in F2009 as the Second Narrows project (2L03/49) is expected to complete early in F2009. Forecast activity for F2010 is expected to be the same as in F2009. This project is expected to continue for the remainder of the 10-year planning period.

The transmission system is exposed to various natural hazards that have the potential to physically damage and impact the system operation. In general terms, the transmission system should be able to withstand or readily recover from high probability/low impact events, and should be able to perform in an acceptable manner following a low probability/high impact event. Earthquakes are one type of low probability/high potential impact event that is important in BC. Much of the older major infrastructure of BC, and elsewhere, was originally constructed to lower seismic standards than exist today.

BCTC commenced an internal review in F2006 to assess the existing transmission system seismic program. This review by BCTC is still ongoing to develop a new seismic standard expected by the end of F2008.

A continuing focus of the F2008 and F2009 project is the Second Narrows Crossing (2L03/49), which is an important structure and is at high risk of suffering damage during an earthquake. The Second Narrows Crossing tower is an essential system component that carries two 230 kV circuits between Vancouver and the North Shore. The Second Narrows project commenced in F2007 and will be completed in F2009.

Additionally, a Terminal Tower (2L56) located west of the Knight Street bridge adjacent to the North Arm of the Fraser River is located in seismically unstable soil and may be subject to liquefaction. Definition work is proposed in F2009 ($0.2 million) to determine the feasibility and cost of a reinforcement project to be completed in F2010 ($1.1 million).

In F2010 and beyond, the feasibility of upgrades to meet the proposed new BCTC seismic withstand standard and other mitigation measures for all other major crossing towers will be reviewed. Depending on the results of the review, additional major crossing towers may require seismic withstand upgrades. If required, future capital plan submissions will address these specific needs.

6.5.2.4.5 Ice Hazard Reduction

This project was in the F2008 Capital Plan and BCTC is forecasting an increase in activity level and expenditures for F2009 to those address four circuits that require upgrading to withstand a 1-in-100 year event. This project is also included in the F2010 plan at approximately the same activity level as F2009. The project is expected to continue for the remainder of the 10-year planning period.

Overhead transmission lines can be subject to significant ice storms, depositing large amounts of ice on structures and conductors, and putting them at risk of collapsing or fracturing under the added weight. The eastern Fraser Valley, Squamish corridor and Skeena River regions of the province are the most prone to these types of storms. Failure to reduce this hazard could result in severe and costly damage to transmission assets but, more significantly, could result in prolonged power outages. Customers in the Lower Mainland could be without power for weeks, possibly months, during the critical winter months in the event of major ice damage. An ice storm in 1972 caused several steel towers to collapse, resulting in expensive repairs and prolonged outages. A system-wide analysis was conducted which established the key circuits that should be reinforced to withstand a 1-in-200 year ice storm event to maintain electrical supply to the Lower Mainland.

The system has been designed to withstand the loss of one circuit (an N-1 contingency) and not result in load loss. However the probability assessment considered that a 1 in 100 year ice storm on the un-reinforced system will result in potential failures of multiple circuits (N-2 or greater contingency) causing a load curtailment of up to approximately 2200 MW. See BCTC's response to BCUC IR 1.106.1 from the F2008 Capital Plan for a table showing the circuits that would likely be affected by a 1 in 100 year ice storm event. The table also indicates the amount of load curtailment that would result pre and post reinforcement.

Due to the very large capital investment required, this project will focus on reinforcing the circuits in two stages over five years. Initially, only those towers that would fail during a 1-in-100 year storm event will be reinforced. However, since the incremental cost to reinforce to the 1-in-200 year level is very small, those initial tower upgrades will be modified to meet the 1-in-200 year ice storm level. In the second stage of this work, those towers that cannot withstand a 1-in-200 year storm event will be reinforced. This strategy will ensure that the key circuits are addressed in a logical, staged manner that first addresses the weakest links and ultimately achieves a storm withstand level that is viewed as the emerging standard for Canadian, American and other utilities around the world.

Six circuits have been identified for reinforcement; four of these will be upgraded to at least the 1-in-100 year ice storm event level by the end of F2009. All six circuits will be upgraded to the 1-in-200 year ice storm event level by F2012. Beyond F2012, the project will address towers on 5L30/32/41 which serve Vancouver Island and the Sechelt peninsula.

6.5.2.4.6 Automatic Splice Replacement Program

This is a new project commencing in F2009 Capital Plan that was not previously identified. It is expected to continue to F2015. The capital expenditure required for this project is forecasted to be $0.3 million in each of F2009 and F2010.

Automatic splices, or "autosplices", that are not compression-type splices have been commonly used by field personnel as a quick and easy but unreliable method of joining conductors for more than 20 years. This method is not approved for use on the transmission system. The automatic splices that were put into the system fail unpredictably resulting in the conductor falling to the ground creating a circuit outage and life-safety hazard to the public. BCTC views this as an unacceptable risk that must be addressed.

Since the late 1980s, eight reported failures of autosplices have occurred, resulting in the hazardous situation of a live, high voltage conductor falling to the ground. Previous failure analyses have indicated that design problems exist with autosplices that could result in corrosion of the splices and premature failure resulting in a public safety risk. In F2008, there have been two failures to date.

Several automatic splices have been identified on the transmission system (as a result of a failure or during overview inspections), some of which have resulted in forced outages that have impacted reliability and safety. It is not known how many automatic splices exist on the transmission system since they were not approved and not captured in the asset databases. Studies and sampling programs were undertaken by Powertech (to address a similar problem on the distribution system) which recommended a total replacement program in high risk areas. The scope of this project is to replace all automatic splices on the transmission system.

The focus of the F2009 program is to identify the location of automatic splices, and prioritize and replace the ones in high risk locations with compression splices. Beyond F2009, the remainder of the automatic splices will be replaced with approved compression splices.

6.5.2.4.7 Overhead Ground Wire Replacement Program

This is a new project commencing in F2009 Capital Plan that was not previously identified. It is expected to be completed in F2010. The capital expenditure required for this project is forecasted to be $0.3 million in each of F2009 and F2010.

An Overhead Ground Wire (OHGW) is installed on the first few 230 kV or 500 kV structures out of a substation to act as lightning protection. The OHGW and its associated hardware in many cases have reached end-of-life. In 2004, an OHGW hardware failure caused by end-of-life asset condition forced an outage at Ingledow station. The outage occurred when the grounding wire failed, dropping onto an energized conductor.

The scope of this project in F2009 and F2010 is to replace the end-of-life OHGW hardware. Work will be prioritized by circuit age, and substation criticality and coordinating work with the station Grounding Upgrades project. The project is required to address unacceptable risks on the 230 kV and 360 kV circuits from Bridge River to the Lower Mainland.

Future upgrades may be required to address other OHGW hardware that will be identified through routine maintenance inspections and condition assessments.

6.5.2.4.8 Copper Conductor Replacement Program

This is a new project commencing in F2009 Capital Plan that was not previously identified. It is expected to be completed in F2015. The capital expenditure required for this project is forecasted to be $0.3 million in F2009 and $0.6 million in F2010.

Copper conductors were installed on the transmission system in the 1950s and 1960s, primarily on 69 kV circuits. As copper conductor ages over time, it becomes brittle and loses strength. Additionally, many field splices have been installed on copper conductors (due to tree falling damage) which are potential points of failure and a public safety risk.

Recently, a copper conductor failed in the Cranbrook area resulting in the energized conductor falling to the ground and subsequently causing an outage for 3.3 hours affecting 450 customers fed from Moyie substation. To maintain system reliability and to minimize life-safety risks to the public, BCTC has developed an asset management strategy to replace copper conductor prior to failure. This strategy is required to develop a replacement project for similar vintage copper conductor for which a repair is not feasible. Over the past several years, there have been many instances of copper conductor failure driving a replacement strategy by all utilities.

The focus of the F2009 program is to replace the copper in high risk locations with Aluminum Conductor Steel Reinforced (ACSR) conductor. Beyond F2009, the remainder of the copper conductor in the system will be replaced by F2015.

In addition to the system reliability risk, there is a potential that thieves will attempt to climb the structures and steal the copper conductor for its salvage value which also represents a serious public life-safety risk. The aluminum conductor is the preferred solution to mitigate the risk of theft as the aluminum conductor has a relatively low scrap-metal value. BCTC and other utilities are experiencing increased metal theft incidents in both stations and on the transmission system (refer to Station Security Section 6.5.1.4.1).

6.5.2.4.9 STER Tower and Equipment Replacement Program

This is a new project commencing in F2009 Capital Plan that was not previously identified. The project is expected to be completed in F2013. The capital expenditure required for this project is forecasted to be $0.3 million in each of F2009 and F2010.

Various types of transmission line construction equipment is recorded and kept in STER (System for Transmission Emergency Response) inventory, such as trailers, tensioners, sheaves, etc. Very few transmission towers are kept in stock and the steel towers currently in stock are not suitable for all situations. Over the past three years, there have been three incidents causing tower failure that required emergency tower replacement under the STER Program: an avalanche destroyed a tower on Circuit 2L101, a vegetation management incident destroyed a tower on Circuit 5L3, and a mudslide destroyed a tower on Circuit 5L91. Emergency response for incidents identified deficiencies with the existing STER inventory. This project addresses the identified deficiencies which will allow BCTC to respond to multiple emergencies. Without the added STER inventory, longer response times will be required to address emergencies to the detriment of customers and the transmission system. This project ensures that available spare parts will enable a timely restoration.

The scope of this project is for specification and procurement of identified STER generic emergency tower, tower components, and other related materials.

6.5.2.4.10 Tower Barrier and Signage Program

This is a new project commencing in F2009 Capital Plan that was not previously identified. It is expected to be completed in F2013. The capital expenditure required for this project is forecast to be $0.5 million in each of F2009 and F2010.

Many lattice steel towers are located in publicly accessible areas such as parks, parking lots, schools and other gathering places and there have been recent incidents where members of the public have climbed a lattice steel tower with energized conductors and have sustained injuries from falling. In 2007, there was a serious injury of a person who climbed and fell from a tower at Buntzen Lake. On Circuit 5L82 in Maple Ridge a person who climbed a tower fell 30 meters and was killed.

Lattice steel towers are easily climbable, so placement of signs and/or barriers on those transmission towers that are determined to be climbable and adjacent to public areas was determined to be an industry best practice. BCTC is developing a Tower Climbing Barrier standard which defines the criteria to be applied to determine whether or not a tower requires a barrier. In F2008, BCTC has installed a Tower Climbing Barrier with signs on some high risk towers that have had incidents or potential for incidences of members of the public climbing the towers.

The focus of the F2009 program is to create a prioritized list of towers which are located in the highest risk locations, design a tower sign warning of the risk, design a tower barrier system, and install the signs and barriers. Beyond F2009, the remainder of the towers on the prioritized list will be retrofitted with the signs and barriers.

BCTC management believes signage and barriers are an appropriate response to a growing safety issue.

6.5.2.5 Right-of-Way Sustainment

In addition to managing the transmission system assets, BCTC is responsible for managing the rights-of-way and assets that allow access to and work to be performed on the system. This includes acquiring and renewing right-of-way agreements, as well as ensuring BCTC's obligations regarding all right-of-way agreements are met.

Right-of-Way Sustainment provides infrastructure for overhead transmission lines, relocates transmission assets due to highway rerouting according to the protocol with the Ministry of Transportation, acquires and renews legal status of rights-of-way for overhead transmission lines throughout the province, and identifies, assesses, and restores rights-of-way assets that are in poor condition.

The Key Drivers for the Right-of-Way Sustainment program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for F2010 as shown in Table 6-19.

Table 6-19. Annual Forecast ROW Sustainment Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$6.1 million	$6.9 million	$0.8 million	$8.2 million	$1.3 million

BCTC is forecasting an increase in expenditures for the ROW Sustainment program from forecast F2008 to F2009. The increase is related to an increase in Miscellaneous ROW Acquisition, partially offset by a decrease in activity for Transmission Highway Relocation. The remaining projects net out to no effective change after an allowance for inflation is considered. The increased spending forecast for F2010 relates primarily to an increase in forecast activity for the ROW Access and Refurbishment project. All other projects remain effectively unchanged once inflation is considered.

The following section describes the projects which make-up the Program. For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.2.5.1 Transmission Highway Relocation

This project was in the F2008 Capital Plan and BCTC is forecasting a decrease in activity in F2009 compared to F2008. This project is also included in the F2010 plan and BCTC is forecasting a minor increase in activity to address anticipated expenditures required by the Ministry of Transportation (MoT) expected upgrades across the Province (i.e., the Gateway Project). The project is expected to continue throughout the remainder of the 10-year planning period.

BCTC has a protocol agreement with the MoT governing Rights-of-Way on road allowances. As a result, many 69 kV and 138 kV transmission lines are built on existing highway right-of-ways at no right-of-way acquisition cost. Placing transmission lines near or alongside roads is beneficial to BCTC since the lines can be built on MoT rights-of-way so separate rights-of-way do not need to be acquired, built and maintained; and roads running alongside transmission lines provide easy access for operations and repair work.

Every year the MoT carries out various road construction projects, including re-routing or expanding existing roads and constructing new roads. Where there are existing transmission lines built along highways, portions of the transmission lines may need to be relocated to accommodate the road construction. Under the protocol agreement, if the MoT requires a 69 kV line to be relocated BCTC is obligated to do so. The MoT currently contributes $400 per structure which represents, on average, approximately 2% of the total relocation costs. The balance of the cost is borne by BCTC.

6.5.2.5.2 Acquire Miscellaneous Rights-of-Way Lease Agreements

This project was in the F2008 Capital Plan and BCTC is expecting an increase in expenditures for F2009. Expenditures are expected to remain relatively stable for F2010. The increase for F2009 is related to an increase in the annual expenditures based on some rental rates being tied to the Consumer Price Index, and various lease arrangements being subject to periodic price renegotiation. This project is expected to continue throughout the remainder of the 10-year planning period.

Transmission rights-of-way provide legal rights to have transmission assets on lands, and access agreements provide legal rights to access those assets for operation, maintenance and repair. This applies for work on First Nations Reserves and work only accessible through First Nations Reserves, on private, municipal, and Crown lands. Access rights on other lands of interest to First Nations are managed by BC Hydro through the consultation and negotiation process. There is an ongoing requirement to acquire or renew rights-of-way, lease and access agreements for existing transmission lines due to expiring lease agreements, requirements for additional property rights (such as expanding an existing right-of-way for public safety), and unusual property arrangements that need attention.

This expenditure is for work required to negotiate, acquire and renew miscellaneous rights-of-way and lease agreements. Failure to acquire or renew transmission-related rights may undermine the integrity of the transmission corridors.

6.5.2.5.3 Deficient Rights-of-Way Study and Acquisition

This project was in the F2008 Capital Plan and BCTC is expecting only minor changes in activity levels over the forecast period. This project is expected to continue throughout the remainder of the 10-year planning period.

The Deficient Right-of-Way Acquisition project is strictly for cases where there are no existing right-of-way or access agreements with landowners; whereas the Miscellaneous Right-of-Way Acquisition project (above) focuses on the renewal of existing agreements.

A project initiated in F2005 identified deficient transmission property rights on private, municipal, and Crown lands, as well as First Nations Reserves. Various portions of transmission lines have no statutory rights and/or no agreements for access to the transmission works. These deficiencies have arisen from a variety of causes. In some instances the BC Land Titles Office inadvertently dropped rights when title to land was subdivided or transferred. In other cases, transmission rights were not acquired for very old lines, or transmission lines were situated outside the surveyed statutory right-of-way areas.

In F2009, BCTC has allocated half of the funding to address deficient rights on First Nations lands and the other half to address deficient rights on private, municipal, and Crown lands.

The goal of this project is to identify, prioritize, and acquire deficient transmission rights-of-way throughout the Province. Priority is given to the rights-of-way for higher voltage transmission lines due to their high impact on the system. Failure to acquire property rights for existing transmission facilities may undermine the ability of BCTC to maintain and operate the transmission system.

BCTC completed its initial inventory of deficient rights in 2005 on private, municipal and Crown lands, identifying 84 deficient rights, of which 57 have been corrected. Two new deficient rights were identified in 2007. New deficiencies may continue to arise over time which will need to be addressed by this project. The acquisition of the remaining identified deficient rights on private and Crown lands is ongoing and will be completed on a priority basis.

The initial inventory of deficient rights on First Nations lands was completed in 2007 and is the highest priority. New deficiencies may continue to arise over time which will need to be addressed by this project. First Nations deficiencies were identified for right-of-way acquisition starting in F2008 and continuing at the same levels in F2009 and beyond.

Some deficient rights can be resolved expeditiously, but others require lengthy negotiations. BCTC believes that it has resolved the less onerous, low cost deficient rights acquisitions. The remaining known deficient rights acquisitions are expected to be more costly.

6.5.2.5.4 Rights-of-Way Access Program Definition and Refurbishment

This project was in the F2008 Capital Plan and there is no change to the F2009 forecast activity level. The project is expected to expand in scope in F2010 to address the deficiencies identified by an inventory and is expected to continue for the remainder of the 10-year planning period and beyond. The forecast expenditure for F2010 is $2.9 million.

Access to overhead line facilities is required for the efficient operation of the transmission system. Access may be by boat, vehicle or helicopter depending on the location, local issues and business needs.

This project consists of two components:

(a) The establishment of a comprehensive inventory of right-of-way access assets (e.g. roads, culverts, bridges, helicopter pads, etc.) was started in F2006, and is ongoing. The inventory for Vancouver Island, Vernon, and Mica and Revelstoke has been completed. Other areas of the Province will be completed in the future; and

(b) The life-extension to assets that were previously identified through maintenance inspections and were assessed as being in poor condition. Preliminary results of the asset inventory indicate that many right-of-way access assets are exhibiting moderate to high levels of damage and deterioration. Assets found to be in need of immediate attention will be remediated under this project. Priority is given to the rights-of-way assets with the highest circuit criticality rankings.

6.5.2.5.5 Enterprise Geographic Information System (EGIS) Enhancement

This project was in the F2008 Capital Plan and there is no change to the F2009 and F2010 forecast levels of activity. This project is expected to continue throughout the remainder of the 10-year planning period.

Effective management of spatial data (three dimensional maps of the transmission system and rights-of-way) concerning the transmission system is critical for the success of the business. BCTC presently maintains an accurate and up-to-date spatial view of the transmission rights-of-way in a centralized location, the Enterprise Geographic Information System (EGIS). EGIS provides the following benefits:

(a) Improved external agency information coordination by facilitating sharing of spatial data with other entities (Integrated Cadastral Information Society – ICIS) such as demonstrated during forest fire response efforts;

(b) Improved responsiveness to government and regulatory authorities (i.e. for vegetation permits it is now required to submit an accurate map of the area);

(c) Assists in describing the asset condition of rights-of-way (vegetation communities, compatible use, wildlife and riparian issues, properties issues, forestry tenures, etc.);

(d) Allows for more thorough environmental analyses of BCTC initiatives and identification of environmental implications;

(e) Improves coordination with external contractors by providing accurate maps for scheduled work and obtaining estimates from contractors;

(f) Allows for the export of data from EGIS to users for external use, including accurately depicting work areas in contracts;

(g) Continues to allow staff to obtain current data from one source;

(h) Extends the life of system by providing an accurate and timely view of the transmission assets along rights-of-way; and

(i) If new right-of-way data is not available, BCTC will not be able to properly manage the transmission rights-of-way due to missing data.

EGIS data is maintained and kept current on a 5-year cycle through an update program for all transmission circuits. When new structures are added, the data is updated at that time. All BCTC service providers are now using PowerGrid to update data. PowerGrid is BCTC's repository of spatial data for the transmission grid.

EGIS allows BCTC business areas to make timely and accurate decisions based on a common geographic view of the transmission assets. The following BCTC departments use the EGIS system: Major Projects, Asset Program Definition, Asset Program Management, Properties, Safety and Environment, and Real-time Operations. BC Hydro uses EGIS to support the following departments: Engineering, Aboriginal Relations and Negotiations, and Field Operations. In addition to BCTC and BC Hydro, other government agencies and departments use EGIS to support their business needs.

There are no changes for F2009. In F2010, BCTC plans to continue with the collection of new planimetric (measurement of planar surfaces) data that is currently missing from EGIS. This will include LiDAR (Light Detection and Ranging) data along existing rights-of-way (i.e., new subdivisions, new roads, etc.) as well as cadastral information along rights-of-way. The combination of the two solutions allows maximum use of the data. The new data will then be loaded into EGIS for right-of-way management. The recommended solution has proved to be a cost effective manner to capture the required digital data. This project is based on historical spending levels.

6.5.2.5.6 5L030 5L032 McNab Creek Road License

This is a new project commencing in F2009 Capital Plan that was not previously identified. It is expected to be completed in F2009 at a cost of $0.2 million.

This asset is comprised of the forestry road that runs from the barge landing at McNab Creek on Howe Sound, up the valley and connects with the right-of-way access track that follows Circuits 5L30 and 5L32 from Sechelt Creek (5L30 and 5L32 are critical circuits that provide service to Vancouver Island). The forestry road has historically been used to access these circuits for the purposes of transmission and vegetation maintenance, and includes the road surface, ditches, culverts, drainage structures, and bridges.

This road is being deactivated by the existing licensee, and BCTC has been approached by the Ministry of Forests to assume the prime Road Use Permit. The existing licensee will close the road if a new Road Use Permit holder cannot be identified. If the road is closed, BCTC's ability to access the 5L30 and 5L32 right-of-way will be reduced, with options limited to accessing the site by alternate methods such as helicopter, or by boat via Salmon Inlet (a much longer route with a less accessible landing). The alternate access methods will increase the time required to access the right-of-way by up to two or more days.

This project is required to refurbish the McNab Creek access road and to obtain the rights to the road use permit.

Completion of this project will realize cost savings since work crews will be able to access the right-of-way for routine maintenance. The completion of the project will also allow timely access during emergencies reducing time required for restoration.

6.5.2.6 Right-of-Way Sustainment – Third Party Requested Projects

Third-party requested line relocations are those projects for which BCTC enters into an agreement with a Third-party who wishes to have transmission lines relocated and who will pay for all costs incurred under the project, resulting in an offsetting

Contribution In Aid of Construction for the capital expenditure. Approval is sought only for the projects that have a signed agreement with the Third-party. Funding for future Third-party projects has been estimated based on anticipated projects and historical investment levels. BCTC is not exposed to any of the costs for Third-party funded projects. Any costs above or below the estimate are managed through the contract language in the Transmission Line Relocation Agreement (i.e., refund or invoice).

Key drivers are:

(a) Risk Mitigation (Safety); and

(b) Third-Party (Relationships).

This section describes the proposed changes in F2009 to the previously approved F2008 forecast expenditures, and changes for the F2010 initiatives within the Right of Way (ROW) Sustainment – Third Party Requested Projects program as shown in Table 6-20.

Table 6-20. Annual Forecast ROW Sustainment – Third Party Requested Project Expenditures

F2008 Forecast (a)	F2009 Forecast (b)	Change F2008 to F2009 (b) – (a)	F2010 Forecast (c)	Change F2009 to F2010 (c) – (b)
$3.0 million	$2.2 million	($0.8 million)	$2.3 million	$0.1 million

BCTC is forecasting a decrease in expenditures for the ROW Sustainment Third Party Requested Projects program over the forecast period. The decrease is related to the Canada RAV Line, an unusually large project. The remaining projects net out to no effective change after an allowance for inflation is considered.

For ease of comparison, BCTC has set out the projects in the program in the same order as in the F2008 Capital Plan. Existing projects are set out first, followed by new projects within the program.

6.5.2.6.1 RAV (Canada) Line: Cambie Cut and Cover Relocations

This fully funded Third-party project is an existing project initiated in F2006 that was originally expected to be complete in F2008 but may need to be extended to F2010 due to Canada Line project delays and additional relocations that have been identified.

BCTC and SNC-Lavalin Inc. have signed a Transmission Line Relocation Agreement under which BCTC has agreed to relocate a variety of circuits to accommodate the Canada Line construction project along Cambie Street in Vancouver. Under this Agreement, SNC-Lavalin will pay all costs associated with the project and has prepaid the estimated costs to complete this work. Activities in this project include relocation of power and telemetry feeds for alarm systems; alterations to the fencing and ground grid; relocation of submarine cable nitrogen/oil supply building; relocation and conversion of portions of overhead circuits to underground cables; review and comment on design of the support system required for direct buried cables; and onsite monitoring of duct bank systems to facilitate installation of piping systems. This project started in F2007 and will finish in F2010 for an estimated total cost of $1.7 million. BCTC is not responsible for any costs above or below the initial estimate, as the Transmission Line Relocation Agreement requires the third-party to pay actual costs.

6.5.2.6.2 60L39 and 60L40 Relocation Still Creek Drive - Costco

This project was completed in F2008.

6.5.2.6.3 Sea to Sky Highway Project Relocations

This project was not included in the F2008 to F2017 TSCP, but was included in response to BCUC IR 1.13.1 pertaining to the above-referenced Capital Plan, due to the timing of the relocation agreement.

BCTC is working with the Sea to Sky Highway Improvement Project team to relocate a number of transmission lines that run alongside the current Sea to Sky route - the portion of Highway 99 that links West Vancouver with Whistler. The route is 100 km long and crosses varied terrain, and as such the project is divided into four segments. The transmission relocation portion of the project has been similarly organized and to date, BCTC has fourteen separate Transmission Line Relocation Agreements for this project. The lines impacted along the route are either 69 kV or 230 kV. Peter Kiewet Sons Co. (PKS), the highway project general contractor, has worked closely with BCTC to identify conflicts between the existing transmission circuits and the new highway design. BCTC is directing BC Hydro Engineering to prepare the relocation studies, undertake the required design work, and to execute the relocations agreed upon with PKS. Where existing structures are located on the original highway easement, the relocation costs are borne by BCTC, in accordance with the protocol agreement with the Ministry of Transportation detailed in section 6.5.2.5.1. Where existing structures are not located on the original highway easement, the full costs are funded by PKS. The project started in F2007 and is estimated to be complete in F2010 with a total cost of $4.8 million.

7.0 BCTC CAPITAL PORTFOLIO

The BCTC Capital portfolio is comprised of three asset programs: Information Technology; Control Centre Technologies; and Facilities.

7.1 BCTC Capital Portfolio Table

Table 7-1. BCTC Capital Portfolio Table

	BCTC Capital Portfolio	Page	IS Date	Project Total ($'000)	Prior Years ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	INFORMATION TECHNOLOGY														
	Projects in Progress														
1	Enterprise Server, PC and Peripheral Replacement		Mar 09	918		561									
2	Financial Modelling Project (FMP) Cognos Enterprise Planning (EP) Phase II		Mar 09	240		240									
3	FSP (Oracle) Supplier Performance Management		Mar 09	205		205									
4	**Subtotal**			**1,363**	**0**	**1,006**									
	Projects for Approval														
5	Asset Management Program (AMP) server refresh F2010	325	Mar 10	225		0	225								
6	B2B Portal	327	May 08	467		467									
7	Data Centre Redundancy F2009 and F2010	329	Mar 10	3,412		1,738	1,674								
8	E-Business Financial Upgrade F2009 (Oracle Upgrade)	332	Mar 09	924		924									
9	Enterprise Server, PCs, Printers and Peripherals Refresh F2010	334	Mar 10	469		0	469								
10	Financial System Sustainment F2009 and F2010 Project	336	Mar 10	1,226		632	594								
11	HR/Payroll Sustainment F2009 and F2010	338	Mar 10	329		223	106								
12	Identity and Access Management F2009 and F2010	341	Mar 10	1,201		622	579								
13	Laptop, Desktop and Removable Media Encryption F2009	343	Mar 09	265		265									
14	Market Operations Workflow -SGIP Sustainment F2009	345	Mar 09	106		106									
15	Mobile Station Inspection Enhancement F2009 and F2010	346	Mar 10	286		143	143								
16	Network Segmentation [Re-issued] F2009	348	Mar 09	651		651									
17	Reliability & Loss Program Integration F2009 and F2010	351	Mar 10	420		238	182								
18	Security Information Management F2009	353	Mar 09	200		200									
19	SharePoint 2007 Upgrade F2009	355	Mar 09	44		44									
20	Transmission Scheduling System (TSS) Enhancements F2009	356	Mar 09	106		106									
21	wesTTrans Open Access Same Time Information System (OASIS) Upgrades F2009 and F201(	358	Mar 10	151		54	97								
22	**Subtotal**			**10,482**	**0**	**6,413**	**4,069**								
	Future Projects														
23	Asset Management Program (AMP) Enhancements - Future	360		4,233		0	0	485	497	509	522	535	548	562	575
24	Business System Enhancements - Future	360		17,500				2,500	2,000	2,000	2,000	2,000	2,500	2,500	2,000
25	Computer Desktop Upgrade - Future	360		4,500		0	1,500			1,500			1,500		
26	Content Management System Upgrade F2010 - Future	360		1,000			1,000								
27	Enterprise Project Management Tool	360		800			800								
28	Enterprise Storage Array Network (SAN) Refresh - Future	361		900			300				300				300
29	Enterprise Servers, PCs, Printers and Peripherals - Future	361		2,656		0	0	237	233	394	431	366	266	324	405
30	Financial System Program (FSP) Sustainment - Future	361		300			150	150							
31	HR Payroll Sustainment - Future	361		523		0	53	54	55	57	58	59	61	62	64
32	Market Operation Workflow - SGIP F2010 Sustainment	361		954		0	106	106	106	106	106	106	106	106	106
33	Miscellaneous Enterprise IT Projects - Future	361		16,000		0	0	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
34	Market Operations (MO) Business System Upgrade F2009	362	Mar 10	16,488		7,961	8,527								
35	Security Enhancements - Future	362		2,950		0	950	250	250	250	250	250	250	250	250
36	System for Transmission Asset Recording and Reporting (STARR) Upgrade F10	362		100			100								
37	Tariff Changes to Market Operations Systems - Future	362		3,567		0	0	0	1,104	0	0	1,189	0	0	1,274
38	WesTTrans Enhancements - Future	362		510		0	0	54	55	57	58	100	61	62	63
39	**Subtotal**			**72,981**	**0**	**7,961**	**13,486**	**5,836**	**6,300**	**6,873**	**5,725**	**6,605**	**7,292**	**5,866**	**7,037**
40	**TOTAL INFORMATION TECHNOLOGY**			**84,826**	**0**	**15,380**	**17,555**	**5,836**	**6,300**	**6,873**	**5,725**	**6,605**	**7,292**	**5,866**	**7,037**

Note:
IS Date = In Service Date

Table 7-1. BCTC Capital Portfolio Table (continued)

	BCTC Capital Portfolio	Page	IS Date	Project Total ($'000)	Prior Years ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
	CONTROL CENTRE TECHNOLOGIES														
	Project in Progress														
41	System Control Modernization Project (SCMP)		Apr 08	132,559	129,145	3,414									
	Projects for Approval														
42	Control Centres Sustainment F2009 and F2010	363	Mar 10	234		117	117								
43	Control Centre Business Application Enhancement F2009 and F2010	364	Mar 10	902		265	637								
44	Real Time Operations (RTO) Servers and Infrastructure Refresh F2009	367	Mar 09	854		854									
45	Site Information System (SIS) Filenet Upgrade F2009	368	Mar 09	471		471									
46	**Subtotal**			**2,461**	**0**	**1,707**	**754**								
	Future Projects														
47	Control Center Sustainment (post-SCMP) - Future	370		24,000			2,000	3,000	3,000	2,000	3,000	3,000	2,000	3,000	3,000
48	Control Room Outage Window (CROW) Enhancements - Future	370		2,500		0	100	500	500	100	100	100	100	500	500
49	Dispatch Compliance Management (DCM) Replacement - Future	371		2,000		0				1,000	1,000				
50	Power System Safety Protection (PSSP) Replacement - Future	371		1,000							1,000				
51	Site Information System (SIS) Sustainment F2010	371		270			30	30	30	30	30	30	30	30	30
52	Total Transfer Capability (TTC) upgrade F2010 - Future	371		1,000		0	1,000								
53	**Subtotal**			**30,770**	**0**	**0**	**3,130**	**3,530**	**3,530**	**3,130**	**5,130**	**3,130**	**2,130**	**3,530**	**3,530**
54	**TOTAL CONTROL CENTRE TECHNOLOGIES**			**165,790**	**129,145**	**5,121**	**3,884**	**3,530**	**3,530**	**3,130**	**5,130**	**3,130**	**2,130**	**3,530**	**3,530**
	FACILITIES														
	Project for Approval														
55	BCTC Facilities Enhancements F2009 and F2010	371	Mar 10	424	0	212	212								
	Future Projects														
56	Facilities Minor Upgrades - Future	373		1,600	0	0	0	200	200	200	200	200	200	200	200
57	**TOTAL FACILITIES**			**2,024**	**0**	**212**	**212**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
58	**TOTAL BCTC PORTFOLIO**			**252,640**	**129,145**	**20,713**	**21,651**	**9,566**	**10,030**	**10,203**	**11,055**	**9,935**	**9,622**	**9,596**	**10,767**

Note:
IS Date = In Service Date

7.2 Historical and Trend Explanations

7.2.1 Program Trends

Table 7-2. BCTC Capital Portfolio Trends

	Program Trends	Actual F2005 ($'000)	Actual F2006 ($'000)	Actual F2007 ($'000)	Forecast F2008 ($'000)	F2009 ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)
1	Information Technology Program	10.8	8.0	3.8	6.6	7.4	9.0	5.8	6.3	6.9	5.7	6.6	7.3	5.9	7.0
2	Market Operations Business Systems					8.0	8.5								
3	Control Centre Technologies Program	1.0	2.1	1.0	1.0	1.7	3.9	3.5	3.5	3.1	5.1	3.1	2.1	3.5	3.5
4	SCMP	0.9	10.1	45.1	71.9	3.4									
5	Facilities	0.6	1.2	0.2	2.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
6	**Total BCTC Capital Portfolio**	**13.3**	**21.4**	**50.0**	**81.7**	**20.7**	**21.7**	**9.6**	**10.0**	**10.2**	**11.1**	**9.9**	**9.6**	**9.6**	**10.8**

The BCTC Capital portfolio as shown in Table 7.2 presents five major capital expenditure categories. The majority of BCTC Capital portfolio expenditures between F2006 to F2008 are attributable to the System Control Modernization Project (SCMP). Notwithstanding this major project, BCTC's overall capital expenditures are relatively stable year over year, with the exception of F2007 which reflects a reduction of $2.4 million in the Information Technology program resulting from Commission Order G-91-05 to reduce aggregate capital spending over the F2006 and F2007 years.

Starting in F2009, BCTC Capital expenditures will increase slightly to ensure the asset health of BCTC's systems is maintained. The increase in spending is driven in part by asset replacement cycles every three years whereby $1.5 million is forecast to be spent on upgrading the desktop operating system, along with projects such as the Market Operations Business Systems Upgrade with forecast capital expenditures of $8.0 million and $8.5 million in F2009 and F2010, respectively.

As the completion of the SCMP approaches, the focus and resources of the Control Centre Technologies program will shift to other needs and this is reflected in the slight increase in program spending from F2009. Similar to the Information Technology program, the ten year forecast for the Control Centre Technologies program is primarily driven by asset replacement cycles. For instance, Control Centre sustainment is reduced from $3 million to $2 million every third year, reflecting the population demographics of the assets. Other applications have longer replacement cycles, such as the Power System Safety Protection system and the Dispatch and Compliance Monitoring system, which are forecast to be replaced every five years.

7.2.2 Ongoing BCTC Capital Project Trends

In the Commission's F2006 Capital Plan Decision, the Commission stated at page 63:

> The Commission Panel therefore directs BCTC to provide, in future capital plan applications, a summary of the previous three years' activities and expenses for each ongoing project whose annual costs exceed $250,000.

In this Application, there are three BCTC Capital projects with proposed or prior annual costs exceeding $250,000 that are considered to be ongoing projects:

(a) Control Centre Sustainment;

(b) Enterprise Server, PC and Peripheral Replacement; and

(c) Financial System Sustainment.

A summary of the previous three years' activities and expenses for these projects is provided in Table 7-3.

Table 7-3. Ongoing BCTC Capital Project Trends

	Period	Actual F2006 Expenditure	Actual F2007 Expenditure	Forecast F2008 Expenditure
	Control Centre Sustainment			
1	Expenditure	$93K	$274K	$419K
2	Activities	Upgrade hardware, software, communications and building repairs	Upgrade hardware, software, communications and building repairs	Upgrade hardware, software, communications and building repairs
3	The F2006 actual capital expenditure of $93K for Control Centre Sustainment reflects the deferral of work activities in response to Commission Order G-91-05. Resumption of Control Centre Sustainment activities, along with aging systems at the existing control centres increased costs for F2007 and F2008. Even so, the F2006 to F2008 expenditures are significantly reduced in F2009, reflecting BCTC's minimal sustainment expenditures in recognition of the new control centres to be implemented in F2009. Sustainment costs of the new control centres are expected to increase to between $2 million and $3 million based on industry recommended practices of replacement cycles for each equipment class.			
	Enterprise Server, PC and Peripheral Replacement			
4	Expenditure	$304K	$249K	$357K
5	Activities	Deployed 123 desktops, 66 laptops, 9 printers and 1 storage system	Deployed 2 servers, 61 desktops, 55 laptops, 6 printers and 1 storage system	Deployed 3 servers, 83 desktops, 52 laptops, 5 printers and 1 storage system
6	The F2006 and F2007 actual data reflects a typical range of desktops and laptops reaching end-of-life or not meeting capacity or performance requirements. In F2008, an additional server replacement was required, increasing the hardware costs. The ten-year forecast is expected to remain within approximately 50% of this level and is based on industry recommended practice of replacement cycle for each equipment type.			
	Financial Sustainment Program			
7	Expenditure	$442K for Financial Modelling	Total: $255K; $55K for Financial Modelling; $200K for Financial Sustainment	Planned Total:$565K: $225K for Financial System Program (Oracle) Minor Enhancement; $240K Financial Modelling Project (FMP) Cognos Enterprise Planning (EP) Phase II (deferred to F2009; refer to Section 7.3 for details)
8	Activities	Deployed new modelling tool using Cognos	Deployed new reporting functions	Deployed additional reporting functionality and enhanced/ patch Oracle Financial Application as required.
9	BCTC needs to enhance budgeting, forecasting, and work planning to meet the increasing business requirements for Financial reporting and modelling each year. With the current Financial System Program (Oracle), sustainment expenditures are proposed to increase from planned $565K to approximately $600K respectively for F2009 and F2010 (not including deferred $240K) and then forecast to remain relatively stable. The current unknown is the investment required to support the accounting changes arising from the adoption of the International Financial Reporting Standards in F2011/F2012.			

7.3 Changes from Previous Capital Plan

In the Commission's F2008 Capital Plan Decision, the Commission issued the following Directive 34 on page 87:

> In all future capital plan applications, the Commission Panel directs BCTC to provide a table in the format of Table 7-4 of the F2008 Capital Plan, modified to show the total dollar amount of each project and the relative priority at the time of approval.

Table 7-4 lists BCTC Capital projects submitted in the F2008 Capital Plan that have been deferred or changed. No projects have been cancelled.

Table 7-4. BCTC Capital Project Changes from F2008 Capital Plan

	Order Number	Project	F2008 Capital Plan Priority/ Total Projects Prioritized	Cost	Change
	Deferred Projects				
1	G-69-07	Financial System Project (Oracle) Supplier Performance Management	10/20	$205K	The project was deferred due to the lack of available internal resources. The resources required to complete this project are not available until F2009.
2	G-69-07	Financial Modeling Project (Cognos EP) Phase II (Budgeting)	12/20	$240K	Due to financial and regulatory reporting requirements identified after the F2008 Capital Plan submission, this project is being re-evaluated at the same time as the F2009 FSP Sustainment project to identify a comprehensive solution to achieve better business requirements. The project is deferred to F2009.
	Additional Project Changes				
3	C-1-05	System Control Modernization Project (SCMP)	NA	$133M	The in-service date for the System Control Modernization Project (SCMP) was reported in the F2008 Capital Plan as September 2008. SCMP is now reporting an earlier in-service date of March 2008. This advance has shifted $3.7 million in cost from F2009 to earlier years; however, the overall project cost remains at $133 million.

7.4 Prioritization Results

In the Commission's F2008 Capital Plan Decision, the Commission issued the following Directive 16 (on page 45):

> Therefore, the Commission Panel directs BCTC to include in its next capital plan filing, tables for each of the Portfolios listing the projects brought for approval, their risk and value scores by category, and the priority numbers and quadrant values, where applicable.

Before the BCTC projects were prioritized, each project was reviewed and those that did not have sufficient justification in BCTC's view were dropped from the portfolio. The remaining projects were validated by BCTC and recommended for approval in this Capital Plan. Table 7-5 contains a list of all projects for approval, with their priority and the rationale for this priority.

Table 7-5. BCTC Capital Prioritization Results

Rank	Project Title	Total Project Cost ($000's)	Values							Deferral Risk						
			Financial	*Reliability*	*M.E.*	*Asset Cond.*	*Relationship*	*Env & Safety*	**Overall Value**	*Financial*	*Reliability*	*M.E.*	*Asset Cond.*	*Relationship*	*Env & Safety*	**Overall DR**
1	Control Centres Sustainment F2009/F2010	$ 234	-0.18	1.20	0	0.85	0.05	0.06	1.98	3	25	0	25	0	12	25
2	Laptop, Desktop and Removable Media Encryption F2009	$ 265	-0.16	0	0	0	0.13	0	-0.04	4	0	0	0	8	0	8
3	Control Centre Business Application Enhancement F2009/F201(	$ 902	-0.21	1.20	0	0.85	0.05	0.06	1.95	3	25	0	25	0	12	25
4	RTO Servers and Infrastructure Refresh F2009	$ 854	-0.29	1.20	0	0.85	0.03	0	1.78	0	25	0	25	3	0	25
5	TSS Enhancements F2009	$ 106	-0.09	0	0	0.25	0.05	0	0.21	4	0	0	25	15	0	25
6	Reliability & Loss Program Integration F2009	$ 420	-0.13	0.96	0.1	0.62	0	0	1.54	9	20	0	15	0	0	20
7	AMP server refresh F2010	$ 225	-0.15	0	0	0.79	0	0	0.64	0	0	0	20	0	0	20
8	Enterprise Server, PCs, Printers and Peripherals Refresh F2010	$ 469	-0.12	0	0	0.79	0	0	0.67	10	0	0	20	0	0	20
9	Data Centre Redundancy F2009 and F2010	$ 3,412	-0.35	0.00	0	0.73	0	0	0.38	10	0	0	20	10	0	20
10	BCTC Facilities Enhancements F2009/F2010	$ 424	-0.18	0	0	0.61	0	0.09	0.52	0	0	0	15	0	12	15
11	HR/Payroll Sustainment F2009/F2010	$ 329	-0.08	0	0	0.34	0	0	0.27	4	0	0	15	0	0	15
12	SIS Filenet Upgrade F2009	$ 471	-0.16	0	0	0.41	0	0	0.25	0	0	0	15	0	0	15
13	E-Business Financial Upgrade F2009 (Oracle Upgrade)	$ 924	-0.22	0	0	0.68	0	0	0.46	3	0	0	15	0	0	15
14	B2B Business Portal	$ 467	-0.21	0	0	0.32	0.01	0	0.13	0	0	0	15	0	0	15
15	wesTTrans OASIS Upgrades F2009/10	$ 151	-0.16	0	0.09	0	0.05	0	-0.02	4	0	15	0	10	0	15
16	Identity and Access Management F2009/F2010	$ 1,201	-0.29	0	0	0	0.09	0	-0.2	15	0	0	0	8	0	15
17	SharePoint 2007 Upgrade F2009	$ 44	-0.04	0	0	0.09	0.02	0	0.07	0	0	0	12	0	0	12
18	Security Information Management F2009	$ 200	-0.16	0	0	0	0.08	0	-0.08	12	0	0	0	8	0	12
19	Mobile Station Inspection Enhancement F2009 and F2010	$ 286	0.43	0	0	0.23	0	0	0.66	4	0	0	10	0	0	10
20	Network Segmentation [Re-issued] F2009	$ 651	-0.22	0	0	0.25	0.02	0	0.05	9	0	0	10	6	0	10
21	Financial System Enhancement Project F2009/F2010	$ 1,190	-0.3	0	0	0.24	0.04	0	-0.02	3	0	0	10	0	0	10
22	Market Operations Workflow (SGIP) Sustainment F2009	$ 106	-0.09	0	0	0	0.08	0	-0.01	0	0	0	0	8	0	8

Projects are ranked primarily according to their risk of deferral. Those projects with a similar level of deferral risk are ranked according to their value scores and project costs. Priority is given to projects needed to meet mandatory requirements. The Control Centre Sustainment F2009/F2010 and Laptop, Desktop and Removable Media Encryption F2009 projects are ranked highest since they are critical in meeting NERC reliability standards and are considered mandatory.[11]

Projects withdrawn, cancelled or modified are included in the following table.

[11] BCTC is not currently under any legal requirement to meet this NERC standard, but has chosen voluntarily to align with this standard as an industry best practice approach to address security risk.

Table 7-6. Withdrawn, Cancelled, or Modified BCTC Capital Projects

Title	Program	Total Capital Cost ($000's)	Capital Cost-F09 (000's)	Capital Cost-F10 (000's)
Projects Cancelled by Peer Review				
BCTC Internet Upgrade F2009	Information Technologies	$ 159	$ 159	
EBI BCTC Data Mart Replacement	Information Technologies	$ 1,077	$ 1,077	
Passport Replacement Definition	Information Technologies	$ 318	$ 318	
Projects Changed after the Peer Review				
IJ Tool Upgrade F2009	Information Technologies	$ 234	$ 234	
EBI Phase 2 Transmission - Veg Reporting F09	Information Technologies	$ 106	$ 106	
Build out of 15th floor F2009	Facilities	$ 350	$ 350	
Financial Modelling Tool Phase 3 F2009	Information Technologies	$ 442	$ 442	
Financial Sustainment Program F2009	Information Technologies	$ 255	$ 255	
New Employee HR Portal F2009	Information Technologies	$ 70	$ 70	
Withdrawn Projects				
B2B Record Management F2009	Information Technologies	$ -	$ 250	
PI Server Upgrade F2009	Control Center Technologies	$ -		
CROW Sustainment F2009	Control Center Technologies	$ -		
Control Center Minor Capital F2009	Control Center Technologies			
ANNSTLF Automation Upgrade F2010	Control Center Technologies	$ -		
Load Allocation Upgrade F2009/10	Control Center Technologies	$ -	$ 100	$ 200
EMS custom enhancements development/production infrastructure F2010	Control Center Technologies	$ -		
PI return to historian role F2009/10	Control Center Technologies	$ -	$ 50	$ 200
Real Time Ops DataMart and Reporting F2010	Control Center Technologies	$ -		
DCM migration to EMS for Compliance F2009	Control Center Technologies	$ -	$ -	
WIT reporting via EIDE F2009	Control Center Technologies	$ -		
Knowledgement Management for RTO F2010	Control Center Technologies	$ -		
Data Fault Recorder Replacement F2009	Information Technologies			
AMP Upgrade F2009	Information Technologies			
BCTC - BCH data exchange F2010	Control Center Technologies	$ -		
TNO SUN servers Upgrade F2009	Control Center Technologies	$ -	$ 250	
ARIS Replacement F2009	Information Technologies			
Ceridian Upgrade/Replacement F2009	Information Technologies			
Electronic White Board F2009	Facilities			
IPS/IDS + Anti-virus Strategy F2009	Information Technologies			
NAC (Network Access Control) F2009	Information Technologies			
Technical Compliance Expansion F2009	Information Technologies			
Share Service Migration F2009	Information Technologies			
Operation Enhancement F2009	Control Center Technologies	$ -	$ 100	
Enterprise PM	Information Technologies			
Financial Systems Enhancements	Information Technologies			
DMS F2009 and F2010	Information Technologies	$ -	$ 500	$ 3,500

7.5 BCTC Capital Portfolio Descriptions

7.5.1 Information Technology Projects for Approval

Information Technology (IT) assets are used to support the efficient and effective operation of BCTC's business processes. There are two categories of IT assets:

(a) Enterprise IT; and

(b) Business Support Systems.

Enterprise IT includes common or shared enterprise applications and supporting hardware that is designed to support all business functions, processes and departments. Examples of Enterprise IT include:

(a) Microsoft Exchange/Outlook e-mail system;

(b) Microsoft SharePoint collaboration system;

(c) Personal computers (desktops and laptops); and

(d) Corporate infrastructure.

Business Support Systems are systems designed to support a specific business process. These systems include software applications and supporting servers, data storage and backup systems. Examples of business applications include:

(a) Financial Systems Program (FSP);

(b) Reliability Data Management System (RDMS);

(c) Asset Management Program (AMP); and

(d) Transmission Scheduling System (TSS).

Projects in the Information Technology program are discussed in the following sections.

7.5.1.1 AMP Server Refresh F2010

"Refresh" refers to a lifecyle replacement of hardware with a repeating pattern of replacements.

Total Capital Cost: This is a new project for approval. The total capital cost is estimated to be $225K (all in F2010).

Priority Ranking: 7 Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2010 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2009 for completion on or before 31 March 2010.

Description

Refresh the six servers that support Asset Management Program (AMP) applications to avoid unplanned outages, failures and obsolescence, and address increased capacity and performance requirements.

Justification

Six servers are used to support Meridium, an analytical tool used in BCTC's AMP to evaluate the performance of transmission assets, and Project Execution, a reporting and monitoring tool used for capital project reporting.

BCTC plans the replacement of application servers every five years to avoid unplanned outages, failures and obsolescence, and to address increased capacity and performance requirements. This replacement strategy is based on:

(a) Standard industry practices;

(b) A supporting study conducted by Gartner Group, an eminent technology research organization that recommends replacing servers every 5 years; and

(c) Increased support costs. Accenture Business Solutions for Utilities (ABSU), BCTC's contracted IT service provider, has indicated that support costs would increase if BCTC lengthened the current server replacement schedule.

(d) Lack of warranty and support. When equipment fails at this stage, compatible replacement parts will be difficult to locate. In the absence of replacement parts, this would force an upgrade to the hardware, the operating system, and also the application for compatibility reasons. Incompatibility issues will prolong the outage and pose additional and preventable project risks.

The servers supporting the AMP applications were purchased in late F2004. In keeping with the BCTC server replacement cycle of five years, the AMP servers are due for replacement in F2010.

Review of Alternatives

BCTC assessed and rejected deferring the server replacement, which BCTC believes is not acceptable due to the length of interruption for users and impact on decision-making.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.[12]

Related / Dependent Projects

There are no dependent projects.

7.5.1.2 B2B (Business to Business) Portal F2009

Total Capital Cost: This is a new project for approval. The total capital cost is $467K.

Priority Ranking: 14 Accuracy of Estimate: ± 10%

In-Service Date: 01 May 2008 Definition Phase: 100% complete

Schedule: This project is scheduled to be complete on 1 May 2008.

Description

Implement a Business to Business Portal to allow external service providers and contractors to share and maintain project data with BCTC.

Justification

Starting in F2008, the Growth portfolio of BCTC's Capital Plan increased significantly. To address the increase in volume of work, BCTC's project execution strategy requires contractors, in addition to BC Hydro, to provide project engineering and team resources. As a result, data needs to be shared between BCTC and non-BC Hydro service providers and contractors in an effort to monitor, manage and execute these projects.

[12] Risk levels are described in the BCTC Project Risk Matrix located in Appendix D.

Since many of the projects are planned and executed outside of the Lower Mainland and some service providers are located outside of BC, the contractors need a method to remotely submit their project data and documentation in a timely manner and, at the same time, access project statistical reports to monitor their projects. The existing Virtual Private Network (VPN) based solution allows authorized project consultants remote access to BCTC's network to communicate project data and documentation. However, VPN requires considerable manual processing in order to update project data flow between BCTC systems and the external engineering consultants, which has caused significant issues and delays in managing BCTC's projects.

A Business to Business internet portal is proposed that will provide contractors with the ability to enter and retrieve data associated with their projects in an efficient manner while ensuring security measures and controls are in place so that authorized contractors have access to only their own data. This project will assist BCTC in implementing its project execution efficiency with external service providers.

Review of Alternatives

The alternative of doing nothing was also assessed. Doing nothing would require continuing with the VPN solution, in combination with a manual process to exchange data. In addition to being labour intensive, this would result in higher costs and inefficiencies from data errors. For instance, the VPN solution does not allow external contractors to access BCTC project management applications. As a result, BCTC staff must retrieve information that contractors post to a Sharepoint site, and then re-enter the data into the relevant applications. It was estimated that at least two additional FTE BCTC resources would be required to handle the increased data flow between BCTC systems and the external engineering consultants. The approximate cost to have two FTE resources performing the work would be $148K per year. Consequently, the do nothing alternative is not recommended.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.3 Data Centre Redundancy F2009 and F2010

Total Capital Cost: This is a new project for approval. The total capital cost is estimated to be $3,412K ($1,738K in F2009 and $1,674K in F2010).

Priority Ranking: 9 Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2010 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

Develop a backup and disaster recovery system at the third party site that BC Hydro is currently implementing to mitigate BCTC's risk associated with hardware and software failures.

Justification

In the F2008 Capital Plan, BCTC identified a future IT project titled, "Disaster Recovery". This project is now being submitted for approval. BCTC also applied for Commission approval of a Backup Environment Separation – Edmonds project[13] to establish a BCTC backup data system separate from BC Hydro.

In its F2008 Capital Plan Decision, the Commission rejected the proposed project and issued Directive 33:

The Commission Panel finds that the requested F2008 capital expenditures for the BCTC Capital Information Technology projects, except for the Corporate Network Segmentation project and Backup Environment Separation project, are in the public interest, and directs BCTC to investigate the cost of a secure IT environment integrated with BC Hydro's IT systems. If BCTC is unsuccessful in negotiating the security it believes it needs within BC Hydro's IT system, BCTC is directed to report on the efforts made to reach an agreement with BC Hydro in the next capital plan. In the report, BCTC should describe its concerns about BC Hydro's IT systems, provided that

[13] F2008 Capital Plan, pages 216 to 218.

it is not necessary to disclose confidential negotiations or commercial interests to do so.

At the time of the previous submission, there was a clear indication from BC Hydro that BCTC should have a separate disaster recovery infrastructure as the aging BC Hydro infrastructure could no longer support BCTC applications. Since then, BC Hydro has made significant progress in its project for backup and disaster recovery, allowing BCTC to consider the alternative of an integrated disaster recovery solution in its analysis.

The need for a disaster recovery solution arose when BCTC identified a gap in its current disaster recovery capabilities. BCTC is exposed to risk of data loss and security issues if the BCTC/BC Hydro shared data centre, accessible to BCTC on the shared BC Hydro corporate Wide Area Network, becomes unavailable. Recognizing that there was a gap in the current disaster recovery capabilities for corporate systems, BCTC had ABSU complete a study to review BCTC's existing software applications, identify the systems presenting the most risk through a Business Impact Analysis, define alternative recovery strategies, and perform an analysis regarding the need for and location of a primary and secondary data centre.

ABSU's Business Impact Analysis concluded that the business processes supported by key business applications could not sustain extended outages (beyond 24 to 48 hours), and that it would take weeks to recover based on current technologies and processes. An outage of four weeks of these key applications could have an estimated negative financial impact of $33 million as well as a significantly negative impact on the reputations of BCTC, BC Hydro and the government, as it could impact BCTC's ability to expediently recover the transmission system.

Working with BC Hydro, BCTC has determined that the new backup system and third party site being commissioned by BC Hydro will be capable of accommodating BCTC applications. BCTC will leverage the third party site as a secondary facility and use the shared data centre and the Fraser Valley Office as its primary facilities. This will allow BCTC to use BC Hydro's backup system, where technically feasible, and continue its use of the Wide Area Network. To compensate BC Hydro, BCTC will assist with incremental costs.

The project will include migrating BCTC's application data onto higher availability storage for improved reliability and recovery time; replacing the existing tape backup infrastructure for a virtual tape solution; and creating redundancy on high exposure systems (MS Exchange, Blackberry, Oracle, File/Print) at a second site using infrastructure built to accommodate future needs.

This alternative leverages the joint ABSU relationship, the shared Wide Area Network and BC Hydro's third party disaster recovery site. Additionally, it is the most cost effective alternative, has the fastest implementation time, and offers a suitable level of control. BC Hydro is a key partner in this initiative and agrees with the direction.

Additional information on BC Hydro's direction for IT disaster recovery programs is described in the BC Hydro F2007/2008 Revenue Requirement Application Volume 1 of 3, Exhibit B-5-1, on page 5-38 as follows:

> Disaster Recovery Program addresses the need for BC Hydro to develop the resources, architecture and implementation plan of an IT recovery site in case of major disasters affecting the technical infrastructure that may impede or limit the ability of BC Hydro to conduct business and provide reliable customer service. The business drivers are business continuity and reduced business risk. The major cost is the purchase of additional backup computer hardware. The U.S. Patriot Act has seen a need for the broader public sector to review their backup and recovery plans and develop Canadian solutions as most backup facilities, including BC Hydro's, were situated in the U.S. The changes to the BC Hydro infrastructure, from mainframe-based to client-server, are now complete and the current disaster recovery solution, which was focused on the mainframe, needs to be upgraded to ensure BC Hydro has an adequate disaster recovery capability.

<u>Review of Alternatives</u>

The do nothing alternative was not considered viable as a result of the substantial negative impact, both financially and to the reputations of BCTC, BC Hydro and the government. Two other options were assessed:

(a) Using the Fraser Valley Office and the shared data centre as primary facilities and establishing the Southern Interior Office as the secondary facility at a capital cost of $4.9 million; and

(b) Moving all BCTC systems from the shared data centre to the Fraser Valley Office as the primary facility and establishing the Southern Interior Office as the secondary facility at a capital cost of $5.0 million.

These options were rejected due to their high capital costs, which are estimated at almost $1.5 million more than the preferred alternative.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

This project is dependent on the successful implementation of BC Hydro's Disaster Recovery Project. BCTC is closely monitoring the progress of the BC Hydro project; currently, the project is on schedule and completion by BC Hydro is expected in F2008.

In BCTC's F2008 Capital Plan, this project was described as also being dependent on the Corporate Network Segmentation project. Through further project definition, it has been determined that these projects are not dependent on each other and that they can be implemented separately.

7.5.1.4 E-Business Financial Upgrade F2009

Total Capital Cost: This is a new project for approval. The total capital cost would be $924K (all in F2009).

Priority Ranking: 13 | Accuracy of Estimate: ± 10%

In-Service Date: 31 October 2008 | Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Upgrade BCTC's financial systems to address vendor support issues and implement the Business Intelligence module to improve information quality, reporting delivery and access to financial information.

Justification

The Oracle e-Business Suite includes General Ledger, Accounts Payable, Accounts Receivable, Cash Management, Internet Expenses, Purchasing, iProcurement, Project Accounting, Enterprise Asset Management and associated tools, as part of the Oracle product family, such as Oracle Discoverer, Oracle Report Builder, and Application Desktop Integrator. BCTC implemented Oracle Version 11.5.9 in 2005 to support BCTC operations as a regulated utility. Oracle has published that the support for patches and bug fixes for Version 11.5.9 will no longer be available as of June 2008. Additionally, BCTC's current versions of Discoverer 4i and Application Desktop Integrator 7.1 are no longer supported by Oracle.

BCTC recommends upgrading applications to Version 11.5.10.2 in order to maintain vendor support. Known functionality bugs and security vulnerabilities would be resolved, and the upgraded version would provide a more stable platform for financial application and reporting. The plan to upgrade to Version 11.5.10.2 would take place by applying a series of patches to the existing system staring in F2008 and completing in F2009. Critical security patching to this version to correct software bugs began in F2008 as part of the 'Financial Systems Program (FSP) Minor Enhancements' project that was approved in BCTC's F2008 Capital Plan. Completion of the full upgrade is proposed to be completed under this project in F2009; there are no current plans to replace the system.

Along with the upgrade of the Oracle financial system, Business Intelligence applications will be implemented to improve reporting and data quality and provide centralized access to financial information for managing BCTC Capital and OMA programs. Currently, BCTC uses ad-hoc reporting with manual processes to reconcile reports from various different systems such as the Asset Management Program (AMP), Project Management (InfoPM), Oracle, Transmission Investment Planning

(TIP), Cognos, to ensure data is accurate. A Business Intelligence tool would eliminate the manual processing while ensuring data accuracy.

Review of Alternatives

BCTC assessed and rejected deferring the Oracle upgrade. Once Oracle ends support for BCTC's current version of Oracle, the asset health of the Oracle e-Business Suite is greatly decreased as the application becomes susceptible to higher outage time and the potential for bugs that cannot be fixed.

BCTC also assessed upgrading directly to Release 12 of the Oracle e-Business Suite. Currently there are no known companies within Canada or the US that have successfully upgraded to Release 12 and companies are holding back until the Release 12 suite is stable and justifiable. This alternative was therefore rejected.

BCTC also does not recommend replacing Oracle with another vendor system. Substantial new customized modules would need to be created in a new vendor system in order to replace the current system. The total cost and risks would likely exceed the initial implementation of the current system. Hence this alternative was rejected.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.5 Enterprise Server, PCs, Printers and Peripherals F2010

Total Capital Cost: This is an ongoing project that was most recently approved by the Commission in Order G-69-07 for $357K and $561K in F2008 and F2009 respectively. BCTC is seeking additional funding for $469K (all in F2010).

Priority Ranking: 8 Accuracy of Estimate ± 10%

In-Service Date: 31 March 2010 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2009 for completion on or before 31 March 2010.

Description

Replace five servers, 149 desktops, 82 laptops, five printers and one storage system to avoid unplanned outages, failures and obsolescence and address increased capacity and performance requirements.

Justification

BCTC currently owns sixteen Enterprise Technology computer servers. These include email exchange, file/print and SharePoint servers. BCTC also owns a large number of personal computers (PCs) and peripherals, such as printers and storage devices. These assets support personnel productivity.

BCTC's policy is to replace servers every five years, desktop PCs every four years, laptop PCs every three years, and printers, storage and peripherals on an as-needed basis to avoid unplanned outages, failures and obsolescence, and to address increased capacity and performance requirements. This replacement strategy is based on:

(a) Standard industry practices;

(b) A study conducted by Gartner Group;[14] and

(c) Increased support costs. ABSU, BCTC's contracted IT service provider, has indicated that support costs would increase if BCTC lengthened the replacement schedule.

Extending the refresh cycle would also be in violation of BCTC's current support agreement with ABSU.

[14] A study by the Garner Group dated March 2006 entitled, "How Long Should Organizations Keep Their PCs?" recommends replacement ages of three years for laptops and four years for most desktop PCs.

Review of Alternatives

BCTC assessed and rejected the alternative of only replacing computer equipment when it fails or when performance requirements necessitate the need for replacement. This reactive approach to equipment replacement is not recommended due to the high impact of outages to BCTC businesses. A server equipment failure can lead to a productivity reduction equivalent to $191K.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.6 Financial System Sustainment Project F2009 and F2010

Total Capital Cost: This is an ongoing project that was most recently approved in the Commission's F2008 Capital Plan Decision. BCTC is seeking additional funding of $1,226K ($632K in F2009 and $594K in F2010).

Priority Ranking: 21 Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2009 and 31 March 2010 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

This project is designed to enhance financial systems, financial reporting and regulatory reporting tools to improve budgeting functionality; develop new work tracking and cost management reports to allow improved project monitoring; and replace applications lacking vendor support.

<u>Justification</u>

BCTC has implemented the basic financial infrastructure and systems necessary to ensure its financial data is centralized and accurate. This project addresses the ongoing need to improve business reporting using existing financial systems, as well as replacing some financial systems that are no longer supported.

From time to time, BCTC recommends reporting changes to the financial system to help meet internal BCTC needs. For example, new reports to track work and cost management related to Transmission Lines capital, OMA and Vegetation OMA will provide additional information to assist BCTC in making decisions in an efficient and timely manner. In other cases, changes from business, regulatory, auditors, government and industry can necessitate enhancements to applications.

The Accounting Standards Board of Canada (AcSB) has declared that Canadian GAAP (Generally Accepted Accounting Principles) will converge with International Financial Reporting Standards (IFRS) for financial reporting purposes, to be fully implemented in 2011. This convergence implementation would be effective for BCTC’s F2012 financial statements. As the Business Transparency and Accountability Act (BTAA) and the Crown Agencies Secretariat Guidelines for Crown Corporations require BCTC to prepare financial statements in accordance with GAAP, BCTC will be required to prepare its financial statements using IFRS for F2012. This project does not include changes to financial systems that are anticipated for the convergence to IFRS. An assessment of system enhancements and changes will be done in F2009 for IFRS convergence. Once this assessment is completed, BCTC plans to submit a funding request for the required system enhancements and changes.

Additionally, BCTC’s policy is to replace systems that are no longer supported. Maintaining a stable vendor-supported system will enable BCTC to address functional problems, meet new requirement changes, and handle new security vulnerabilities that may cause prolonged system outage time. The Cash Management and Treasury System requires replacement, as the vendor no longer sells nor supports this system.

The Transmission Investment Planning (TIP) tool for Capital Project Planning and the Investment Justification (IJ) tool used for documenting project justification and facilitating the approval process are internally developed systems. BCTC business requirements have outgrown the database storage capabilities of these systems and therefore they will need to be upgraded.

Review of Alternatives

Deferral of this project was considered and rejected as BCTC's financial systems would not be able to meet the increasing business requirement to address data integrity, reconcile reports, meet business deadlines, and comply with regulatory enforced changes. Furthermore, unsupported systems pose a high risk of long duration outages of the financial system. For these reasons, BCTC believes that the deferral alternative is not acceptable.

BCTC also does not recommend replacing Oracle with another vendor system. Substantial new customized modules would need to be created in the other system in order to replace the current system. The total cost and risks would likely exceed the initial implementation of the current system. Hence this alternative was rejected.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.7 HR/Payroll Sustainment F2009 and F2010

Total Capital Cost: This is an ongoing project that was most recently approved in the Commission's F2008 Capital Plan Decision. BCTC is seeking additional funding of $329K ($223K in F2009 and $106K in F2010).

Priority Ranking: 11	Accuracy of Estimate: ± 10%
In-Service Date: 31 March 2010	Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

This project is to replace the existing payroll / Human Resource Information System (HRIS) solution with a new Ceridian end-to-end payroll/HRIS solution. The project will address the expiration of the existing Ceridian payroll/HR contract in April 2008 under which Ceridian uses an HRIS solution provided by ASL Consulting. The ASL solution is no longer provided by Ceridian.

Justification

During F2005 and F2006, BCTC engaged Ceridian to host a payroll/HRIS solution under an Application Service Provider arrangement. Ceridian subcontracted ASL for use of its HRIS system. There were significant growing pains in the first two years of this contract and BCTC had to work diligently with Ceridian to resolve numerous issues related to the Ceridian / ASL interface, Ceridian staff turnover, and a lack of understanding of BCTC's processes.[15] Ceridian has overcome some of these issues by dedicating staff to the BCTC account and also by gaining and documenting processes.

To help address these issues, BCTC hired a full-time payroll administrator in September 2006 and a consultant to manage the payroll function. With the efforts of all involved, the current state of payroll and Human Resource Administration is stable. However, the current Ceridian payroll/HR contract will end in April 2008.

Ceridian has indicated that they are no longer willing to provide BCTC with the HRIS service that they have outsourced from ASL. Ceridian has proposed instead to provide their own in-house HRIS, which BCTC believes is a more robust and cost-effective system rather than managing Ceridian and ASL contracts separately. The current solution from ASL was customized for BCTC whereas Ceridian offers an established HRIS system with a larger user base.

BCTC recommends implementing the new HRIS with Ceridian as BCTC believes this will provide a more stable and reliable payroll process and improved flexibility to accommodate ongoing changes, including collective bargaining changes, job changes, and shift schedules. BCTC also believes that the use of this more robust HRIS would

[15] See, for example, page 232 of BCTC's F2008 Capital Plan.

free up the Payroll Administrator and HR staff to perform more value-added analysis, respond to customer service requests, and reduce the requirement for external consultants. The estimated financial benefits are:

(a) Direct cost avoidance of $15K per year resulting from the avoidance of consultant fees; and

(b) Personnel efficiency savings across the company of $100K per year in cost avoidance. HR, Time Reporting and Payroll Administration staff will be able to direct more resources towards value-added customer service and analyses work, rather than trouble-shooting and resolving system issues.

Review of Alternatives

As Ceridian is terminating services from ASL, a do-nothing approach is not possible. The alternative of contracting ASL directly for its HRIS system is not recommended as this option creates more contractual difficulties to manage two service providers and more difficulties in sorting out system problems. An end-to-end one-supplier system such as one offered by Ceridian would be a more robust solution. Ceridian has a larger user base for long term viability.

BCTC also does not recommend replacing Ceridian with another service provider. The existing Ceridian system has been configured and customized to BCTC's unique requirements. As well, Ceridian has now developed a fairly extensive knowledge of BCTC's processes. Changing to a new service provider would require time and effort to customize and configure the new system. There will also be a learning curve requirement for the new service provider to gain the same level of knowledge on BCTC processes. Consequently, the costs and risks would be higher than the recommended alternative. Hence, this alternative was rejected.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.8 Identity and Access Management F2009 and F2010

Total Capital Cost: This is a new project for approval. The total capital cost is $1,201K for F2009 and F2010 ($622K in F2009 and $579K in F2010).

Priority Ranking: 16 Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2010 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

This project is to implement an Identity and Access Management system that is an authoritative source for employee and contractor identification, allows for single-sign-on and password self-service, and improves and automates user administration processes.

Justification

In August 2007, an independent assessment was completed by Deloitte & Touche LLP that analyzed the risks and challenges associated with managing access to IT systems (referenced as Identity and Access Management) at BCTC and to develop a strategy for reducing these risks. BCTC recommends the implementation of the Identity and Access Management system as proposed by Deloitte. The proposed system addresses the following issues:

(a) Security compliance with regulations, legislation, BCTC policies and industry best practices, in particular NERC's Critical Infrastructure Protection standard. Currently, BCTC has difficulty enforcing passwords in accordance with NERC's standard effectively for some Critical Cyber Asset systems. BCTC can meet the mandatory requirement using manual processing, but this is risky and prone to error.

(b) Security risks. BCTC recognized that there were deficiencies in the employee departure processes as well as the strength of passwords. To address this, user access would be automatically deactivated or removed from systems when employees and contractors stop working for BCTC and password strengths would be enforced through the solution of a single-sign-on concept. Each user would be given one username and one password to grant them access to all applications they are authorized to use. With the new system, the right people would be granted access at the right time to applications based on their predefined role, without the potential for manual errors.

(c) Overall efficiency and productivity. The current system requires manual activities and processes (including multiple setups for email, personal folders, department folders, special applications, and password resets) thereby delaying access to technology for new employees. With the proposed system (including a single user identification and password setup), new employees would automatically receive prompt access to the technology from the day they start so they can be productive immediately. Reduced administrative and manual activities would also save effort and costs, while reducing the risk of errors.

BCTC proposes to implement this solution by using BC Hydro's identity management infrastructure. BC Hydro has agreed to BCTC's use of its infrastructure.

Review of Alternatives

The following solutions were assessed and rejected:

(a) Do Nothing. In this alternative, BCTC would not implement an identity management solution. This is not recommended since BCTC would not be able to address the security and compliance risks and deficiencies in complying with NERC's Critical Infrastructure Protection standard, nor be able to capitalize on productivity and efficiency benefits.

(b) Implement an identity management solution by leveraging BC Hydro's identity management infrastructure, but using separate servers. This alternative was rejected as the additional costs compared to the preferred alternative are $685K over a five-year period. There is no justification for the additional costs.

(c) Implement an identity management solution using a technology other than BC Hydro's. This alternative was rejected as it would be $799K more costly over a five year period. There is no justification for the additional costs.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependant projects.

7.5.1.9 Laptop, Desktop and Removable Media Encryption F2009

Total Capital Cost: This is a new project for approval. The total capital cost is $265K (all in F2009).

Priority Ranking: 2 Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2009 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Implement encryption software to protect the information that resides on laptops, desktops and removable media (e.g., USB devices or CDs).

Justification

Any lost or stolen mobile or removable media equipment creates a risk that confidential BCTC information will be released. Therefore, while BCTC's first objective is to prevent the loss and theft of equipment, precautions must be taken to mitigate against the risk of the release of confidential information should such an incident occur. Other organizations have suffered from the release of confidential information due to the loss and theft of laptops, desktops and removable media resulting in damage to public relations and public image, cost of replacement of missing information, and other consequences. If the equipment contains information on critical cyber assets[16] this can be used to gain access to those assets and pose a risk to system reliability and security. In addition, NERC's-Critical Infrastructure Protection standard requires the protection of critical cyber asset information and the Electric

[16] See NERC for definition of Critical Cyber Assets This definition can be found at www.nerc.com

Sector Information Sharing and Analysis Centre (ES-ISAC) has advised laptop encryption to protect critical cyber asset information. Hence, this project is considered necessary to comply with NERC-CIP requirements.

Currently, BCTC does not have encryption technologies activated for laptop, desktop and removable media. To reduce the risk exposure from the loss or theft of laptops, desktops and removable media and to adequately comply with NERC-CIP requirements, BCTC proposes to implement encryption software to protect the information that resides on laptops, desktops and removable media. This will allow the Windows encrypting file system for laptops and desktops, currently used voluntarily by users, to be enforced. A third-party software would be implemented for encrypting removable media.

In F2008, BC Hydro is planning to implement a Windows Encrypting File System in an enforced format. BCTC proposes to use BC Hydro's Encrypting File System server infrastructure, lessons learned and methods used from their implementation.

<u>Review of Alternatives</u>

The alternatives of a full disk media encryption along with status quo were considered. The option to implement a full disk media was rejected due to the additional $400K cost over the recommended solution. BCTC does not recommend continuing with the status quo since adequate controls are not in place to comply with requirements such as NERC CIP, nor follow Electric Sector-Information Sharing and Analysis Centre advisories. In addition, the risk of the release of confidential information would not be addressed.

<u>Project Risks / Impacts</u>

There are no high or extreme implementation risks for this project.

<u>Related / Dependent Projects</u>

The preferred option will be implemented after BC Hydro has implemented the enforcement of the Windows Encrypting File System, planned for late F2008 or early F2009.

7.5.1.10 Market Operations Workflow SGIP Sustainment F2009

Total Capital Cost: This is an ongoing project and was most recently approved in the Commission's F2008 Capital Plan Decision. BCTC is seeking additional funding for $106K (all in F2009).

Priority Ranking: 22 Accuracy of Estimate: ± 50%

In-Service Date: 31 March 2009 Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Enhance the Standard Generator Interconnection Procedures (SGIP) Workflow System to align with BCTC's Competitive Electricity Acquisition Process (CEAP) tariff and add enhancements for undefined future changes. The Commission has approved the CEAP tariff and this tariff came into effect July 1, 2007.

Justification

The SGIP section of BCTC's OATT prescribes the process for generator interconnections. This process includes numerous steps and milestones that need to be achieved by both the interconnecting customer and BCTC. BCTC is responsible for posting and maintaining a queue position of all interconnection projects. To meet tariff obligations, the SGIP Workflow System was developed and implemented to take the place of the manual process, which was previously used.

The SGIP Workflow System is an essential system for BCTC to ensure it is meeting its regulatory requirements. Subsequent to the original implementation in F2005, there has been an ongoing need for enhancement and changes to improve system performance and functionality and to keep current with tariff changes. Increasing user knowledge of the System and its capabilities combined with evolving business needs and tariff changes require further enhancements to the SGIP Workflow System. BCTC is unable to predict the specific changes that will be required and, therefore, has estimated the work volume for this project based on historical amounts. The initial implementation cost for SGIP was $404K and the F2008 expenditure is forecast to be $110K.

Review of Alternatives

The do nothing alternative was assessed and BCTC believes this is not acceptable since the current configuration of the system may not support BCTC’s changing business processes and may adversely affect BCTC’s ability to meet tariff obligations and capture future productivity gains given historically that tariff changes require system changes.

Project Risks / Impacts

There are no high or extreme execution risks related to this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.11 Mobile Station Inspection Enhancement F2009 and F2010

Total Capital Cost: This is an ongoing project that was most recently approved in the Commission’s F2008 Capital Plan Decision. BCTC is seeking additional funding for $286K ($143K in F2009 and $143K in F2010).

Priority Ranking: 19 | Accuracy of Estimate: ± 30%

In-Service Date: 31 March 2010 | Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

This project is to add asset health data collection capability and Maintenance Standards for Telecom, Telecontrol, and Protection and Control equipment condition records to the Substation Mobile Computing System.

Justification

The Substation Mobile Computing System, known as IMAX, is presently used to collect substation asset information; specifically, information specified in BCTC Maintenance Standards for Inspections (STNI), and substation equipment readings specified by BC Hydro Field Operations Service. IMAX is integrated with Indus Passport, BC Hydro's work management application, and ensures that the IMAX asset register is always up to date. IMAX is also integrated with BCTC's Asset Management Project (AMP) system, which allows data gathered from station inspections to be analyzed at the same time as asset information from other sources.

Asset health and condition information is used to predict the future condition and expected life of assets to make the appropriate investment decisions. Presently, a significant number of asset health and condition records are on paper and located in various places throughout the province, limiting BCTC's ability to analyze asset health and plan system investments. These include Telecom, Telecontrol and Protection and Control records.

BCTC is also periodically required to provide updated asset health information to BC Hydro. The Asset Baseline Study performed in 2005 was expensive, in part because of the difficulty in retrieving asset information. Additional discussion with regard to the baseline study is contained in Section 6.1 of the STSR (Appendix B).

This project proposes to enhance IMAX such that asset health information can be collected electronically and centrally stored for Telecom, Telecontrol and Protection and Control assets. This will be accomplished by adding an automated standard process to create and post BCTC Maintenance Standards to IMAX, which will provide the field with instructions for when to collect asset health information, what data to collect, and how to interpret the asset's condition. This IMAX enhancement provides efficient and low cost access to asset information.

In F2008, data collection of asset health information and posting of BCTC Maintenance Standards related to electrical equipment classes, such as circuit breakers, station equipment and reactive equipment, were implemented in IMAX, under the Mobile Applications Enhancement project in the F2008 Capital Plan.[17] The work related to the Telecom, Telecontrol and Protection and Control equipment classes is proposed in F2009 and F2010.

Review of Alternatives

Alternatives assessed included doing nothing, which is not recommended as it limits BCTC's ability to analyze the health of system assets and plan investments accordingly.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.12 Network Segmentation F2009

Total Capital Cost: This is a new project for approval following Commission Decision on BCTC's proposed Corporate Network Segmentation project in the F2008 Capital Plan and the Commission's Direction to investigate the cost of a secure IT environment integrated with BC Hydro's IT systems. The total capital cost is $651K (all in F2009).

Priority Ranking: 20 | Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2009 | Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Implement a set of firewalls at BCTC Corporate Headquarters and the shared data centre to segment BCTC applications and data on the shared Wide Area Network.

[17] F2008 Capital Plan, page 236.

Justification

In the F2008 Capital Plan, BCTC applied for Commission approval of a Corporate Network Segmentation project.[18] In its Decision, the Commission rejected the project and issued Directive 33:

> The Commission Panel finds that the requested F2008 capital expenditures for the BCTC Capital Information Technology projects, except for the Corporate Network Segmentation project and Backup Environment Separation project, are in the public interest, and directs BCTC to investigate the cost of a secure IT environment integrated with BC Hydro's IT systems. If BCTC is unsuccessful in negotiating the security it believes it needs within BC Hydro's IT system, BCTC is directed to report on the efforts made to reach an agreement with BC Hydro in the next capital plan. In the report, BCTC should describe its concerns about BC Hydro's IT systems, provided that it is not necessary to disclose confidential negotiations or commercial interests to do so.

Since then, BCTC has worked with BC Hydro to identify an integrated disaster recovery solution (refer to section 7.6.1.3 'Data Centre Redundancy F2009 and F2010' for further details). This new integrated solution for the Data Centre Redundancy project compliments BCTC's preferred alternative for the Network Segmentation project which continues to use BC Hydro/BCTC's shared common network infrastructure to achieve overall cost-efficiencies. However, with this project, BCTC proposes to implement a set of firewalls and related network equipment to segment BCTC's application and data on the shared network infrastructure to ensure security strategies are met for BCTC.

The need for this project initially arose as a result of BC Hydro's initiative to segment the common network infrastructure, driven by security risks and industry best practices. This segmentation included Powerex and Power Tech in F2008. BCTC's preferred alternative is to implement firewalls at BCTC Corporate Headquarters and the shared BCTC-BC Hydro data centre. This alternative has been approved by BC Hydro and is supported by:

(a) BC Hydro's overall strategy; and

[18] F2008 Capital Plan, pages 220 to 221.

(b) BCTC's security direction in addressing security risks.

This solution is expected to improve BCTC's ability to prevent unauthorized activity over the network; increase the ability to efficiently monitor system activities and contain incidents to selected parts of the network; enable BCTC to implement a defence-in-depth cyber security strategy (implementing layers of controls to ensure that the failure of one layer does not result in compromising the entire network); improve network performance; and allow for future growth.

The preferred alternative also offers functions that can be leveraged in the future, including Voice over Internet Protocol (VOIP), Video and Wireless, and will establish the foundation for enhanced network controls to reduce the risk of information loss and system outages that could impact commercial customers.

As the security program is driven by balancing risks and costs, monetized benefits associated with risk mitigation are difficult to forecast. Expected efficiency savings from redeploying resources over five years are $1 million and include cost reductions related to incident investigations and clean-up, as well as future savings expected from more efficient deployment of planned security monitoring, including intrusion prevention/detection and network access controls.

In addition, there will be a reduced risk for security breaches. Based on the business impact study completed by ABSU, the impact of a week's outage of the twelve most important BCTC systems on the corporate network is estimated at $9.4 million to $11.5 million. Although some systems may be brought back sooner than one week, others may take longer than this. In addition, there is a further group of over 80 applications that was not captured as part of the impact estimate.

Review of Alternatives

BCTC assessed and rejected the alternative of remaining on the BC Hydro network without segmentation. In this alternative, BCTC Corporate Headquarters, as well as BCTC's data centre would continue not to be segmented. BCTC would continue to face significant business risk, as would BC Hydro, because critical BCTC systems and applications share a common corporate network infrastructure with BC Hydro. BC

Hydro's segmentation project for PowerTech and PowerEx does not alleviate this risk for BCTC. Consequently, this alternative was rejected.

<u>Project Risks / Impacts</u>

There are no high or extreme implementation risks for this project.

<u>Related / Dependent Projects</u>

In BCTC's F2008 Capital Plan, this project was described as being dependent on the Backup Environment Separation project. Through further project evaluation, it has been determined that the Network Segmentation project is not dependent on any other projects and can be implemented independently.

7.5.1.13 Reliability and Loss Program Integration F2009 and F2010

Total Capital Cost: This is a new project for approval. The total capital cost is estimated to be $420K ($238K in F2009 and $182K in F2010).

Priority Ranking: 6 Accuracy of Estimate: ± 30%

In-Service Date: 31 March 2010 Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

<u>Description</u>

Integrate five computer programs used to calculate system reliability and loss evaluation into the Reliability Database Management System (RDMS) to improve study turnaround time.

<u>Justification</u>

Reliability evaluation of the electric power system is a fundamental part of the studies conducted by BCTC. These studies are used to identify and plan necessary investments in the transmission system. The Commission F2006 Capital Plan Decision states at page 19, "The Commission Panel commends BCTC for augmenting its deterministic planning with probabilistic and economic assessments and suggests that it look for additional opportunities to do so in the future."

There are five in-house-developed computer programs used by BCTC for calculating system reliability and loss evaluation:

(a) Monte Carlo Evaluation of COmposite system Reliability (MECORE);

(b) Monte Carlo Generation System Reliability (MCGSR);

(c) SPARE, a computing tool for power system component reliability and spare analysis of a component group;

(d) NETREL, a NETwork RELiability program is a tool to calculate availability / unavailability of a network consisting of components in parallel and/or series; and

(e) PLOSS, a power flow based network loss evaluation tool.

Outage and load curve data are the main data required by these programs, but this data is collected and stored in a separate system called the Reliability Data Management System (RDMS). BCTC has been limited in its ability to conduct reliability studies for more capital projects partly because of the difficulties in data file preparation.

The preferred alternative of integrating these programs into RDMS will greatly reduce data file preparation, allowing reliability studies to be conducted more efficiently and on a timelier basis. More reliability studies will provide planners with better information to assess the impact, in terms of reliability improvement, of a proposed project.

Additionally, the PLOSS program is used for system loss evaluation. Integrating this program into RDMS will increase its usability and improve its data quality, thereby contributing to loss evaluation capability.

With BC Hydro expecting more frequent calls for power, the demands on BCTC to conduct studies will increase. Increasing the efficiency of the study process is key to BCTC meeting its tariff obligations and mandate.

Review of Alternatives

BCTC assessed doing nothing, but does not recommend this alternative since data preparation is currently a bottleneck in the number of reliability studies that can be conducted. Additionally, the likelihood of errors during the manual preparation of data may lead to errors in the analysis. Consequently, this alternative was rejected.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.14 Security Information Management F2009

Total Capital Cost: This is a new project for approval. The total capital cost is estimated to be $200K (all in F2009).

Priority Ranking: 18 Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2009 Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Implement the Security Information and Event Management (SIEM) system for the corporate environment (i.e., the enterprise system excluding the control systems) to allow for improved security event monitoring.

Justification

BCTC has acquired a SIEM system for Critical Cyber Assets as part of the NERC Critical Infrastructure Project, which was approved in Order G-69-07. The system is in the process of being implemented with completion scheduled in March 2008. As part of the project justification for the Critical Cyber Assets, it was highlighted that the SIEM system could be used for the corporate environment as well to collect, analyze and report on system events to allow for timely detection of unauthorized activities, improve efficiencies, and, where possible, limit the security risk exposure. Industry research indicates that 49% of the security incidents related to critical automation systems come through the Corporate/Business networks. Therefore, rolling the SIEM system out to the corporate environment is in line with NERC's direction and BCTC's "defence-in-depth" strategy of implementing layers of controls to ensure that the failure of one layer does not result in compromising the entire network.

Currently, BCTC does not have a mechanism to review security logs on the corporate environment network and, as a result, system logs are only reviewed on an ad hoc basis in response to incidents. Manual review of system logs is practically impossible as BCTC has several million log entries per day. The types of security threats are becoming more sophisticated and targeted. Gartner Group expects that by the end of 2007, 75% of enterprises will be infected with undetected, financially motivated, targeted unauthorized software that evaded their traditional perimeter and host defences.

The proposed SIEM system will process security logs, provide the ability to monitor security activities on the network in real time, and, where feasible, prevent unauthorized activities from occurring.

In addition, there is a reduced outage risk to business resulting from security breaches. Based on an ABSU business impact assessment there could be an impact of $9.4 million to $11.5 million if the twelve most important corporate systems of BCTC were not available for one week. Efficiency savings by redeploying resources of $400K over the first four years are expected due to more efficient identification, investigation and remediation of minor security events.

Review of Alternatives

BCTC also assessed the alternative of doing nothing, which is not viable based on the risk to BCTC's corporate networks. BCTC would not be able to review logs, identify correlations between the million of events per day, and address security threats adequately using the current manual process. Consequently, this alternative was rejected.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

This project is proposed for F2009 based on the assumption that BCTC's Security Information Management system for NERC Critical Infrastructure Protection will be implemented by 31 March 2008, as currently forecasted.

7.5.1.15 SharePoint Version 2007 Upgrade F2009

Total Capital Cost: This is a new project for approval. The total capital cost is $44K (all in F2009).

Priority Ranking: 17	Accuracy of Estimate: ± 50%
In-Service Date: 31 March 2009	Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Upgrade the existing corporate SharePoint infrastructure to SharePoint Server 2007 and Windows SharePoint Services 3.0.

Justification

BCTC implemented the corporate SharePoint Version 2003 system in F2006 to improve collaboration among employees and to facilitate project management processes. The adoption of this version of SharePoint has been extensive and rapid.

Vendor support for this version will end on January 13, 2009. BCTC recommends upgrading applications when vendor support is no longer available to ensure functionality bugs and security vulnerabilities are resolved, and the upgraded version provides a stable platform to continue to support business processes.

The upgrade will also increase personnel efficiency. SharePoint 2007 contains numerous enhancements that BCTC users will benefit from and that will improve collaboration and staff efficiency, including Document Workflow, Item Level Security, Recycle Bin Functionality, new site templates, support for internal blogs[19], and wikis[20], enhanced integration with email and other applications, and an improved user interface.

Review of Alternatives

BCTC also assessed the alternative of deferring the upgrade. However, the end of support for this product version signals that it should be upgraded. By not upgrading, BCTC would not get the benefit of the new enhancements and out-of-the-box functions available in the newer version. In addition, there may be increased costs over time if end users seek to implement these new enhancements and functions in an ad hoc manner in the absence of a consolidated corporate platform. Consequently, this alternative was rejected.

Project Risks / Impacts

There are no high or extreme execution risks related to this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.16 Transmission Scheduling System (TSS) Enhancements F2009

Total Capital Cost: This is an ongoing project that was most recently approved by the Commission in its F2008 Capital Plan Decision. BCTC is seeking additional funding for $106K (all in F2009).

Priority Ranking: 5 Accuracy of Estimate: ± 50%

In-Service Date: 31 March 2009 Study Phase: 100% complete

[19] A blog is a website where entries are written in chronological order and commonly displayed in reverse chronological order.

[20] A wiki is a kind of computer software that allows users to create, edit, and link web pages easily. Wikis help with the collaboration of ideas and projects.

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

This project is to make incremental functional enhancements to the Transmission Scheduling System in response to changing customer needs, regulatory rules and changes in BCTC's operational needs.

Justification

The TSS is a critical business system used by BCTC to schedule transmission service to customers. BCTC is required to maintain and enhance this system on an ongoing basis to keep up with changes in the regulatory environment, maintain operational effectiveness, and meet new customer demands.

Historically, BCTC has made incremental functional enhancements to TSS such as:

(a) Dynamic Scheduling Automation;

(b) NERC Mandatory Reliability Standard changes to E-tagging to improve reliability;

(c) Introduction of the Lower Mainland to BPA Transmission path and additional export capability;

(d) Introduction of the internal path for IPP use of Wholesale Transmission Service (WTS); and

(e) Available Transfer Capability (ATC) and Displacement modifications.

The specific functional enhancements and new technologies required for F2009 cannot be described in detail at this time because changes in customer needs and regulatory rules cannot always be forecast in advance. The amount requested is based on historical experience, but is reduced from the F2008 expenditures in recognition of the Market Operations Business Systems project, which will be raised to replace TSS. Given the Market Operations Business project, BCTC will only make those investments to the TSS which will maintain its functionality until the system is replaced.

Review of Alternatives

If the TSS is not enhanced, BCTC will be unable to satisfy changing customer needs, meet regulatory obligations, and address changes in BCTC's own operational needs. Consequently, doing nothing is not recommended.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.1.17 wesTTrans OASIS Upgrades F2009 and F2010

Total Capital Cost: This is an ongoing project that was most recently approved in the Commission's F2008 Capital Plan Decision. BCTC is seeking additional funding for $151K (with $54K in F2009 and $97K in F2010).

Priority Ranking: 15 Accuracy of Estimate: +10%, -50%

In-Service Date: 31 March 2010 Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

Make minor capital investments as required to maintain Open Access Same Time Information System (OASIS) hardware and network asset health in F2009 and implement a hardware replacement system in F2010.

Justification

The Open Access Same-time Information System (OASIS) is BCTC's main interface for selling transmission services to customers. The OASIS is a critical business system; it is expected to operate 24 hours a day, 7 days a week, and support the generation of revenue for BCTC. BCTC's OATT requires all transmission requests to BCTC for wholesale transmission services to be made on an OASIS System.

BCTC currently shares its OASIS services through the wesTTrans consortium. From time to time, enhancements to OASIS services are implemented to promote the usability of transmission for customers. These investments fall into two categories:

(a) Shared Cost Projects: If a proposal for an OASIS enhancement is supported by a majority of consortium members, it will be implemented, and all consortium members – including BCTC - pay their share of the implementation costs. If a shared cost project is not supported by a majority of the wesTTrans consortium members, then the costs of the project are split amongst the minority members who support the project and are willing to pay the shared cost.

(b) Special projects: If BCTC requests an OASIS enhancement that is not approved by any other consortium members, BCTC is expected to pay the full implementation costs.

Through participating in the wesTTrans consortium, BCTC expects the shared cost to be lower overall. Additionally, transmission customers are provided with common and efficient market interface access to nearly all transmission within the West. In F2009, BCTC proposes to make reasonable provisions for such enhancements, consistent with historical expenditure levels.

In F2010, there will be a major hardware upgrade required to support the existing OATI OASIS system. This work typically comprises upgrading hard drives, firewalls, LAN switches, and communication lines to maintain acceptable performance and to replace failed hardware.

<u>Review of Alternatives</u>

BCTC assessed and rejected the alternative of doing nothing. If BCTC does not make a provision for Shared Cost or Special Projects, BCTC will need to provide its own OASIS to provide similar functionalities expected by BCTC’s customers. A replacement OASIS service provider would require a substantial expenditure, similar to the OATI startup investment in the order of $0.5 million. If a suitable service provider could not be found, then the in-house solution would be over $1 million. In addition, transmission customers will not have a common access to transmission services in the West.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.2 Information Technology Future Projects

7.5.2.1 Asset Management Program Enhancements - Future

Future expenditures will need to be made to renew, replace and enhance the Asset Management Program to maintain its technical health to support BCTC's business operations.

7.5.2.2 Business System Enhancements - Future

The purpose of this project is to periodically upgrade Business System software and associated hardware to maintain its technical health to support BCTC's business operations.

7.5.2.3 Computer Desktop Upgrade - Future

The purpose of this project is to periodically upgrade computer desktop software and associated hardware (e.g., Microsoft Windows and Office).

7.5.2.4 Content Management System Upgrade F2010 - Future

Future expenditures will need to be made to renew, replace and enhance the system management of the content of the internet and intranet.

7.5.2.5 Enterprise Project Management Tool - Future

BCTC is currently using BC Hydro's InfoPM tool for managing projects delivered by BC Hydro staff for BCTC. InfoPM is near the end of its software lifecycle and future expenditures will need to be made to replace this system.

7.5.2.6 Enterprise SAN Refresh - Future

Future expenditures will need to be made to replace the Storage Array Network (SAN) that provides reliable storage to critical enterprise systems.

7.5.2.7 Enterprise Servers, PCs, Printers and Peripherals – Future

The purpose of this project is to periodically replace enterprise servers, PCs, printers and peripherals to maintain their technical health to support BCTC's business operations.

7.5.2.8 FSP Sustainment – Future

For financial reporting purposes, the Accounting Standards Board of Canada (AcSB) has declared that Canadian General Accepted Accounting Principles (GAAP) will be converged with the International Financial Reporting Standard (IFRS) in 2011. This change will require system changes in advance of F2012 to be ready for the implementation deadline. It is anticipated that due to certain differences between current GAAP and IFRS, BCTC may be required to maintain two sets of books: one based on IFRS and one for regulatory reporting. Unlike current GAAP, IFRS does not specifically provide for rate regulated accounting such as BCTC's deferral accounts. This will require ongoing sustainment of the FSP to maintain compliance with these principles and standards in addition to activities started in F2009 and F2010.[21]

7.5.2.9 HR Payroll Sustainment - Future

Over the long-term, future expenditures will need to be made to renew, replace and enhance the HR Payroll System to maintain its technical health.

7.5.2.10 Market Operation Workflow SGIP F2010 Sustainment - Future

Future expenditures will need to be made to renew, replace and enhance the Market Operation Workflow -SGIP System to facilitate future tariff changes.

7.5.2.11 Miscellaneous Enterprise IT Projects - Future

The purpose of this project is to periodically upgrade Enterprise IT software and associated hardware to maintain its technical health.

[21] Section 7.5.1.6 Financial System Sustainment Project F2009 and F2010

7.5.2.12 Market Operations Business System Upgrade F2009 - Future

Future expenditures will need to be made to renew, replace and enhance the Market Operation Business System to maintain its technical health to support BCTC's business operations. This project was originally identified in the F2008 Capital Plan as a F2009 project completing in F2009. Now this project will start in F2009 and complete in F2010. Since the project scope and timing are dependent on the implementation of FERC Order No. 890, and BCTC has not yet determined whether a capital or other solution is preferred, a separate submission will be made for this project.

7.5.2.13 Security Enhancements - Future

Future expenditures will need to be made to renew, replace and enhance the System Security to maintain the security protection and continuity of BCTC's business operations.

7.5.2.14 STARR Upgrade - Future

The System for Transmission Asset Recording and Reporting (STARR) is used to maintain and track deficiencies of Transmission Structures. Additional vegetation information will be added to this system to help manage the maintenance program.

7.5.2.15 Tariff Changes to Market Operations Systems - Future

Future expenditures will need to be made to enhance Market Operation Systems to support future changes to BCTC's tariff.

7.5.2.16 wesTTrans Enhancements - Future

The purpose of this project is to renew, replace and enhance OASIS to meet BCTC's contractual obligations to wesTTrans.

7.5.3 Control Centre Technologies for Approval

Control Centre Technologies assets include:

(a) Two new control centres and five existing control centres;

(b) Telecommunications Network Operations centre;

(c) Dispatch Compliance Management (DCM) system;

(d) Control Room Operating Window (CROW) system;

(e) Power System Safety Protection (PSSP) system;

(f) Site Information System (SIS);

(g) Total Transfer Capability (TTC) system; and

(h) Energy Management System (EMS), comprising software and hardware that controls the transmission system.

The Control Centre Technologies program includes the following four projects:

7.5.3.1 Control Centre Sustainment F2009 and F2010

Total Capital Cost: This is an ongoing project that was most recently approved in the Commission's F2008 Capital Plan Decision. BCTC is seeking additional funding for $234K ($117K in F2009; $117K in F2010).

Priority Ranking: 1 Accuracy of Estimate: ± 50%

In-Service Date: 31 March 2010 Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

<u>Description</u>

This project is to fund emergency equipment replacement at the existing control centres until they are decommissioned and at the new control centres once they are put into service. The existing control centres and the new control centres will be operated in parallel in F2009 during which the systems at the existing control centres will gradually be phased out.

<u>Justification</u>

The equipment at the existing control centres is at the end of its reliable operational life. Due to the SCMP, there are no plans to replace this equipment. However, immediate restoration of unplanned outages is necessary to ensure that transmission system equipment is visible from the control centre (for the safety of field workers working on failed equipment), to maintain reliability of the transmission system, and to comply with NERC reliability standards and other regulatory bodies regarding equipment outage duration. The work level for this project is based on historical experience.

Additionally, although equipment at the new control centre is new and malfunctions will be covered under warranty, a modest budget, based on historical work volume, is allocated in this project to cover any unforeseen emergencies.

Dependant on the timing of the transition to the new Control Centres and the decommissioning of the existing Control Centres, there may be additional expenditures in F2009 and F2010 as part of this project to cover the scope identified above.

Review of Alternatives

No other alternatives were assessed.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

Capital investments on this project for F2009 (and possibly F2010) are related to the SCMP project timeline and it is required to keep the existing control centres functional until the SCMP is fully in service.

7.5.3.2 Control Centre Business Application Enhancement F2009 and F2010

Total Capital Cost: This is a new project for approval. The total capital cost is estimated to be $902K ($265K in F2009; $637K in F2010).

Priority Ranking: 3 Accuracy of Estimate: ± 50%

In-Service Date: 31 March 2010 Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

Implement power system analysis enhancements to applications used by the Energy Management System (EMS) and migrate the BCTC – BC Hydro Generation Interface and NERC and WECC regulatory reporting functions into EMS.

Justification

Due to new transmission additions, transmission reconfigurations and remedial action scheme changes, some existing power system analysis tools used in the control room for operating the transmission system require enhancements to remain effective. A number of these enhancements were identified and will be required once SCMP is in service. The functionality delivered in the new EMS will comprise the vendor's baseline product customized according to specifications. However, to maintain alignment with changes taking place in the electrical industry and new requirements in the operating practices, further enhancements in the functionality are required. A description of the enhancements proposed for F2009 and F2010 follows:

(a) Load Allocation Factors (LAF): LAF is a tool used to model the system, based on historical data, where telemetry is scarce or non-existent. Currently, the LAF lacks maintainability and expandability to meet on-going power system changes. This project will upgrade the LAF tool to address these deficiencies.

(b) Dynamic VAr (DVAR): Overvoltage situations can occur due to disturbances on the network and result in significant damage to substations, generating plants, circuit breakers or transformers; the value of such damage could be well into the millions of dollars. Undervoltage situations, also the result of system disturbances, can result in loss of the system. To mitigate this risk, the implementation of voltage stability monitoring and alarming (Dynamic VAR levels) will be implemented in the new EMS.

(c) Transient Stability Assessment Tool (TSAT): The TSAT models system behaviour after a disturbance, analyses the system, and identifies actions to recover the system from the disturbance. As the configuration of the system changes, the TSAT must be updated to accurately model disturbance behaviour.

(d) State Estimator (SE): The SE tool combines data from system modeling tools with telemetry to estimate electrical parameters. Currently, there is little data for certain areas of the Power system. By adding Automatic Meter Reading, the SE tool will be capable of providing improved modeling of the Power system.

(e) BCTC – BC Hydro Generation Interface: This data interface is currently the Plant Information (PI) system. PI is a data archive and was not built for this purpose. Additionally, it is not backed up at a secondary site. As this data interchange requires high availability infrastructure, the interface will be migrated into the new EMS architecture, which has high availability, reliability and a secondary backup site. Furthermore, at BCTC PI is a main data processor in the Dispatch and Compliance Monitoring (DCM) tool for producing regulatory compliance reports, although compliance reporting is commonly performed in the industry using the EMS. It is expected that utilities on the West Coast of North America with the same EMS vendor will benefit from lower implementation cost for compliance reporting, although this amount has not been estimated. In F2009, this project will migrate the BCTC – BC Hydro Generation interface to a platform based on industry standard protocol (ICCP) used in EMS.

Review of Alternatives

BCTC assessed and rejected the alternative of doing nothing. If the power system analytical tools are not enhanced, they would not be as effective in providing BCTC with secure and reliable operation of its electric system. Also, by doing nothing, BCTC will not take advantage of the suggested migration. It is expected that the cost to address the high availability requirement would be higher in the long term.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

The project schedule is tied directly to the in-service date of the SCMP project.

7.5.3.3 RTO Servers and Infrastructure Refresh F2009

Total Capital Cost: This is a new project for approval. The total capital cost is $854K (all in F2009).

Priority Ranking: 4 Accuracy of Estimates: ± 10%

In-Service Date: 31 March 2009 Definition Phase: 100% complete

Schedule: The project is scheduled for completion on or before 31 March 2009.

<u>Description</u>

Replace 13 computer servers and one Storage Array Network (SAN) that support Real Time Operations (RTO) applications.

<u>Justification</u>

The RTO servers and SAN are responsible for the smooth and reliable operation of the transmission system. These provide additional functionality over and above what the EMS technology provides. Therefore this equipment was not replaced by the SCMP project. The servers are located in the existing control centres and support the following applications: System Management, Plant Information, Telecom Network Operations, Load Allocation Factors, Web Service, and E-Training. The SAN provides high availability disk storage to the PI and Dispatch Compliance monitoring applications.

The servers and SANs recommended for replacement in this project were not included in the SCMP as they were not directly part of the EMS system and these assets were not at the end of their life cycle for server replacement.

BCTC recommends replacement of application servers and SANs every five years to avoid unplanned outages, failures and obsolescence and address increased capacity and performance requirements. This replacement strategy is based on:

(a) Standard industry practices;

(b) Supporting studies done by Gartner Group (referenced above);

(c) Increased server support costs. ABSU, BCTC's contracted service provider, has indicated that support costs would increase if BCTC lengthened the current server replacement schedule; and

(d) Increased SAN support costs. EMC, BCTC's contracted service provider for the RTO SAN, has indicated that support costs would increase if BCTC lengthened the current SAN replacement schedule.

The 13 servers and one SAN supporting the identified RTO applications were purchased in F2004 and earlier. In keeping with the BCTC CTO server replacement cycle of five years, these servers and SAN are due for replacement in F2009.

<u>Review of Alternatives</u>

The other alternative that was assessed and rejected was to do nothing. BCTC believes this is not acceptable due to the increased risk of server and SAN failures, which may result in decreased reliability and productivity and have negative financial impacts. Additionally, some of the RTO servers are classified as Critical Cyber Assets (CCA) under NERC policies because outages on these servers can have safety and reliability impacts for the transmission system. Prolonged outage can lead to actions from supervisory bodies. Consequently, the do nothing alternative was rejected.

<u>Project Risks / Impacts</u>

There are no high or extreme implementation risks for this project.

<u>Related / Dependent Projects</u>

This project is not dependent on SCMP.

7.5.3.4 SIS FileNet Upgrade F2009

Total Capital Cost: This is a new project for approval. The total capital cost is $471K (all in F2009).

Priority Ranking: 12 — Accuracy of Estimate: ± 10%

In-Service Date: 31 March 2009 — Definition Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2009.

Description

Redevelop the existing Site Information System (SIS) to interface with FileNet P8[22]; migrate SIS documents to FileNet P8; and establish the new workflow procedures to keep the system up to date.

Justification

BCTC's SIS is designed to provide quick and easy access to all site/station related documentation. Examples of these documents include maps, operating orders, one-line diagrams, protection information, vegetation management plans, etc. The SIS system is used extensively by BCTC and BC Hydro employees in control centres, head offices and field sites. It is owned and managed by BCTC.

All SIS-related documentation is currently stored in BC Hydro's legacy FileNet system. There are various workflow procedures implemented to ensure that these documents are managed properly (e.g., appropriate updates and approvals before publishing).

BC Hydro is replacing the legacy FileNet system with FileNet P8. Although the existing legacy system is still operational, it is running on obsolete hardware with an increasing likelihood of failure. The server operating system is nearing the end of its extended support phase and the version of FileNet itself is now unsupported by the vendor. BC Hydro has set a final decommissioning date for the legacy FileNet system of April 2009 – assuming that the system does not fail before then.

The preferred alternative is to redevelop the existing SIS system to interface with FileNet P8; migrate SIS documents to FileNet P8; and establish new workflow procedures to keep the system up to date. This will allow continued use of the SIS to find and maintain station information.

[22] Filenet P8 is an Electronic Document Management System.

Review of Alternatives

The do nothing alternative is not considered feasible as it would result in reverting to time consuming manual procedures for finding and maintaining Station Information, which are likely to be unreliable and highly error prone, following BC Hydro's decommissioning of the legacy FileNet system. This would have negative impacts on BCTC's reliability, customer service and environmental metrics, as well as impacting BCTC's ability to meet NERC requirements for providing Operating Orders to control centre staff.

Project Risks / Impacts

The schedule for this project is dependent on the successful implementation of BC Hydro Engineering's Drawing Management redesign process. If BC Hydro's project is delayed, this project will be delayed by the same amount of time.

Related / Dependent Projects

There is some interdependency with BC Hydro Engineering's Drawing Management redesign process, as some of the file types in SIS are drawings managed by BC Hydro. BC Hydro and BCTC need to coordinate the migration of these files with the implementation of the new system for drawing management and the new SIS application. BCTC and BC Hydro are both aware of this interdependency and are committed to working together to ensure a smooth transition.

7.5.4 Control Centre Technologies Future Projects

7.5.4.1 Control Centres Sustainment (Post-SCMP) - Future

Future expenditures will be required to renew, replace and enhance BCTC's Control Centres Technology to maintain the technical and functional health of the applications and building facilities to support BCTC's system operations.

7.5.4.2 CROW Enhancements - Future

Future expenditures will be required to renew, replace and enhance BCTC's Control Room Outage Window (CROW) system to maintain the technical and functional health to support BCTC's system operations.

7.5.4.3 DCM Replacements - Future

Future expenditures will be required to renew, replace and enhance BCTC's Dispatch Compliance Management (DCM) system to maintain the technical and functional health to support BCTC's system operations.

7.5.4.4 PSSP Replacements - Future

Future expenditures will be required to renew, replace and enhance BCTC's Power System Safety Protection (PSSP) system to maintain the technical and functional health to support BCTC's system operations.

7.5.4.5 SIS Sustainment F2010 - Future

Future expenditures will be required to renew and enhance BCTC's Site Information System (SIS) in F2010 to maintain the technical and functional health to support BCTC's system operations.

7.5.4.6 TTC Upgrade F2010 - Future

Future expenditures will be required to upgrade the existing Total Transfer Capability (TTC) assessment package using the new Energy Management System.

7.5.5 Facilities for Approval

Facilities assets are primarily office furniture and equipment, leasehold improvements, telephone and facsimile systems and related facilities infrastructure that support BCTC's business operations.

The Facilities program includes the following ongoing and future projects:

7.5.5.1 BCTC Facilities Enhancements F2009 and F2010

Total Capital Cost: This is an ongoing project that was most recently approved in the Commission's F2008 Capital Plan Decision. BCTC is seeking additional funding for $424K ($212K in F2009 and $212K in F2010).

Priority Ranking: 10 Accuracy of Estimate: ± 40%

In-Service Date: 31 March 2010 Study Phase: 100% complete

Schedule: This project is scheduled to commence on or about 1 April 2008 for completion on or before 31 March 2010.

Description

Replace equipment that has unexpectedly failed and add equipment to address growth resulting from project requirements.

Justification

This project addresses requirements for standard office equipment at BCTC facilities. This includes phones, photocopiers, fax machines, and furniture.

The preferred alternative is to repair and replace equipment when it fails and add equipment as required allowing personnel to increase/maintain efficiency in their work as they perform basic office functionalities. By repairing equipment when it fails, the remaining life of the equipment is extended and further failures may be prevented. When repair isn't possible, replacement of the equipment is necessary since equipment failure can be a potential safety hazard for employees as prolonged periods of working under non-ergonomic conditions can introduce health issues. The work level for this project is based on historical work volume.

Review of Alternatives

The do nothing alternative is not considered feasible as properly functioning equipment is required for the efficient operation of BCTC Offices. Similarly, mandatory upgrades or enhancements required to address safety concerns or changing business needs must also be completed.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects.

7.5.6 Facilities Future Project

7.5.6.1 Facilities Minor Upgrades – Future

Future expenditures will be required to renew, replace and enhance office furniture, telephone and related facilities assets to support BCTC's business operations.

8.0 TRANSMISSION REVENUE REQUIREMENT IMPACTS

PRE-FILED EVIDENCE OF PATTI JER, MANAGER, COSTING AND REGULATORY SUPPORT

BCTC has prepared a forecast of the Capital Plan in-service additions impact on the Transmission Revenue Requirement (TRR). The forecast impact of the Capital Plan in-service additions on the TRR is related to the depreciation expense, financing costs and return on equity associated with the capital projects and programs proposed in the Capital Plan. With the exception of approved CPCN projects for SCMP and VITR and future CPCN applications minor factors that may affect the TRR as a result of this capital plan (e.g., OMA, Grants and Taxes) are not included in this forecast.

The expenditures of the Growth and Sustaining portfolios will impact the BCH Owner's Revenue Requirement, reflecting BC Hydro's capitalization costs as these asset additions are funded and owned by BC Hydro. Expenditures relating to the BCTC portfolio will impact the BCTC Revenue Requirement and reflect BCTC's capitalization costs as these asset additions are funded and owned by BCTC. The BCH Owner's Revenue Requirement and the BCTC Revenue Requirement are components of the TRR.

In consultation with BC Hydro and as directed by the Commission , the forecast reflects the assumption that assets placed in service for the Growth and Sustaining Capital portfolios are financed at 100% debt. The TRR impacts related to assets in service from the BCTC portfolio reflect BCTC's deemed capital structure. The financial assumptions used in the TRR impact forecast are set out in Table 8-1.

Table 8-1. Financial Assumptions for Revenue Requirement Impact Analysis

Line No.	BC Hydro	(a) F2009	(b) F2010	(c) F2011	(d) F2012	(e) F2013	(f) F2014	(g) F2015	(h) F2016	(i) F2017	(j) F2018
1	ROE	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%
2	Blended CDN Long and Short Term Interest Rate[1]	5.19%	5.89%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%
3	Retained Earnings	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
4	Equity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	Debt	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	BCTC										
6	ROE	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%
7	Weighted Average Cost of Borrowing[1]	4.91%	4.95%	4.93%	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%
8	Deemed Equity	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%
9	Deemed Debt	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%

Note 1: BC Hydro and BCTC use the economic planning assumptions provided by the provincial Treasury Board. Finance charges relating to asset additions for Growth and Sustaining Capital Portfolios are calculated based on a blend of the long (64%) and short (36%) term interest rates and for the BCTC Portfolio are based on a the blend of long term and short term interest rates based on BCTC's borrowing forecast.

The forecast TRR impact associated with the Capital Plan additions is shown in Table 8-2. The year-over-year changes are relative to the prior year, beginning with the approved TRR for F2008, and reflect the forecast of asset additions in each year from F2009 to F2018.

Table 8-2. Estimated Capital Plan Impact on TRR

Line No.	Annual Impact - $ millions	BC Hydro Growth	BC Hydro Sustain	BCTC	Total Change	Annual % Change
	F2008 Transmission Revenue Requirement (TRR) - $ millions					**517.9**
		(a)	(b)	(c)	(d)	(e)
1	**F2009**	24.6	9.7	21.6	55.9	10.8%
2	**F2010**	32.0	8.6	(7.5)	33.1	5.8%
3	**F2011**	29.7	7.9	1.5	39.1	6.4%
4	**F2012**	30.4	5.2	1.4	37.0	5.7%
5	**F2013**	23.7	8.9	1.0	33.6	4.9%
6	**F2014**	20.4	11.0	(4.5)	26.9	3.8%
7	**F2015**	48.2	5.1	(0.7)	52.5	7.1%
8	**F2016**	33.8	6.8	(2.4)	38.2	4.8%
9	**F2017**	5.8	7.0	(1.5)	11.3	1.3%
10	**F2018**	5.6	8.7	(0.7)	13.7	1.6%
11	**Cumulative TRR Change over 10 Years:**	254.2	79.0	8.1	341.3	**65.9%**

Note 1: Numbers may not add due to rounding.

Note 2: ( ) = reduction in revenue requirement.

9.0 COMMISSION DIRECTIVES

The Commission issued Directives to BCTC under Order G-69-07 related to BCTC's F2008 Capital Plan Application. These Directives are summarized in a Concordance Table in Appendix A. The Concordance Table also cross-references other sections of this Application that respond to the Commission's Directives.

Of the 44 directives in the Concordance Table, BCTC believes it has complied with 43. It provides status update for the remaining Directive in Section 9.25. Each of the 44 Directives is addressed below.

9.1 Order G-69-07 page 14 Directive 01

> **"The Commission Panel directs BCTC to identify in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and to identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for first contingency events."**

The projects in this Capital Plan that are being proposed to avoid generation shedding for first contingency events are identified in Section 5.7. BCTC will continue to provide this table in future Capital Plans until directed otherwise.

9.2 Order G-69-07 page 14 Directive 02

> **"The Commission Panel directs BCTC to submit with its next capital plan a comprehensive description of the planning assumptions used in the IEP portfolio evaluations, LTAP analysis, and analysis of BC Hydro's NITS application. Future capital plan filings should either re-affirm the previous planning assumptions or describe any changes made to the previously described planning assumptions."**

A description of the planning assumptions used in the IEP portfolio evaluation, in the LTAP analysis, and possibly in the future analysis of BC Hydro's next NITS application was filed with the Commission in BC Hydro's 2006 IEP/LTAP Proceeding as Exhibit B-102, and is filed in this Application as Appendix K. A description of the assumptions used for the planning of the Growth Capital portfolio in this Capital Plan and the changes made to the previously described planning assumptions is provided in Section 4.6.2.3.

BCTC will continue to provide a description of the planning assumptions in future Capital Plans unless directed otherwise.

9.3 Order G-69-07 page 15 Directive 03

> **"The Commission Panel directs BCTC to submit as part of future capital plan filings an assessment of which transmission reinforcements could be delayed or deferred through the reasonable re-dispatch of generation resources nominated in NITS applications. BCTC should also identify in this assessment the mechanisms under OATT that allow the re-dispatch of generation around transmission constraints, and comment on whether these mechanisms are available for operating purposes, planning purposes, or both."**

9.3.1 Definition of Re-Dispatch

BCTC understands the term re-dispatch, in the context of this question, to mean the reduction of generation in one area and an increase of generation in another area to either avoid or defer transmission reinforcements or to allow another resource to be scheduled on the same path. In that sense, it is a variation from the dispatch patterns determined by the existing planning processes. The transmission system is planned for a dispatch pattern that allows the full use of the existing and planned generation resources. These resources require transmission reinforcements to provide firm transfer to the load to keep the system secure if there is not enough ATC.

9.3.2 Transmission Reinforcements That Could Be Delayed Through Re-Dispatch

The following reinforcement projects, where approval is requested either through this Capital Plan or through a separate filing, could be delayed through re-dispatch:

9.3.2.1 Ashton Creek Substation Shunt Capacitor Banks – Implementation Phase

This project is described in Section 5.5.1.1.1. These reinforcements could be deferred if the generation that impacts the West-of Selkirk Cut-plane is reduced and other generation output not using the path is increased to serve the load. Up to 243 MW of SI generation will have to be restricted to keep the ATC on the West of Selkirk Cut-Plane zero or positive. This action changes the optimal dispatch of the generation resources and may result in water spill at the plants in the Selkirk area. The action may also be constrained by the amount of generation operating reserves, maintenance outages available in the system and generation availability in other areas of the system.

9.3.2.2 Interior to Lower Mainland Reinforcement – Implementation Phase

This reinforcement could be deferred if Coastal Generation or continued use of the Canadian Entitlement is dispatched instead of generation from the Interior of the Province. This alternative is discussed in Report SPA2007-28 "Reinforcement Alternatives for the ILM Transmission Grid" dated October 2007 which was filed as Appendix I of the ILM CPCN Application. The specific discussion of this alternative is in Section 2.1 of the report. This alternative was rejected on the basis that, "because BCTC must also be able to deal with scenarios that require earlier in-service dates, additional Coastal Generation or DSM is not considered a viable alternative from a planning perspective."

9.3.3 Re-Dispatch in the Context of the IEP/LTAP/NITS

BCTC would like to comment on whether the concept of re-dispatch, as implied in these questions, is meaningful given the existing IEP/LTAP/NITS processes that are in place.

Under the OATT, BCTC provides NITS to BC Hydro. NITS allows BC Hydro to "integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load".[23] In addition, BCTC has an obligation to "provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads".[24] The outcome of the IEP/LTAP/NITS processes is transmission reinforcements to provide the required NITS transmission service to meet BC Hydro's needs.

In the existing IEP/LTAP/NITS processes, the combined cost of generation portfolios and their transmission requirements are compared and a portfolio selection is made by BC Hydro on the appropriate plan. BCTC is involved in these processes by providing input to BC Hydro on transmission options for various portfolios. Determining an appropriate generation portfolio, dispatch pattern, transmission reinforcements and generation reserves is part of this process. In other words, re-dispatch is already taken into account and the appropriate level of transmission is

[23] OATT Section III Preamble.
[24] OATT Paragraph 28.3.

provided. Once the resource plans have been accepted, using re-dispatch of resources to delay transmission reinforcement would result in a sub-optimal plan.

9.3.4 Mechanisms Under OATT that Allow the Re-Dispatch of Generation

Under the OATT, there is no obligation on BC Hydro or any other generator to re-dispatch generation. Re-dispatch arrangements are entirely voluntary. The only mechanism available to BCTC to drive the re-dispatch of generation in the above context would be simply to not accept generation schedules requiring firm transmission that would be in violation of the ATC on that path, contrary to the OATT. Therefore, BCTC cannot rely on re-dispatch for planning purposes. The provisions under OATT pertaining to the re-dispatch of generation are also discussed in Appendix B of BCTC's Review of Rate Design Alternative Report filed with the Commission on December 20, 2006.

BCTC does have the power to re-dispatch generation for system security reasons.

BCTC believes that its role in facilitating a re-dispatch market may be in the provision of information on re-dispatch opportunities that would relieve transmission constraints. BCTC will include the provision of re-dispatch information as part of the posting requirements in the new Attachment K required under FERC Order 890, which will be the subject of consultations with customers. BCTC provided the status of its Assessment and Response to FERC Order 890 to the Commission on October 2, 2007. BCTC's response to FERC Order 890 is also discussed in Section 9.38.

A discussion of the issues related to economic opportunity which might be captured through generation re-dispatch is provided in the report prepared by BCTC in response to Directive 39. The report will be filed with the Commission on or about December 21, 2007. Directive 39 can be found in section 9.39.

9.4 Order G-69-07 page 16 Directive 04

> **"BCTC is directed to provide with its next capital plan its position as to the disposition of costs for Definition Phase project costs, in circumstances where the need for the project is either established in the Planning Phase or assumed for the purposes of completion of the Planning Phase, but the project is no longer needed by the time of completion of the Definition Phase, either due to changed circumstances**

within the control of BCTC or due to further analysis completed after the Planning Phase."

Definition Phase costs associated with a project that is cancelled are currently written off against operations in the year the decision is made to cancel the project. A project/asset write-off amount, to which cancelled Definition Phase project costs are charged, is currently included in the depreciation forecast for BC Hydro Transmission. In the event that the write-off amounts are significant, BCTC would likely apply to the Commission for recovery of these costs in rates.

BCTC appreciates that there may be instances where the Commission wishes to review the treatment of Definition Phase costs if a project has subsequently been cancelled. BCTC believes that the appropriate time for this review to take place is when BCTC applies to have these costs recovered in rates during a revenue requirements proceeding.

9.5 Order G-69-07 page 17 Directive 05

"The Commission Panel specifically denies Definition Phase funding in F2009 for the Golden 69 kV System Reinforcement and North Thompson 138 KV System projects. If BCTC applies for Definition Phase funding for these projects before or as part of the next capital plan, it should be prepared to show how it has considered existing transmission expansion policies for the identification of project alternatives during the Planning Phase evaluation."

BCTC is seeking approval to proceed with the Definition Phase work for the Golden 69 kV System Reinforcement as part of this Capital Plan. Section 5.5.2.1.1 provides a description of the project and how it considered the TEP for the identification of project alternatives during the Planning Phase evaluation.

BCTC is not seeking approval to proceed with Definition Phase work for the North Thompson 138kV System Reinforcement in this Capital Plan.

9.6 Order G-69-07 page 19 Directive 06

"The Commission Panel directs BCTC to track past years' approved Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures, as was done in Table 9-1 of the Application."

Information on historical and current Emergency Capital Expenditures is provided in Table 6.2. BCTC will continue to report this information in future Capital Plans unless directed otherwise.

9.7 Order G-69-07 page 20 Directive 07

> **"...the Commission Panel directs BCTC to annually review projects with a budget in excess of $10 million, where the budgeted costs differs from actual by 20 percent or more, or where the project in-service date changed by in excess of six months, and prepare an internal report of the lessons, if any, that were learned from the project implementation and that may be applicable to future projects. The report should make reference to the Project Implementation Risk Matrices, and how this tool influenced the outcome. The report could also address issues such as project management, contracting and external matters that were contributing factors to the outcome. The Commission Panel directs BCTC to provide a list of those projects for which a report was prepared in its next capital plan."**

Table 9-1 following identifies all capital projects with an initial budget, or actual cost, in excess of $10 million that have been completed between September 2005 and November 2007.

Table 9-1. Projects Over $10 Million Completed From Sept 2005 to Nov 2007

Portfolio	Project	BCUC Approval Order	Final/ Forecast Completion Cost ($,000)	BCUC Filing Amount ($,000)	Cost Variance ($,000)	Cost Variance %	Actual In-Service Date	BCUC Filing In-Service Date	In-Service Variance (Months)
Growth	Vaseux Terminal Station Interconnection	G-103-04	10,014	11,448	(1,434)	-13%	Oct-05	Nov-05	-1
Growth	Ft St John-Area Reinforcement	G-91-05	27,861	17,986	9,875	55%	Dec-06	Oct-06	2
Growth	Central Langley Area System Reinforcement	G-91-05	27,317	28,289	(972)	-3%	Dec-06	Oct-06	2
Growth	Maple Ridge Area Capacity Increase - Haney Substation	G-91-05	14,700	14,238	462	3%	Dec-06	Nov-06	1
Growth	Whistler Village Reinforcement - Function Junction Substation	G-91-05	14,540	13,655	885	6%	Apr-07	Nov-06	5

The Fort St John Area Reinforcement (Fox Creek) project is the only project where actual costs differed from the estimate at the time of approval by 20% or more. No project had an in-service date delay of more than six months.

BCTC filed the Fox Creek Project report with the Commission on 23 October 2007, and this report included a section on lessons learned.

BCTC has revised its Project Management standards to expand the content of its Project Completion Reports to include the identification of lessons learned. The Project Completion Reports will also address all of the issues (including project management, contracting, external factors and project risks) that contributed to the cost and/or schedule variation. The use of the Project Implementation Risk Matrix will be included in BCTC's Project Management standards when its development is completed. The Project Implementation Risk Matrix is discussed in Section 4.3.

BCTC will continue to identify those projects for which a report was prepared in its next Capital Plan unless directed otherwise.

9.8 Order G-69-07 page 20 Directive 08

> **"The Commission Panel agrees with BCOAPO's submission on variance reporting, and accepts BCTC's proposal to provide information in its next capital plan filing regarding variances exceeding both 10 percent and $100,000 of budgeted amounts submitted in this Application for approved projects, and to continue such reporting in future capital plan filings until directed otherwise."**

Table 5-3 provides the list of "Projects In Progress" in the F2009 Capital Plan which has forecast amounts with variances exceeding both 10 percent and $100,000 compared to the amounts shown in the F2008 Capital Plan. BCTC will continue to provide this variance information in future Capital Plan Applications until directed otherwise.

9.9 Order G-69-07 page 30 Directive 09

> **"The Commission Panel encourages BCTC to suggest changes to the frequency of the STSR if BCTC determines the existing frequency does not serve a useful purpose, but directs BCTC to submit an updated STSR with future capital plan applications until directed otherwise."**

BCTC has considered the frequency of the STSR and is of the opinion that the STSR continues to serve a useful purpose in supporting the Capital Plan. Accordingly, BCTC will continue to submit an updated STSR with future Capital Plan applications. Beginning in F2010, future BCTC Capital Plans will cover a two-year period; this means the STSR will only be updated every two years.

9.10 Order G-69-07 pages 30 Directive 10

> **"The Commission Panel directs BCTC to continue reporting performance measures in future capital plans, largely as they are provided in the 2006 STSR. BCTC should report its performance measure with and without planned outages in order to make the comparison against CEA statistics more relevant. The Commission Panel also considers the trend graph supplied in response to BCUC 1.131.1 (Exhibit B-6) to be a useful long-term indicator, and directs BCTC to file this trend information in future capital plans."**

Performance measures, as provided in the 2006 STSR, are provided in Section 8.0 of the 2007 STSR located in Appendix B. These figures provide performance measures with and without planned outages, together with the relevant CEA statistics.

A trend graph, similar to the graph supplied in response to BCUC IR 1.131.1 of the F2008 Capital Plan is supplied in Figure 6-1 in Section 6.0 of the Application. BCTC will continue to provide the performance measures and trend graph as described above in future Capital Plan applications until directed otherwise.

9.11 Order G-69-07 page 32 Directive 11

> **"In all future capital plan applications, BCTC is to provide a modified table in the format of the "Projects in Progress" portion of Table 5-1 in this Application. For each year during the Implementation Phase of a project BCTC is to include the approved total annual expenditures, the revised total annual expenditures, and the difference between the approved and revised annual expenditures, as well as the approved and revised in-service dates. The Commission Panel further directs BCTC to provide a modified table in the format of Table 5-3 in this Application, modified to include the total dollar value for each project, as well as the priority ranking of the project when the project was approved."**

Table 5-4 provides, for all "Projects In Progress", revised total and annual expenditures as well as in-service date, compared to the total and annual expenditures and in-service date provided to the Commission at the time the project was approved. Table 5-4 also provides the priority ranking of the project when it was approved.

Table 5-3 in this Capital Plan provides the list of "Projects In Progress" in the F2009 Capital Plan which had variances exceeding both 10 percent and $100,000 of budgeted amounts compared to the amounts shown in the F2008 Capital Plan. Table 5-3 provides the total dollar values and in-service dates. The priority ranking of the projects at the time of approval is not included in Table 5-3 because the comparison is to the F2008 Capital Plan values and in-service dates, which is not necessarily the same as when the project was approved.

9.12 Order G-69-07 page 35 Directive 12

> **"The Commission Panel concurs with BCTC that the provisions in the OATT adequately address future IPP interconnections, and accepts BCTC's proposal to forecast capital for the interconnection of IPP projects for the upcoming year; however, where possible, BCTC should assign such amounts to specific IPP projects. For projects identified in the F2006 TSCP Update Decision as requiring further approval, the Commission Panel accepts BCTC's proposal that it will sign facilities agreements with IPP customers, will proceed with study work and the interconnection process, and will seek Commission approval or file a letter with the Commission."**

With the understanding that the provisions in the OATT provide adequate authority to proceed with generation interconnections, BCTC is no longer seeking approval from the Commission for generation interconnections through the Capital Plan submission except as noted below. Generation interconnections are treated in the following manner in this Capital Plan.

Projects related to generation interconnections are shown under the heading Generation Interconnection Projects in Table 5-1. Those generation related projects for which a Facilities Agreement has been signed are shown as Projects in Progress,[25] together with a specific amount. In addition, BCTC also identifies forecast amounts for future generation related projects under Future Projects.

For those projects which were originally approved by the Commission and subsequently deferred, and for which the Commission has indicated in Order G-67-06

[25] Table 5-1 shows the Forest Kerr project as a Project in Progress since it was approved by the Commission in G-103-04. A Facilities Agreement has yet to be signed for the project.

that further approval is now required prior to resurrecting such projects, BCTC is either seeking a new approval through the Capital Plan submission when the timing coincides, or is filing a letter with the Commission, as directed. There are no projects in this category for approval in this Capital Plan. Since the last Capital Plan submission, BCTC filed letters with the Commission for the Zeballos Lake IPP Interconnection (G-157-06), the Ashlu Creek IPP Interconnection (G-7-07) and the South Cranberry Creek IPP Interconnection (G-104-07) projects. The forecast amounts shown under Future Projects in Table 5-1 also include amounts for the generation projects in this category as appropriate.

9.13 Order G-69-07 page 37 Directive 13

> **"The Commission Panel considers that BCTC is complying with the second outstanding Directive and expects BCTC to report on the progress of establishing correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI."**

The "BCTC Report in Response to BCUC Order G-139-06, Appendix A, Item 10" located in Appendix H of this Application provides information on BCTC's progress in establishing correlations between asset condition, reliability and remaining life. In addition, Section 6.4 of the STSR discusses the Sustainment Investment Model and the correlation between asset health, end of life and impacts on SAIDI.

9.14 Order G-69-07 page 37 Directive 14

> **"The Commission Panel directs BCTC to provide in future capital plans equipment reliability data as selected by BCTC and provide the CEA averages, and in the case of Line-related Forced Sustained Outages (as defined in the 2006 STSR, Section 8.3), to separate equipment failure outages from those outages caused primarily by weather or vegetation."**

Equipment reliability data, together with CEA averages, are provided in Section 8 of the 2007 STSR located in Appendix B. The data is as defined in the 2006 STSR except for Line-related Forced Sustained Outages for which additional data was provided to separate outages from defective equipment from outages caused by lightning, weather and vegetation. BCTC will continue to provide equipment reliability data in future STSRs unless directed otherwise.

9.15 Order G-69-07 page 45 directive 15

> **"… the Commission Panel directs BCTC to file a report that could be described as the "operator's manual" for the Prioritization Model. This report should contain all weightings and probabilities for each category and criteria and any sub criteria, as well as a full description of the methodology employed in determining the weights and probabilities. The report should describe key assumptions, particularly those used to derive values as a result of a judgment process, as opposed to quantitatively. The report should contain a detailed example, including all numeric calculations for at least one project in each of the Growth, Sustaining, or BCTC Capital Portfolios. If BCTC cannot provide the information for proprietary reasons, it is encouraged to select examples from the beta testing of the model. The report should be filed with the next capital plan."**

An "Operator's Manual" on the prioritization methodology is provided in Appendix J. The report provides details on how the categories and criteria are selected. It also provides details on the methodology employed in determining the weights used to calculate the scores. All the weights and financial rates used in the prioritization of the F2009 Capital Plan are provided. Finally, the report provides three detailed examples, one from each of the three portfolios, including all assumptions and numeric calculations to illustrate how the methodology is applied.

9.16 Order G-69-07 page 45 Directive 16

> **"… the Commission Panel directs BCTC to include in its next capital plan filing, tables for each of the Portfolios listing the projects brought for approval, their risk and value scores by category, and the priority numbers and quadrant values, where applicable. For projects with alternatives that are considered feasible or for which there is evidence that a more detailed and costly assessment should be undertaken prior to eliminating the alternative completely, those alternatives should be listed, along with their total (only) risk and value scores, and priority numbers and quadrants, where applicable."**

Tables providing the project prioritization results for the three portfolios are located in Sections 5.4 (Growth), 6.4 (Sustain) and 7.4 (BCTC). The tables provide the risk and value scores by category, and the priority numbers and quadrant values, where applicable.

BCTC uses its prioritization model to compare proposed projects to identify the projects with highest value or projects with high risk of deferral. The results of the methodology are used to aid in the creation and management of the capital portfolios.

BCTC does not believe that extending its prioritization model to include all alternatives that are considered feasible or for which there is evidence that a more detailed and costly assessment should be undertaken prior to eliminating the alternative completely will aid in the creation of capital portfolios. Comparing multiple solutions to a need with multiple solutions to other needs will not provide useful insights for portfolio building.

BCTC believes that alternative solutions to a need only need to be compared among themselves. BCTC also believes that the process used by BCTC to compare alternatives is more appropriate than the prioritization model for that purpose because it uses criteria specific to the need for the evaluation and comparison of the alternatives. The prioritization methodology, on the other hand, must use ‘universal’ criteria to allow for the comparison of widely different investments. The process to compare alternative solutions and select the preferred solution is described in Section 4.2.

9.17 Order G-69-07 page 46 Directive 17

> **“The Commission Panel notes that many of the quadrant four sustaining projects that were not deferred appear to be justified not on the model results but for safety or reliability considerations. This suggests to the Commission Panel that there may be threshold values for the safety and reliability metrics beyond which projects become mandatory much as they currently become mandatory for legislative or NERC reliability reasons. The Commission Panel directs BCTC to comment on this issue in the next capital plan.”**

The prioritization methodology is used to aid management in identifying the critical and valuable projects that should be undertaken or deferred. The fourth quadrant is a ranking which BCTC utilizes to determine the relative priority of projects. Projects in the fourth quadrant may have lower value or risk of deferral than others, but it does not mean they have no value or risk.

BCTC considers corporate objectives when reviewing projects in the fourth quadrant and projects meeting the following “threshold” criteria will not be deferred:

Table 9-2. Description of Criteria

Criteria	Description
1	Safety – the work is necessary to reduce a safety risk to the general public.
2	Environment – the work is necessary to comply with environmental regulations and recommended targets (e.g., all PCB equipment must be removed by 2010).
3	Reliability – the work is necessary to resolve a system reliability problem which has safety consequences which would harm the public if not addressed.
4	Legal – the work is necessary to comply with property laws and ROW agreements (e.g., trespassing or equipment located on private property).
5	Relationship – the work is necessary to comply with new business or operating agreements (e.g., to relocate structures or lines as agreed with the Department of Highways or Indian Reserves).
6	Third Party Funded – the work is necessary to meet requests funded by others.
7	Market Efficiency – the work is necessary to meet interconnection agreements with other utilities and enables energy trading (e.g., radio communication must be upgraded at both ends to meet an interconnection).

Table 6.5 provides the prioritization results for the Sustaining Portfolio. The following fourth quadrant projects meet one of the "threshold" criteria. Each project is described in Section 6.5.

Table 9-3. Fourth Quadrant Projects Meeting Threshold Criteria

	Project Name	Criteria
1	F2009-S-5004-Protection Control Metering (PCM) - TLOB Portion	2
2	F2009-S-5002-Voltage & VAr Optimization VVO - Phase 2 - TLOB Portion	2
3	F2009-S-5003-Voltage & VAr Optimization VVO - Phase 3 - TLOB Portion	2
4	F2010-S-5004-Protection Control Metering (PCM) - TLOB Portion	2
5	F2010-S-5006-Voltage & VAr Optimization VVO - Phase 3 - TLOB Portion	2
6	F2010-S-5302-Nelway-Metaline Radio Upgrade	5

9.18 Order G-69-07 page 46 Directive 18

> **"Since corporate risks may ultimately be reflected in costs which will impact rates, BCTC is directed to include its Corporate Risk Matrix in its next capital plan filing."**

BCTC's Corporate Risk Matrix in provided in Appendix D.

9.19 Order G-69-07 page 46 Directive 19

> **"Since a growth project by definition results from an anticipation of growth, the Commission Panel is concerned that BCTC cannot estimate the likely revenues, and hence includes in the heavily weighted financial category, a value for rate impact which it knows to be inaccurate. The Commission Panel encourages BCTC to comment on this issue in its next capital plan."**

The Commission appears to be asking for comments on the impact of not including likely revenues in the rate impact calculations used in the prioritization model. BCTC actually incorporates the likely revenues in the rate impact calculation used in the prioritization model. The approach to calculate the likely revenues is described below. If BCTC's understanding of this Directive is incorrect, BCTC will provide additional comments as required during the IR process.

Incremental revenues used to offset the cost of projects that pertain to load growth are calculated from the following data:

(a) Incremental load growth in MW each year within the investment's scope area (starting in the in-service year) - the incremental load growth is established from the load forecasts provided by BC Hydro;

(b) MW of the above growth that can be served by existing capacity (pre-investment);

(c) Load Factor of the expected growth; and

(d) MW of new capacity that the investment will add.

The information provided is translated to the likely incremental revenues using BC Hydro's embedded cost of Transmission.[26] The resulting incremental revenue is then reflected as a benefit associated with the project. The estimated additional revenue from the Growth transmission project is used in the determination of the net present value, the benefit-to-cost ratio and the rate impact of the project.

[26] The total BC Hydro average embedded cost of service is $52.67/MW.h. The transmission portion is $8.82/MW.h. BC Hydro, 2007 Rate Design Application (March 2007), Appendix A, Cost of Service Model, Schedules 4.0 and 5.0.

9.20 Order G-69-07 page 48 directive 20

> **"… the Commission Panel directs BCTC to include in future capital plans a summary table by project, showing the average load growth for the most recent five historical years, preferably weather normalized if possible, and the growth rates projected for future years. The table should also show the planning region in which the project resides and the regional load growth rates for the same periods. If there is significant divergence between the load growth rate upon which the project need is determined, and that of the planning region, BCTC is to provide an explanation of the divergence."**

A table showing load growth information is provided in Sections 5.5.2 and 5.5.3 for each regional reinforcement and station expansion project submitted for approval. The information includes normalized actual load growth for the most recent five historical years and the growth rate projected for the next 10 years. The load forecast for the planning region is also shown and an explanation of any divergence is provided. BCTC will continue to provide this information in future Capital Plans unless directed otherwise.

9.21 Order G-69-07 page 53 Directive 21

> **"The Commission Panel directs BCTC to prioritize potential TEP projects with other projects using the Prioritization Model.**
>
> **The Commission Panel directs BCTC to report on potential TEP projects in the next capital plan, and provide a detailed description of the highest ranked potential TEP project. In the event that BCTC identifies a potential TEP project and then decides that the project should be implemented, BCTC should seek approval of the project prior to the next capital plan."**

BCTC has identified the 5L51/5L52 Thermal Upgrade project as the first project to be advanced under the TEP. An application to seek Commission approval of the project was filed on December 12, 2007. In the application, BCTC has provided an overview of all potential TEP projects identified and currently under analysis by BCTC.

BCTC has modified the prioritization model to allow for the inclusion of TEP projects. The modifications made to the model are described in Section 4.4.2.2. The 5L51/5L52 Thermal Upgrade project was included in the prioritization of the Growth Portfolio projects. The planning of the other potential TEP projects was not sufficiently advanced to include them in the prioritization. The results of the prioritization are provided in Section 5.4.

9.22 Order G-69-07 page 55 Directive 22

> **"The Commission Panel directs BCTC to provide a detailed description of the highest ranked intertie expansion project in the next capital plan. The description should include, if possible, the identification and quantification of potential benefits accruing to ratepayers."**

As referenced in Section 9.21, BCTC is proposing the 5L51/5L52 Thermal Upgrade project under TEP. This project is the only intertie expansion project associated with this year's Capital Plan. The application filed with the Commission provides an identification and quantification of the potential benefits accruing to ratepayers.

9.23 Order G-69-07 page 56 directive 23

> **"For future capital plans, the Commission Panel directs BCTC to identify separately those projects and corresponding expenditures that are directly attributable to specific generation additions."**

The projects and corresponding expenditures attributable to specific generation additions are provided in Section 5.6. BCTC will continue to provide this information in future Capital Plans until directed otherwise.

9.24 Order G-69-07 page 56 Directive 24

> **"The Commission Panel approves BCTC's request for a determination under Section 45(6.2)(b) of the Act that capital expenditures on the Selkirk 500/230 kV Transformer T4 Addition, the Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors – Definition Phase, and the 5L91/5L98 Series Compensation – Definition Phase projects are in the public interest."**

BCTC is proceeding with the Definition Phase work for the SI Series Compensation (formerly called 5L91/5L98 Series Compensation) projects, and the implementation of the Selkirk 500/230 kV Transformer T4 Addition project. BCTC has completed the Definition Phase for the Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors and is requesting approval in this Capital Plan for the Implementation Phase.

9.25 Order G-69-07 page 58 Directive 25

> **"The Commission Panel accepts BCTC's proposal in its letter of March 30, 2007, that upon reaching an agreement with the District of Mission regarding the potential rerouting of a portion of the 69 kV transmission facilities associated with the Mission and Matsqui Area Supply project in the vicinity of Mission, BCTC will apply to the Commission to find the revised project to be in the public interest."**

BCTC received approval to proceed with the Mission and Matsqui Area Supply Project in the F2006 Capital Plan at a cost of $43.2 million. Project costs were updated in the F2008 Capital Plan, reducing the overall cost of the project by $1.8 million to $41.4 million.

During the review of the F2008 Capital Plan, the District of Mission received late Intervenor status and requested that the planned Clayburn to Mission overhead circuits be relocated away from the waterfront, to cross as cables on the Mission Bridge, thereby freeing up important development lands for Mission. The Commission's F2008 Capital Plan Decision accepted BCTC's proposal that, upon reaching an agreement with the District of Mission regarding the potential rerouting of a portion of the 69 kV transmission facilities in the vicinity of Mission, BCTC would apply to the Commission for approval of the revised project.

BCTC and the District of Mission reached an agreement, the Mission Bridge Alignment Agreement (the Agreement), in August 2007. As part of the Agreement, BCTC agreed to support a Mission Bridge alignment using a cable crossing instead of the originally approved overhead crossing. The District of Mission agreed to provide a contribution in aid of construction of $1.0 million towards the additional costs of realigning the project to cross the Mission Bridge, and the added cost of cables on the bridge. This proposed change in alignment was estimated at $2M. The Agreement is subject to:

(a) Ministry of Transportation (MoT) permission to install cables on the Mission Bridge under terms acceptable to BCTC;

(b) Commission Approval for BCTC to capitalize and recover in rates, sunk costs in the amount of $0.9 million associated with the overhead river crossing; and

(c) Commission approval that the revised project is in the public interest.

In a letter dated August 9, 2007, BCTC informed the Commission that BCTC and Mission had reached an agreement to route the 69 kV double circuit transmission line on the Mission Bridge, subject to MoT review and Commission review and approval of the revised project. The letter also informed the Commission that the project costs had increased significantly and that BCTC was undertaking a project review to determine what adjustments to the project implementation or scope could be made to control costs, while satisfying the need that justified the original project. The letter informed the Commission that the review would be completed by late September and an application to the Commission would be filed in early October.

The cost escalation discussed above has resulted in total forecast project costs increasing from $41.4 million to a revised forecast of $55.2 million.[27] Cost escalation has been experienced on both the Matsqui and Mission components of the Project. The main reasons for the cost escalation of $9.8 million for the Matsqui portion of the Project from $15.8 million to $25.6 million are:

(a) Higher property purchase costs for the Matsqui area of $1.2 million than originally forecast;

(b) Higher than forecast property improvements totaling $3.9 million to address environmental concerns, and significant cut and fill to build foundations for the Mount Lehman substation property;

(c) Higher than forecast equipment and construction costs totaling $3.5 million for the EPC contract and BC Hydro Engineering and Field Operations costs;

(d) Telecommunications costs for Mt. Lehman of $0.7 million; and

(e) Overheads and IDC due to cost increases and delayed in-service of $0.8 million.

The main reasons for the cost escalation of $4.0 million for the Mission portion of the Project (based on double overhead circuit crossing of the Fraser River at the Rail Crossing) from $25.6 million to $29.6 million are:

(a) Equipment and construction cost increases of $7.0 million for construction cost increases for Clayburn substation and the 69 kV transmission line;

(b) Overhead and IDC of $0.5 million for higher construction costs and delayed in-service;

[27] The forecast cost included in the F2009 Capital Plan is $56.9 million. Due to the late settlement of this issue, BCTC has not revised its Capital Plan to reflect this change.

(c) A partial offset resulting from cancellation of 500 kV and 230 kV upgrade work at Clayburn substation no longer needed ($3.0) million; and

(d) Change to double circuit 69 kV overhead transmission line from single circuit 69 kV transmission line and MIS switchyard ($0.4) million.

Due to the significant cost escalation, BCTC ceased work on the Clayburn to Mission component of the project in June 2007, and undertook a variance review in an effort to determine if costs could be reduced by reviewing other alternatives to supplying Mission. The Matsqui portion of the project, including Mt. Lehman substation, proceeded to completion and was put into service on December 13, 2007. The variance review on the Mission component included a review of BC Hydro Engineering estimates of costs for the Clayburn to Mission 69 kV supply portion of the Project by a third party, and a value engineering review to determine if any additional cost savings were available to help reduce costs. BCTC has now completed its cost and variance review, and will publish its findings shortly.

Since August 2007, BCTC has also been working closely with the MoT on the design and construction of cables on the Mission Bridge. Currently MoT is not in favour of allowing cables on the bridge due to the bridge requiring a seismic upgrade in the near future, the bridge already at its design dead loads prior to allowing the associated cables and cable trays to cross the Mission Bridge, and potential conflicts with other utilities already on the Bridge. Although MoT has not refused access to the bridge, it would require that BCTC complete engineering studies that would demonstrate that the cable alignment could be accommodated on the bridge, and that the methods of attaching the cables would be appropriate to the MoT requirements and within bridge loading limits. BCTC has studied these requirements and has reviewed its cost estimate of the Highway Alignment (crossing the Mission Bridge using cables) and has increased its direct cost estimate from between $8.0 million to $15.0 million to reflect the added risks for design and installation restrictions imposed on BCTC by MoT to use the Mission Bridge. Extensive bridge work would be necessary as the bridge design is not conducive to the installation of the cables.

Due to the high cost of the Highway Alignment, BCTC is not able to continue to support the Highway Alignment as contemplated in the Agreement without significant further contributions being made by those parties that are requesting the realignment. Additionally, BCTC believes that the time required in order to carry out all of the studies directed by MoT would jeopardize the required in-service date of Fall 2008 for the Mission portion of the project. There is also no guarantee that the MoT would provide the necessary permits to occupy the bridge even after all of the necessary studies are complete. BCTC met with the District of Mission on December 17, 2007 to explain the situation, and District of Mission Council understands BCTC's position and does not oppose BCTC's decision to use the agreed upon Railway Alignment.

For the above reasons, BCTC proposes to proceed with the original overhead crossing of the Fraser River to Mission, using the previously agreed upon Railway Alignment, a project that can be completed within the revised cost estimate of $55.2 million, and can be completed within the required time frame of Fall 2008. A report will be provided to the Commission requesting approval for the additional costs to complete the Project.

9.26 Order G-69-07 page 66 Directive 26

> **"If and when BCTC submits a CPCN application for the 5L91/5L98 Series Compensation project, the Commission Panel directs BCTC to submit a study that analyzes and describes the anticipated amount of seasonal and hourly reliability-driven Canadian Entitlement utilization. In order to assist in the determination of whether or not the anticipated seasonal and hourly Canadian Entitlement utilization from the requested study is consistent or inconsistent with past utilization of the Canadian Entitlement, the Commission Panel also directs BCTC to provide historical data of the reliability-driven utilization of the Canadian Entitlement in a format that allows for a reasonable comparison to the anticipated seasonal and hourly Canadian Entitlement utilization."**

The Definition phase of the SI Series Compensation (formerly called 5L91/5L98 Series Compensation) project is underway. A CPCN Application for this project is expected to be submitted in 2008.

9.27 Order G-69-07 page 67 Directive 27

> **"The Commission Panel directs BCTC to submit as part of its next capital plan a report that provides an analysis of, and a proposal for, the Lower Mainland's reactive power requirements. This report should describe and attempt to quantify the various benefits associated with the options for the Lower Mainland's reactive power requirements, and also contain a comprehensive description of the planning assumptions used in the analysis."**

BCTC stated that it would undertake a comprehensive analysis of the Lower Mainland reactive power requirements following the approval of BC Hydro's LTAP Base Resource Plan and Contingency Resource Plans. The analysis was to take into account the benefits of an Ingledow SVC identified by BC Hydro in BC Hydro's IR 1.5.1 related to BCTC's F2008 Capital Plan, as follows:

> **5.1 When considering the benefits of an Ingledow SVC, did BCTC include:**
>
> - **Trade benefits from increasing the BC-US Dynamic Scheduling limit;**
> - **Trade benefits from increased BC-US Export Total Transfer Capability (TTC) during the summer months;**
> - **Loss savings that accrue when Burrard Thermal units are not running in Synchronous Condense mode to provide dynamic VArs;**
> - **Reliability benefits of having more equivalent Synchronous Condensers in the Lower Mainland during winter peak load conditions;**
> - **Capacity benefits in the Lower Mainland from being able to run Burrard Thermal units at maximum output during winter peak load conditions, without concern that their equivalent Synchronous Condenser value is derated at maximum output?**

BCTC has undertaken an analysis of the Lower Mainland reactive power requirements focusing on the long term development of the grid. The long-term information is given in Report SPA 2007-68 "Interior to Lower Mainland (ILM) Horizon Year – Total Transfer Capability Study" dated November 2007 which was filed as Appendix K in the ILM CPCN Application. One of the key findings of the study is that mechanically switched shunt capacitors (MSC) at Nicola and Meridian can be used to reinforce the system and increase the voltage stability of the system thus avoiding the immediate need for an SVC at Ingledow and saving considerable capital cost.

The following comments are offered in response to the specific considerations in BC Hydro IR 1.5.1:

(a) The trade benefits from increasing the BC-US Dynamic Scheduling limit (less than or equal to 300 MW change per hourly schedule) potentially afforded by an Ingledow SVC would benefit BC Hydro and Powerex. Although an SVC may increase the dynamic scheduling limit, it is not required at Ingledow to serve domestic load for many years. The restriction on dynamic scheduling likely occurs at BPA's Custer Substation because of the excessive switching of a 500 kV shunt reactor at that bus caused by a sudden change in flows on the tie greater than 300 MW. The dynamic scheduling limitations are being investigated by BCTC, Powerex and BPA. There may be more cost-effective solutions that could be applied in the system.

(b) The MSCs at Meridian and Nicola provide the primary non-firm trade benefit at much lower cost in relation to reinforcement of the ILM grid for reliable supply of domestic load. These trade benefits will also be provided by 5L83. A discussion on the trade benefits of the Meridian and Nicola Shunt capacitors is given in Section 5.5.1.2.4;

(c) There would be loss savings if dynamic VArs are provided by an Ingledow SVC rather than by operating the Burrard units as synchronous condensers. However, these loss savings are much less than the cost of an SVC.

(d) There would be some reliability benefits of having more equivalent synchronous condensers in the Lower Mainland during winter peak load conditions. However, the reactive power requirements, as assessed in BCTC's Report SPA 2007-68, shows that the planned transmission reinforcements provide sufficient reliability for secure supply to the Lower Mainland from the Interior resources.

(e) The planned reactive support in the Lower mainland is adequate to meet the reduced dynamic VAr support from the Burrard units at maximum output.

9.28 Order G-69-07 page 73 Directive 28

> **"The Commission Panel directs BCTC to submit by September 30, 2007, a report for the Fox Creek Project detailing changes to project scope, schedule and cost between the request for approval and the completed project. The report should explain and justify changes to the project scope and schedule, provide explanations for all material cost variances, and include a discussion of changes to its capital planning process that BCTC has implemented or recommends based on experience with this project."**

The requested report for the Fox Creek Project was filed with the Commission on 23 October 2007. The Commission responded on 4 December 2007 acknowledging receipt of the report and identifying four matters requiring BCTC's attention. Sections 9.41 to 9.44 discuss the four matters.

9.29 Order G-69-07 page 77 Directive 29

> **"The Commission Panel does not approve the Chapman Fibre Optic Cable Replacement project as proposed because absent an explanation of the large expenditure in F2012, it is higher cost than a potential alternative and does not appear to be justified by safety, environmental, or compliance considerations."**

BCTC has reviewed the Chapman Fibre Optic Cable Replacement justification following the Commission decision. The project is resubmitted for approval in this Capital Plan in Section 6.5.1.6.1.

9.30 Order G-69-07 page 82 Directive 30

> **"Therefore, the Commission Panel directs BCTC to conform to the directives made in the F2006 TSCP Decision and the F2006 TSCP Update Decision with respect to Sustaining Capital expenditures."**

Directive 35 from the F2006 Capital Plan Decision (and reiterated in the F2006 Capital Plan Update Decision) stated that the approved F2007 Sustaining Capital expenditures level should apply to future years' forecasts until changes in the trends of the reliability indices or asset health assessments suggest the need for changes from the status quo.

Table 6.3 of the Application provides a comparison of the proposed F2009 Capital Plan Sustaining expenditures to the level approved in F2008. Sections 6.2 and 6.3 provide the justification for the change in the expenditures level.

9.31 Order G-69-07 page 83 Directive 31

> **"The Commission Panel directs BCTC to use an inflation factor of 2.0 percent for each of F2008 and F2009 to budget for Sustaining Capital based on the forecast of BCCPI. The Commission Panel invites BCTC to provide comprehensive justification of any other inflation adjustment it may propose for F2009 and beyond, as part of its next capital plan filing."**

BCTC is proposing to use the following inflation adjustment rates for F2009 and beyond.

Table 9-4. Annual Inflation Rates

	Year	Rate
1	F2009	5.0%
2	F2010	5.0%
3	F2011	4.0%
4	F2012	3.0%
5	F2013	3.0%
6	F2014	3.0%
7	F2015	3.0%
8	F2016	3.0%
9	F2017	3.0%
10	F2018	3.0%

BCTC believes that these proposed rates are appropriate based on the recent trend in the industry, and the expectation that the trend will continue due to the substantial increase in investments by electric utilities across North America and the continued high level of construction activities in BC. As indicated in Section 2, BCTC has filed the September 2007 MMK Consulting report in support of the proposed inflation rates in Appendix E.

BCTC selected the high end of the recommended range for F2008 and the mid-range for F2009 and F2010 to reflect significant increases in the cost of equipment.[28] BCTC has been mostly protected from the significant increases in the cost of certain equipment through the use of long term procurement contracts. The majority of these contracts did not include escalation clauses for metal pricing and currency exchange that are now the norm in new contracts. The contracts are now coming due for renewal and BCTC is experiencing the cost increases seen in the industry. Examples of inflation experienced by BCTC are provided in Section 2.2.10.

A document of interest is the report titled “Rising Utility Construction Costs: Sources and Impacts” dated September 2007 and prepared by The Brattle Group for The Edison Foundation. The report is available at: www.edisonfoundation.net/reports.htm#construction

[28] Appendix E, MMK Report Section 3.5.

or at:

www.eei.org/industry_issues/electricity_policy/state_and_local_policies/rising_electricity_costs/index.htm.

The report documents recent increases in the construction costs of utility infrastructure in the US, identifies the underlying causes of these increases, and explains how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment.

9.32 Order G-69-07 page 83 Directive 32

> **"For clarity, the Commission Panel approves as being in the public interest Sustaining Capital expenditures of $83.1 million in each of F2008 and F2009 when expressed in F2007 dollars, and further Third-Party Funded expenditures of $2.9 million and $1.9 million expressed on the same basis. The same amounts expressed in nominal dollars are Sustaining Capital expenditures of $84.8 million and $86.5 million in F2008 and F2009 respectively, and Third-Party Funded expenditures of $3.0 million and $2.0 million in F2008 and F2009, respectively."**

BCTC is proceeding with the implementation of the F2008 Sustaining Capital program. Forecast expenditures for F2008 and a reconciliation to the approved amount are provided in Section 6.3.

BCTC is proposing a revised F2009 Sustaining Capital program in this Capital Plan. A reconciliation between the previously approved F2009 and the current proposal is provided in Section 6.3.

9.33 Order G-69-07 page 87 Directive 33

> **"The Commission Panel finds that the requested F2008 capital expenditures for the BCTC Capital Information Technology projects, except for the Corporate Network Segmentation project and Backup Environment Separation project, are in the public interest, and directs BCTC to investigate the cost of a secure IT environment integrated with BC Hydro's IT systems. If BCTC is unsuccessful in negotiating the security it believes it needs within BC Hydro's IT system, BCTC is directed to report on the efforts made to reach an agreement with BC Hydro in the next capital plan. In the report, BCTC should describe its concerns about BC Hydro's IT systems, provided that it is not necessary to disclose confidential negotiations or commercial interests to do so."**

BCTC has investigated and negotiated the cost of a secure integrated disaster recovery solution with BC Hydro. An updated proposal for the Backup Environment Separation project is discussed in Section 7.5.1.3 using the new system delivered by BC Hydro's Disaster Recovery Project. After further consultation with BC Hydro, the Corporate Network Segmentation project is renamed and submitted for approval in Section 7.5.1.12 as Network Segmentation F2009. BC Hydro agrees with this project and it is aligned with BC Hydro's own initiative to segment its network infrastructure to improve security.

9.34 Order G-69-07 page 87 Directive 34

> **"In all future capital plan applications, the Commission Panel directs BCTC to provide a table in the format of Table 7-4 of the F2008 TSCP, modified to show the total dollar amount of each project and the relative priority at the time of approval."**

The requested table is entitled "Table 7-4 BCTC Capital Project Changes from F2008 Capital Plan" and is provided in Section 7.3 of this Application. BCTC will be providing a table in all future capital plan applications showing changes to approved projects from previous plan unless directed otherwise. The table will show the relative priority at the time of approval, the project cost, and an explanation for the change.

9.35 Order G-69-07 page 88 Directive 35

> **"The Commission Panel finds the requested F2008 capital expenditures for the BCTC Capital Control Centre Sustainment project are in the public interest."**

BCTC is proceeding with the implementation of the BCTC Capital Control Centre Sustainment project.

9.36 Order G-69-07 page 89 Directive 36

> **"The Commission Panel finds the requested F2008 expenditures for the BCTC Capital Facilities assets projects are in the public interest."**

BCTC is proceeding with the implementation of the BCTC Capital Facilities assets projects.

9.37 Order G-69-07 page 92 Directive 37

> **"The Commission Panel directs BCTC to file a report related to Policy Action 12 and Policy Action 13 on or before December 1, 2007. The**

report should comment on the progress of consultation initiatives and further steps that BCTC considers to be appropriate to implement Policy Action 12 and Policy Action 13. In the filing, BCTC may also seek regulatory comments or direction that may be useful for the creation of the Congestion Relief Policy and the evolution of the TEP. If BCTC does seek such regulatory comments or direction, it may be helpful for BCTC to include a policy discussion paper that could be circulated to stakeholders for comment prior to Commission comments or directions."

BCTC filed a report with the Commission on 3 December 2007.

9.38 Order G-69-07 page 93 Directive 38

"To continue to satisfy the reciprocity requirements under the pro-forma OATT, BCTC must carefully assess the implications of FERC Order No. 890, and therefore the Commission Panel directs BCTC to bring its assessment of FERC Order No. 890 forward to the Commission once its consultations and assessments are concluded."

BCTC's assessment of the implications of FERC Order No. 890 is ongoing. The status of BCTC's assessment was provided to the Commission through two letters dated 20 June 2007 and 2 October 2007 respectively. A status update as of November 2007 follows.

(a) ATC Methodology

BCTC continues to actively participate in the NERC Workshops on the standardization of the methodology to determining ATC. NERC is now expected to complete this effort by August 2008 instead of March 2008. BCTC will conduct information sessions for its customers and stakeholders when the ATC Methodology is finalized.

(b) Planning Process

FERC Order No. 890 requires jurisdictional utilities to document its planning process in Attachment K of the OATT. There has been no change in this area since BCTC filed the status letter dated 2 October 2007. BCTC plans to consult with customers and stakeholders on a revised Attachment K in the first quarter of 2008.

(c) Other Tariff Provisions

> BCTC continues to assess any necessary tariff language amendments and/or system changes necessitated by FERC Order 890 or as a result of Commission direction and stakeholder input. The assessment is expected to be completed by the end of 2007. BCTC now plans on consulting with customers and stakeholders on the Other Tariff Provisions in the first quarter of 2008 together with the consultations on the Planning Process.

BCTC plans to bring its assessment on the Planning Process and Other Tariff Provisions forward to the Commission in the second quarter of 2008.

9.39 Order G-69-07 page 97 Directive 39

> **"The Commission Panel directs BCTC to file a report on or before December 1, 2007 that first identifies congested paths, if any, that might be economically resolved by generation re-dispatch, and then assesses opportunities for resolving congestion by re-dispatching generation. This report may form part of the report related to Policy Action 12 and Policy Action 13"**

BCTC will file a report with the Commission on or about 21 December 2007.

9.40 Order G-91-05 page 26 Directive 11

> **"The Commission Panel finds that the three-year interval between asset condition audits is appropriate. However, increasing amounts of asset data should be available at each interval. BCTC's data monitoring, collation and analysis activity should be sufficient to ensure that an adequate data-based condition assessment is available for at least 90 percent of the assets within each class meeting the 70 Percent Rule by the third audit. "**

On 9 November 2006 the Commission approved the Settlement Agreement for the BCTC F2007 Transmission Revenue Requirement, attached as Appendix A to BCUC Order G-139-06. Through the Settlement Agreement, the parties agreed to several items including:

> "11. BCTC will discuss with BC Hydro the advisability and possibility of reducing the frequency of the Asset Condition Assessment Report and will advise the Commission of the results of those discussions."

BCTC filed a Compliance Filing on NSP Items 6, 11, 15, 16, 19 with the Commission on 3 August 2007. The filing states:

> “It appears to BCTC that Directive 11 from Order G-91-05 may be in conflict with Item 11 in Order G-139-06, and BCTC respectfully seeks clarification from the Commission regarding the approach to transmission asset condition assessments.”

and

> “BCTC recommends that the Commission resolve this apparent conflict by acceptance of the agreement between BCTC and BC Hydro regarding the conduct of asset health assessments.”

The Commission accepted BCTC’s recommendation in Letter L-92-07 dated 15 November 2007.

According to the agreement with BC Hydro, BCTC continues to collect asset condition data and to work on initiatives to improve the asset health information management process. A description of these activities is provided in Section 6.1 of the STSR located in Appendix B.

9.41 BCUC Letter to BCTC dated 4 December 2007 on Fox Creek Project Report

> **“After reviewing the BCTC lessons learned from this project, the commission suggests that the future capital planning process and CPCNs should include all the lessons learned in this report.”**

The Fox Creek Project report identified the following lessons learned:

(a) BCTC learned that it should identify the accuracy of its estimates to the Commission and Intervenors. Beginning with BCTC's Transmission System Capital Plan F2009-F2018, the capital planning process requires all estimates to be shown with an identified level of accuracy for the projects submitted for approval. This identified level of accuracy should improve communication of capital project costs, and associated scope and schedule expectations.

(b) BCTC learned that it should identify the stage of its projects to the Commission and Intervenors. Beginning with BCTC's Transmission System Capital Plan F2009-F2018, BCTC Capital Plans clearly identify whether Growth and BCTC capital projects are at the planning estimate stage (Definition Phase) or implementation estimate stage (Implementation Phase). BCTC learned that it should identify to the Commission and Intervenors that the timing of project development in relation to the timing of the Capital Plan application will affect the level of estimate submitted. Beginning with BCTC's Transmission System Capital Plan F2009-F2018, capital projects proceeding prior to the implementation estimate stage due to customer requirements will clearly be identified as being at the planning estimate stage (Definition Phase). Projects with aggressive schedules that require definition and implementation activities to proceed in parallel should recognize the increased risk and provide an appropriate risk allowance to project cost estimates.

(c) BCTC learned that it should complete route selection and site selection as part of the planning estimate stage (Definition Phase). BCTC is working to have more projects proceed through the Study and Definition Phases prior to being included in future Capital Plans, resulting in better estimates and more complete justifications.

Each of the lessons learned identified in the Fox Creek Project report are demonstrated in this Capital Plan in the following manner:

(a) The description of all Growth and BCTC Capital projects submitted for approval identifies the accuracy of the estimate provided. The description of the projects and accuracy information can be found in Section 5.5 for Growth projects and Section 7.5 for BCTC projects. The accuracy of Sustaining Capital expenditures is not provided as the portfolio is managed to the approved envelope.

(b) i. The description of all Growth and BCTC Capital projects submitted for approval also identifies the planning stage of the project at the time the estimate was prepared. This information is also provided in Sections 5.5 and 7.5.

ii. In this Capital Plan, BCTC is not requesting approval to proceed with the implementation phase of projects on the basis of an estimate prepared during the Study Phase (termed ‘planning estimate’ in the Fox Creek Report).

(c) BCTC is requesting approval in this Capital Plan to proceed with the Definition Phase for the Golden 69 kV Reinforcement and Woods Lake Area Reinforcement projects as soon as BCTC completes the Study Phase work. In both cases, the Definition Phase will include the required consultations to confirm the use of currently available rights-of-way and sites, or the selection of alternate routes and sites if required. The Golden 69 kV Reinforcement and Woods Lake Area Reinforcement projects are described in Sections 5.5.2.1.1 and 5.5.2.1.2, respectively.

9.42 BCUC Letter to BCTC dated December 4, 2007 on Fox Creek Project Report

> **"In the context of the next BCTC Capital Plan, the Commission would be interested in receiving comments from BCTC on 1. increasing the level of accuracy of the estimates used in the capital planning process from ± 50% to ± 30% or even ± 25%, …"**

The accuracy of a project estimate improves as it proceeds through the planning process and the scope of the project is better defined. The scope of simple routine projects could often be sufficiently defined ahead of the Definition Phase to achieve accuracies of ± 30%. More complex projects would only achieve accuracies of +100% / -50% at the completion of the Study Phase. BCTC has learned that it needs to better define the scope of the project through more planning activities in the Definition Stage to achieve estimate accuracy of up to ± 10% depending on the complexity of the project.

Increasing the accuracy of estimates to ± 30% or ± 25% at the time of approval from the ± 50% level provided in previous Capital Plans requires completion of sufficient planning activities ahead of the request for approval, which increases the financial risk in the event the project is not approved. BCTC is striving to complete the Definition Stage prior to seeking approval whenever the financial risk is acceptable. For large projects, requiring significant expenditures in the Definition Stage, BCTC seeks approval to proceed with the Definition work from the Commission first.

Increasing the planning activities ahead of the request for approval also requires schedule coordination with the filing of the Capital Plan. Projects with short timelines may not allow for sufficient planning activities prior to the Capital Plan filing, and separate filings would be required if a specific level of accuracy is expected. BCTC is currently evaluating the appropriateness and impact of submitting requests for approval for non-CPCN projects separately from the Capital Plan filing.

9.43 BCUC Letter to BCTC dated December 4, 2007 on Fox Creek Project Report

> **"In the context of the next BCTC Capital Plan, the Commission would be interested in receiving comments from BCTC on ... 2. the costing of transmission line route uncertainty and adequate project scope, …"**

The costing of transmission line routing uncertainty is difficult as the establishment of the final line routing is a process of balancing:

(a) Technical requirements;

(b) Project cost and/or schedule;

(c) Environmental impact; and

(d) Community acceptance.

In the case of the Fox Creek Project, efforts to ensure community acceptance and to meet the aggressive schedule resulted in increased project costs.

Transmission line projects require route assessment and consultation with the public, stakeholder and First Nations before an adequate scope can be established and more accurate cost estimates can be prepared. These activities also require sufficient lead time to ensure the reasonable balancing of cost, overall schedule, technical requirements, environmental impact and community acceptance.

BCTC learned with the Fox Creek Project that route and site selection should be done during the Definition Phase of the project to reduce cost uncertainty at the time of approval. Whenever the schedule allows it, BCTC will seek approval for the Definition Phase before seeking approval for the Implementation Phase of projects requiring route and site selections. If the schedule does not allow for it, the cost estimate will have to reflect the uncertainty.

Generally uncertainty is factored into a project through a project contingency allowance. The contingency is developed by identifying the various project specific risks, their probability of occurrence and the estimated cost if they occur.

Transmission routing uncertainty would normally be factored into the contingencies. The value would be determined based on the general location of the line and proximity to known issues or sensitivities. Sometimes, however, it can still be underestimated given the time to adequately identify and assess potential problems.

9.44 BCUC Letter to BCTC dated December 4, 2007 on Fox Creek Project Report

> **"In the context of the next BCTC Capital Plan, the Commission would be interested in receiving comments from BCTC on ... 3. reporting of significant potential cost increase (+20% or $5M) to the Commission."**

BCTC reports significant potential cost increases (+20% or $5M) to the Commission through its Capital Plan filings and Quarterly reports.

In response to Commission Directive No 11 in Order G-69-07, BCTC is reporting variances of ongoing approved Growth Capital projects by providing the approved total annual expenditures, the revised total annual expenditures, and the difference between the approved and revised annual expenditures, as well as the approved and revised in-service dates. The variance data is provided in the form of tables and are accompanied with variance explanations for all significant cost variances (+20% or $5M). The tables and variance explanations are located in Section 5.3.

In response to Commission Directive No 37 in Order G-91-05, BCTC is providing a summary of the previous three years' activities and expenses for each ongoing BCTC Capital portfolio project whose annual costs exceed $250,000. The summary of activities and expenses, accompanied with variance explanations, is provided in Section 7.2.2.

In addition, BCTC reports variance during the Implementation Phase of CPCN projects through the Quarterly filings.

Appendix A

Directive Concordance Table

This table lists directives from:

(a) the Decision on the BCTC Transmission System Capital Plan F2008 to F2017 Application issued with Commission Order G-69-07;

(b) the Decision on the BCTC Transmission System Capital Plan F2006 to F2015 issued with Commission Order G-91-05; and

(c) BCUC letter dated December 4, 2007 on the Fox Creek Project Report.

For each directive, the table provides the page number where the directive can be located in the corresponding Decision, the directive number (if one was assigned), a brief description of the topic addressed by the directive, and the section(s) of the Application that addresses the directive.

Decision Page Number (a)	**Directive Number** (b)	**Topic** (c)	**Application Section** (d)
Commission Order G-69-07			
14	1	Identification of projects that avoid generation shedding for first contingency events	9.1
14	2	Planning assumptions	9.2
15	3	Re-dispatch of generation resources	9.3
16	4	Disposition of Definition Phase project costs	9.4
17	5	Transmission Expansion Policy and alternatives to Golden and North Thompson projects	9.5
19	6	Report on emergency capital expenditures	9.6
20	7	Lessons-learned reports for over-budget or over-timeline projects	9.7
20	8	Variance reporting	9.8
30	9	Frequency of State of the Transmission System Reports	9.9
30	10	Reporting of performance measures	9.10
32	11	Projects in progress from Growth Capital Portfolio, and changes to previously approved projects	9.11
35	12	Forecasting capital for IPP projects	9.12

Decision Page Number (a)	Directive Number (b)	Topic (c)	Application Section (d)
37	13	Report on progress of establishing correlations among asset class parameters	9.13
37	14	Providing equipment reliability data	9.14
45	15	File an “operators manual” for Prioritization Model	9.15
45	16	Project prioritization results for the three portfolios	9.16
46	17	Comment on issue of safety and reliability versus prioritization results	9.17
46	18	Provide a corporate risk matrix	9.18
46	19	Comment on issue of estimating revenue of growth projects	9.19
48	20	Table showing load growth information for each regional reinforcement project	9.20
53	21	Prioritize potential TEP projects with other projects	9.21
55	22	Highest ranking intertie expansion project	9.22
56	23	projects and corresponding expenditures attributable to specific generation additions	9.23
56	24	Selkirk Transformer Addition, Ashton Creek Shunt Capacitor, Series Compensation projects	9.24
58	25	Mission Matsqui Area Supply project	9.25
66	26	Series Compensation project study describing Canadian Entitlement use	9.26
67	27	Report on Lower Mainland’s reactive power requirements	9.27
73	28	Report on Fox Creek project	9.28
77	29	Chapman Fibre Optic Cable Replacement project	9.29
82	30	Conform to directives from F2006 and F2006 Update Capital Plan Decisions on Sustaining Capital expenditures	9.30
83	31	Use 2% inflation to budget for Sustaining Capital	9.31
83	32	Sustaining Capital expenditures	9.32
87	33	Investigate and report on integrating IT system with BC Hydro	9.33

Decision Page Number (a)	**Directive Number** (b)	**Topic** (c)	**Application Section** (d)
87	34	Table showing project changes from previous capital plan	9.34
88	35	Capital Control Centre Sustainment project	9.35
89	36	Capital Facilities assets projects	9.36
92	37	File report on Policy Actions 12 and 13	9.37
93	38	Assess FERC Order 890	9.38
97	39	File report on resolving congestion with generation re-dispatch	9.39
Commission Order G-91-05			
26	11	Data for asset condition audits	9.40
Commission Letter dated December 4, 2007			
1	(Fox Creek)	Future Capital Plans and CPCNs to include Lessons Learned	9.41
1	(Fox Creek)	Level of accuracy of estimates	9.42
1	(Fox Creek)	Costing of uncertainty and adequate project scope	9.43
2	(Fox Creek)	Reporting significant cost increases	9.44

Appendix B

2007 State of the Transmission System Report

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LIST OF APPENDICES

1.0 INTRODUCTION

The 2007 State of the Transmission System Report (STSR) provides stakeholders with an updated “big picture” of the current state of the transmission system and the issues the BC Transmission Corporation (BCTC) is addressing by the projects and programs proposed in BCTC’s F2009 Transmission System Capital Plan (F2009 Capital Plan). It is an updated version of the 2006 STSR and describes issues that BCTC is facing regarding:

(a) The bulk system;

(b) The regional and local systems;

(c) Specific equipment; and

(d) Strategic issues.

This STSR reviews the transfer capability of the transmission system at the bulk, regional and local area levels and discusses the condition of installed equipment and control infrastructure. The STSR highlights emerging capacity and sustainment challenges, and identifies some potential solutions. These solutions range from replacing defective equipment to enhancing the system with the objective of increasing efficiency, reliability, or capacity. The report also discusses methods for evaluating appropriate investment levels to maintain the current condition and performance of system equipment.

The STSR contains page references to BCTC’s F2009 Capital Plan in which there is a description of proposed investments to address the identified issues.

BCTC’s annual analysis of the performance and needs of the transmission system is undertaken to ensure that the system can carry the generation and loads forecast by BC Hydro[1] and others. BC Hydro’s demand forecast shows the demand for energy increasing by 25% to 45% over the next twenty years. BC Hydro filed an Amended

[1] BC Hydro filed its 20-year Integrated Electricity Plan (IEP), including the Long Term Acquisition Plan (LTAP), with the BC Utilities Commission (the Commission) on March 29, 2006. The IEP forecasts demand growth and describes how BC Hydro expects to meet the forecast demand using new generation facilities, demand side management programs (DSM), Independent Power Producer (IPP) calls for tender, and energy imports.

LTAP with the Commission on August 31, 2006 which combines conservation, IPP purchases and BC Hydro projects to meet the growing demand.

In its May 11, 2007 decision on BC Hydro's Amended LTAP, the Commission accepted the use of the LTAP Base Case and Contingency Resources Plans (CRPs) described in Exhibits B-1E and B-55 for use in BC Hydro's next Network Integration Transmission Service (NITS) update application. The Commission went on to direct BC Hydro to submit for approval an updated LTAP Base Case and CRPs that better reflect BC Hydro's expectations of future resource additions. BC Hydro has provided BCTC with preliminary resource information on this matter in resource plans called Base Resource Plans (BRPs). These BRPs are likely to become the updates to the amended LTAP/CRPs and eventually the next NITS application. BCTC has developed the F2009 Capital Plan based on the information contained in these resource plans.

This 2007 STSR is BCTC's third State of the Transmission System Report. This version provides an update on the status of the issues discussed in the 2006 STSR and identifies new issues that have emerged since that report. It generally follows the structure and outline used in the 2006 STSR to facilitate reading for individuals who are already familiar with the STSR format. Those who have read the 2006 version may be familiar with the basic transmission system and its condition and the general challenges of BCTC to sustain and expand its capability in the face of increasing usage. Nevertheless, for convenience and context, the 2007 STSR repeats some material which describes these general issues and conditions to support the reader in understanding the F2009 Capital Plan of which this document is a part. It is anticipated that this repetition will relieve the reader of the need to refer back to prior versions of the STSR to understand a particular issue or descriptive text.

In February 2007, the B.C. government issued a new Energy Plan. This plan included several policy actions relating to transmission to ensure adequate transmission is in place to support the provincial goal of energy self sufficiency. This has several immediate impacts on the Capital Plan. For example: the IPP work load will continue at an increased level as new IPP projects are added to the system; Mandatory Reliability Standards will be introduced in BC; BCTC has committed to developing a long term outlook for the transmission system; and a congestion relief policy is being developed by the provincial government to help ensure that adequate transmission infrastructure is in place to meet provincial energy objectives and customer needs.

2.0 THE TRANSMISSION SYSTEM

2.1 Overview of the Transmission System

The transmission system is part of the Western Interconnection, which extends from BC and Alberta in the north, to northern Mexico in the south, and includes most systems in the western U.S. As required by the Western Electricity Coordinating Council (WECC), the transmission system is planned, built and operated in a manner that avoids negative impact on the interconnected neighbouring systems outside BC. Interties to neighbouring systems provide opportunities for electricity trade, improve the overall reliability of the system, make backup energy resources available in emergencies, and improve control of frequency and power fluctuations.

The Transmission System contains:

(a) 18,336 km circuit transmission lines,

(b) 291 switching, distribution and capacitor stations,[2]

(c) One System Control Center,

(d) Four regional control centers,

(e) 169 microwave and fibre optic sites, and

(f) Interconnections to Alberta and the Pacific Northwest.

For planning purposes, BCTC defines the transmission system to be made up of:

(a) The bulk transmission system;

(b) The regional transmission systems;

(c) The internal interties to the Alcan system and the FortisBC system;

[2] New substations added to the system in the past year include Fox Creek, Function Junction, Haney, and Harvie Road.

(d) The external interties to systems in Alberta and Washington State; and

(e) A comprehensive communication, protection and control system.

The bulk transmission system includes the 500 kV transmission system, parts of the 230 kV system, the transmission connections to Vancouver Island, and interconnections with other utilities through interties. These lines connect the large remote generating stations in the Peace River and Columbia River areas with the major load centres of the Lower Mainland and Vancouver Island, which together comprise over 70% of the BC Hydro load.

Four regional transmission systems transfer energy within specific geographic areas of the province: the Northern Interior, the Southern Interior, the Lower Mainland, and Vancouver Island. The regional systems generally consist of 230 kV, 138 kV, and 60 kV transmission networks that connect local generation and deliver power to distribution utilities or transmission customers located within the region.

The transmission system is currently managed by BCTC's System Control Centre (SCC) located in the Lower Mainland, with support from four Regional Control Centres (RCCs). The SCC operates the bulk system, controls intertie flows, and balances the generation supply to meet the real time demand for electrical energy. Control and monitoring activity is automated through a computerized Energy Management System (EMS) and Supervisory Control and Data Acquisition (SCADA) system.

The RCCs, located in Vancouver, Duncan, Vernon and Prince George, focus on regional operations. Coordination between the SCC and the regional centres ensures that the electric system can operate reliably while meeting customer demands, facilitating electricity trade, and accommodating maintenance outage requirements. By late F2008, BCTC will have replaced the current SCC and RCCs with a centralized control centre. The centralization project, known as the System Control Modernization Project (SCMP), is replacing obsolete technology, resolving seismic risk issues, providing a geographically separate backup facility, streamlining control and operating infrastructure, and addressing limitations of the existing SCC facility.

2.2 The Bulk Transmission System

Figure 2-1 provides an overview map of the bulk transmission system. It illustrates how the bulk system connects the major generation areas in the system to the urban load centers and how it interconnects to Alberta and the U.S.

Figure 2-1. Map of the Bulk Transmission System

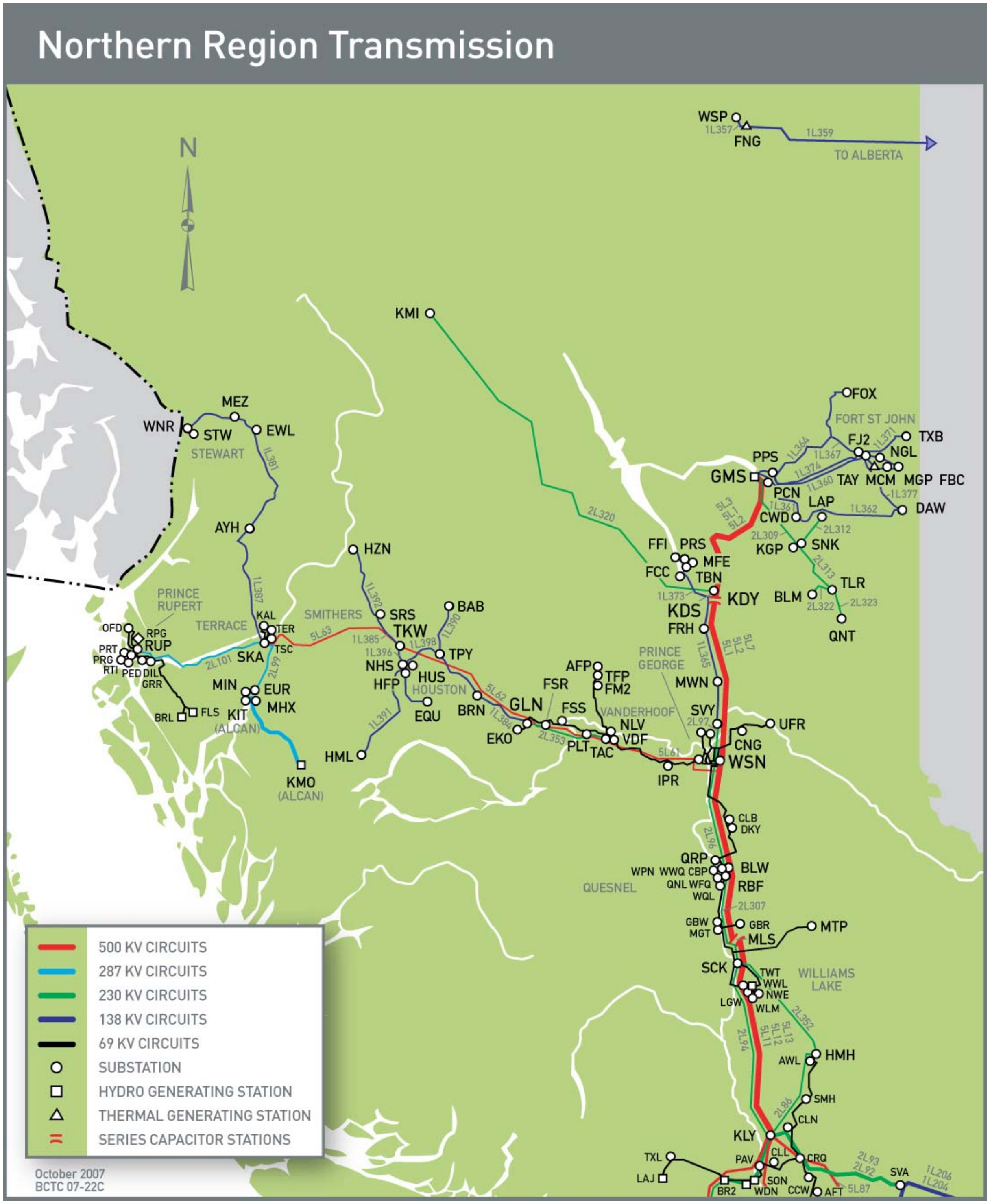
For planning purposes, the bulk system is subdivided into four grids which deliver energy from one area to another: the Northern Grid, the Southern Grid, the Interior to

Lower Mainland (ILM) Grid, and the Lower Mainland (LM) to Vancouver Island (VI) Grid. These four systems are discussed in Sections 2.2.1 through 2.2.4, respectively.

2.2.1 The Northern Grid

Figure 2-2 shows the Northern Grid, including the major Peace River generating region in the northeast and the main transmission lines to Williston Substation (WSN), near Prince George, from WSN to Kelly Lake Substation (KLY), near Clinton, and from WSN to the North Coast System, which interconnects to the bulk system at Skeena Substation (SKA). It also shows much of the regional transmission, which is discussed in Section 2.3.2.

Figure 2-2. Northern Region Transmission System Map



The Northern Grid transmits electrical energy from GM Shrum (GMS) and Peace Canyon (PCN) generating facilities near Fort St. John southward to the ILM Grid at KLY. The Northern Grid also transmits electrical energy to and from the North Coast area of the province depending on whether Alcan is importing energy from the BCTC system or exporting energy it produces at its Kemano generating facility to the BCTC system.

The Northern Grid can be viewed as three distinct systems: the Peace to Williston System, the Williston to Kelly Lake System, and the Williston to North Coast System.

2.2.1.1 Peace to WSN System

Three parallel 500 kV transmission circuits from GMS south to WSN make up the Peace to WSN System. Two of these lines, 5L1 and 5L2, transmit energy directly to WSN and are series compensated at Kennedy Capacitor Station (KDY). The third has three sections, 5L4 from GMS to PCN, 5L3 from PCN to Kennedy Substation (KDS) and the adjacent Kennedy Capacitor Station (KDY), and 5L7 from KDY to WSN.

The Peace to WSN System south of KDS is limited by voltage stability under winter peak load conditions. Preliminary studies indicate that the existing capacity is adequate to serve the forecast dependable generation capacity additions up to 2010 including the dependable generation capacity from BC Hydro's F2006 Call for Tender (CFT).

In the past year, BCTC has studied potential future transmission upgrades required to integrate new generation resources in the Peace region. After 2010, shunt capacitors and a Static VAR Compensator (SVC) at WSN are one option to add additional voltage support to the north of WSN cut plane[3] resulting in about 600 MW of additional TTC. A new GMS to WSN 500 kV line is another option and would further increase the TTC significantly. The amount of additional TTC required north of WSN will depend on the future Peace area generation additions and changes in the area load.

2.2.1.2 WSN to Kelly Lake System

From WSN, three 500 kV transmission lines (5L11, 5L12, 5L13) transmit energy south to KLY. Preliminary studies indicate the following:

[3] "Cut-planes" are used in transmission studies to illustrate the capability and needs of the bulk system transmission paths to move energy from one location to another. They are hypothetical lines "cutting" through the transmission circuits connecting two areas of the system.

(a) The existing capacity will adequately cover the forecast dependable generation capacity additions up to 2010 including the dependable generation capacity from BC Hydro's F2006 CFT and firm transfer service to Alcan.

(b) Further generation additions in the Peace region and North Coast will require capacity additions on the path sometime after 2010.

(c) An SVC at WSN together with a shunt capacitor bank at KLY could provide an additional 660 MW of TTC when there is a need for more capacity.

BCTC is continuing to study these issues but the resource plans for the Northern Interior are still uncertain and the transmission reinforcements will stay in the planning study phase until the resource additions are more certain.

2.2.1.3 WSN to North Coast System

A single radial transmission line system transmits energy to the North Coast area from WSN on three 500 kV transmission lines (5L61, 5L62 and 5L63) connected in series to Glenannan (GLN), Telkwa (TKW), and then Skeena (SKA) Substations.

Energy flows on these lines either to or from the North Coast depending on whether Alcan is exporting or importing power. Alcan has installed generating capacity of 920 MW at its Kemano Generating Station. The Alcan smelter load can be as high as 610 MW. Depending on the time of year and at different combinations of generation and smelter load, Alcan can be either a net importer (up to 200 MW) or exporter (up to 380 MW) of power.

The risk of load loss from interruption of the single 500 kV radial transmission service is mitigated by a Remedial Action Scheme (RAS) that provides underfrequency load shedding to stabilize the system in the event of islanding[4] to balance load to the on-line local generation. The line also has single-pole reclosing to minimize the risk of a separation by maintaining synchronism and automatically restoring the connection in the case of a single line to ground transient fault. Most faults are single-phase transient events and islanding of the North Coast area is infrequent. For the North

[4] Islanding is an undesirable condition that exists when a portion of the integrated system is separated from the rest and is forced to operate with its own generation and load in a balanced condition. Without a balance of load and generation the frequency deviations of the islanded system may be large and both load and generation need to be constantly monitored and controlled.

Coast system, the planning practice has been to provide enough load carrying capability to at least serve the District Load under single-contingency (N-1) system conditions.

A significant initiative in this area of the province is the proposed changes to the Alcan smelter in Kitimat (see Section 2.2.5.1).

BCTC is now reviewing how the addition of proposed major industrial loads or large generating facilities in the North Coast area could trigger investments to reinforce the bulk system. For example, the impact of adding a large wind generation installation (in the order of 500 MW) in this region would require two reinforcements:

(a) An SVC at Skeena to maintain a proper voltage profile on the 500 kV line between WSN and Skeena; and

(b) Series compensation of 5L61 Williston – Glenannan 500 kV to keep the system transiently stable when there are large flows on the 500 kV system from Skeena towards WSN (west to east).

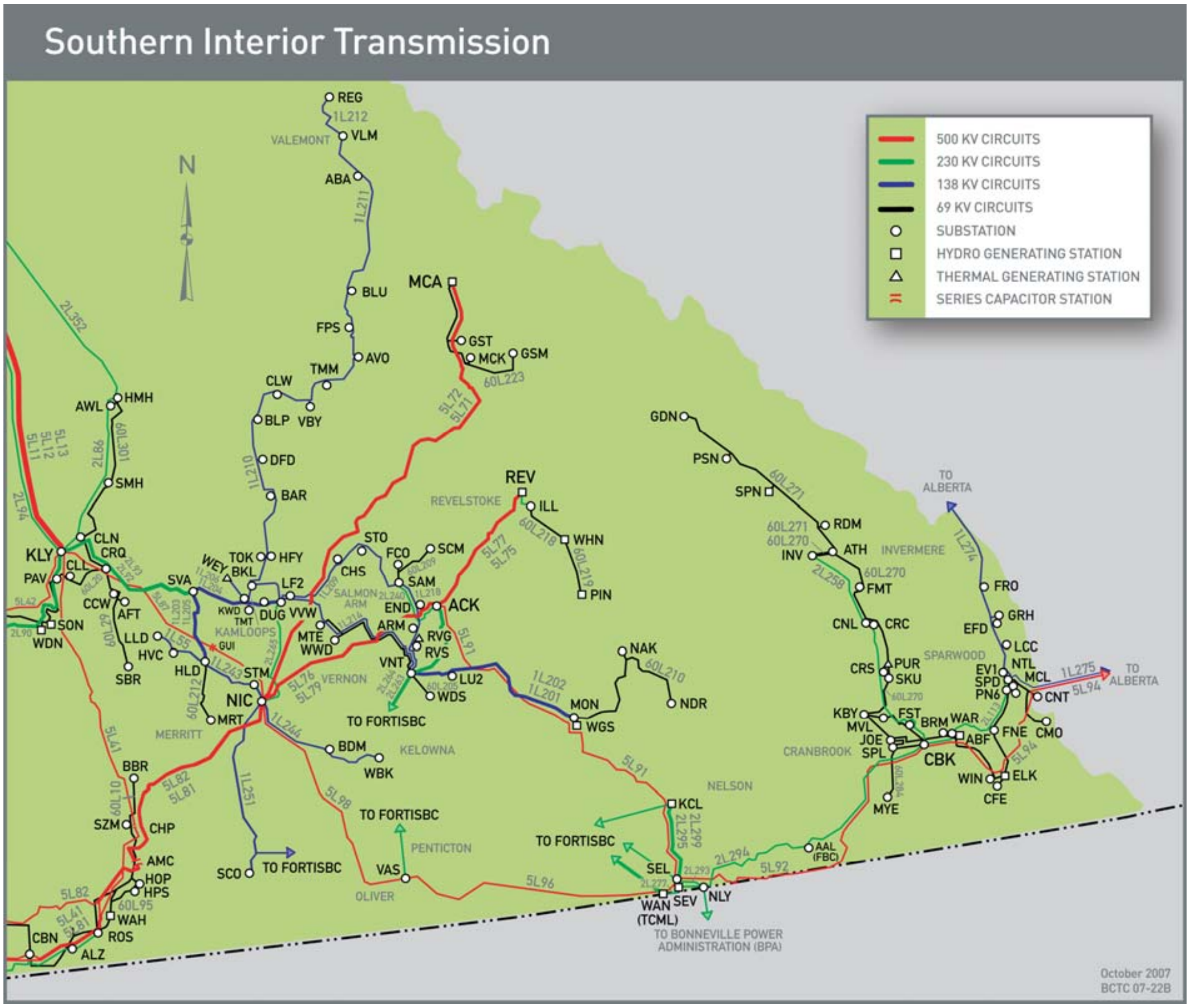
These reinforcements are still in the planning study phase, due to the uncertainty of the generation additions.

2.2.2 The Southern Interior Grid

Approximately half of BC Hydro's generation is located in the Southern Interior (SI), one of the largest generation regions in BC. The SI Grid transmits energy generated by BC Hydro in the Columbia and Kootenay regions, plus imported energy from the US and Alberta. The energy flows west to the ILM Grid at Nicola Substation (NIC) near Merritt. The SI System is also used to deliver FortisBC energy from the Kootenay area to the Okanagan area according to the General Wheeling Agreement.

Figure 2-3 shows the SI Grid. It also shows much of the regional transmission system, which is discussed in Section 2.3.3.

Figure 2-3. Southern Interior Transmission



2.2.2.1 Overview of the Southern Interior Grid

BC Hydro's total installed generation capacity connected to the SI System is 5264 MW[5]. Revelstoke and Mica Generating Stations connect directly into the 500 kV system, while Kootenay Canal, Seven Mile and Arrow Lakes generating stations are integrated into the 230 kV system. Other hydroelectric generating stations in the southeast are connected to the FortisBC transmission system (Waneta, Brilliant, South Slocan, Lower Bonnington, Upper Bonnington and Corra Linn), which connects an additional 813 MW[6] to the SI Grid at Selkirk Substation (SEL) near Trail. The

[5] This amount is based on nameplate ratings.
[6] This amount is based on maximum continuous output.

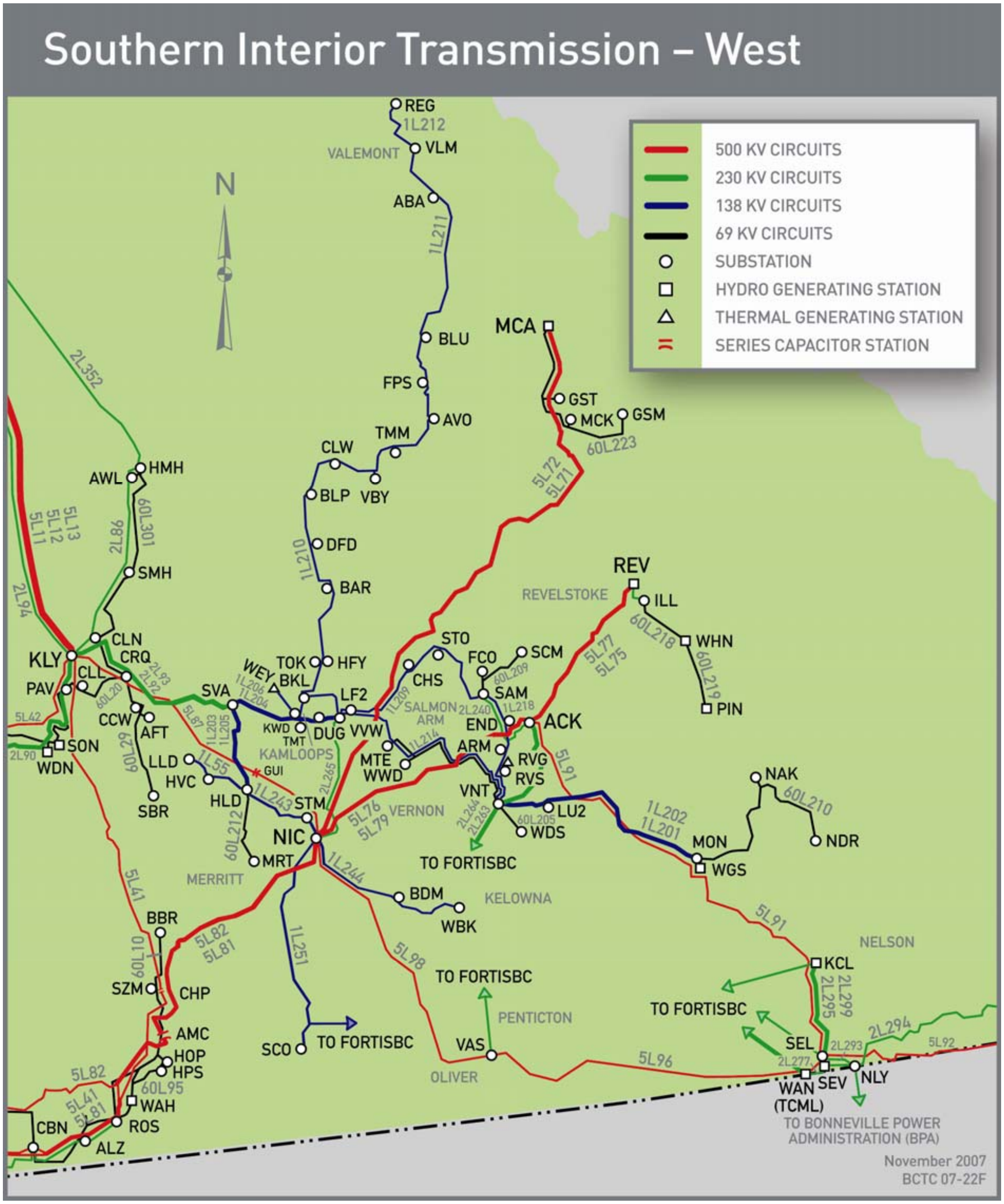
majority of generation in the southeast is transformed from 230 kV to 500 kV through the transformers at SEL.

The SI Grid can be divided into two distinct subsystems, the system from the lower Columbia area west to NIC (SI West), and the upper Columbia area east to Alberta (SI East). The two areas connect at SEL.

2.2.2.2 SI West

Major transmission paths collect electrical energy generated in the SI West, shown in Figure 2-4, and deliver the energy to NIC where the SI West System connects to the ILM Grid.

Figure 2-4. SI West Section of Southern Interior Bulk System



SEL collects most of the energy generated in the Trail area and adds it to the bulk system. SEL receives energy from Seven Mile Generating Station on 2L221 and

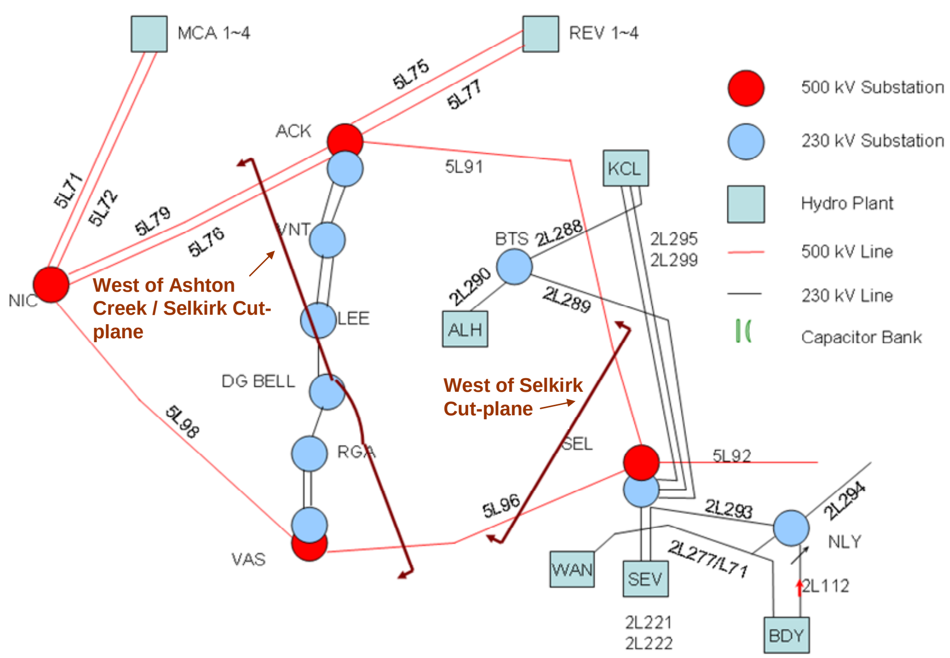
2L222 and receives energy from Kootenay Canal Generating Station on 2L295 and 2L299.

From SEL, energy is delivered west over the 500 kV Selkirk-Vaseux-Nicola 5L96/98 line and the 5L91 line to Ashton Creek Substation (ACK), where it is merged with energy from Revelstoke Generating Station and then travels over two 500 kV lines (5L76 and 5L79) to NIC. The transfer of energy west from SEL is limited by capacity restrictions on the 5L96 path and the 5L91 path which together are referred to as the West of Selkirk cut plane which is discussed below.

Energy from Mica Generating Station is delivered on two 500 kV transmission lines (5L71 and 5L72) directly to NIC.

Figure 2-5 identifies two important cut planes on the SI West system.

Figure 2-5. SI West System 2008 - Cut Planes



The West of Selkirk cut-plane consists of 5L91 and 5L96. Energy from SEL flowing west through this cut-plane towards ACK and NIC is restricted to less than the present need. Generation shedding schemes are presently used to prevent a system voltage violation from a single contingency of 5L91, 5L96, or 5L98. The new SEL transformer and the planned FortisBC Vaseux 230 kV system upgrades will increase the TTC in 2010.

The West of Ashton Creek/Selkirk cut-plane consists of lines 5L76, 5L79 and 5L96. Energy from Revelstoke and SEL flows westward through this cut-plane. The TTC is limited by voltage instability which could occur when 5L96 is forced out of service. An increase in the West of Selkirk cut plane limit will also raise the TTC limit in this cut plane because the two cut planes overlap. BCTC expects that reinforcing the West of Selkirk cut-plane for Revelstoke G5 will defer any need to reinforce this cut-plane until Revelstoke Unit 6 is added to the system.

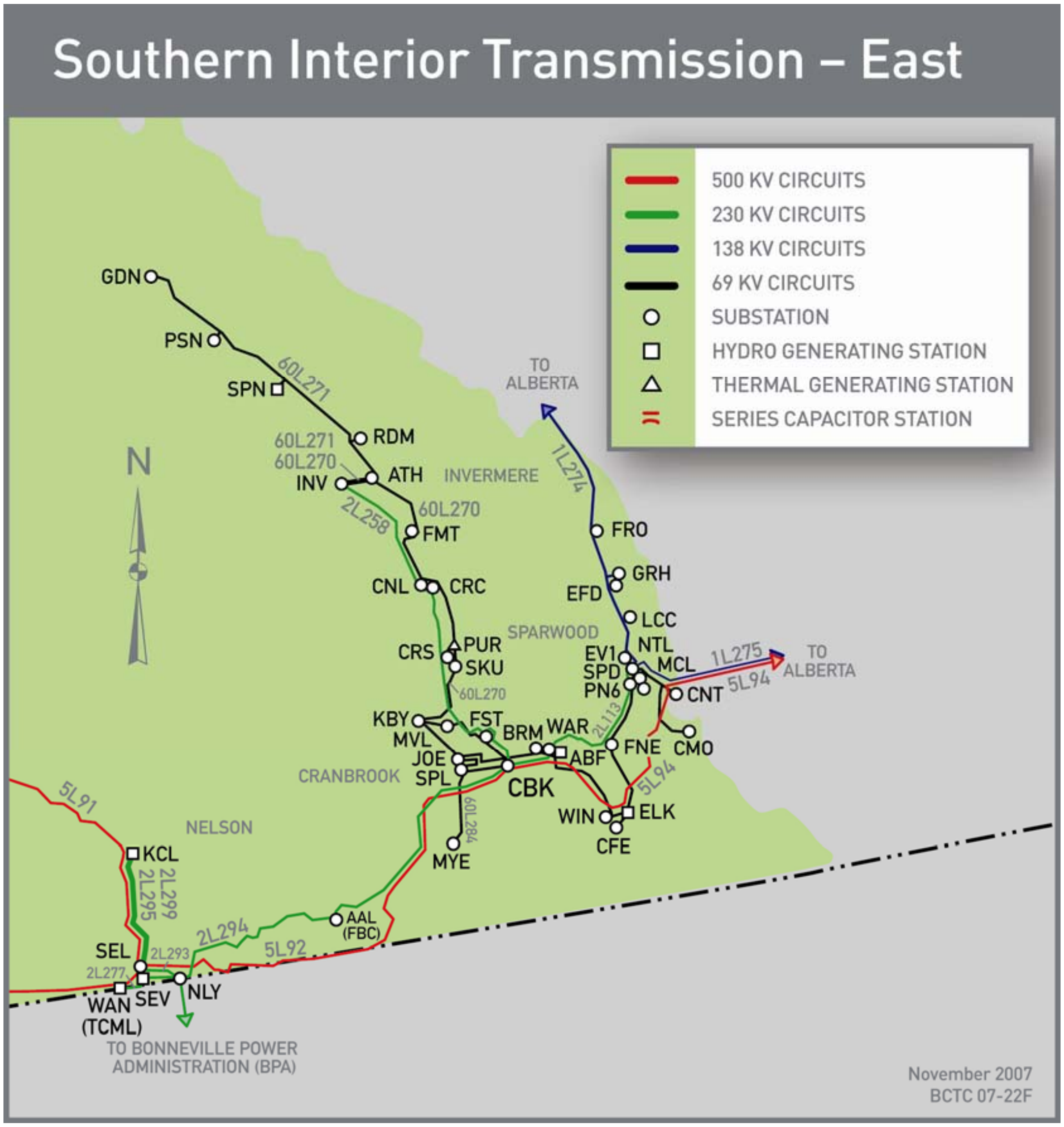
In the past year, BC Hydro has received Commission approval to install the new Revelstoke Unit 5 in 2010. This new unit and further increases in area generation or imports will require more SI West reinforcements. BCTC has completed Definition Phase activities on the addition of shunt capacitor banks at ACK and series capacitors on 5L91/5L98 which were approved by the Commission in its F2008 Capital Plan Decision. In the F2009 Capital Plan, BCTC is requesting approval for the implementation phase of the ACK shunt capacitor banks (Section 5.5.1.1).

BCTC has performed a conceptual study for integrating three more large generating units (Revelstoke 6, Mica 5 and Mica 6) into the SI West system. The Mica units require adding 50% series compensation to 5L71 and 5L72 and Revelstoke 6 requires adding 50% series compensation to 5L76, 5L79 and 5L96. For double contingency outages of the two circuits to Mica or to Revelstoke, a load shedding RAS would be required. An alternative to the load shedding is to build a new Downie Substation and new Mica – Downie – Revelstoke 500 kV transmission lines. These reinforcements are still being studied to evaluate alternative solutions and timing, which will be influenced by the schedule of projects to add the three new generating units.

2.2.2.3 SI East

Figure 2-6 provides a map of the SI East system. Energy is transferred eastward from SEL to Cranbrook (CBK) by Circuits 5L92, 2L293 and 2L294 to serve load. Energy is then transmitted further eastward from CBK to Alberta by 5L94. Energy also flows from CBK on 2L113 to Natal Substation (NTL), which in turn is connected by two 138 kV lines to Alberta. The capacity of the SI East system is currently adequate and reinforcement is not required for this area of the bulk system under existing contracts.

Figure 2-6. SI East Section of SI Bulk System

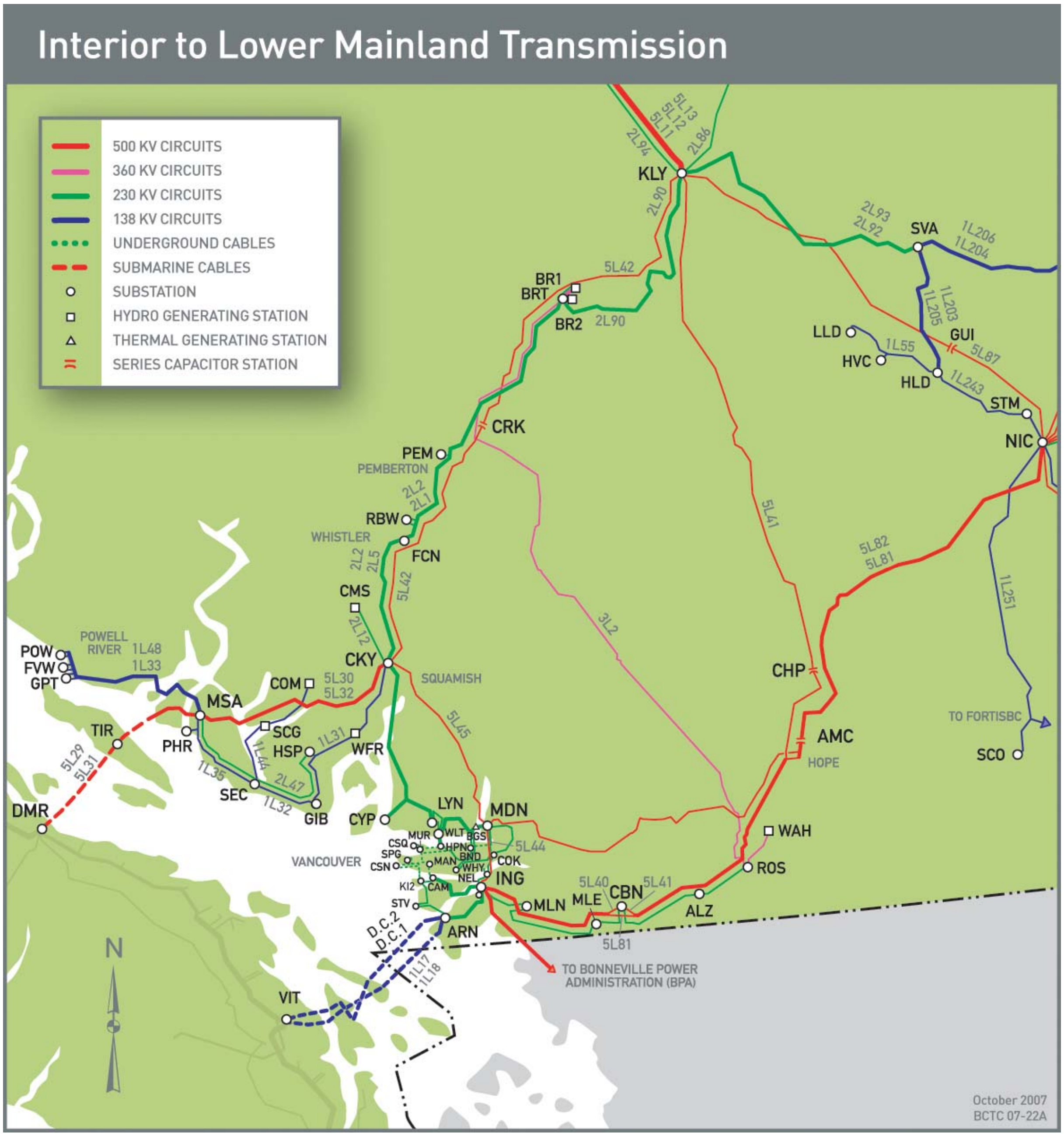


2.2.3 The Interior to Lower Mainland (ILM) System

The ILM Grid is the most critical transmission path in the province. It transmits energy from the Interior to serve the Lower Mainland (LM) and Vancouver Island (VI) load centers and is a key transmission path for both firm and non-firm energy trading activity.

Figure 2-7 is a map of the ILM Grid and shows the transmission to VI as well as much of the regional transmission system in the LM, which is discussed in Section 2.3.1.

Figure 2-7. Interior to Lower Mainland System Map



2.2.3.1 Overview of the ILM System

The ILM grid is comprised of eight 500 kV transmission lines. The power transfer from the Interior to the LM and VI takes place over four of these lines:

(a) 5L81 and 5L82 connect Nicola (NIC) Substation in the South Interior to Ingledow (ING) and Meridian (MDN) substations in the LM; and

(b) 5L42 connects Kelly Lake (KLY) Substation in the Interior to Cheekye (CKY) Substation and 5L41 connects KLY to Clayburn (CBN) Substation in the LM.

Four additional lines allow for power sharing between the substations:

(a) 5L45 connects CKY and MDN substations in the LM;

(b) 5L44 connects MDN and ING substations in the LM;

(c) 5L40 connects CBN an ING substations in the LM; and

(d) 5L87 connects NIC and KLY substations in the Interior.

Five of the ILM lines (5L41, 5L42, 5L87, 5L81, and 5L82) are series compensated to increase transfer capability.

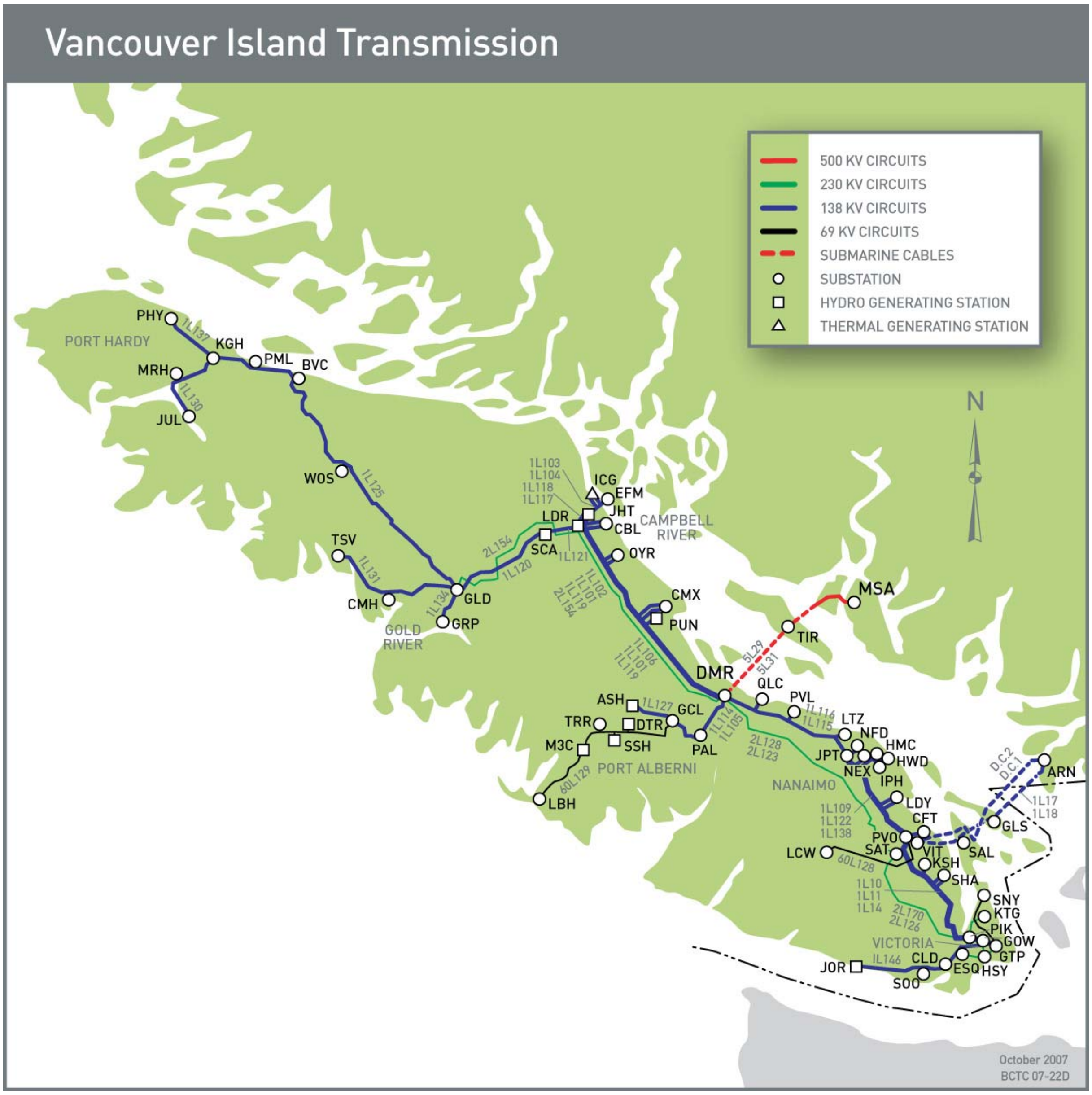
BCTC is continuing to advance a new series compensated 500 kV line (5L83) between NIC and MDN to satisfy the need for more TTC on the ILM Grid. BCTC submitted a Project Description to the Environmental Assessment Office (BCEAO) in December 2006 and the EAO issued a Section 10 Order on December 18, 2006 designating the project as reviewable under the BC Environmental Assessment Act. BCTC plans to file an Application for an Environmental Assessment Certificate (EAC) in the fall of 2008.

On November 5, 2007, BCTC filed a CPCN application with the Commission seeking a Certificate of Public Convenience and Necessity (CPCN) for the ILM Project.

BCTC has studied the ILM grid’s voltage stability limits and the options available to overcome them. This limit can be effectively increased by adding reactive power support at MDN and NIC. Beyond this, adding more reactive support to increase the voltage stability limits of the ILM grid is ineffective and additional circuits will be required to extend the transfer capability of the system. After 5L83 is added to the grid, thermal and reactive reinforcements, including another 500 kV line between KLY and CKY (5L46), can then be effective additions to maximize the capability of the grid.

2.2.4 The Lower Mainland to Vancouver Island (LM-VI) System

Figure 2-8. Lower Mainland to Vancouver Island System Map



2.2.4.1 Overview of the LM-VI Grid

VI and the southern Gulf Islands are supplied by submarine cable circuits crossing Georgia Strait which are shown in Figure 2-8. Until this year the LM-VI Grid included:

(a) Two 500 kV submarine cables (5L29, 5L31) from Malaspina Substation (MSA) near Pender Harbour to Dunsmuir Substation (DMR) near Parksville on Vancouver Island;

(b) Two 138 kV circuits (1L17, 1L18) each comprised of:

  i. A submarine cable section from Arnott (ARN) Substation (in Delta) to the southern Gulf Islands, containing a combination of 138 kV submarine cables and 138 kV overhead lines; and

  ii. An overhead 138 kV line section from the Gulf Islands to Vancouver Island Terminal (VIT) near Duncan; and

(c) A bi-pole High Voltage Direct Current (HVDC) cable system from ARN to VIT.

The two 500 kV circuits (5L29 and 5L31) are in good condition and the combined winter firm capacity rating for the two circuits has been determined to be 1400 MW as a result of studies which consider the daily variation in VI load, the short term overload capability of the cables, and the cooling of the cables during the lower transfer hours between the two peak load periods each day. The 5L29 plus 5L31 transfer limit allows for a continuous load of 1200 MW with 4 hours of morning plus 4 hours of evening overload at 1400 MW each day. The summer firm capacity rating is 1300 MW.

The two 138 kV circuits, 1L17 and 1L18, were built in the 1950’s were in poor condition and are zero-rated[7] for planning purposes because they have reached their end of life. The overhead line sections of both 1L17 and 1L18 and the submarine cable sections of 1L17 are being replaced as part of the 230 kV Vancouver Island Transmission Reinforcement Project (VITR). This project has been granted a CPCN by the Commission and an EAC Certificate. Currently, the overhead line sections on

[7] This means that the circuits cannot be depended on for long term use as they may fail at any time and are uneconomical to repair for long term service; however, parts of them are still in service and will continue to be used until they are permanently replaced as part of the VITR Project.

Vancouver Island and Saltspring Island have been removed and replaced with 230 kV. The submarine cables of 1L17 have been removed as well.

The VITR Project is currently under construction with an in-service date of October 2008. During the construction period, the southern Gulf Islands will continue to be served at 138 kV through existing and/or rebuilt sections of 1L17 and 1L18. After the completion of VITR, the new circuit, 2L129, will replace 1L17, which will be retired. The new 2L129 will supply Vancouver Island load at 230 kV. The southern Gulf Islands will then be supplied by the remaining 1L18 with its old 138 kV cable and its newly-built 230 kV-rated overhead line sections. The southern Gulf Islands will be primarily supplied from VIT through the upgraded overhead section of 1L18. At a future date[8], a second 230 kV ARN to VIT circuit may be required to serve VI load depending on other alternatives at the time.

The HVDC system, including overhead lines, submarine cables and terminal converter station equipment, is old and deteriorating. The dependable TTC of the HVDC system has been de-rated over time from 788 MW to zero for planning purposes as the reliability of the system has diminished. The HVDC system needs to be maintained in an operational capacity for security until the VITR Project is in service. BCTC will then keep the HVDC system in service so long as the operational benefit exceeds the economic cost to do so.

On June 4, 2007, a permanent failure occurred on one of the two HVDC Pole 1 cables crossing Georgia Strait. As a result of this incident, BCTC has been forced to modify its operation of the HVDC system. During off-peak seasons, Pole 1 is being shutdown to preserve its availability for use if another outage occurs in the system supplying VI. In the peak season (winter), Pole 1 will be operated to add capacity to VI. BCTC has decided not to repair the failed DC cable because a submarine cable repair would take a long time, would have a very high cost, and the capacity addition from VITR will be in service in 2008.

[8] This would be required when the Vancouver Island demand exceeds the capacity of the supply. The supply capacity depends on the resource plans submitted by BC Hydro, which at this time indicate the second phase will not be required until after 2023. All then appropriate options would be considered at that point in time.

Until VITR is in service, the firm load carrying capacity of the LM-VI Grid will be approximately 300 MW below the peak VI demand given in BC Hydro's December 2006 load forecast. The Vancouver Island Operating Plan is revised annually to ensure operators have a strategy to deal with contingencies to mitigate the risk from this capacity shortfall until VITR comes into service.

2.2.5 Internal BC Interties

2.2.5.1 Alcan Intertie

The transmission system is connected to the Alcan transmission system in the Kitimat area by a single 287 kV line from Minette Substation (MIN) to Alcan's Kitimat Substation (KIT).

Alcan plans to modernize its Kitimat Works and the modernized smelter could use virtually all of the firm power from Alcan's wholly-owned Kemano hydro-electric plant.

At the request of Alcan, BCTC has assessed the system impact for the modernization project and posted the study report on BCTC's website. For the detailed impact study results, please refer to the report at:

> www.bctc.com/NR/rdonlyres/5C6577C2-7939-4ABC-B9AF-5B9963D31CC7/0/AlcanModernizationProject_SPPA_MO.pdf

With the Kitimat modernization project, Alcan's surplus power will be reduced as a result of the increased Kitimat smelter load. The transfer limit from Alcan to BCTC will need to be reassessed due to the impacts of the new Kitimat smelter design and the associated need for reactive power compensation.

2.2.5.2 FortisBC Interties

The SI Grid has interconnections to FortisBC's transmission system known as the Okanagan Interconnection (OI) and the Kootenay Interconnection (KI). The OI consists of two 500/230 kV transformers at Vaseux Lake Substation (VAS) connecting VAS to the FortisBC system near Oliver and two 230 kV transmission lines (2L263 and 2L264) connecting Vernon Terminal Substation (VNT) to FortisBC's system. The KI consists of interconnections at Kootenay Canal, SEL, and NLY at the 63 kV and 230 kV level.

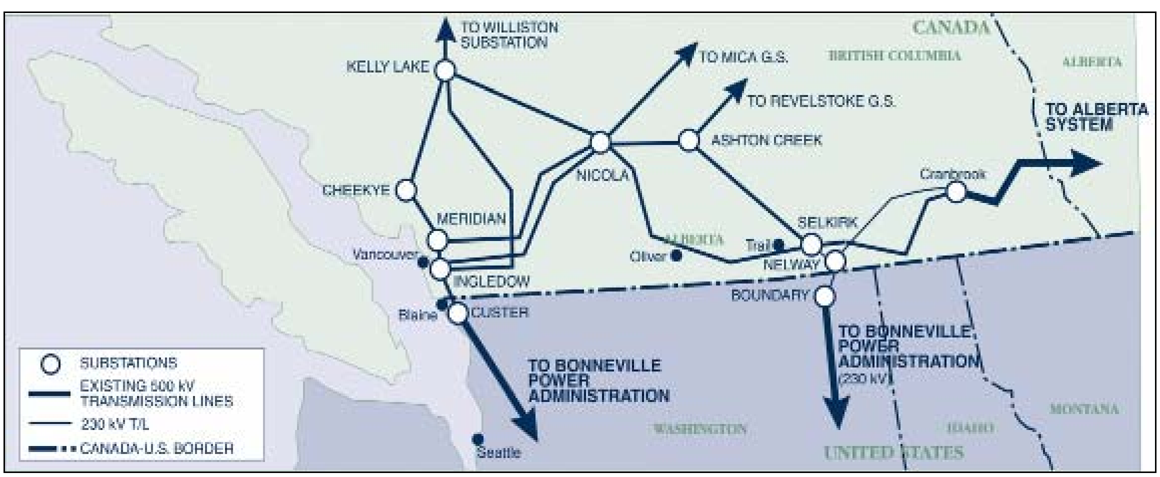
BCTC is obligated under the General Wheeling Agreement (GWA) to deliver FortisBC's energy over the transmission system from the KI to the OI and from the KI to their Lambert Substation. The GWA requires FortisBC to nominate its wheeling needs five years in advance. The five year wheeling nomination from KI to OI currently has a maximum of 200 MW[9] and from KI to Lambert Substation the maximum nomination is 35 MW. The wheeling to OI may be increased to 600 MW by 2014 according to the GWA Amending Agreement (2002) which allows annual increments in the nomination each year until 2014.

2.2.6 External Interties

The transmission system is also interconnected with transmission systems in Alberta and Washington State, providing opportunities for trade and improving the overall reliability of the system by providing a connection to a strong system with considerable reserves.

The TTC for each intertie is determined in two ways. A WECC Path Rating Process establishes the maximum permitted transfer capability based on WECC criteria. BCTC also uses real-time and forecast load and resource data to continually calculate the TTC based on the NERC/WECC criteria and then sets present day hourly operating limits (which cannot exceed the WECC Path Rating).

Figure 2-9. Interties to Alberta and the US



[9] The nomination is 180 MW in 2007 and rises to 200 MW in 2011.

2.2.6.1 BC – Alberta Intertie

The transmission system is connected with Alberta by one 500 kV line (5L94) from CBK to Langdon Substation in Alberta and two 138 kV lines from Natal substation near Sparwood to the 138 kV AltaLink network in Alberta (1L274 and 1L275).

Transient stability limitations require that on a 5L94 contingency the two 138 kV ties be tripped, except during low transfer conditions. As a result, the BC-Alberta intertie is effectively limited to the capacity of only 5L94.

The WECC-approved non-firm path rating for the BC to Alberta path is 1200 MW, but the coordinated operating TTC is usually limited by constraints in the Alberta system to 780 MW. The 1200 MW level of transfer would require significant load shedding in Alberta if the intertie were tripped. Higher transfer levels are required to be coordinated between BCTC and the Alberta Electric System Operator (AESO).

In 2007, BCTC completed a conceptual planning study to provide voltage support which would facilitate a 1200 MW transfer capacity from BC to Alberta. Two possible reinforcement options are an SVC at CBK or series compensation of 5L91 and 5L94 with the 138 kV ties to Alberta operated in an open loop configuration during high transfer levels.

In the Alberta to BC direction, the WECC approved non-firm path rating for the Alberta-BC path is 1000 MW. Limitations inside Alberta limit the coordinated operating TTC to 800 MW. Those limitations were expected to be partially alleviated by a new 500 kV transmission line between Edmonton and Calgary in 2009/2010, and fully alleviated by a proposed second 500 kV circuit between Edmonton and Calgary, which was anticipated to be in service between 2012 and 2016. However, the proposed reinforcements and in-service dates are now uncertain as the Alberta Energy and Utilities Board (EUB) has decided (Decision 2007-075) to restart the regulatory approval process.

In June 2006, a BC-Alberta Electricity Transmission Subcommittee was established as a permanent sub-committee of the Alberta-British Columbia Electricity Policy Working Group. This subcommittee studies the feasibility and potential benefits of reinforcing the transmission between Alberta and BC and makes recommendations to the Policy Working Group. BCTC recently completed a joint study with the AESO to examine the potential economic benefits from a second Alberta-BC intertie. The study shows that the present level of interconnection between the Alberta and BC electricity systems is amongst the lowest levels of interconnection for two electricity systems of comparable size. The report reflects the BC Energy Plan objective of self-sufficiency in BC and it concludes there are future scenarios that warrant the development of significant additional intertie capacity. The report acknowledges that the analysis does not account for all of the indirect benefits or indirect costs associated with new intertie capacity. However, it concludes that the value of the unquantified benefits is far greater than the value of the unquantified costs. The report recommends BCTC and AESO work with the Alberta and BC governments to develop possible business models that would result in an equitable sharing of costs and benefits from additional intertie capacity (see also Section 4.1.1).

2.2.6.2 The BC – US Interties

The interconnection between the BC transmission system and Bonneville Power Administration's (BPA) transmission system in Washington State is called Path 3 in the WECC Path Rating Catalogue. This interconnection includes two interties, the 500 kV Westside Intertie and 230 kV Eastside Intertie.

The Westside Intertie consists of two 500 kV transmission lines, 5L51 and 5L52, from ING to BPA's Custer Substation (near Bellingham). 5L52 has a lower capability than 5L51.

The Eastside Intertie has two lines:

(a) A 230 kV line (2L112) from Nelway to BPA's Boundary Substation; and

(b) A 230 kV transmission line (2L277)[10] owned by Teck Cominco and operated by FortisBC. 2L277 is normally connected between Waneta Generating Station (near Trail) and NLY with the final section from NLY to Boundary Substation (BDY) open.

The WECC approved path rating from BC to US is 3150 MW, a combined limit for the east and west-side tie, with maximum flow limited to 2850 MW on the 500 kV Westside Intertie. The Boundary - Nelway 230 kV line has a limit of 400 MW.

[10] 2L277 is the BCTC designation for this circuit which is designated 71L in the FortisBC system.

The path is transient stability limited under low load conditions, and the transfer limit is lower during heavy load and outage conditions.

The WECC approved path rating[11] from US to BC is 2000 MW, a combined limit for the east and west-side ties, with maximum flow limited to 2000 MW on the 500 kV Westside Intertie and the Boundary – Nelway 230 kV line has a limit of 400 MW.

The simultaneous imports from AB, US, and Alcan may be reduced to ensure that the system is able to withstand a frequency dip associated with a sudden loss of high imports. This is an issue when the amount of on-line BC Hydro generation is low.

In 2007, the firm transfer capacity[12] from the US to BC was raised to 1930 MW and is based on the capacity available after the loss of 5L51.

The firm transfer capability meets the total demand from existing contracts, Canadian Entitlements, and Teck Cominco entitlements.

The actual hourly flows on the BC interties with the US and Alberta are posted on the BCTC's web-site at:

http://www.bctc.com/the_transmission_system/actual_flow_data/

These charts show the hourly fluctuation in MW power flows each day of the current week on the interties between BC and US, and BC and Alberta.

2.3 The Regional Systems

BCTC has four regional transmission systems which connect the bulk transmission system to the local distribution systems, generating plants, and transmission-voltage customers: the Lower Mainland; the Northern Interior; the Southern Interior; and Vancouver Island.

The regional transmission systems are generally comprised of a large portion of the 230 kV system and all of the 138 kV and 60 kV systems.

[11] WECC approved path ratings define the maximum transfer over the path under most favourable conditions.
[12] In this instance, the Firm Transfer capacity is the maximum capability with one line out of service.

Over 200 substations and approximately 300 transmission circuits make up the regional transmission systems. Regional maps identify the key substations and circuits in each area.

BCTC has numerous programs and projects throughout the regional systems to maintain facilities and meet local load growth. This section describes each region, and the major issues and/or major new facilities that may be required in each region. Information on projects being requested for approval and future initiatives are included in the F2009 Capital Plan. The need to reinforce the regional systems to interconnect IPPs is also described in the discussion of each region.

2.3.1 The Lower Mainland Regional System

The Lower Mainland regional system supplies the southwest area of the mainland and extends from Powell River on the Sunshine Coast to Boston Bar, east of Hope and south to the US border. There are two large generation sources supplying this region; Bridge River near Lillooet, and Burrard Thermal (Burrard) in Port Moody. There are also several small generating stations in the watersheds close to Vancouver. Most of the region’s load is served by energy delivered by the ILM Grid. Figure 2-7 in Section 2.2.3 above shows the area as well as the bulk system delivering energy from the Interior to the Lower Mainland.

Energy from Bridge River is delivered by two 230 kV transmission lines to Cheekye Substation (CKY) near Squamish, supplying North Shore/Coastal load, and also by one 360 kV transmission line to Rosedale Substation (ROS) near Chilliwack, supplying the eastern Fraser Valley. Energy generated at Burrard is delivered to the Lower Mainland’s 230 kV transmission network via five 230 kV lines.

New IPP generation is expected in this region as a result of BC Hydro Calls for Tender and several circuits will need to be upgraded to integrate the additional energy into the regional system. The upgrades are described in the area descriptions below.

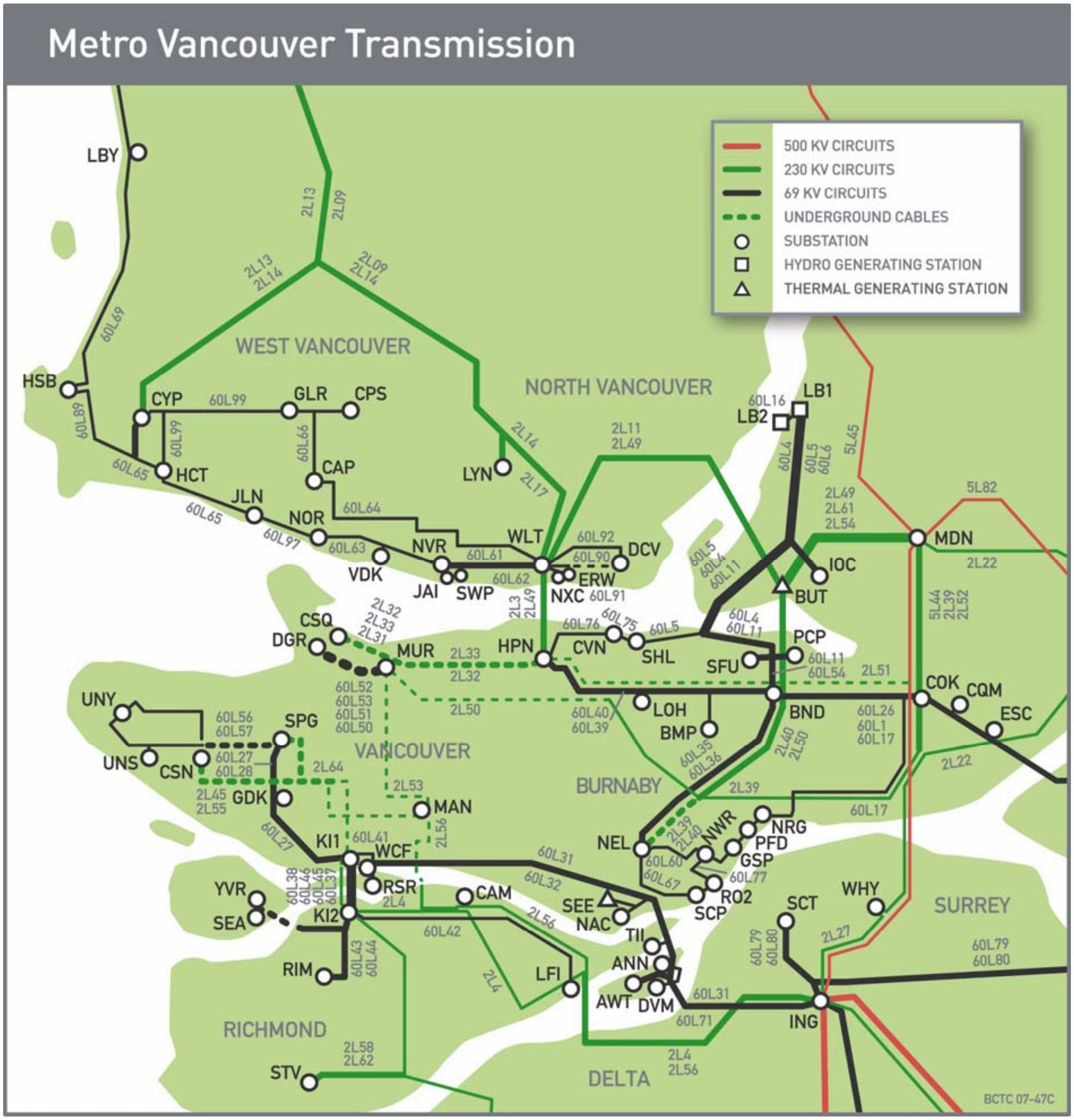
Energy from the bulk system is delivered to the Lower Mainland by transformation at four 500 kV substations (MSA, MDN, ING and CBN). These stations, which are linked by 500 kV transmission lines, supply an extensive network of 230 kV, 138 kV, and 60 kV lines which deliver energy to distribution substations throughout the region.

The Lower Mainland Regional System is sub-divided into three planning areas: Metro Vancouver; Fraser Valley (east to Boston Bar); and North Shore Coastal (from Burrard Inlet to Powell River).

2.3.1.1 Metro Vancouver Issues

The Metro Vancouver system Vancouver (including Downtown, Mount Pleasant and Vancouver South), Burnaby, Coquitlam, Richmond and New Westminster as shown in Figure 2-10.

Figure 2-10. Lower Mainland Regional System– Metro Vancouver Map



Load growth, significant seismic risks, and age-associated deterioration are the major drivers for Metro Vancouver area reinforcement requirements.

2.3.1.1.1 Downtown Vancouver

Downtown Vancouver is supplied by three substations: Cathedral Square (CSQ), Murrin (MUR) and Dal Grauer (DGR). All three substations are loaded close to their capacity and reinforcement projects are now underway to meet downtown load growth. There is no space to expand capacity at DGR or MUR; however, capacity additions at CSQ are feasible and BCTC is presently installing a third 150 MVA transformer and more feeder positions at CSQ. The CSQ project has been re-approved by the Commission's F2008 Capital Plan decision and is underway. The feeder positions are 100% SDA. The transformer has an in-service date of fall 2008 and the feeder positions for the spring of 2009.

As well as supplying additional load, the new transformer at CSQ will mitigate a low probability / high consequence risk[13] of a complete loss of supply which would interrupt one-third of the downtown load. Such an outage would have a high socio-economic impact because the time needed to replace them would be many months.

On July 5, 2007, CSQ T2 (transformer) tripped out and the risk of a further T1 outage was a concern. BCTC conducted an internal inspection and found multiple insulation flashovers from the selector switch to ground. The cause of the flashovers was a set of damaged contacts on the tap changer's diverter switch. BCTC replaced the diverter switch, repaired the selector switch contacts and returned the transformer to service on July 22, 2007. The situation was assessed and BCTC concluded that:

(a) The damaged contacts were an isolated incident/problem;

(b) A similar defect is not expected on T1; and

(c) The two transformers are in good health and reliable.

As a result of this event, BCTC developed an emergency plan using two spare outdoor transformers at CSQ to restore the CSQ supply. The emergency plan uses a 60 kV supply from Horne Payne Substation via an existing 230kv cable circuit to two transformers installed in a parking lot across from CSQ and then via 12 kV cables into the buildings. The contingency plan objective is to provide an N-1 condition in the event of one transformer failure within 14 days.

MUR is located partly on reclaimed land, which is seismically unstable. Directly, and through DGR which it feeds, MUR supplies more than 60 percent of downtown

[13] This risk is associated with loss of both existing CSQ transformers. They are identical and over 20 years old. If any inherent defect causes one to fail the other could have the identical defect and may also fail before the first unit is repaired.

Vancouver load demand. Due to the nature of the site, it is not reasonable to upgrade all of the MUR equipment to meet current seismic standards. BCTC requested and was given approval for a sustaining capital expenditure to do some seismic upgrading by installing a curtain wall in its 2006 Capital Plan.[14] The project was based on the understanding that soils in the substation could be stabilized by the installation of a seismic dike. It has now been determined that soil stabilization is not practical. The project scope is under review; however, it is expected that the new scope will involve the relocation of critical infrastructure components (e.g. 230 kV cables, circuit breakers, control systems, etc.) from the 230 kV switch yard to an area of the station site that is seismically stable. This solution calls for the construction of a building to house new 230 kV GIS and a control room. In addition, the 230 kV cables which are also at seismic risk need to be relocated. The scope, schedule, and cost estimates for execution are expected to be complete by the end of F2009. For additional details please see section 6.5.1.4.6 in the F2009 Capital Plan.

2.3.1.1.2 Mount Pleasant Area

The Mount Pleasant/Grandview area load south of False Creek is growing rapidly and is served by feeder circuits from MUR, SPG and MAN. The MUR duct banks which supply 70 MVA of the Mount Pleasant area load are at risk because the duct banks and associated manholes are significantly deteriorated and they pass through seismically unstable ground. A new feeder section is being added at SPG to be in service in the fall of 2008 so that the area can be served by feeder circuits in the short term. To meet BC Hydro’s load supply needs and address the MUR duct bank risk for the longer term, BCTC and BC Hydro are jointly reviewing the need and timing of, a new 230/12 kV substation (see section 5.5.2.2.14).

2.3.1.1.3 Vancouver South

The south area of Vancouver is supplied by Kidd#1 (KI1) and MAN, which are both loaded near to capacity. BCTC plans to add 12 kV capacity in KI1 in stages as the load grows in this area and as the existing 4 kV load is converted to 12 kV. The Commission’s F2008 Capital Plan Decision (Order G-69-07) approved a project to increase capacity at Kidd by replacing the under-rated 12 kV transformer cables in

[14] Commission Order G-91-05

2008 and install a 75 MVA 60/12 kV transformer with a new feeder section in 2010. This will increase the KI1 capacity from 54 MVA to 75 MVA.

2.3.1.1.4 Burnaby

Horne Payne Substation (HPN) serves the northern part of Burnaby and the northeastern part of Vancouver. The forecast load demand at HPN will exceed the station capacity by 2012. To increase the capacity at HPN, BCTC plans to replace two existing 230/12 kV – 84 MVA transformers with larger 150 MVA units before the fall of 2012 (see section 5.5.2.2.9 of the F2009 Capital Plan).

In the long-term, BCTC plans to continue serving this area from HPN, replacing the last 84 MVA transformer with a 150 MVA unit and adding feeder sections, as required, to reach the ultimate design capacity of 400 MVA.

2.3.1.1.5 New Westminster

New Westminster load growth has exceeded the capacity of the two 60 kV transmission circuits (60L60 and 60L67) that serve the New Westminster area. The capacities of these two circuits are being increased in the fall of 2007 by increasing the conductor–to-ground clearance. This is a cost effective short term option to provide immediate relief. BCTC will initiate a study of longer term options to further reinforce the supply to the area as requested by the City of New Westminster.

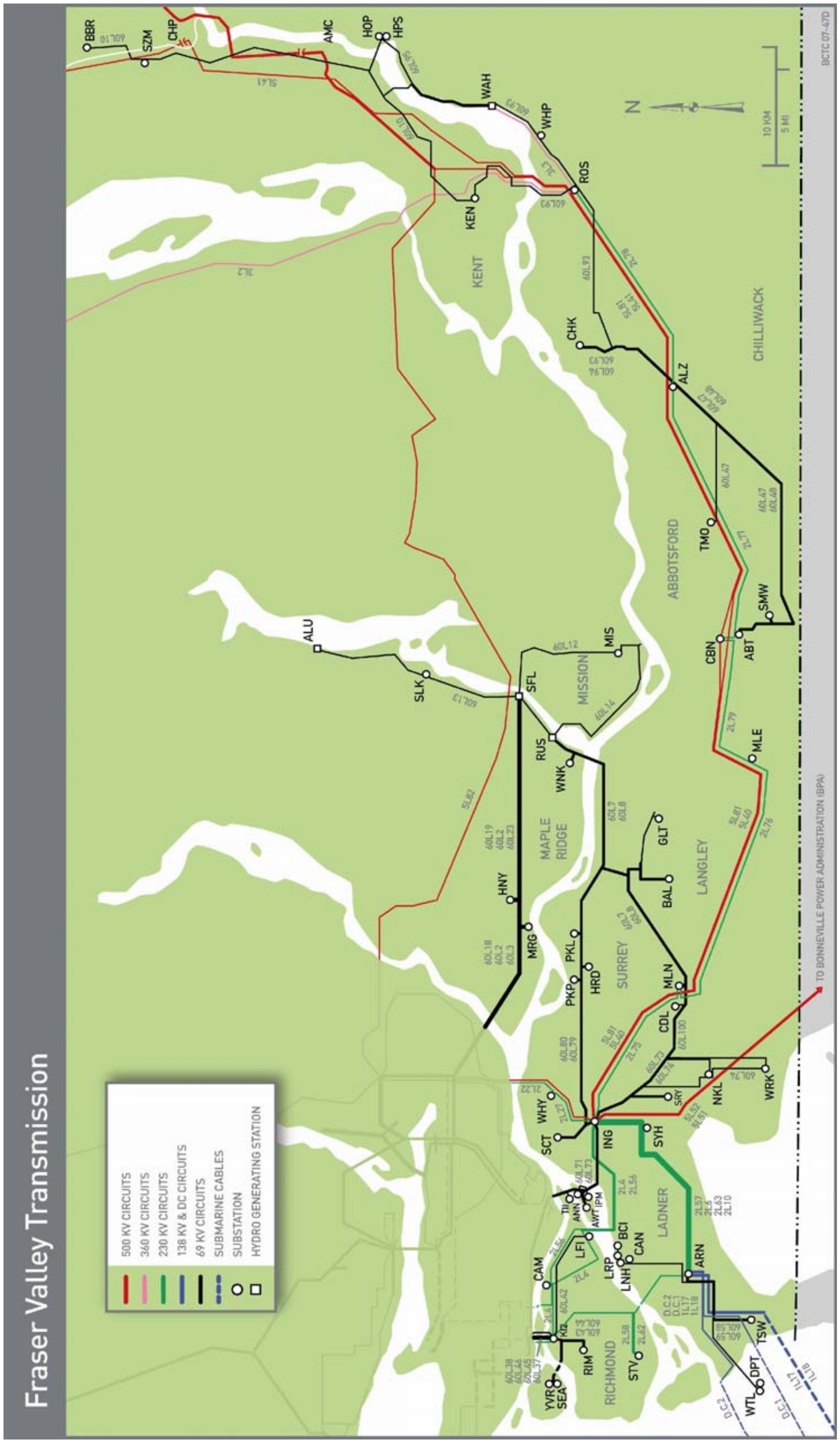
2.3.1.1.6 Metro North 230 kV Transmission System

The northern areas of Vancouver and Burnaby, and all of Coquitlam, are supplied by a network of 230 kV circuits originating at MDN (the Metro North 230 kV Transmission System). Circuit 2L52, a major circuit in this network, connects MDN to Como Lake Substation (COK) in Coquitlam. An outage of 2L52 results in transfer of its load to other circuits in the Metro North 230 kV Transmission System. By 2010 this scenario will result in overloading of 2L50 (Burrard Thermal – Murrin). BCTC proposes a future project to loop an adjacent circuit, 2L39 (Meridian – Newell), into COK to provide a second circuit path between MDN and COK to resolve this problem (see section 5.5.2.2.1 of the F2009 Capital Plan).

2.3.1.2 Fraser Valley Issues

This area serves the geographic region surrounding the Fraser River from Boston Bar to the Fraser River delta, excluding the Metro Vancouver service area. The Fraser Valley area has several issues resulting from distribution load growth. Figure 2-11 provides a map of the Fraser Valley system and service area.

Figure 2-11. Lower Mainland Regional System – Fraser Valley Map



2.3.1.2.1 West Fraser Valley

Port Kells Substation (PKL), which serves a portion of the load in Langley, is supplied from Ruskin Generating Station, Stave Falls Generating Station and McLellan Substation (MLN) via two 60 kV circuits. If there is a loss of one of its supply circuits the distribution voltage at the substation drops to an unacceptable level.

BCTC is proposing the addition of two 9.6 MVAR shunt capacitors at PKL to maintain the voltage at an acceptable level (see section 5.5.3.1.1 of the F2009 Capital Plan).

MLN, which also serves the growing Langley load, will be loaded beyond the substation's present capacity in the winter of 2010. BCTC is evaluating two options to resolve this issue:

(a) Increase MLN's capacity by adding a third transformer and expanding its feeder section; and

(b) Building a new substation close to the area of load growth.

The preferred option to resolve the MLN capacity issue will be proposed in a future Capital Plan.

The Mission area load will exceed the Mission Substation (MIS) capacity by the winter of 2010. BCTC is evaluating three options to resolve this issue:

(a) Expand the capacity of MIS;

(b) Add a new Silverdale Substation northwest of MIS; and

(c) Expand and convert Whonnock Substation (WNK) to 25 kV.

BCTC intends to complete the evaluation of alternatives and propose a project in its F2010 Capital Plan.

The south and west areas of Richmond are supplied by Steveston Substation (STV). The growing load will exceed the station capacity in 2010. An area reinforcement study is underway and BCTC is evaluating two options to resolve this issue:

(a) Supply load growth in the South Richmond area by adding capacity at STV; or

(b) Transfer a portion of the existing STV load to Cambie Substation (CAM) in the North Richmond area.

BCTC intends to propose a project in its F2010 Capital Plan to implement the preferred solution.

2.3.1.2.2 East Fraser Valley

The system in the area east of Abbotsford includes Wahleach (WAH) Generating Station, Rosedale (ROS), Hope (HOP), Spuzzum (SPZ) and Boston Bar (BBR) Substations. HOP, SPZ and BBR are connected radially at 60 kV from WAH. WAH is connected radially by a 360 kV circuit from ROS substation, with an alternate connection from Atchelitz Substation (ALZ) via a 60 kV circuit if the 360 kV circuit is out-of-service.

New IPP generation (Log and Kookipi Creek) will be interconnected to the 60 kV transmission line in the vicinity of Boston Bar. Energy from these IPPs, when added to the existing generation from Wahleach Generating Station, will heavily load but not exceed both the WAH 360 kV/13 kV transformer and the 60 kV circuit between WAH and ALZ substations. The existing capacity is adequate to serve the projected load growth and the currently contracted IPP additions. In future years, more IPPs are possible in the area and the capacity would need to be expanded to integrate them.

In addition to the capacity problem in the East Fraser Valley, the 360 kV/13 kV transformer at WAH and the 360 kV circuit breakers at ROS are nearing their end-of-life.

Another long-standing problem is that the 13 kV bus at WAH is used as part of a transmission path. Power is transformed from 60 kV to 13 kV first and then stepped up to 360 kV to reach the rest of the transmission system. This double transformation results in excessive loss and loose coupling of the Fraser Valley transmission system with the rest of the system. The existing 360 kV circuit 3L3 can be changed to operate at a lower voltage to better integrate and provide coordination with the replacement of the WAH 360 kV/13 kV transformer.

BCTC is conducting an integrated planning study to determine the preferred option to resolve the following issues beyond 2010:

(a) Integration of the new transmission IPPs into the area;

(b) Aging of the WAH 360 to 13 kV transformer;

(c) Double transformation at WAH;

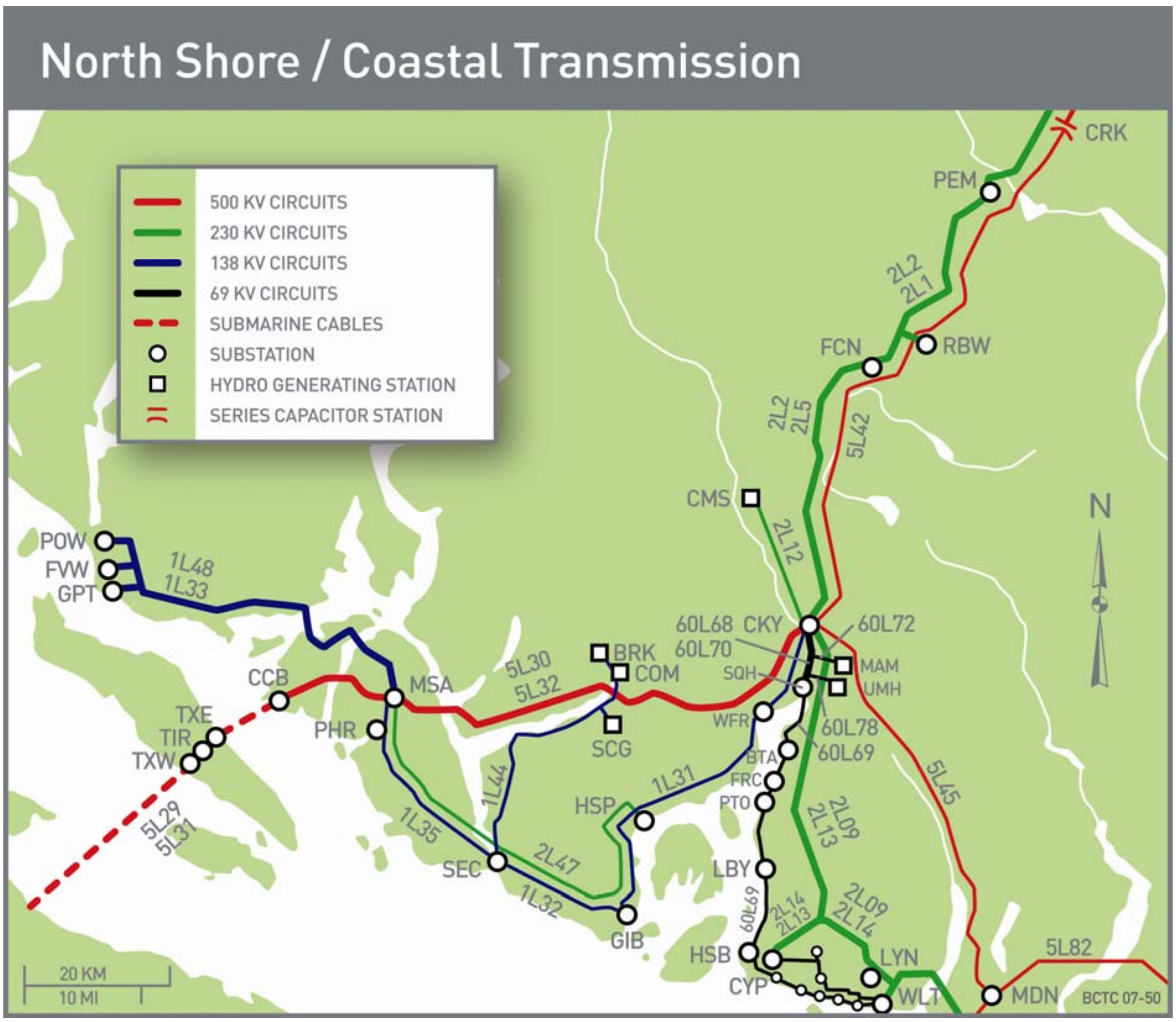
(d) End of life of 360 kV circuit breakers at ROS; and

(e) Conversion of the 360 kV ROS to WAH line to a lower voltage.

2.3.1.3 North Shore/Coastal Issues

Figure 2-12 is a map of the North Shore/Coastal system and service area.

Figure 2-12. Lower Mainland Regional System – North Shore/Coastal Map



Grief Point Substation Upgrade, Sechelt Transformer Replacement, and Walters Transformer Addition are projects in progress needed to meet load growth in the North Shore/Coastal systems.

Load growth at two distribution substations in the North Shore/Coastal system is forecast to exceed capacity beginning in 2010. The following projects are planned to address these shortfalls:

(a) Upgrade North Vancouver Substation (NVR) in 2010 (see Section 5.5.3.2.2 F2009 Capital Plan); and

(b) Upgrade the Deep Cove Substation (DCV) bus in 2014.

In addition, the East Toba and Montrose Hydroelectric Project will require conversion of circuit 1L48 from 138 kV to 230 kV to integrate this IPP located north of Powell River near Toba Inlet. The East Toba and Montrose IPP interconnection is ongoing and the circuit conversion is being studied.

2.3.2 The Northern Interior Regional System

The Northern Interior regional system and service area is shown in Figure 2-2 in Section 2.2.1.

This very large area includes all of the integrated system north from Hundred Mile House Substation (HMH) to the northeast and northwest extremes of the integrated system in the Fort St. John and Prince Rupert areas. It also includes the Fort Nelson area, which is interconnected with the Alberta system through circuit 1L359.

2.3.2.1 Northern Interior Regional System Issues

The Northern Interior Region is experiencing significant load growth in four areas:

(a) Around and north of Prince Rupert,

(b) The Fort St. James area,

(c) The Fort St. John area, and

(d) The Fort Nelson area.

There is also significant generation development in the area.

2.3.2.1.1 Northwest Area

The new tap line to the recently completed Prince Rupert Container Port project is in service with a load of 5.5 MVA, which is 2.5 MVA less than was expected and reported in the 2006 STSR.

2.3.2.1.2 Northwest Transmission Line Project

The Northwest Transmission Line (NTL) is planned to be a new 287 kV transmission line that would extend 335 kilometers from the Skeena Substation near Terrace, BC to Meziadin Junction and north to a new substation at Bob Quinn Lake.

This new line would provide access to the electricity grid for customers while supporting economic diversification of the area. The Galore Creek Partnership (GCP) (the company building the Galore Creek mine in northwest B.C.) was to be the initial customer taking service from the NTL by interconnecting at the new Bob Quinn Lake substation.

The estimated total cost of the NTL for a fall 2011 in-service date would be approximately $400 million. The NTL project is based on a proposed cost-sharing agreement with the GCP. The GCP’s contribution to the capital cost of the NTL is $158 million and the balance is proposed to be paid by BC Hydro and recovered through electricity rates.

On November 26, 2007 the Galore Creek Partnership announced that due to a significant escalation in construction costs, it is suspending construction activities on the Galore Creek mining project immediately. As a direct consequence of this development the NTL project is currently on hold. BCTC and the provincial government are working together to determine the next steps for NTL.

In light of the above described circumstances, BCTC has not included any requests for approvals from the Commission for the NTL project nor any of the estimated $400 million in capital costs in this Capital Plan.

2.3.2.1.3 Fort St. James Area

In the Fort St James area, Apollo Forest Products has now completed and energized their transmission interconnection. The previously anticipated upgrade of circuit 60L344, which the Apollo load was expected to require has been deferred after reviewing the actual area loads.

Load growth has caused voltage control problems at Fort St. James Substation (FM2) which requires additional VAR support in the form of shunt capacitor banks. This reinforcement project is under study and BCTC expects to request approval for the project with an in-service date of October 2009 in the F2010 Capital Plan.

2.3.2.1.4 Fort St. John Area

Near Fort St. John, the new Fox Creek Substation (FOX) was placed in service in December 2006 to resolve several capacity, power quality, and reliability problems in the area.

At Chetwynd, the capacity of Chetwynd Substation (CWD) is inadequate to meet its growing demand. The existing substation transformers are being replaced with two new 50 MVA units to be in service in August 2008.[15] Supplementary transformer chillers have been installed on the existing units to raise their capacity by 10 percent, which added enough capacity to accommodate load growth until the new units are in service.

As CWD load continues to grow, there is an increased risk of voltage collapse if the 138 kV transmission line from GM Shrum to CWD is forced out of service. BCTC is studying the possible addition of capacitor banks at CWD to mitigate this risk.

The Tumbler Ridge load continues to grow due to coal mining and oil and natural gas exploration activity. The firm capacity of Tumbler Ridge Substation (TLR) will be increased by a proposed project to replace two existing transformers with two 75 MVA transformers (see section 5.5.3.1.4 of the F2009 Capital Plan).

The 120 MW Bear Mountain IPP project with 57 wind turbines is being planned 16 km southwest of Dawson Creek. To integrate the Bear Mountain project into the

[15] Project approved by Commission Order G-69-07.

transmission system, the following major reinforcements will be required to the area transmission system:

(a) Add a 138 kV 3 circuit breaker ring at Bear Mountain Substation (BEA) to become the Point of Interconnection;

(b) Split the existing circuit 1L362 (CWD to DAW) into two sections to integrate BEA into the system and thermally upgrade the two split sections (1L358 (CWD to BEA) and 1L362 (BEA to DAW)) and the line (1L361(GMS to CWD)) to meet the N-1 reliability requirement; and

(c) Add an 8 km 138 kV tap line to connect the IPP to BEA (this is the responsibility of the proponent).

2.3.2.1.5 Fort Nelson Area

BCTC is currently addressing the impact on the system of additional industrial loads at 144 kV in the Fort Nelson area. Petro-Canada has requested 144 kV supply to its new loads at the Klua and Clarke Lake fields and Harvest Energy has requested a 144 kV supply to a new load near the BC-Alberta border. This area is served by long overhead transmission lines and there is a risk of voltage collapse under some contingencies. An under voltage load shedding scheme is being implemented in F2008 to mitigate the risk of voltage collapse.

2.3.3 The Southern Interior Regional System

The Southern Interior regional system is a large network of 230 kV, 138 kV and 69 kV circuits generally located in the southeastern portion of BC extending from the US border in the south to Valemount in the north. This regional system consists of two sub-regions: the Southern Interior West (SIW); and the Southern Interior East (SIE).

The SIW area extends from the Fraser Canyon to Slocan Lake and is interconnected to the FortisBC system at Vernon in the Okanagan area and Princeton in the Similkameen area. The SIE area extends from the Columbia Valley to the Alberta border. The SIE and SIW are geographically separated by the FortisBC system and are interconnected by 500 kV transmission lines.

Figure 2-3, in Section 2.2.2, shows the geographic area of Southern Interior regional system. The two primary issues in the Southern Interior region are area load growth and reliability requirements for communities supplied by radial single-circuit transmission systems.

2.3.3.1 Area Load Growth

Some parts of the Southern Interior regional transmission system are operating close to their maximum capacity due to significant area load growth over the last several years. Reinforcement has become urgent as the load growth is expected to continue for the foreseeable future. Areas that are approaching their maximum capacity include:

(a) The Upper Columbia 69 kV system north of Invermere (due to development in the Golden area);

(b) The North Okanagan 69 kV system south of Vernon (due to development in the District of Lake Country); and

(c) The North Thompson 138 kV system north of Kamloops (due to significant load additions resulting from upgrades to Kinder Morgan Canada's Trans Mountain Pipeline system between Alberta and the Lower Mainland).

2.3.3.1.1 Upper Columbia 69 kV System

Golden is supplied radially from Invermere by a 69 kV line which also supplies Athalmer and Radium. Capacitors are scheduled to be installed by the fall of 2008 at Golden Substation (GDN) to provide system voltage support. This is an ongoing project approved by Commission Order G-67-06. A major system reinforcement project will also be required by 2012 to meet area load growth (see Section 5.5.2.1.1 of the F2009 Capital Plan).

2.3.3.1.2 North Okanagan 69 kV System

The supply to the District of Lake Country will require significant reinforcement in the immediate future. BCTC is reviewing the options available to reinforce the supply to this area and is proposing to undertake the Definition Phase of a Woods Lake Reinforcement Project (see section 5.5.2.1.2 of the F2009 Capital Plan).

2.3.3.1.3 North Thompson 138 kV System

The supply to the North Thompson area may require reinforcement to accommodate any significant increases in industrial load or resource development. The second stage of Kinder Morgan's pipeline expansion project will enter service in the spring of 2008, resulting in an additional 13 MW of load in an already constrained system. The facilities installed at Avola Substation (AVO) to meet the first stage of development are being upgraded to meet the requirements of this second stage of development. The load will then be close to the system's maximum upgradeable supply capability and the system could require major reinforcement if area load continues to grow. BCTC will continue to monitor the load and the capacity requirements and will initiate a project when the system needs to be reinforced.

2.3.3.1.4 Savona ERG

Savona ERG, a distribution connected IPP, is being added to a feeder from Savona Substation which requires an upgrade to the station to facilitate integration of the new generation.

2.3.3.2 Reliability of Supply

Many communities in the Southern Interior regional system are supplied by single-circuit radial transmission systems and the reliability of their supply is a concern. Forest fires in 2003 resulted in a major outage to the circuit supplying the North Thompson area and significantly impacted the communities supplied by that circuit. Several other communities in the Southern Interior could be similarly affected.

Westbank is the largest community exposed to this risk and has over 70 MW of load supplied by a single radial 138 kV transmission line approximately 80 km in length. BCTC is continuing to study the possible alternatives which could improve the reliability of supply to Westbank. A second transmission supply, a fire retardant treatment of the existing circuit, or a new IPP in the area could significantly reduce this risk. BCTC will initiate planning study in the near future to identify a preferred option for system reinforcement or risk-mitigation purposes.

2.3.4 The Vancouver Island Regional System

The Vancouver Island regional system is comprised of a network of 230 kV, 138 kV, and 60 kV systems, which are shown in Figure 2-8. Most of the Vancouver Island load is connected to the 138 kV system.

The Vancouver Island system has three areas:

(a) North Vancouver Island (north of DMR), where most of the island generation is located;

(b) Central Vancouver Island (from DMR to VIT), serving most of the industrial load and the west coast loads of Port Alberni and Long Beach; and

(c) South Vancouver Island (south of VIT), which is mainly residential and commercial load.

About 22 percent of the Vancouver Island load is in the North, 46 percent is in the Central, and 32 percent is in the South Vancouver Island area.

The Vancouver Island regional system load is supplied by:

(a) BC Hydro generation in North Vancouver Island;

(b) Several small IPPs;

(c) One large IPP near Campbell River;

(d) The LM-VI Grid from the mainland to Dunsmuir and VIT;

(e) The 138 kV transmission to the southern Gulf Islands; and

(f) Generation at Jordan River in the South Vancouver Island area.

At this time most of the electric energy used on Vancouver Island is delivered from DMR and North Vancouver Island generating plants to the major load centres south of Dunsmuir over a congested 138 kV system and a lightly loaded 230 kV transmission system. After VITR is in service in the fall of 2008, Vancouver Island load will have a secure supply for the case of an N-1 forced outage at DMR.

Load growth in the South and Central Vancouver Island areas has been significant for several years. Prior to VITR, upgrades to the system were incremental enhancements to previously existing capacity and served local load growth without the need for major system reinforcements. The opportunity to accommodate more growth with similar enhancements has been exhausted on some parts of the system and more significant system reinforcements are now required or anticipated. In addition, potential new generation in the North Vancouver Island may require upgrades to the system to transfer the energy south.

At this time, the following issues in the Vancouver Island regional system are being studied or resolved.

The Port Hardy and surrounding area at the north end of Vancouver Island is radially supplied by 138 kV circuits (1L125 and 1L137 which have a combined length of 165 km) There is adequate capacity to serve existing and forecast demand, but accelerated load growth and potential IPP projects could require reinforcing the system in this area.

The Courtenay district is supplied by Comox (CMX) and Puntledge (PUN) substations north of Dunsmuir. The load in both substations is currently adequate but is forecast to reach their firm capacity limit within ten years and additional capacity will then be required.

The west coast of Vancouver Island is radially supplied by a single 60 kV line (60L129) which passes through 84 km of remote rough terrain. Circuit 60L129 has the worst performance in the province with respect to the Transmission Reliability Index and almost 180,000 customer-hours of service were interrupted by outages on this line over the last five years. There are frequent complaints of low voltage caused by the long feeders in the area and the radial nature of 60L129. Replacement of much of the transmission line hardware over the past year will improve reliability of the supply to some extent. The planned upgrade of equipment in LBH is expected to improve service in the area until the supply is reinforced.

The growing load at Long Beach Substation (LBH) is approaching the voltage limits of 60L129 and the capacity of the two transformers at Great Central Substation (GCL) which supply it. BCTC is currently studying how to address the low voltage issue at

Long Beach, and is planning a transformer upgrade at GCL. Studies are ongoing to determine the preferred solution which will be included in a future project. In the longer term, BCTC is considering a reinforcement of the supply to the Long Beach area.

The transfer of energy from the generation in the north area of Vancouver Island, and from the mainland connection to DMR supplies the load in the central area of the Island. This supply is supplemented by the 230-138 kV transformers at VIT, which are connected to the Lower Mainland via the HVDC system (soon to be replaced by VITR). The load is now at a level that causes the 138 kV system in this area to exceed the system’s firm capacity.

To reduce the risk of overloading the 138 kV system, BCTC obtained approval in the Commission’s F2008 Capital Plan Decision (Order G-69-07) to conduct definition work and will be submitting a CPCN application in 2008 for the Central Vancouver Island Transmission Project (CVI). CVI will connect the existing 230 kV and 138 kV systems together by adding two new 230 kV transmission lines and a substation near Nanaimo to be in service in October 2010. This will resolve constraints on 1L115/116 and on the VIT 230-138 kV transformers in the Central Island area.

Before CVI goes into service, BCTC is proposing (see section 5.5.3.1.2 of the F2009 Capital Plan) to change the supply to Qualicum Substation (QLC) so that it is simultaneously supplied by both 1L115 and 1L116 to reduce the risk of overloading these circuits during heavy load periods. Presently, QLC can only be supplied from either 1L115 or 1L116, which causes the power flow on these two circuits to be unequal and can cause one of these circuits to overload during peak periods.

South Vancouver Island is primarily supplied from VIT and Sahtlam (SAT) Substations in the Vancouver Island Central system. VIT is connected via the 138 kV circuits 1L10, 1L11 and 1L14 to Goward Substation (GOW), which is in turn connected to George Tripp Substation (GTP) near Victoria. The 230 kV system also supplies part of the South Vancouver Island load, using lines from DMR to SAT, and from SAT to Pike Lake Substation (PIK) near Victoria. PIK is connected to Goward (GOW), Horsey (HSY), Esquimalt (ESQ) and Keating (KTG) Substations in the Victoria area at 230 kV. SAT and VIT are connected by a pair of 230 kV lines.

In the F2008 Capital Plan, two projects were proposed, approved, and are in progress to alleviate the constraints on the 138 kV circuits that serve South Vancouver Island:

(a) A thermal upgrade project on 1L10/11 which will increase the clearance of the transmission lines spans to provide 54 MVA of additional load transfer capability; and

(b) A project to re-terminate Sidney to Keating, effectively moving the Sidney load from the 138 kV system to the 230 kV system. Sidney is supplied from Goward at 138 kV but when the project is complete it will be supplied from Keating at 230 kV. The project will expand Keating, build new 60 kV transmission lines from Keating to connect to 60L83/87, and will decommission the 138/60 kV transformers in Goward.

In the area west of Victoria, Colwood Substation (CLD), Sooke Substation (SOO), and Jordan River Generating Station are connected to the system radially by one 138 kV circuit, 1L146, which terminates at GOW in Victoria. Jordan River Generating Station has a maximum output of 170 MVA. If an outage of 1L146 occurs between GOW and CLD, the generation at Jordan River can presently supply the combined peak load of Colwood, Sooke, and Jordan River. Within the next five years, the peak load at these three stations will exceed Jordan River's generation capacity. BCTC will initiate an area study within the next few months and will determine how to supply peak load for this future condition.

Several substations (Lake Cowichan (LCW), Galiano (GLS), Woss (WOS) and Long Beach (LBH)) rely on a mobile transformer to restore load during a transformer outage. The mobile transformer in the area has failed several times and was not available for several years. It has now been repaired and is again available for this purpose. The mobile transformer is presently located at Shawnigan Lake Substation (SHA) and can be relocated quickly if needed at any of these substations.

2.3.4.1 IPP Projects

New generation is expected in this region as a result of BC Hydro Calls for Tender, and several circuits will need to be upgraded to enable the new generation to deliver energy into the regional system.

Transmission line thermal upgrades are required for various line sections on circuit 1L121 near Campbell River to integrate the following IPPs:

(a) Clint Creek Hydro Project;

(b) Gold River Power Project; and

(c) Ucona River Hydro Project.

Transmission line thermal upgrades are also required for various line sections on circuit 1L134 near Gold River to integrate the following IPPs:

(a) Gold River Power Project; and

(b) Ucona River Hydro Project.

2.4 System Control and Communications Systems

2.4.1 BCTC's System Control Centres

As indicated in Section 2.1, BCTC operates the transmission system from its SCC located in the Lower Mainland with support from four RCCs. In February 2005, BCTC received approval for its System Control Modernization Project (SCMP)[16] to build a new primary control centre in the Fraser Valley (the Fraser Valley Office) and a back-up control center in Vernon (the Southern Interior Office). Both of these facilities will be equipped with modern and fully redundant EMS systems. The new buildings are complete, a new EMS system has been purchased, and BCTC has started installing the new equipment. Process mapping for the new centralized organization has been drafted, transition plans have been prepared, and the telecommunication upgrade for a fully redundant communication infrastructure for SCADA control has been implemented. SCMP is on schedule and is expected to be in service late F2008. The existing control centres and old EMS equipment will be decommissioned once the new control centres and EMS are fully operational.

Until the SCMP is in service, minor expenditures will be necessary to cover the replacement of any unexpected equipment failures and enhancements required to meet mandatory requirements (see section 7.5.3 of the F2009 Capital Plan). No

[16] Commission Order C-1-05

replacement of existing control centre equipment is planned prior to their retirement. After the SCMP is in service, BCTC will need to make ongoing capital expenditures to sustain the performance of the new Control Centres and the EMS system.

2.4.2 Communication Systems

BCTC operates an extensive private telecommunications system to support power system protection, SCADA, and business requirements. A variety of telecommunications systems are used to meet technical, economic and reliability requirements. These include microwave radio, fibre optics, power line carrier, copper pairs, and leased lines. A point-to-point microwave radio communications system provides the majority of the communications needs of the bulk power system. This high reliability telecommunications system is an integral component of the high-speed protection relaying system, RAS systems, monitoring and control, generation dispatch, and the EMS. The microwave radio system is interconnected with similar systems used in the Washington State and the Alberta transmission systems.

While the primary purpose of the telecommunications system is for power system protection, EMS, and SCADA; it also provides facilities for a low cost alternative to the public network for internal and inter-utility voice and data traffic. The telecommunication system can also be used for a secure intercom system for voice communication between BCTC operators and neighbouring utility systems.

In 2006, BCTC completed a multi-year program to replace the analogue microwave radio system with a digital microwave radio and fibre optic system. The microwave system is largely in a radial configuration and in the event of a path failure can result in severe curtailments to the transfer capability of the transmission system. BCTC has initiated a plan to improve the performance of the system by creating a loop around the Lower Mainland and into the Southern Interior. This work is being done under the Lower Mainland Telecom Network Robustness and SCMP Projects and will be completed in 2008. The one remaining analogue microwave link is from Nelway Substation (NLY) near Salmo, BC to Metaline, Washington. It will not be replaced until an agreement is reached between BCTC and BPA.

The most critical single point of failure site now is the Microwave Control Center (MCC), located on Burnaby Mountain. Work being undertaken as part of the Lower

Mainland Telecom Network Robustness project (approved by Commission Order G-69-07), will eliminate this potential point of failure and will distribute the functionality of the MCC throughout the network of Lower Mainland microwave radio and fibre optic sites. This will reduce the risks from earthquakes, climatic conditions, or human-related events which could degrade the control capabilities of BCTC operators. Elimination of the MCC will also mitigate the need for a seismic upgrade to the MCC which would have been needed if it were to be kept in service.

The telecommunications system is critical to BCTC's system operations and to electric system reliability and is recognized as an integral part of the power system in NERC Standard COM-001 and the WECC guideline, "Communications Systems Performance Guide for Protective Relaying Applications". The utilization of the telecommunications system is continuing to grow to serve many information technology applications which require rapid and interactive information exchange. Telecommunications traffic on the system is growing at 5 percent per annum due to additional substations, IPPs, and smart substation equipment being installed on the power system. Increasing numbers of uses require a high reliability system to support that work in real time. Reliability of a communications site is critical to many users and to meet WECC standards. Standby generators and HVAC systems are therefore critical at remote sites. Based on risk and cost assessments, the most critical generators and HVAC systems will be replaced in a program to maintain reliability.

Other telecommunication projects that are planned to maintain reliability and to meet new environmental standards[17] include the removal of older Halon fire suppression systems (see section 6.5.1.6.8 of the F2009 Capital Plan) and the replacement of power line carrier (PLC) systems (see section 6.5.1.6.4 of the Capital Plan). The Halon fire suppression systems are no longer serviceable and need to be removed. PLC systems are used on some 230 kV transmission lines, and extensively on 138 kV and 60 kV transmission lines for line protection, station supervision, telemetry and voice communications. Most of the PLC terminals are nearing 30 years old, and are no longer supported by the manufacturer, and are being replaced as part of a program that started in 2002. Replacement is expected to occur mainly in F2008, with the remainder in F2009.

[17] The "Montreal Protocol", an international accord under which Canada agreed to stop the production of Halon due to its ozone depleting properties.

Other Sustaining Capital programs addressed at the telecommunications system are identified in BCTC's F2009 Capital Plan (Section 6.5.1.6.6).

3.0 GENERATION INTERCONNECTIONS

BC Hydro's recent CFT processes have led to an unprecedented growth in the development of IPP projects in BC. To accommodate new IPPs, BCTC must undertake a series of studies to assess the impact of each project on the transmission system. Under BCTC's Open Access Transmission Tariff (OATT) Standard Generator Interconnection Procedures, BCTC must conduct an Interconnection Feasibility Study, a System Impact Study, and an Interconnection Facilities Study for each project. These studies involve increasing levels of detail and determine the ability of the system to accept the new generation at specific interconnection locations and what enhancements are required to enable the proposed generation project to be added to the system.

Several of the 2006 Call for Tender transmission connected IPPs require network integrated transmission service (NITS) reinforcements to enable the IPP interconnections and transmission of the IPPs' energy to the load centers.

Many transmission lines require thermal upgrading and, in one case, a conversion to a higher voltage level to accommodate the interconnection of the IPPs. These upgrades are in three regions of the transmission system; Vancouver Island, the Lower Mainland, and the Northern Region, and are detailed in the description of these regions in Section 2.3.

3.1 New IPP Projects

In July 2006, BC Hydro awarded 39 Electricity Purchase Agreements (EPAs) for new IPPs. The EPAs include thirty hydro projects, three wind projects, and six thermal projects listed in Table 3-1.[18] A map showing the location of these projects is available on the Independent Power Producers Association of BC's website at: http://www.ippbc.com/media/IPPBC%20Poster%20May%2018%20Secure.pdf.

[18] Further information on these IPP projects is available on BC Hydro' website at http://www.bchydro.com/rx_files/info/info47610.pdf

Table 3-1. IPP Projects with EPAs Issued in July 2006

	Project Name and Type H (hydro)/T (thermal)/W (wind)		Region	MW Capacity[19]
1.	East Toba and Montrose Hydroelectric Project	H	Lower Mainland	196
2.	Kwalsa Energy Project	H	Lower Mainland	85.9
3.	Upper Stave Energy Project	H	Lower Mainland	54.7
4.	Kwoiek Creek Hydroelectric Project	H	Lower Mainland	49.9
5.	Rainy River Hydroelectric Project[20]	H	Lower Mainland	15
6.	Lower Clowhom	H	Lower Mainland	9.99
7.	Upper Clowhom	H	Lower Mainland	9.99
8.	Kookipi Creek Hydroelectric Project	H	Lower Mainland	9.99
9.	Log Creek Hydroelectric Project	H	Lower Mainland	9.99
10.	Tamihi Creek Hydro Project	H	Lower Mainland	9.9
11.	Fries Creek Project	H	Lower Mainland	9
12.	Tyson Creek Hydro Project	H	Lower Mainland	7.5
13.	Sakwi Creek Run of River Project	H	Lower Mainland	5
	Sub Total for Lower Mainland			**472.86**
14.	AES Wapiti Energy Corporation[21]	T	Northern Interior	184
15.	Dokie Wind Project	W	Northern Interior	180
16.	Bear Mountain Wind Park	W	Northern Interior	120
17.	Mackenzie Green Energy Centre	T	Northern Interior	50

[19] Only nameplate capacity values are known at this time. Actual MW output is to be confirmed.
[20] In August 2007, Plutonic Power advised BC Hydro of its intention to exit the EPA for the 15 MW Rainy River run-of-river project due to unexpected complexities in the environmental permitting process caused by the discovery of a number of fish species in the area.
[21] AES Wapiti Energy has terminated its EPA.

	Project Name and Type H (hydro)/T (thermal)/W (wind)		Region	MW Capacity[19]
18.	Mount Hays Wind Farm	W	Northern Interior	25.2
19.	150 Mile House ERG Project	T	Northern Interior	5.89
20.	Maroon Creek Hydro Project	H	Northern Interior	5
21.	Anyox and Kitsault River Hydroelectric Projects	H	Northern Interior	56.5
	Sub Total for Northern Interior			**626.59**
22.	Canada - Glacier / Howser / East - Project	H	Southern Interior	90.5
23.	Princeton Power Project	T	Southern Interior	56
24.	Bone Creek Hydro Project	H	Southern Interior	20
25.	Clemina Creek Hydro Project	H	Southern Interior	9.95
26.	Serpentine Creek Hydro Project	H	Southern Interior	9.6
27.	Savona ERG Project	T	Southern Interior	5.89
28.	English Creek Hydro Project	H	Southern Interior	5
29.	Cranberry Creek Power Project	H	Southern Interior	3
30.	Eldorado Reservoir	H	Southern Interior	0.8
31.	Brilliant Expansion Project (2)	H	Southern Interior	120
	Sub Total for Southern Interior			**320.74**
32.	Gold River Power Project	T	Vancouver Island	90
33.	Songhees Creek Hydro Project	H	Vancouver Island	15
34.	Victoria Lake Hydroelectric Project	H	Vancouver Island	9.5
35.	Franklin River Hydro Project	H	Vancouver Island	6.65
36.	Clint Creek Hydro Project	H	Vancouver Island	6
37.	Barr Creek Hydroelectric Project	H	Vancouver Island	4

	Project Name and Type H (hydro)/T (thermal)/W (wind)		Region	MW Capacity[19]
38.	Raging River 2	H	Vancouver Island	4
39.	McKelvie Creek Hydroelectric Project	H	Vancouver Island	3.4
	Sub Total for Vancouver Island			**138.55**
	Total for All Regions			**1,559**

3.2 Capacity Studies of Cut-Planes for Potential IPPs

To assist IPP proponents in identifying existing transmission capacity, BCTC has produced planning level estimates of the firm ATC in each area of the provincial grid. These estimates predict the capacity of the existing transmission system to absorb new generation in areas where it might be added, given the existing flows on the system. Study results are posted on the internet (Cut-Plane Studies)[22]. The preliminary estimated cost, implementation period, and solution strategy to enhance the ATC for these cut-planes is posted with the study results.

The Cut-Plane Studies were based on the assumption that any generation being added would serve network load and do not represent any specific point-to-point capabilities. Any generation project will require additional transient stability studies which could further limit the power flows after specific data on the site, size, and characteristics of individual new generation projects are made available.

3.3 Impact of IPPs on Transmission Planning

The potential addition of IPPs has a large influence on BCTC's planning assumptions because the need for transmission is driven by both new load and also by resource additions to serve the load. BCTC expects BC Hydro to include the new IPP projects in its next NITS Application and BCTC will then determine the required transmission network reinforcements to integrate these resources. BCTC has used IPP information from the amended LTAP, CRP1, CRP2, and BRPs with and without Burrard in its planning process to determine bulk transmission reinforcements for the F2009 Capital

[22] www.bctc.com/the_transmission_system/engineering_reports_studies/

Plan. However, these transmission reinforcements will be adjusted in future Capital Plans when detailed IPP information is provided in NITS applications or updates.

3.4 Special Challenge of Wind Generation for Integration to the System

As indicated in the new Energy Plan, BC has "abundant and widely distributed" wind energy resources. The Peace River region, the Northern Coast and Northern Vancouver Island each have high concentrations of wind power potential. The 2006 CFT resulted in contracts for 325 MW of wind projects and there is considerable interest in wind power for future CFT processes.

BCTC expects growth in this industry and recognizes that wind energy has natural characteristics that make it challenging to integrate. The intra-hour, hourly and daily fluctuation of wind power output due to the variability of the wind creates several technical challenges.

Integration of wind power impacts a wide range of control area activities including: resource planning, transmission and distribution system planning, interconnection protocols, operating procedures, dispatch work, control and monitoring work and system operation. Solutions to these complex issues are somewhat unique to each control area due to the specific nature of each integrated electric system. Each utility needs to learn how to effectively integrate this resource into the particular generation mix of their control area.

BCTC is working to better understand these issues to facilitate integrating wind power into the provincial resource mix in such a manner that the transmission system can reliably carry the energy produced. This work includes:

3.4.1 Wind Generation Interconnection Requirements

BCTC is reviewing its draft "Wind Generation Interconnection Requirements" and FERC Orders No. 661 and No. 661-A, to incorporate appropriate industry best practices. BCTC will engage stakeholders in the reviews of the draft document. A workshop with stakeholders was held on this topic on November 7, 2007.

3.4.2 BCTC Wind Integration Study

BCTC is conducting a detailed Wind Integration Study to consider the impact of the wind resource variability in many time frames ranging from milliseconds to minutes, hours, days, and years. The short time frames are analyzed to determine real-time impacts on the system and the associated operating impacts and adjustments which will be required; the longer time frames are used to estimate the requirement to reinforce the transmission system to accommodate future wind generation. The results from the BCTC study will be made available to the stakeholders, including BC Hydro.[23]

3.4.3 Transmission System Planning Issues

BCTC is reviewing Wind Plant Modeling tools for Interconnection Studies, and for related transmission studies.

3.4.4 Transmission System Operating Issues

BCTC is learning about wind power operating characteristics to prepare for the associated operating issues and ancillary services requirements that will accompany the addition of wind energy to the system. Control center operators need information to ensure that real time generation by varying wind speed does not cause violations of transmission operating limits or cause reliability problems in specific areas of the system.

3.4.5 Data Collection Issues

BCTC is investigating the data collection requirements for wind energy forecasting and monitoring. This will enable BCTC to ensure that operators have good forecasting tools when wind energy is added to the system.

3.4.6 Potential Tariff Amendments

BCTC is assessing FERC Order 890, which contains proposals for Conditional Firm Service and Generator Imbalance Service. These services could complement and support intermittent generation from wind power.

[23] It is anticipated that this study will be of interest to BC Hydro for its resource planning activities. BCTC will also review studies that BC Hydro and others may do to examine the impacts and use of wind energy. Sharing of this information facilitates the industry learning about wind energy issues

4.0 WECC INITIATIVES OF INTEREST TO BCTC

The following section provides an updated report on the initiatives captured in the 2006 STSR, and describes new developments within the WECC region.

There are proposed projects in neighbouring jurisdictions and proposed new interconnections that could have impacts on the existing transmission system or on proposed projects in BC. It is a general requirement of member systems in the WECC that projects are coordinated between companies and/or system operators to avoid negative impacts on neighbouring systems. BCTC monitors and, where necessary, participates in WECC processes to ensure that BCTC's interests and those of its customers are protected and advanced.

BCTC also studies these initiatives to understand how they may impact the self sufficiency and renewable energy objectives of the new Energy Plan.

The new Energy Plan directs BC Hydro to acquire sufficient electricity supply from sources within BC by 2016 to meet its domestic demand under critical water year conditions, and to provide a surplus of 3000 GWh by 2026. To enable BC Hydro to optimize the economic value of its generation assets, including the value of its regional electricity trade, it will likely be necessary for BCTC to expand the capacity of both its internal transmission facilities and of its inter-tie facilities with neighbouring jurisdictions to allow for the sale of surplus energy when not needed internally.

Federal governments and legislatures in Canada and the US are actively exploring ways to introduce new national standards on clean renewable sources of electricity, commonly referred to as "green energy". California has set the most aggressive targets for green energy supply on the Pacific coast, mandating a 20% Renewable Portfolio Standard by 2010 with potential for a 33% target by 2020. California has diminishing potential to meet these targets with in-state renewable generation and is interested in partnering with BC to source green energy. Premier Campbell supports the joint initiative and signed a Memorandum of Understanding in June 2007 with Governor Schwarzenegger to work with California on this. Consequently, BCTC anticipates an expansion of US market demand for clean and renewable generation in BC. New transmission infrastructure would likely be required to enable BC Hydro and BC IPPs to pursue these opportunities.

4.1 Transmission Expansion Initiatives in Alberta

4.1.1 New BC-Alberta Intertie

In 2006, BCTC and the AESO started a high level study to assess the economic viability of a new Alberta-BC intertie circuit. The study considered two routing options: a new 500 kV connection in the north; and a second 500 kV connection in the south, roughly paralleling the existing 500 kV connection.

The study was completed in mid-2007 and concluded that, for both BC and Alberta, an expanded intertie would provide a number of benefits, such as greater future supply adequacy; improved integration and operation of intermittent generation; greater utilization of generation resources on a regional basis; and lower electricity price volatility. There was broad recognition of a number of non-monetized benefits such as system reliability and market liquidity. The working group will next consider mechanisms for sharing costs and benefits.

4.1.2 Edmonton-Calgary 500 kV Transmission Line

In 2005, an application was made to the AEUB to build a 500 kV circuit between Edmonton and Calgary. This line would supply energy to fast-growing Southern Alberta and would partially restore the Alberta export capacity on the AB-BC Intertie, by relieving the limitations in the Alberta system that occur when BC is importing energy from Alberta during heavy load periods. The second phase of the project would add a parallel line between Edmonton and Calgary that would fully restore the AB-BC inter-tie to its rated capacity. When this inter-tie limit is restored, the constraints which limit increases to electricity trade with Alberta will likely be on internal paths in the BC transmission system.

This project was originally due for completion in 2009. In 2007, the regulatory processes for this project ran into significant landholder resistance and AEUB ended its proceedings.

The project proponent is revising the original project concept and is re-examining a number of design and route alternatives.

4.1.3 Southwest Alberta

In 2005, the AEUB approved a need application for a transmission project to build two 240 kV circuits south of Calgary to enable the integration of up to 600 MW of wind generation in southwest Alberta. The first circuit was scheduled for completion in 2007 but has been delayed until late 2008.

In September 2007, the AESO lifted a 900 MW limit, which it had imposed on the integration of wind power generation due to uncertainties related to the amount of generation reserves required to compensate for the intermittent nature of wind power. This is expected to result in the ultimate integration of more wind power generation resources, which by some estimates will provide well over 3000 MW.

The addition of wind in Alberta will increase the AESO's need for generation reserves and dynamic scheduling. As a result, there may be opportunities for BC Hydro and others to provide these services. Additional intermittent, renewable generation could also provide BC with a source of lower cost imports when Alberta has surplus energy. In the long term, it may also result in AESO building a new 500/240 kV substation near Pincher Creek to integrate the wind power generation, which would also provide a close interconnection point to expand the inter-tie capacity between BC and Alberta.

The addition of wind in southwest Alberta has caused overloading at times on BCTC's 138 kV ties from Natal into Alberta. A study is underway with Alberta to determine the best solution to this issue.

4.1.4 Northwest Alberta

In August 2006, the AESO received regulatory approval to reinforce the regional transmission system throughout the northwest Alberta region between the areas of Wabasca and Peace River. This region has reached capacity on many circuits and a number of many must-run generation contracts costing about $40 million a year are being relied upon to serve the load.

The first phase of this project, planned to come in service in 2009, is a reinforcement of the existing Rainbow Lake area transmission system into which the Fort Nelson area is integrated. The planned second phase of the project is a second 240 kV supply line to Wesley Creek, scheduled to be completed by 2014.

These reinforcements are designed to serve the load growth in Alberta and may not meet the load growth in BC. However, given the expected load growth in the Fort Nelson region, there may be an opportunity to reinforce the supply to the Fort Nelson region through the Alberta system.

4.1.5 Alberta/Montana

Montana Alberta Tie Ltd. (MATL) is seeking approval to build a merchant transmission project between Lethbridge in southern Alberta and Great Falls in northern Montana. The 300 km, 240 kV transmission line would provide 300 MW of capacity.

This tie would complicate the operation of the existing BC-AB intertie, increase the competition for electricity trade with Alberta, and impact the electric system in BC when the Montana-Alberta transmission path has contingency events.

It appears that the funding for this project is not yet fully secured, but despite this, regulatory applications in various jurisdictions have progressed. In April 2007, the National Energy Board (NEB) granted MATL a Permit to construct this transmission project. In August 2007, the MATL project achieved Phase III status of the WECC rating review process, and was granted an Accepted Rating of 300 MW.

BCTC participates in the Project Review Group of the WECC rating review process for the MATL project, to ensure there are sufficient operating procedures and remedies to address any potential impacts of this new line to the BCTC system. The MATL project is planned to come into service in December 2008.

4.1.6 Northern Lights

TransCanada Pipelines is proposing a transmission path from Alberta to the U.S. through the southeastern corner of BC. This route would provide BCTC with an interconnection opportunity to expand inter-tie capacity with both Alberta and the US within one project.

This proposed project could transmit over 2000 MW of Alberta oil sands or Montana/Wyoming wind and coal generation to Washington or to California markets. A Direct Current (DC) transmission line is the preferred option due to lower overall costs (including transmission losses over this long path).

There could be synergies between this project and the proposed PG&E BC-California project discussed in Section 4.2.1, as there is potential to develop cogeneration projects in the Alberta oil sands to feed into a potential northern segment of the proposed PG&E Canada-California project.

The project cost was estimated in the $2 billion range over a year ago, but general cost escalations suggest the costs would be higher today. TransCanada held a WECC Regional Review Group meeting in September 2006 but there has been little public consultation since then. This project has an earliest completion date of 2015.

4.2 Transmission Expansion Initiatives in the United States

4.2.1 Pacific Gas & Electric

Pacific Gas and Electric (PG&E) initiated a WECC Regional Planning Review process in 2006 to investigate the feasibility of delivering either 1500 MW or 3000 MW of renewable energy from the WECC Region (including the Pacific Northwest) to Northern California. This project is driven by California's Renewable Portfolio Standard (RPS) target of 20 percent by 2010, which, pending legislation, may increase to 33% by 2020.

Three study groups reviewed resource availability, transmission requirements and economic feasibility. The regional planning process studied a variety of resource options, including Canadian (BC and Alberta) renewable resources. As well, a variety of transmission route alternatives, involving both overhead and underwater cable solutions were identified and studied. BCTC participated in each of the study groups, and sits on the Steering Committee.

The WECC Regional Planning Review process for the PG&E project concluded in October 2007. The preferred alternative that emerged from this process is a hybrid transmission project consisting of a 1500 MW 500 kV AC line extending from Selkirk in BC to McNary or Grizzly in Oregon, at which point the line would convert to a 500 kV DC line capable of transmitting 3000 MW south to Tesla in northern California.

The next phase of the WECC planning process for the PG&E project is the WECC Project Rating Review process. This phase is expected to commence in November of 2007 and last approximately one year. Through Steering Committee participation, BCTC will place particular focus on the required upgrades to BCTC's internal bulk transmission system for this proposed project. The target in-service date for the PG&E project is Q4 of 2015.

4.2.2 PacifiCorp and Idaho Power Expansion

This potential project would consist of new 500 kV lines between Utah/Wyoming and Oregon and is synergistic with PG&E's potential 3000 MW transmission project for the "Canada Resources" option described above.

PacifiCorp announced plans to build more than 1,200 miles of new 500 kV lines originating in Wyoming and connecting into Utah, Idaho, Oregon and the desert southwest. The two lines are set for completion in 2014. The $4 billion-plus project includes plans to deliver wind and other renewable energy resources to more customers throughout PacifiCorp's six-state service area and the western region. The lines would likely connect with the 500 kV transmission lines from the PG&E project described above, near the existing Burns substation in Eastern Oregon. This connection between two high capacity transmission projects would enable improved utilization of existing regional resources and transmission, improving the economic viability of both projects.

4.2.3 Juan de Fuca Cable (JDF)

Sea Breeze Power proposes to build a 49-km HVDC Light submarine cable transmission interconnection across the Strait of Juan de Fuca, connecting Port Angeles substation on the Olympic Peninsula in Washington State with Pike Lake Substation near Victoria, BC. The project also includes upgrades to the transmission networks west of Puget Sound on the Olympic Peninsula.

In 2006, the National Energy Board (NEB) granted Sea Breeze approval of the JDF Project. The JDF project has also undergone Phase 1 of the WECC Rating Review process, and has achieved Phase 2 status, with a planned rating of 550 MW.

Sea Breeze made an interconnection application to BCTC and was provided with study proposals in 2007. BCTC will commence work on the requested interconnection study as soon as Sea Breeze signs the study agreement.

The target in-service date of this project is December 2008.

4.2.4 Frontier Line

The Frontier Line is a major project proposed by Western US state governors to deliver clean coal and wind energy from Montana, Wyoming and Colorado to major load centers in Utah, Nevada and California. It is distinct from the Northern Lights project. A partnership of Pacific Gas & Electric (PG&E), San Diego Gas & Electric, Southern California Edison, Sierra Pacific Power Company, Nevada Power Company, and MidAmerican Energy Holdings Company is advancing this project. The proponents have done preliminary scoping and set a proposed in-service date of 2015. The project may integrate up to 12,000 MW of new wind and coal generation throughout a broad region, with transmission costs estimated between $3.5 and $5 billion.

The Frontier Line project is geographically remote from and unlikely to have much impact on the BC transmission system. However, its significant size would alter regional power flows throughout the U.S. regions of the WECC. Of significance to BC is that it competes with the potential PG&E project from BC to California by delivering renewable energy from Montana and Wyoming to Northern California.

4.2.5 Portland General Electric Southern Crossing

In 2007, Portland General Electric initiated a WECC Regional Planning Review process for a proposed project that would improve service to loads west of McNary in the BPA system and would enable integration of significant renewable resources located in central Oregon. The proposed project consists of rebuilding the existing 230 kV Cross-Cascade South line to 500 kV, and would significantly increase the east-to-west transfer capability to the California intertie. Portland General Electric is studying alternatives and examining synergies with other regional projects.

5.0 BCTC TRANSMISSION EXPANSION POLICY (TEP)

BCTC uses its Transmission Expansion Policy (TEP) to study and advance proposals that consider expanding the transmission system in anticipation of future transmission needs.

BCTC's TEP Paper "Evaluation Methodology for Considering Transmission System Expansion without Committed Contract" was developed in 2005 in conjunction with BCTC's Transmission Planning Advisory Committee (TPAC) with input from stakeholders. The Policy Paper was filed with the Commission in response to Provincial Government's Special Direction 9 (SD9), and sets out a framework that BCTC could follow to plan and expand the transmission system in the absence of firm customer contracts for transmission service, when it is in the best interest of ratepayers to do so.

In 2006, the Commission stated that it will assess the TEP in the context of the first TEP project that is advanced by BCTC.

While BCTC is advancing with TEP implementation, as described further in Section 5.1, BCTC recognizes that development of a Congestion Relief Policy as intended in the new Energy Plan will provide further information on BCTC's TEP efforts. BCTC is confident that efforts which BCTC is expending in the context of TEP implementation will continue, either in their current form, or become embedded in broader efforts concerned with the application of the new Energy Plan initiatives.

5.1 TEP Implementation Plan

In 2006 and 2007 BCTC worked to incorporate the TEP into BCTC's existing planning processes. BCTC examined its system planning, capital planning, and strategic planning processes to determine the capability and readiness of BCTC to identify, evaluate, and advance projects in pursuit of TEP opportunities. Upon completion of this work, BCTC developed a TEP Implementation Plan.

The TEP Implementation Plan sets outs the process that BCTC will follow to pursue TEP opportunities, and outlines expectations with respect to stakeholder engagement in this process. BCTC will work to identify and address customer and stakeholder transmission needs before actual services are requested, to identify opportunities for strategic transmission expansion.

As outlined in the TEP Implementation Plan, BCTC will proactively plan the transmission system to not only accommodate contracts for service, but also to support timely development of future domestic generation and enable the capture of electricity markets' opportunities. BCTC will hold open technical workshops with transmission customers and other stakeholders, including where applicable representation from interconnected jurisdictions and regional players, to identify opportunities for TEP projects. BCTC will use the information collected from TEP processes to identify transmission needs, conduct relevant studies and prepare investment justifications for TEP projects.

BCTC announced the TEP Implementation Plan at its annual Technical Planning Session on June 12, 2007. At this session, BCTC also invited customers and other interested parties to submit Expressions of Interest for project ideas or concepts by August 15, 2007 which BCTC could study for potential advancement under the TEP. At the request of stakeholders, BCTC extended the deadline for submissions pursuant to the Request for TEP Expressions of Interest to September 7, 2007.

The Request for TEP Expressions of Interest generated a considerable response from IPPs, market participants and other parties. The majority of submissions highlight opportunities for transmission system expansion to provide access to clusters with high potential for IPP generation projects.

BCTC held the first open TEP workshop on October 18, 2007. The workshop was attended by over 50 individuals, representing BCTC, BC Hydro, IPPs, market participants, and other stakeholders. At the workshop, BCTC provided an overview of the TEP submissions, and facilitated stakeholder discussion on the next process steps, including the need to set up a Technical Advisory Committee that will oversee the assessment of TEP proposals.

Over the next three months, BCTC will analyze the TEP submissions in conjunction with the Technical Advisory Committee and, where appropriate, will make recommendations to further pursue TEP project concepts.

In addition to setting up a TEP implementation process, in 2007 BCTC also identified, studied, and prepared an investment justification for a first project to be advanced under TEP. This project is being “fast tracked” to comply with a Commission Directive to advance a project under the TEP. BCTC filed an application for this project on December 12, 2007.

The project BCTC has filed with the Commission is to upgrade the 500 kV 5L51 and 5L52 circuits of the Ingledow-Custer transmission line, resulting in an increase in the Total Transfer Capability (TTC) of the US-BC intertie. If approved, this investment would be driven by an opportunity to meet future transmission requirements for Point-to-Point transmission service on the US-BC intertie.

6.0 EQUIPMENT CONDITION AND PERFORMANCE

The transmission system infrastructure is deteriorating and an increasing number of original components are approaching end-of-life as a result of normal aging and wear and tear. This section discusses the equipment condition challenges that BCTC is working to resolve.

6.1 Asset Condition

BCTC ensures that transmission system equipment and supporting infrastructure provide reliable service. Overall, the condition of the transmission system assets is generally good, but is deteriorating at an increasing rate. In response, BCTC has developed a capital program to refurbish or replace assets and smooth the investment profile over the long-term. The Capital Plan considers outage, materials and labour resource constraints.

In 2004, an Asset Baseline Study (ABS) established a baseline measure of asset condition and developed a framework of condition-based asset health indices (AHI) for all thirty-three classes of assets. AHI baselines were produced for most of the asset classes except for Access Roads, Civil Works, and Wood Pole Structures. The ABS provided:

(a) An assessment of asset condition to enable monitoring of BCTC's asset management;

(b) A documented repeatable process for future comparative studies;

(c) Best practice asset health metrics; and

(d) Indices to use in planning capital and OMA investments in equipment.

Under Article 7 of the Asset Management and Maintenance Agreement with BC Hydro an update to the ABS was to be completed every three years. The initial baseline study was a large undertaking and aggregated all of the available and surveyed data. For some asset types however, the available data was incomplete or was in a form not compatible for the study. To address the need for more data BCTC now collects specified asset health and demographic data as part of revised routine maintenance procedures so that future audits will be more comprehensive and valuable. For most equipment BCTC will have good data in 2010. For some types of assets, such as circuit breakers with a long (eight year) maintenance cycle, it will take up to eight years to capture complete data.

BCTC and BC Hydro discussed the persistence of old data and the expected high cost of obtaining data for the study which was scheduled for 2007. This study would not be expected to show many changes from the initial Asset Baseline Study until the data is updated. Accordingly, BCTC and BC Hydro agreed to defer the 2007 study until more complete and updated data is collected by field inspections. It was agreed that BCTC would:

(a) Continue collecting asset condition data;

(b) Automate the AHI calculation;

(c) Complete a baseline health study on access roads[24] in F2008;

(d) Produce an inventory and condition data for all civil and wood pole structures before the next full study in F2011; and

(e) Report by June 2007 on the actions taken and the present status of assets rated as poor or very poor in the 2004 ABS.[25]

This new data, and the data now routinely gathered by field maintenance crews and contractors, will enable the next asset condition audit to include Access Roads, Civil Works, and Wood Pole Structures which the baseline study was unable to address.

BCTC's initiatives to improve the asset health information management process include:

(a) Revising maintenance standards to capture AHI raw data according to standardized condition values during the maintenance of all assets;[26]

[24] Access roads were one of the asset classes for which inventory and condition data is very sparse.
[25] This report the Condition Assessment (Baseline Study) Update was completed and sent to BC Hydro in June of 2007.
[26] Attribute scoring will be more detailed than in the past, capturing degrees of wear and tear rather than traditional reporting of pass/fail judgment in the field.

(b) Collecting data with hand held devices, IMAX and STARR software, and uploading it to a central database;

(c) Automatically calculating the AHI for each asset along with other decision support information for asset managers including the confidence level of the analysis[27], data completeness, and attribute scores;

(d) Generating AHI reports to communicate condition results and to support asset management decisions and system performance reviews;

(e) Collecting new planimetric data (measurement of planar surfaces), including LIDAR (Light Detection and Ranging) data, along existing Rights of Way (ROWs) (i.e., new subdivisions, new roads, etc.) as well as cadastral information along ROWs. The data will be loaded into EGIS PowerGrid for ROW management;

(f) Building an inventory of access roads together with condition data and a sampling program to build a statistically representative subset of all roads based on the amount of sampled data which can be obtained in F2008;

(g) Building an inventory of wood pole structures together with condition data and a sampling program to produce a statistically representative subset based on the amount of sampled data which can be obtained in F2008 and F2009; and

(h) Implementing trend reports in BCTC's System Asset Management Suite to help managers identify and avoid emerging reliability and cost problems.

In the F2008 Capital Plan, the following systems were approved which enhanced data collection and decision support:

(a) IMAX – Added electronic system condition assessments and Asset Health Index data collection; and

(b) AMP – Added/enhanced a project management tool and statistical analysis.

[27] Confidence is based on the staleness of the assessment data. Old data may not be true and recent data produces high confidence in the assessment.

These initiatives will provide a system that automatically updates asset condition in the database whenever routine inspections are done, enabling continuous updating of the AHI reports. The above initiatives are being implemented as routine procedures and a complete data set is expected by F2014.

6.2 Condition Issues

The 2004 ABS identified several areas of concern regarding the condition of certain transmission system assets. In many cases, BCTC had already identified these issues and had initiated programs to address these.

In addition to the ABS, BCTC is continuing to enhance reliability risk models to identify the end of life of assets and is optimizing programs for their repair, refurbishment, or replacement. BCTC reviews its Sustaining Capital programs holistically each year to ensure that they are adjusted if necessary to provide the highest value. Programs have been developed to address the needs of the following assets that must be dealt with in a timely manner to maintain the transmission system to acceptable levels of reliability, safety, and environmental performance

6.2.1 Circuit Breakers and Circuit Switchers

The ABS identified 14.8 percent of circuit breakers as being in poor condition. BCTC has had circuit breaker refurbishment and replacement programs in place before the ABS took place. The audit confirmed that the programs in place were addressing the highest risk equipment. The results of the ABS for circuit breakers are used as a guideline in conjunction with actual condition assessments to determine and prioritize circuit breakers for repair or replacement. BCTC reviews the approach each year to ensure that it meets current needs, and has successfully replaced or repaired many of the breakers identified in the ABS.

The following key issues have been identified related to circuit breakers, circuit switchers and disconnect switches, and BCTC has projects in place to address each of the following issues as described in section 6.5.1.2 of the F2009 Capital Plan:

(a) According to BCTC maintenance standards, all 104 air blast circuit breakers are due for major upgrades by 2014. The air blast circuit breakers are approaching 40 years of service and are currently exhibiting deteriorating asset condition.

BCTC undertook a major life extension refurbishment approximately 20 years ago to extend the useful life of air blast circuit breakers to 2014. However, only one major life extension refurbishment is economically and technically feasible on these circuit breakers, leaving replacement as the only option. This work is required to avoid catastrophic failures and mitigate the impact on system reliability. Increasing failure rates, resource constraints, and transmission outage constraints require the advancement of the replacement project;

(b) Reliability issues with 60 kV to 230 kV circuit breakers are caused by moisture ingress, wear-out, and end-of-life. In addition, double-pressure SF6 circuit breakers are subject to significant SF6 gas leaks requiring costly repairs that are short-term solutions to the problem. SF6 is a major greenhouse gas with the same effect as releasing over 23,000 times its volume in CO2. These issues lead to the requirement to replace these circuit breakers;

(c) Reliability issues with MICA GIS circuit breakers are caused by SF6 leaks, poor performance, and lack of OEM support. These issues lead to the requirement to replace these circuit breakers;

(d) Issues with Horsey GIS circuit breakers are caused by SF6 leaks and wear-out. These issues lead to the requirement for major refurbishment to ensure reliable electric supply to Victoria;

(e) Reliability issues with 500kV circuit switchers are caused by increasing operational needs, poor performance, and lack of OEM support. These issues lead to the requirement to replace these circuit switchers; and

(f) Reliability issues with 500 kV disconnect switches are caused by increasing operational needs and poor performance. These issues lead to the requirement for major refurbishment to extend the life of the equipment.

To address these issues, the F2009 Capital Plan (see section 6.5.1.2 of the F2009 Capital Plan) includes the following projects:

(a) Replace 500 kV air blast breakers at Ingledow, Dunsmuir, and Nicola;

(b) Replace 230 kV circuit breakers to address issues with 230 kV bulk oil circuit breakers and 230kV double-pressure SF6 circuit breakers;

(c) Replace Mica GIS breakers;

(d) Replace 500 kV circuit switchers at Dunsmuir and Williston;

(e) Betterment of Gas Insulated Switchgear (GIS) at Sperling and Ashton Creek;

(f) Replace less than 230kV circuit breakers;

(g) Replace 12 kV reactor circuit breakers at Malaspina 12CB2 and Cranbrook 12CB16, 12CB17;

(h) Addition of spare 230 kV circuit breaker; and

(i) Refurbish Horsey GIS circuit Breakers.

6.2.2 Transformers

Generally, transformers are considered to be in good condition. However, there are enhancements that can be implemented that increase transformer capacity and life expectancy (e.g., Mechanical gauge replacements with electronic temperature monitors (see section 6.5.1.3.1 of the F2009 Capital Plan) and maintenance free dehydrating breathers (see section 6.5.1.3.6 of the F2009 Capital Plan)).

In addition, an issue was identified with Selkirk T1A which has a potential for internal failure caused by a foreign object resulting from a broken flow switch. To mitigate the consequences, BCTC purchased a spare transformer which will be used as part of the Selkirk T4 project.

6.2.3 Shunt Capacitors

The ABS identified 4.5 percent of shunt capacitors as being in poor condition, mainly due to the environmental risk they presented because of their PCB content. Prior to the audit, a program (see section 6.5.1.3.7 of the F2009 Capital Plan) had been in place for several years and had succeeded in replacing all the PCB capacitors except for those at VIT. BCTC plans on replacing the PCB-filled capacitors at VIT in F2010, based on the successful completion of VITR and the future need of the capacitors.[28]

6.2.4 Insulators

Pin and cap insulators were installed in stations from the 1950s to the 1970s to support energized equipment. They have a metal stud base mortared together with one or more porcelain skirts. Changing weather (resulting in temperature and humidity changes) expands and contracts the mortar, allowing water to penetrate and crack the porcelain skirts. This type of failure has resulted in approximately thirty known system faults in the last ten years at BCTC managed stations. On-going failures pose a risk to personnel and to the transmission system caused by catastrophic failures.

Replacement priority is given to insulators associated with disconnect switches and those found to be in poor condition based on inspection. Insulators are inspected as part of station inspections which occur every three to six months. The work required in this project will increase substantially in F2009 and F2010 to address the insulators at greatest risk of failure. The replacement program (see section 6.5.1.1.1 in the F2009 Capital Plan) is expected to continue for the next 25 years.

6.2.5 Protection and Control

BCTC has several programs (see section 6.5.1.5 in the F2009 Capital Plan) to replace the 59 percent of protection and control systems that were identified in the ABS as being in poor condition and having reached their end of life as well as some infrastructure that have been recently identified. The following key issues have been identified related to protection and control equipment:

(a) Reliability issues with 60 kV to 500 kV line protection systems are caused by mis-operation and lack of OEM support. These issues lead to the requirement to replace these protection systems;

[28] The federal government recommended date for removal of all PCB capacitors is December 31, 2009.

(b) Reliability issues with transformer protection systems are caused by mis-operation and lack of OEM support. These issues lead to the requirement to replace these protection systems;

(c) Recently, a critical reliability issue with Programmable Logic Controllers (Model PLC984) was identified that threatened the integrity of the entire transmission system and required urgent mitigation. The issue is due to unpredictable performance that cannot be repaired because of lack of OEM support. A replacement program has been established to replace the units in priority sequence at critical substations; and

(d) Recent changes in technology of protection and control system enables advanced functionality that offers benefits to BC Hydro customers. Examples include metering, fault identification and analysis, faster protection, and energy conservation. BCTC is supporting BC Hydro to implement strategic initiatives which support the BC Energy Plan through third-party improvements to the transmission system (e.g., Voltage and VAR Optimization – an energy conservation initiative).

6.2.6 Surge Arrestors

Surge arrestors are a critical element in protection of transformers, the substation's most expensive asset, against voltage transients caused by lightning or switching surges. The ABS identified that 58.7 percent of existing surge arrestors are gap-type and are in poor condition. Gap-type surge arrestors installed more than thirty years ago have been recognized as having a high risk of not being effective to perform their function as intended. These arrestors are being replaced with a newer technology type known as a Metal Oxide Varistor (MOV).

Failure of surge arrestors to perform, results in damage to transformers and other critical transmission system infrastructure during lightning and switching events. This poses a significant risk.

BCTC is addressing this risk with a Surge Arrestor replacement program which is constrained by resources and outage requirements and will be completed by F2013 (see section 6.5.1.3.2 in the F2009 Capital Plan).

6.2.7 Station Grounding

The ABS identified 1.1 percent of grounding systems as being in poor condition and 19.1 percent as being in fair condition. Deficiencies in station grounding may create step and touch potentials during faults, which is a safety concern for both employees and the public. BCTC initiated work to correct the minor deficiencies to upgrade the grounding systems identified in poor condition. For efficiency, BCTC has also initiated spot checks to confirm buried copper grounding systems are in good condition during construction project opportunities. BCTC completed four assessments at substations in F2007 which indicated minor improvements were required to bring the substations up to standard. These improvements will be completed in F2008. BCTC is continuing the program to assess and mitigate step and touch potentials at four substations per year prioritized on stations that are recognized as having the highest risk (see section 6.5.1.1.7 in the F2009 Capital Plan). The annual upgrade work in this multi-year program will be done in the year following the assessments. Overhead shield wires, which are used for station lightning protection and forms part of the grounding system, will also be included in the assessments when they are scheduled. BCTC also has a station gravel replacement program to mitigate step and touch potential safety issues (see section 6.5.1.1.4 in the F2009 Capital Plan).

6.2.8 Batteries and Chargers

Batteries are required for emergency operation of switchgear, relays, telecommunications equipment, emergency lighting, motors, inverters, and other devices. Batteries provide energy to circuit breakers during an outage, allowing the protective devices to function. Without batteries, there would be no emergency power at substations when a power outage occurs.

Based on historical results, the average battery life is twenty-five years. Batteries are inspected yearly and are load tested after eighteen years of life. Replacement of failing batteries and chargers is required to ensure that there are no safety incidents, loss of station control protection, customer outages, or equipment damage resulting from loss of battery power.

There are over 220 stations that have 124 volt batteries. Six to nine battery banks are replaced each year. Priority is given to leaking or cracked batteries, those with a known failure rate, and those that have failed the load test. BCTC has initiated a program to address the replacement of batteries (see sections 6.5.1.1.3 and 6.5.1.6.2 in the F2009 Capital Plan).

6.2.9 Facilities General

Facilities General includes station buildings and structures, security, fencing, roofing (see sections 6.5.1.1.5 in the F2009 Capital Plan), drainage, culverts, and ditches. BCTC has developed programs to address issues with these items.

One of the most recent and significant risks that is being addressed is station security caused by materials theft and vandalism. BCTC has initiated a $2 million annual program to improve station security to address this issue (see section 6.5.1.4.1 in the F2009 Capital Plan).

6.2.10 Fire Protection Systems

One percent of the fire protection systems on the transmission system are rated very poor as a result of being CO2 and Halon-based. An ongoing program is in place to replace or eliminate the need for those systems. It is expected that this program will be completed in F2009 (see section 6.5.1.4.2 in the F2009 Capital Plan).

A major issue related to fire protection and unacceptable life safety risk was identified at Cathedral Square substation and requires removal of the CO2 Fire Suppression System and relocation of the oil filled 2L31/32 cables terminations that present an unacceptable fire hazard in the substation (see section 6.5.1.3.4 in the F2009 Capital Plan).

6.2.11 Telecommunication Equipment

The ABS identified 19 percent of the telecommunication system to be in fair condition. Prior to the ABS, BCTC had a program in place to convert all of the existing analog systems to digital, which is required to support protection and operation of the bulk transmission system. Replacement of all analog microwave equipment is now complete, including the portion of equipment that was assessed to be in fair condition.

There is presently a probability that the existing fibre optic cable between Chapman’s and American Creek could fail at any time, which would subject BCTC and its customers to financial consequences related to the loss of transmission transfer capability on the ILM Grid.

6.2.11.1 Chapman’s Fibre Optic Cable Replacement

A fibre optic cable required to enable Chapman’s Capacitor station to function is at end-of-life condition and requires replacement. Loss of the Chapman’s (CHP) capacitor bank would result in a reduction in capacity of 400 MW from the Interior to Lower Mainland. Communications are required to provide protection of CHP and are currently provided by a fibre optic cable. Loss of this fibre optic cable will require CHP to be taken out of service and there is presently a high probability that the existing fibre optic cable could fail at any time. Loss of CHP capacitor station would not result in loss of circuit 5L41, however, it would result in reduction transfer capability (line loading) to the Lower Mainland. Communications at CHP are provided by a 31 km fibre-optic cable between CHP series capacitor station and the American Creek series capacitor station. The fibre optic cable enables protection, status indication, control, and alarm systems for CHP series capacitor station. Over the years, this early-vintage cable has had a variety of problems with splices and terminations and is in poor condition. Between 1998 and December 2005, eighteen incidents required nearly $400 K in maintenance costs to remediate. Further maintenance costs are expected to continue if the fibre optic cable is not replaced. The fibre optic cable that was originally installed in 1998 was incorrectly designed for its environment of 500 kV corona and ultra-violet light exposure. These environmental effects have resulted in accelerated deterioration of the cable. Due to this deterioration, the cable is not expected to last past 2012. To mitigate the consequences of failure, the fibre optic cable must be replaced with a microwave radio link (see section 6.5.1.6.1 in the F2009 Capital Plan).

6.2.11.2 Power Line Carrier Equipment

The ABS identified 19 percent of power line carrier equipment as being in fair condition. This equipment is in the process of being replaced using the most effective options available (power line carrier, microwave radio, or fibre optic cable) (see section 6.5.1.6.4 in the F2009 Capital Plan).

6.2.11.3 Tone and Test Equipment

There have been 233 tone and test panel failures between February 1999 and September 2006 requiring corrective action, and there is evidence that failures are continuing. The consequence of a loss of communications related to the failure of tone and test equipment reduces the functionality of the circuit and/or transformer protection. Failures result in slow tripping, no tripping, and inadvertent tripping of protection that could lead to equipment damage or unnecessary outages. The impact of failure is mitigated by redundancy (N-1 design).

Tone and test panel equipment provide the interface, testing and isolation functions between station protection equipment and the telecommunications system. Tone transmitters convert protection relay logic to a specific frequency allowing it to be carried over a telecommunications channel. Tone receivers convert the transmitted frequency to relay logic. Test panels are used to isolate protective relays and tone transmitters and receivers thereby allowing the testing of telecommunication channels without operating the relays. Due to the tone and test panel failures and impact on system reliability, a replacement project has been initiated (see section 6.5.1.6.3 in the F2009 Capital Plan).

6.2.11.4 High-Voltage Entrance Protection

There are a number of substations on the transmission system that use old style reactors and isolating transformers for High Voltage Entrance Protection (HVEP). Testing has shown that this equipment is not adequate in the event of a lightning strike or Ground Potential Rise (GPR) resulting from an electrical fault. As well as the electrical hazard to personnel, GPR would likely damage the communication circuits with possible loss of valuable data.

HVEP is used to provide ground protection for workers in substations. As an example, the majority of substations have telephone service wires and, in the event of an electrical fault at a station, there may be a hazard from GPR, which could cause electrical injuries to crews working on or near those telephone wires inside or outside the substation. Due to the GPR hazard, a replacement project has been initiated (see section 6.5.1.6.7 in the F2009 Capital Plan).

6.2.12 Series Capacitors

As stated in the 2006 STSR, all previously identified deficiencies have been addressed. The series capacitor stations are now considered to be in good condition, with the exception of Chapman's Capacitor station where the issue is related to telecommunications.

6.2.13 HVDC Pole 1 and 2

The ABS identified Pole 1 and 2 to be in poor to fair condition. A major refurbishment of Synchronous Condensers Numbers 3 and 4 at VIT are required to address system reliability issues related to asset condition. BCTC is ensuring that the condition of the HVDC system is adequate until the VITR project is complete, after which the HVDC system will be maintained and kept in service until it ceases to be economic to do so (see section 6.5.1.3.5 in the F2009 Capital Plan).

6.2.14 Synchronous Condensers

Synchronous condensers at VIT, which are presently used to support the operation of the HVDC system, will continue to assist the area voltage control even after the HVDC system is physically retired.

Condition assessments of VIT SC3 and SC4 detail major wear that must be addressed. A significant refurbishment is required (see section 6.5.1.3.5 in the F2009 Capital Plan).

6.2.15 Conductor Spans

The ABS identified 12 percent of all conductors on the transmission system to be in poor or fair condition. BCTC regularly inspects, identifies and repairs deteriorated conductors in its maintenance program. BCTC has developed a conductor replacement program through consultation with other utilities and the CEA's Transmission Line Asset Management Interest Group to determine “best practice” techniques and methods to manage this asset class. The large inventory of aging conductors will need to be replaced at their end of life and BCTC is working to establish the most effective strategies to manage this emerging problem (see section 6.5.2.4.8 in the F2009 Capital Plan).

6.2.16 Metal Structures

The ABS identified 21 percent of all metal structures (galvanized steel lattice towers) on the transmission system to be in very poor, poor or fair condition. Galvanizing protects the steel for many years but, over time, the galvanizing deteriorates and exposes the raw steel. The raw steel is then unprotected from oxygen, humidity, and chemical pollution and reddish, brittle oxide forms on it (rust or corrosion). The corroded steel loses thickness and eventually weakens the structure.

There are approximately 22,000 metal structures in the system. Many metal structures, especially in industrial or marine environments, are now corroded. BCTC has developed and is now using techniques to identify the type and degree of corrosion. Appropriate methods to prepare and hand paint the steel have been developed which will provide long term protection and will increase the life of the asset by at least 30 years. New techniques are under development which will enable recoating 500 kV towers without a circuit outage.

This was initiated in F2006 and will be extended to all voltage classes in the future (see section.6.5.1.1.8 in the F2009 Capital Plan).

6.2.17 Wood Pole Structures

The ABS did not report on the health of wood poles structures due to the lack of data. There are approximately 100,000 wood poles in the transmission system on 69 kV to 287 kV transmission structures. The average age of the transmission wood poles is 28 years. The poles have an expected mean life of 55 years (based on a fitted Weibull survival curve interpolated from field data). The condition of wood poles is assessed by applying criteria in the Wood Pole Test and Treat Maintenance Standards. BCTC does the first Test and Treat inspection (to assess and collect field data) on a pole when the circuit is 25 years old and every 8 years thereafter. The field data obtained is used to perform structural strength calculations[29] to determine the pole's serviceability (remaining life). Poles that do not meet the serviceability criteria as defined in the Wood Pole Strength Standard are deemed to be at their end-of-life and are scheduled for replacement. Each year, approximately 10% (10,000 poles) of the total transmission pole population is tested and treated and 4% (400 poles) of the

[29] Structural Engineering calculations are done using PLS-CADD software.

test population are found to be in need of replacement. The failure rate is increasing as the average age increases and this trend will continue for the foreseeable future.

By following this inspection process and capturing data in the STARR system, BCTC will continue to update the ABS and will simultaneously identify and replace structures that are found to be at their end of life (see section 6.5.2.2.1 in the F2009 Capital Plan).

6.2.18 ROW / Access Road and Civil Work

The ABS did not report on the health of ROW/Access Roads and Civil work due to the lack of available data. BCTC is now building an inventory of these assets and collecting condition data. This will establish a database from which the asset health can be quantified on a statistically representative subset of all roads based on the sampled data which can be obtained in F2008. The full inventory is expected to be completed within 15 years by gathering data while crews are on site to do other maintenance work. BCTC is also developing ROW/Access Road maintenance standards. An audited sampling program is underway to retrieve an accurate representation of access road condition for use in base line comparison. Civil work continues to be driven by annual Hazard Review inspections which determine where remedial work must be done (see sections 6.5.2.5.4 and 6.5.1.6.5 in the F2009 Capital Plan).

6.2.19 Self Contained Fluid Filled Cables

The ABS identified 4 percent of cables in the system as being in poor condition. Recent failures of cable stop joints on December 20, 2005 (2L64) and December 22, 2006 (2L53) resulted in explosive failure causing damage to the cables, and other cables in close proximity. Repair costs were in excess of $1 million per occurrence. Typical cables with stop joints are approximately $45 million in value and are used to supply load to downtown Vancouver, the west side of Vancouver, and Downtown Victoria, and require a high degree of reliability. The recent failures and subsequent analysis identified the need to initiate stop joint explosion prevention and monitoring projects (see sections 6.5.2.1.8 and 6.5.2.1.9 in the F2009 Capital Plan).

6.2.20 Vegetation/Rights-of-Way

The ABS indicated that 49 percent of vegetation/ROW circuit areas were in very poor, poor or fair condition. Because of continuous tree growth this is an expected natural phenomenon which accompanies the cyclical maintenance[30] work and the percentage in this condition will now be different[31]. Brushing is done on a schedule that ensures adequate line clearances are maintained before they pose a threat to the system. At any given time some of the ROW has just been recently managed, some is due for work in an upcoming year, and some is due to be brushed in the current year.

For each circuit section the maintenance program is determined by the actual growth rates of target vegetation and the conductor to ground clearance. This results in customized maintenance cycles that range from 2 to 15 years (average 7 years) to keep up with the particular growth characteristics in each section. NERC standards dictate that "grow-into" outages from trees growing within a ROW are to be avoided. BCTC places a high emphasis on preventing forced outages from vegetation through a comprehensive annual operation and maintenance work program. This program is on-schedule and includes heavy clearing workloads for the North Central, Okanagan-Shuswap, North Shore-Pemberton and Southern Vancouver Island areas.

A very few remote radial circuits, each with a small number of customers, have a history of poorer than average performance because of the difficult terrain and vegetation they pass through. On these circuits, vegetation related outages tend to occur during storms and for the balance of the year their reliability related to vegetation is satisfactory. To improve their vegetation related performance would require investments exceeding the amount of benefit that could be achieved.
As the customer load grows on those lines the level of investment made in their reliability will be re-evaluated.

[30] Vegetation maintenance on Rights of Way is not a capitalized investment under current accounting rules. It is an important expense and a critical activity and is reported for the completeness of this document.
[31] Most of the ROW areas which are in this group are in fair condition which is quite acceptable for operation. Only a minor fraction will be in poor or very poor condition. Some percentage of the ROW vegetation will always be found in these categories since it is inappropriate to do clearing every year if the growth takes years to become a threat to a circuit.

A key risk comes from “off the Right of Way” trees (Edge Trees) falling into a line from their position at the ROW edge. The NERC Standard specifies that these risks also must be managed. BCTC has a $3M per annum OMA Edge Tree program to identify and remove trees that could fall into transmission lines. This program minimized the very significant impacts and storm damage experienced in November and December of 2006. The Mountain Pine Beetle epidemic in the Interior and pockets of root rot near the Coast can weaken trees just outside the ROWs and these issues pose a new Edge Tree risk. BCTC, working with BC Hydro and the Ministry of Forests and Range, developed a “Guideline for Logging near Powerlines” to encourage the logging of diseased stands adjacent to the ROW by forest licensees. The Guideline allows for wood to be effectively used and ensures that silvicultural and debris obligations are met by the licensees who can recover their expenses by marketing the timber. This enhanced the benefits of the Edge Tree program and was most effective in managing the risk in the Northern and Southern Interior and in parts of Vancouver Island.

BCTC established a debris management program to reduce the ignition and spread of fire on ROWs to reduce the risk to the system from wildfires. BCTC executed a Fire Services Agreement with MOFR to act on wildfires that threaten the system and is working with their Protection Branch to establish a long term agreement.

6.3 Current Sustain Capital Initiatives

In addition to asset management maintenance activities, BCTC prepares a Sustaining Capital Plan that is required to maintain the transmission system to acceptable levels of reliability, safety and environmental performance, and to address other risks such as seismic, life-safety, weather, fire, and security.

To guide Sustaining Capital decisions, BCTC uses the Sustaining Investment Model that illustrates long-term capital requirements and impacts on system reliability as well as asset health assessments (asset condition and asset performance) to justify the refurbishment/replacement of transmission assets on an asset-class or specific asset basis.

For a detailed description of the Sustaining Capital Plan, refer to Section 6 of the F2009 Capital Plan.

6.4 Long Term Sustainment Investment Level

The model is useful in predicting long-term replacement or refurbishment capital expenditures related to the maintenance of the transmission system at its design level of reliability. The Sustainment model does not take into consideration those Sustaining Capital expenditures that are required to mitigate risks. For example, Murrin substation, as discussed above, is now considered to have an unacceptable seismic risk. Criteria for acceptable risks change from time-to-time. It is difficult to model future changes in acceptable risk level and this investment need is not included in the model. Refurbishment or maintaining Capital is used for investments in rebuilding or replacing existing assets to maintain current levels of reliability within an aging transmission system.

This analytical tool is important because equipment failures are closely associated with asset condition. Age-related wear and tear will cause degradation of asset condition, is a significant cause of system outages and will increase in significance as transmission assets get older. This will result in increasing corrective maintenance and increasing refurbishment capital costs. This investment model is related to Commission Order G-91-05 Directive 35, which pertains to future levels of mid and long-term Sustaining Capital expenditures.

The overall asset base is aging and both the investment in replacement of assets and the corrective work costs have been increasing. The accumulating wear and tear has implications for both system performance and capital planning. In the prior decade the replacement of assets averaged 6.1 percent of the in-service base. Modeling asset end-of-life state predicts a need to replace approximately 8.1 percent of the base over the next decade.

6.4.1 Sustainment Investment Model

Using the Sustainment Investment Model, BCTC forecasts mid and long-term Sustaining Capital investment requirements. The model is based on the forecasted number of transmission system assets reaching the end of their useful life in each decade.

To determine end-of-life asset retirements, the population of assets in the transmission system was categorized into the 33 asset classes identified within the

2004 Asset Baseline Study (ABS). Each class contains assets of similar characteristics to enable modeling end-of-life with reasonable accuracy.

In Phase 1 of the model development, a number of factors were considered including: catastrophic failure rate, repair costs and risk based obsolescence. Information the model was provided by expert opinion, system data, industry studies and manufacturer provided data, and was used to determine the end-of-life estimate for each asset class. These end-of-life estimates were then used, in combination with the age distribution of the asset class, to forecast retirements in each of the next ten decades.

To forecast required investment levels, replacement costs were calculated based on the historical purchase price of the assets, inflated to current dollars, and then applied to the forecasted retirements in each of the following decades. The required investment in each decade was then summed across all asset classes to derive forecasted investment level for the Sustaining portfolio in each decade.

Based on the Phase 1 results, the model predicts an appropriate level of sustaining capital expenditures between $72 million and $102 million based on +/- 5% of the end-of-life estimates per year for the 10-year period when expressed in F2006 dollars. The mid-point of this range is $87 million. This level of investment is required to meet forecast asset replacement due to end-of-life condition. The investment level does not address other risks, such as seismic, life-safety, fire, weather, and security, or implement opportunities that will improve the transmission system to a level of reliability that is higher than its original design. BCTC forecasts that the appropriate level of investment in the Sustain Capital Portfolio, in F2006 dollars, necessary to meet the estimated level of retirements will be $870 million over the next ten years. .

BCTC tested the model by applying it to the transmission system asset base from ten years ago. The model predicted 5.9% of the asset base would reach end of life in the past decade compared to actual records of 6.1%. BCTC believes that this is within acceptable forecast limits and indicates that the system level model had good predictive capability.

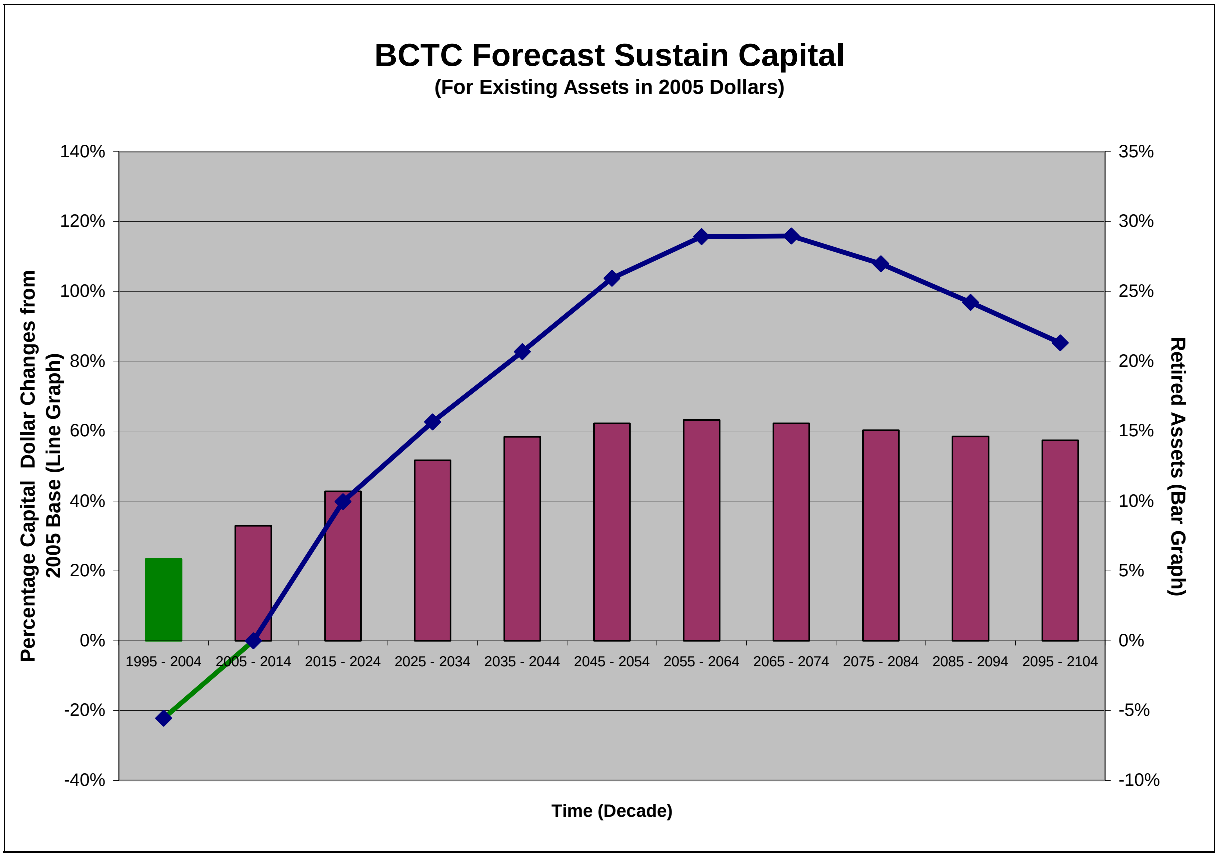
In Phase 2 of model development, which is currently underway, BCTC is using historical data to calculate the end-of-life retirements. This historical end of life data for most asset classes is found to be very similar to the end-of-life retirements predicted in Phase 1, providing some comfort that the model is performing consistently. The second phase work is also updating the replacement cost estimates by including recent actual replacement cost data. The outcome of this phase will be a more accurate model.

To date, end-of-life retirements for 11 asset classes with adequate historical data have been calculated and used to forecast future asset investments. These revised asset class estimates resulted in similar outcomes to the Phase 1 model forecast.

Figure 6-1shows the prediction from the model for future Sustaining investments needed based on end-of-life expectations over all assets.

Figure 6-1 shows the forecast levels of Maintain Capital investments for Sustaining Capital for the next 100 years. The bar chart indicates the percentage of assets forecast to be retired, while the line graph indicates the percentage change of Maintain Capital compared to the current decade. This forecast shows that investments will need to increase significantly over the next five decades to replace retiring assets if BCTC continues with its current strategy for Maintain Capital. Levels of investment need to be higher in future decades to maintain the current level of reliability. The curve has a peaked shape because assets added to the system during the high-growth period of the 1960s and 1970s need to be replaced as they reach end-of-life.

Figure 6-1. BCTC Sustain Capital Model Future Forecast



The 11 asset classes that have been completed in Phase 2 are primarily the station assets. The data from station assets are more readily available and these assets typically have shorter life spans than transmission line assets. A large portion of the BCTC assets reaching end of life in the near future are station assets. Transmission line assets also have a significant effect on capital expenditures due to their large share of the total BCTC portfolio. Most transmission assets are still far from end of life.

Completion of Phase 2 for transmission assets is required to better forecast long term sustain capital beyond 10 years. BCTC does not expect the forecast for the first ten years of the Sustain capital forecast to change significantly. In the longer term it is expected that improvements made to complete records of demographics and cost data will result in better estimates.

6.4.2 Future Model Enhancements

BCTC has completed modeling of eleven asset classes. A further twenty-two classes are to be modeled at a similar level of detail to complete the necessary work. Validation and calibration work will continue to refine the model's quality as more data becomes available through routine maintenance work on the inventory and the recording of demographic data for those classes. It is a significant challenge to assemble good inventory data for some classes of equipment. In cases where records were not kept some data can be inferred from in-service dates of associated nearby equipment. For example, by reviewing the in-service date of a transmission line the original commissioning date of associated electromechanical relays can be inferred. Also from reviewing commissioning records on relays which are replacing old relays the end-of-life date can be captured for some old relay types. Together, these two data types may provide good data to enable estimating the mean length of life and its standard deviation for relays. Over time, improved record keeping will provide good population demographics and the inventory of all equipment classes as well as their mean life and standard deviation will be more fully documented.

Modeling of the relationship between Sustaining investment and reliability is currently underway. Preliminary results show that, as a consequence of an older asset population, SAIDI is expected to deteriorate slightly due to more equipment defects. Further work is required in this area to refine and validate these preliminary results.

Continued effort is focused on identifying, refining and implementing reliability improvement initiatives resulting from non-equipment causes that may potentially offset the forecasted deterioration in SAIDI due to equipment failures. An example of work BCTC has already done in this area is the Edge Tree program, which focuses on reducing outages caused by trees falling into transmission lines from the edges of ROWs.

6.5 Summary

A large portion of the transmission system asset base, installed between 20 and 40 years ago, will reach end-of-life in the next several decades. The Sustainment Investment Model demonstrates the need to manage the maintenance and replacement of the transmission system assets to extend their life and to avoid a large bubble in the investment stream as the entire population of assets goes through their life cycle.

BCTC is forecasting a total Sustaining Capital Portfolio of $112.9 million for F2009 and $123.4 million for F2010. This is supported by the results of the Sustaining Investment Model and asset condition assessments. This level of investment is further validated by the UMS Report, which concludes that although the projected rate of spending in comparison to current levels is high, it is found that BCTC's projected capital investments relative to its industry peers is within the expected range and is reasonable.

BCTC believes that acceptable reliability levels can be maintained at this level of investment. There may be unforeseen events (i.e., asset condition deterioration or other risks), that may need to be addressed that could create variability in investment levels.

7.0 RISK ITEMS

A number of risks threaten the transmission system. BCTC plans for these risks, and responds to events in real time by following emergency response plans to restore the system after severe events. If a section of a transmission line is destroyed, stockpiles of emergency transmission repair equipment can be mobilized on short notice to restore service promptly. BCTC also invests to limit the risk exposure of the transmission system recognizing that the electric system is an element of critical infrastructure.

The system is protected by physical security controls, redundancy built into the transmission system, and BCTC's Critical Infrastructure Protection (CIP) program. The CIP program implements processes and systems to protect the critical cyber assets within BCTC to comply with NERC standards.

7.1 Natural Risks

Threats to the transmission system include ice storms, fire, earthquakes, and other weather[32] and human-related events. BCTC analyzes the probability of each threat and the expected impact, to prioritize these risks. BCTC has ongoing risk management programs in place to address all known hazards to reduce retained risk to an appropriate level. The robustness of the system where it is designed to sustain N-1 events reduces the expected consequence of many events, enabling some risk reduction investments to be deferred unless safety or economic evaluations support taking action sooner. A more detailed discussion of each of the risks BCTC faces is provided below.

7.1.1 Seismic

In F2006, BCTC reviewed its existing transmission system seismic program, which assesses earthquake risk to transmission lines, substations, and telecommunication assets. The recommendations from this review are being used as a working basis for

[32] The occurrence of wind and snow storms can have a significant impact on the delivery of energy to customers. In the past fall and winter the most severe storms caused numerous outages in the transmission system. The total SAIDI contribution from these storms was approximately 1.55 hours, a significant portion of the yearly average of 2.15 hours. The Customer Hours Lost contribution from these storms was approximately 450,000 compared to the yearly average of 730,000.

current projects. BCTC has a large amount of work to be done in this area, and is gradually undertaking this work through a multi-year program.

As part of the F2009 seismic upgrade programs, BCTC proposes to address the following assets:

7.1.1.1 Transmission Lines

The following transmission line initiatives are underway to mitigate seismic risk to existing circuits:

(a) Seismic upgrading of 2L3/49 Second Narrows Crossing (definition work to be done in F2007 and implementation to occur in F2008 and F2009 (see section 6.5.2.4.4 of the F2009 Capital Plan).

(b) Seismic upgrading of 2L56 Terminal Tower located west of the Knight Street Bridge adjacent to the North Arm of the Fraser River. The unstable soil may be subject to liquefaction. A seismic study is proposed in F2009 to determine the feasibility and cost of a reinforcement project.

(c) Seismic risk assessment of the 5L29 and 5L31 circuits to Vancouver Island to prioritize future reinforcements. If the assessments indicate that reinforcements are required, BCTC will include those projects in future Capital Plans.

7.1.1.2 Substations

BCTC's ongoing seismic program continues to be refined and has recently been affected by revisions to the National Building Code of Canada, which provide guidelines for new projects and upgrades (see section 6.5.1.4 of the F2009 Capital Plan). As part of the seismic program, preliminary design work has identified issues and detailed designs were made for remediation. The following remedial work was started in F2008 and will be completed in F2009:

(a) Williston Substation Control Building Seismic Upgrade. The Prince George area is not considered to be a high seismic risk area, but the Williston control building is a priority due to specific weak soil conditions at this site;

(b) Meridian Substation (MDN) Control Building Seismic Upgrade. MDN is in a high seismic risk area; and

(c) Atchelitz Substation (ALZ) Control Building Seismic Upgrade. ALZ is in a high seismic risk area.

At MUR the solution for the seismic risk is in definition stage and other capital work presently underway is complementing a long term strategy to mitigate this risk (see section 2.3.1.1 in this report and section 6.5.1.4.6 in the F2009 Capital Plan).

7.1.1.3 Microwave Sites

Recently, microwave sites were added to the seismic risk program. The microwave sites at Jarvis and Thynne are being upgraded in an ongoing program to address high priority facilities with seismic risk (see section 6.5.1.4.4 in the F2009 Capital Plan). Implementation will be completed in F2009.

7.1.1.4 Control Centers

The SCMP project is underway to consolidate existing control centers into a seismically secure building by 2008, which will reduce the risk of losing communication and control in a seismic event. The SCMP project will also provide a second fully functional backup control center outside the active seismic zone to ensure no loss of capability in the event that it is needed in response to any kind of event.

7.1.1.5 Tsunamis

BCTC assessed earthquake-induced tsunami risk to the system as part of the seismic risk assessment. The highest risk areas are at Long Beach (LBH) and Port Alberni (PAL) Substations. Any future seismic studies will consider tsunami risk in the overall assessment to determine prioritization of projects.

7.1.2 River Erosion and Flooding

A yearly field hazard review is undertaken by geotechnical experts to assess the risk of damage from flooding or foundation erosion in high stream flow conditions. BCTC uses rip-rap protection, deflective berms, and other geotechnical work under the Civil Protective Work Program to address urgent items (see section 6.5.2.4.2 in the F2009

Capital Plan). Further studies will be done to rank these risks in the overall system risk assessment, taking into account changing weather patterns and the severe flooding conditions that have been experienced in the recent past.

In 2007, BC experienced snow-pack conditions that were higher than average. BCTC updated its emergency plans to accommodate new information to ensure that substation and transmission assets would meet reliability expectations should flooding occur.

7.1.3 Avalanches

Given the very difficult, mountainous terrain that much of the transmission system must traverse, there are hundreds of locations where avalanches are possible[33]. Since the early 1970's, there have been at least twenty major mudslide or avalanche events that caused serious damage on the transmission system.

Every year, geotechnical experts inspect and assess all known sites and BCTC makes improvements under both capital and maintenance programs as required. It is difficult to build towers to withstand all conceivable events and therefore the system is built with multiple transmission paths that reduce the risk of major impacts from a single event. In some areas, there is a single contingency risk such as the Williston to Skeena 500 kV corridor and the 5L94 interconnection from BC to Alberta. These risk exposures are being studied and will be ranked with other system risks when fully analyzed.

7.1.4 Snow Creep

Snow creep can exert sufficient force on tower components to cause deformation and breakage of cross-bracing and other components. In 1999, there was a serious threat to the supply to Vancouver Island when snow in the 5L30-5L32 corridor crept in steep terrain, causing several 500 kV towers to fail, and major damage to thirty other towers. BCTC will monitor this risk and rank specific towers for appropriate reinforcements based on identified vulnerable and high impact locations.

[33] In spring and early summer these locations are often at risk of mudslides. See Section 7.1.5.

7.1.5 Mud Slides

Under warm weather conditions in winter and spring there is a risk, especially in the coastal area, of rapid melting snow pack that creates mudslides, which can cause transmission towers to fail. At least fifteen mudslide or soil instability events have caused serious line damage and/or failed structures in the past including the failure of a 500 kV tower in 2006 due to slope failure.

Mudslide risks are considered and ranked for mitigation under the Civil Protective Work Program identified above (see section 6.5.2.4.2 in the F2009 Capital Plan). Riprap, berms, and other types of base reinforcement or relocation of some structures may be required depending on the specific scenarios.

7.1.6 Ice Storms

The overhead transmission system is vulnerable to severe ice storms. The last event that collapsed towers was in 1972 when 26 towers were severely damaged on 5L41 near Agassiz and two were badly damaged on Circuit 3L1 in the same area. One tower also failed on 5L42 at Stawamus Pass and ground wires were damaged on 138 kV and 230 kV structures near Squamish Substation (SQH). A more recent freezing rain event occurred in December 2001 causing insulation flashovers and the separation of Vancouver Island from the integrated system although no towers failed.

The existing transmission system is designed to withstand ice storms of a severity expected once in 50 years. BCTC is evaluating tower reinforcements, line clearance upgrades and uneven ice loads on lines and, in collaboration with the CEA, is developing methods to reduce this risk. BCTC is preparing ice load performance criteria for use in design of future projects to build them to withstand expected events dependent on location.

Engineering studies have identified areas of the system at greatest risk and BCTC has an Ice Hazard Reduction Program to selectively upgrade ice-prone areas (see section 6.5.2.4.5 in the F2009 Capital Plan). Under the Ice Hazard Reduction Program, BCTC has identified three principle areas of concern for ice on transmission lines. Those are:

(a) The Fraser Valley transmission corridor east of Langley which carries the majority of the energy into the Lower Mainland;[34]

(b) The Howe Sound to Pemberton area which can threaten the supply to Whistler, the Sunshine Coast and Vancouver Island; and

(c) The Skeena River Valley which supplies the North Coast load center and interconnects the transmission system to the Alcan system.

BCTC's Ice Hazard Risk Reduction project will initially focus on the Fraser Valley transmission corridor to the Lower Mainland load by reinforcing 500 kV and 230 kV towers to survive a 1 in 200 year ice storm. That work will be done over a 4-year program. A longer-term program will ultimately reinforce 5L30, 5L42, 5L82, 2L77, and 2L78 to reduce the risk to transmission circuits to Vancouver Island and in the Fraser Valley.

7.1.7 Lightning

Lightning can cause momentary circuit interruptions and, in severe cases, extended circuit outages due to equipment damage. Transmission lines in BC generally do not have overhead shield wire to mitigate the impact of lightning, since lightning frequency in BC is relatively low in comparison to other areas; this reduces the cost of line construction. BCTC plans to improve lightning performance of the most at-risk circuits to improve system reliability. Operators also monitor lightning activity in real time and configure the system to minimize risk.

BCTC has a Sustaining Capital project to manage lightning risks. In lightning prone areas, BCTC proposes to add arcing horn assemblies to 138 kV, 230 kV and 500 kV suspension insulator strings when inspections find damage from lightning induced flashovers. This will prevent further insulator damage and lower future maintenance costs by moving the arc column away from the insulator surfaces (see section 6.5.2.3.1 in the F2009 Capital Plan).

[34] See Figure 2.11 for a map of the Fraser Valley Transmission corridor.

7.1.8 Forest Fires

Fires on some transmission circuits can occur due to the insulators on the wooden poles not being electrically bonded. This can result in transmission outages and can also initiate forest fires. BCTC has a capital program in place to add bonding to the insulators on wooden poles to avoid these risks (see section 6.5.2.4.1 in the F2009 Capital Plan).

To minimize the threat of fire related damage to transmission structures, BCTC ensures that brush fuel is routinely cleared from the base of wood pole structures and applies fire retardant in high risk areas under its OMA programs. BCTC applied fire retardant in F2008 during the fire season on several circuits in the Southern Interior that were at risk of damage from forest fires.

7.1.9 Geomagnetically Induced Currents

Solar magnetic disturbances (SMDs) cause geomagnetically induced currents (GICs) to flow in power systems that can damage power transformers and cause line outages due to protection equipment mis-operation. In both 1981 and 1991, protective relays mis-operated due to GICs, causing 500 kV and 138 kV lines to trip. These line protection systems were modified or replaced and will not mis-operate again from GICs. Future line protection replacements will apply microprocessor relays with 60 Hz filtering to make the transmission system more secure during a SMD, and series capacitors will block GIC flows.

7.2 Other Risks

In addition to natural risks and hazards, BCTC also faces the following risks that must be managed.

7.2.1 Security Risk

BCTC conducts ongoing physical security, cyber security, and business continuity risk assessments. Currently, the most common security problem, which is increasing in frequency and cost, is substation copper theft, resulting from the high value of base metals. The incremental cost to manage this issue in F2007 was $900,000 in capital expenditures and approximately $700,000 of operating expenditures for repair and additional security services. To mitigate the risk and costs, BCTC has implemented several strategies including a "Clean Site" policy, increasing security guards, enhancing fencing, replacing copper materials with lower value but equally functional material such as copperweld and marking expensive material with micro-dots to facilitate traceability of the material to the electric system. In F2008, BCTC initiated a $2M annual program to improve Station Physical Security to further mitigate security risks. This program will provide enhanced fencing, transformer neutral encasement, perimeter alarm systems, and video surveillance (see section 6.5.1.4.1 in the F2009 Capital Plan).

7.2.1.1 Oil Spill Risk

There is a considerable amount of oil-filled equipment throughout the transmission system, primarily in transformers, bulk oil circuit breakers, and reactors. There are also fuel storage facilities for diesel generators at microwave communication sites and at many stations and control centers. BCTC invests in risk reduction based on analyses of the expected benefits from improving the current installations. BCTC is addressing the largest risks first and will continue with incremental upgrades over a 25-year process.

In F2008, BCTC started a program to replace above-ground storage tanks that pose an unacceptable spill risk and do not meet the Canadian Council of Ministers of Environment recommended code of practice (see section 6.5.1.4.3 in the F2009 Capital Plan).

In F2009, the remaining above-ground fuel and oil storage tanks will be replaced and/or removed, based on their condition, to reduce the risk of oil spills to an acceptable level.

7.2.2 Station Fire Risk Management

BCTC has an ongoing program to increase station fire withstand capability. Combustibles in substations and microwave sites pose a fire risk that could cause loss of service, injury to people and harm to the environment.

In F2009, BCTC will begin a project to increase the fire withstand capability of assets at Nile Creek, Cape Cockburn, Texada Island East, Texada Island West, and Texada Island Reactor Substations by implementing fire protection measures while replacing halon based fire suppression systems. The target date to complete this program is F2026 and individual projects will be selected based on annual analysis of risk and mitigation costs across the portfolio of sites (see section 6.5.1.4.2 in the F2009 Capital Plan).

At CSQ, the existing CO2 fire suppression system poses an unacceptable life safety risk. The CO2 is used to mitigate fire and explosion risk and protects the electrical equipment installed at the substation. BCTC and BC Hydro have jointly developed temporary work procedures to address the immediate worker safety risk. BCTC initiated mitigation of the fire and explosion risk for the transformers and is investigating several options to mitigate fire and life safety risks in the switchgear portion of the building.

7.2.3 2010 Olympics

BCTC is assessing risks in the various substations and transmission systems that will supply the 2010 Olympic venues. The established maintenance and capital replacement programs will be prioritized to ensure reliability of the transmission system is sustained for the Olympics.

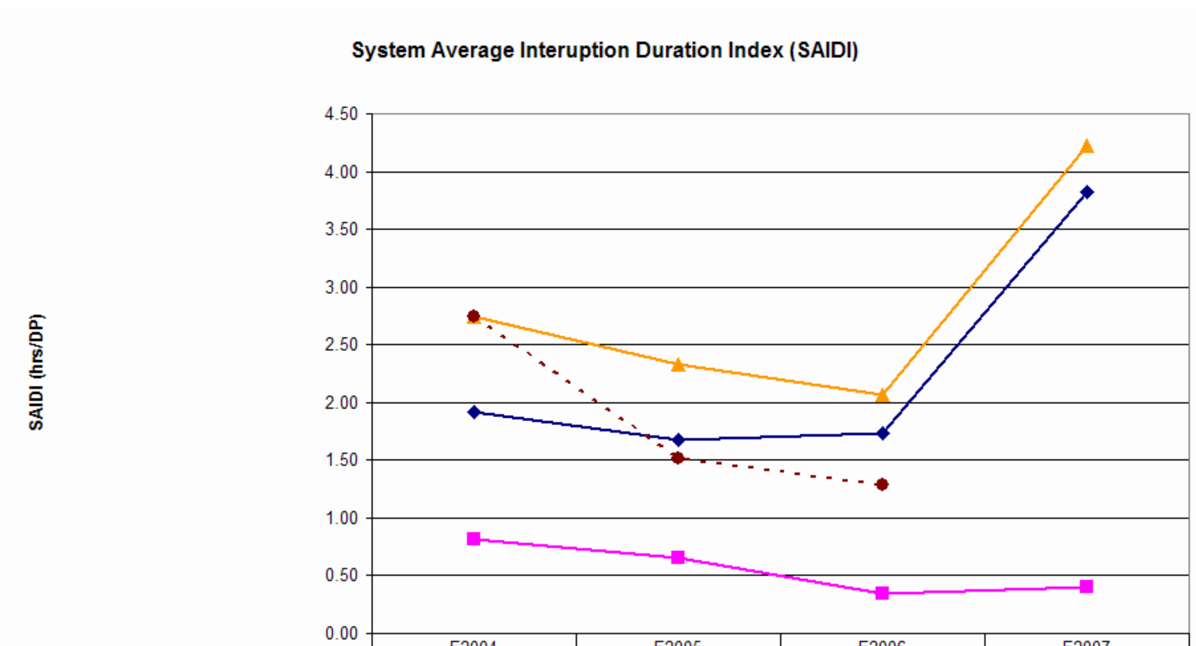
8.0 SYSTEM PERFORMANCE MEASURES

8.1 System Average Interruption Duration Index (SAIDI)

SAIDI is a measure of the reliability of the transmission system. It is calculated as the average amount of time in hours across all transmission delivery points that service is interrupted in a year due to planned or unplanned outages. The measure takes the total service interruption time during the fiscal year from all planned and unplanned outages at all delivery points and divides it by the total number of points.

Figure 8-1 shows BCTC's SAIDI and the industry composite SAIDI from the Canadian Electrical Association (CEA), Bulk Electricity benchmarking study. It should be noted that the CEA measure does not include the effect of planned outages. To allow a better comparison to CEA averages, BCTC has separated the forced and planned outages as per Directive 10 from the F2008 Capital Plan Decision.

Figure 8-1. SAIDI F2004 to F2007



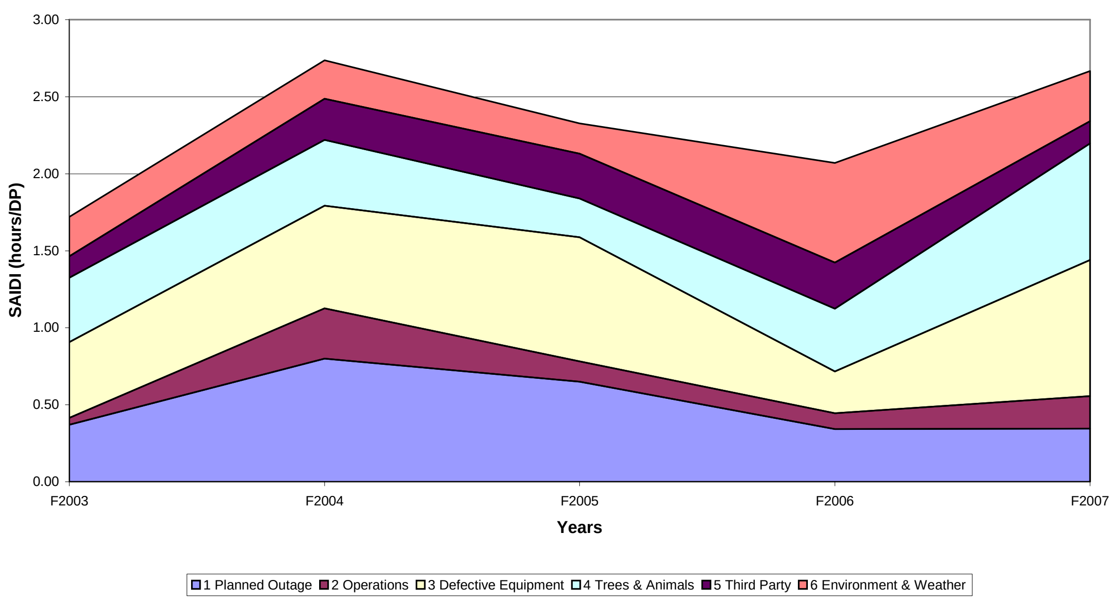
	F2004	F2005	F2006	F2007
SAIDI Forced	1.92	1.68	1.73	3.82
SAIDI Planned	0.82	0.65	0.34	0.41
SAIDI Total	2.74	2.33	2.07	4.23
CEA Composite (with 2003 Fire)	2.74	1.51	1.29	

Reliability data provided to the CEA by members is confidential, thus direct comparisons between companies are not possible. The SAIDI values vary from utility to utility, and the causes of these differences include network configuration, climate and terrain, and possible inconsistency in the collection and submission of data. Through CEA initiatives, member utilities are continually working to ensure consistency in definitions and data quality.

At the highest level, BCTC's total SAIDI is the result of six categories of causes. These are Planned Outages, Operations, Defective Equipment, Trees & Animals, Third Party, and Environment & Weather. Figure 8-2 shows the historical contribution of these six categories of causes to BCTC's total SAIDI over the past five years.

This high level view of SAIDI is useful for monitoring the major SAIDI contributors and the impact of asset management programs on these contributors. For instance, the effectiveness over time of maintenance initiatives, such as major vegetation clearing work or co-ordination can be reflected in changes seen in the cause category breakdown.

Figure 8-2. SAIDI Breakdown by Cause Category[35]



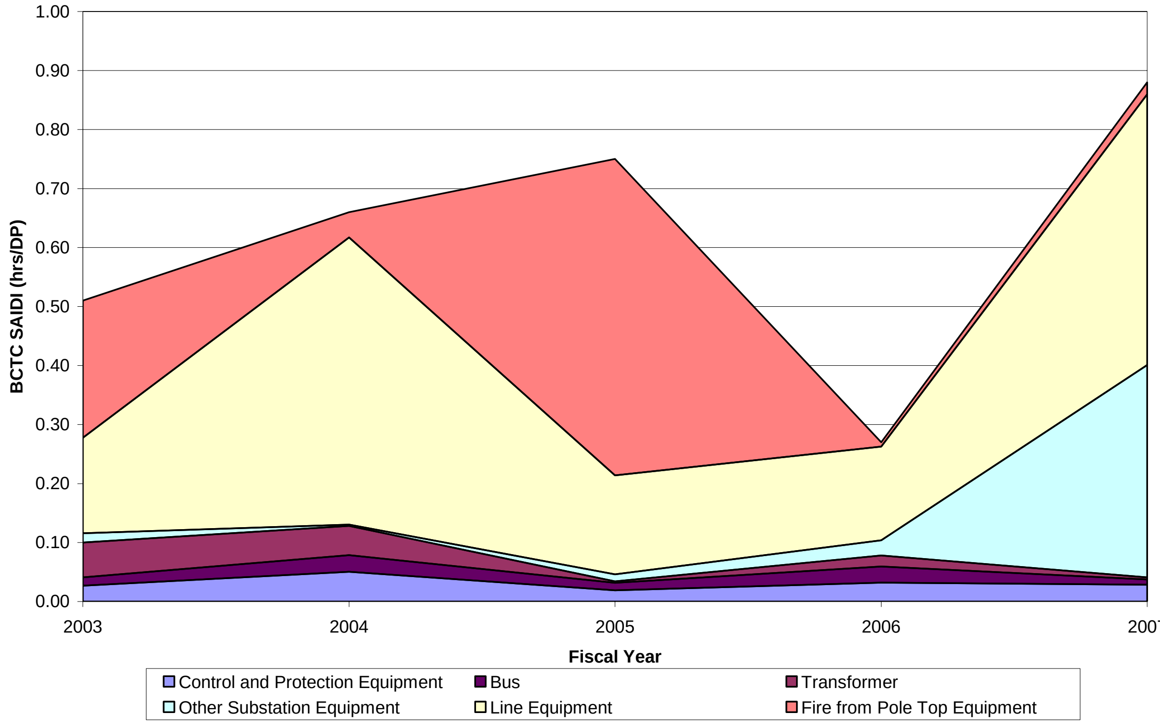
[35] SAIDI values used for Cause analysis exclude the summer of 2003 (F2004) fire storm and November and December 2006 (F2007) major wind and snow storms.

Environment and weather, shown in pink in Figure 8-2, plays a significant role in BCTC's SAIDI. While BCTC cannot directly control this category, in some cases BCTC can reduce the impact that the environment and weather have on system reliability. For instance, as discussed above, BCTC has begun performance improvement initiatives to reduce the contribution of lightning to BCTC's SAIDI by installing surge arrestors and arcing horns on lightning prone circuits (see section 6.5.2.3.1 in the F2009 Capital Plan).

More generally, BCTC has recently initiated a major project to improve SAIDI through the addition of single pole reclosing on transmission lines. Approximately 60 to 80 percent of faults are single phase to ground faults which presently result in complete interruption of the circuit and can adversely impact generation, transmission capacity, and end-use customers. Single-pole Trip and Reclose installations allow a single phase of a three-phase circuit to be interrupted and re-energized, as opposed to the interruption of all three phases, thereby improving reliability (see section 6.5.1.5.3 in the F2009 Capital Plan).

Figure 8-3 presents a breakdown, by equipment type, of the "Defective Equipment" Cause Category.

Figure 8-3. SAIDI Breakdown by Equipment Type – Defective Equipment



As shown in Figure 8-3, Pole Top Equipment and Line Equipment are the main contributors to the Defective Equipment Cause Category.

In F2006, BCTC undertook a bonding program to reduce the number of pole top fires. BCTC expects to complete the bonding program in F2010 (see section 6.5.2.4.1 in the F2009 Capital Plan).

BCTC has also focused its efforts on reducing delivery point outages due to line equipment. For example a two year Sustaining Capital program to upgrade circuit 60L129[36] commenced in F2007. In F2008, an investment of $1,900k will complete the upgrade, adding approximately 100 new full-length CCA treated wood poles,

[36] 60L129 is 79 km long and is the radial supply to Long Beach Substation which has the worst record of Transmission Reliability Index of all the Delivery Points in the system. Long Beach Substation has the highest (i.e. worst) number of Customer Hours Lost during the last 5 years, measuring 321,071. Rough terrain, age, and the oceanside environment (with salt corrosion & high winds) all contribute to the poor reliability of 60L129. The main outage causes are defective equipment, adverse weather and trees. In F2006 a comprehensive condition assessment confirmed the overall state of the assets is poor. No maintenance solution can completely resolve the health state of this circuit and greatly improve the reliability performance. BCTC will replace all poorly performing sections of the circuit over this 2 year program and will improve reliability performance somewhat but the approach of "replacements by sections" has shown that is will not cause significant reliability performance improvements.

hardware, insulators, timbers and approximately 45 circuit kilometers of new conductor. It includes some design modifications in places where this was necessary to improve the reliability.

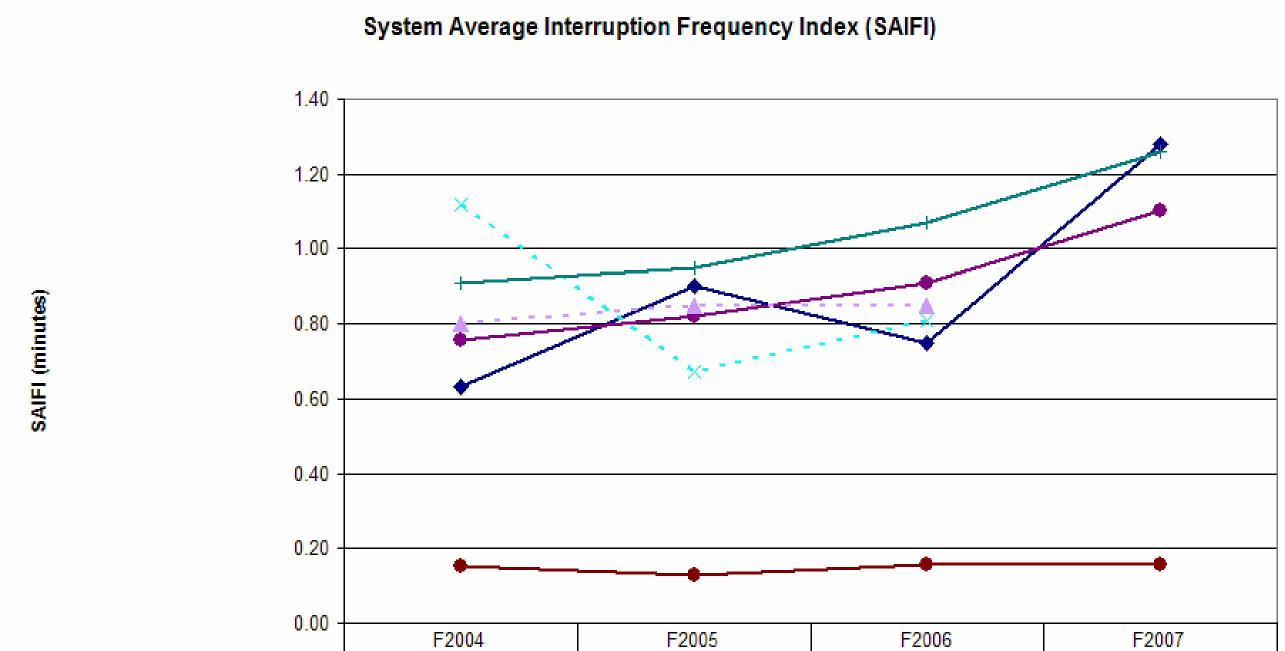
8.2 System Average Interruption Frequency Index (SAIFI)

System Average Interruption Frequency Index (SAIFI) is a measure of the reliability of the transmission system. It is calculated as the total number of interruptions across all transmission delivery points in a year due to planned or unplanned outages, excluding interruptions due to outages attributed to generators.

Interruptions can be categorized as Momentary (less than one minute in duration) or Sustained (one minute or greater in duration). Thus, SAIFI can be broken down into SAIFI-MI, the number of momentary interruptions across all transmission delivery points in a year, and SAIFI-SI, the number of sustained interruptions across all transmission delivery points in a year.

Figure 8-4 provides historic SAIFI results for the period F2004 to F2007 for BCTC and CEA. It should be noted that the CEA measure does not include the effect of planned outages. To allow a better comparison, BCTC has separated the forced and planned outages as per Directive 10 from the F2008 Capital Plan Decision. BCTC does not have a target for SAIFI.

Figure 8-4. SAIFI F2004 to F2007



	F2004	F2005	F2006	F2007
SAIFI-MI Forced	0.63	0.90	0.75	1.28
SAIFI-MI CEA Composite	1.12	0.67	0.81	
SAIFI-SI Forced	0.76	0.82	0.91	1.10
SAIFI-SI Planned	0.15	0.13	0.16	0.16
SAIFI-SI Total	0.91	0.95	1.07	1.26
SAIFI-SI CEA Composite	0.80	0.85	0.85	

Fiscal Year

Note 1: BCTC's SAIDI excludes the impact of the F2004 wildfires.

Note 2: the Eastern Blackout has been excluded from the F04 CEA Composite.

Similar to the SAIDI results, the CEA SAIFI values vary from utility to utility, and the causes of these differences include network configuration, climate and terrain, and possible inconsistency in the collection and submission of data. Through CEA initiatives, it is hoped that there will be more consistency in definitions and data quality in the future.

The programs that BCTC is undertaking to improve SAIDI, discussed in Section 8.1, are also expected to improve BCTC's SAIFI since these programs address certain types of equipment outages, hence reducing the frequency of the outages as well.

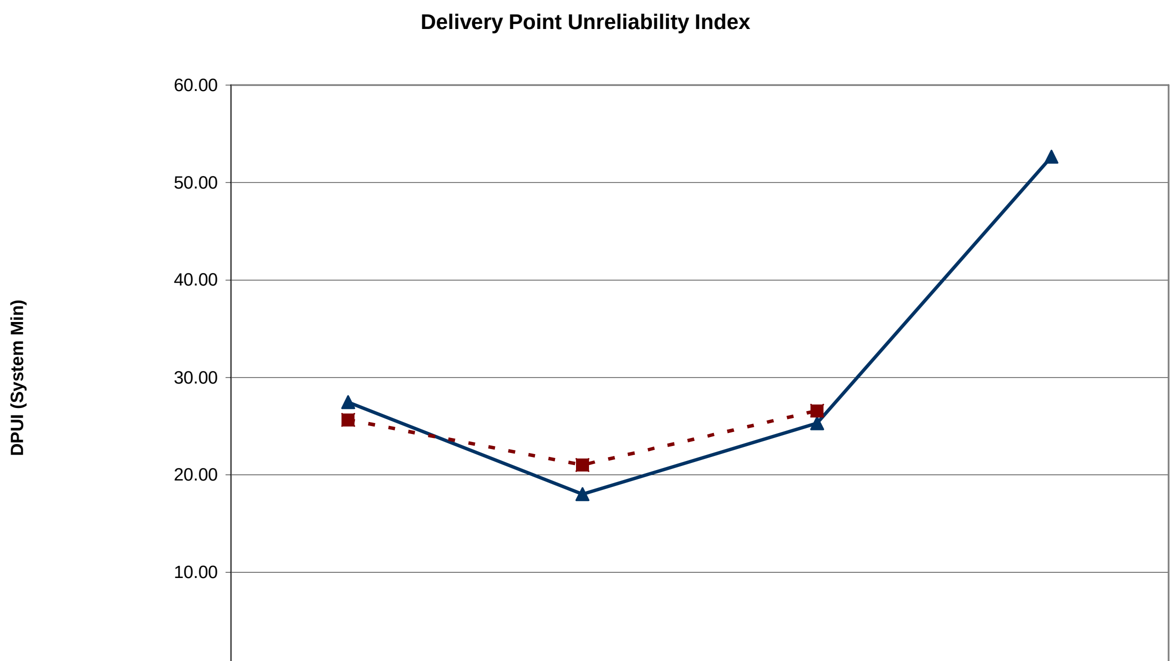
8.3 Delivery Point Unreliability Index (DPUI)

The Delivery Point Unreliability Index (DPUI) is a composite index of reliability in terms of System Minutes. It includes all planned and unplanned outages, excludes interruptions due to outages attributed to generators, and is calculated as follows:

$$\text{DPUI} = \frac{\text{Total Unsupplied Energy (MW Minutes)}}{\text{System Peak Load (MW)}}$$

If the total energy not supplied due to all outages was produced by a single outage event causing whole system blackout during the peak time, DPUI indicates how long this equivalent outage would last. Figure 8-5 provides historic results of the DPUI measurement from F2004 to F2007.

Figure 8-5. DPUI F2004 to F2007



	F2004	F2005	F2006	F2007
DPUI Total	27.47	18.02	25.31	52.66
CEA Composite	25.65	21.00	26.60	

8.4 Summary of Outage Indices by Voltage and Equipment Class

The following are examples of the types of data BCTC currently collects for the purpose of external reporting on equipment reliability, BCTC maintains a database on forced outages[37] of major system components and reports that data annually to the CEA. Tables 8-1 and 8-2 provide BCTC-specific calendar-year data collected on forced outages compared to the CEA average reported from all Canadian electric utilities for Line-Related Sustained Forced outages, Cable-Related Sustained Forced outages, Transformer-Related Sustained Forced outages, and Circuit Breaker-Related Sustained Forced outages.

[37] Definition of forced outages is consistent with the definition in the CEA ERIS – Forced Outage Performance of Transmission Equipment Report.

Table 8-1. Line-Related Sustained Forced Outage Indices of BCTC Transmission Lines

Outages from All Causes

	Frequency (per 100 km.a)						Mean Duration (h)						Unavailability - %				
KV	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006
60	5.5521	4.7573	3.2974	4.8787	9.6199	2.6151	15.6	17.1	9.2	13.2	12.9	11.0	0.9857	0.9290	0.3460	0.7360	1.4167
138	2.1974	0.9603	0.9397	1.0588	1.3165	1.0089	14.8	19.9	10.1	10.4	14.6	8.5	0.3723	0.2180	0.1086	0.1259	0.2191
230	0.2571	0.1831	1.7600	0.4483	0.2077	0.3396	2.6	10.2	4.0	44.7	51.8	35.2	0.0080	0.0213	0.0800	0.2288	0.1229
360	0.0743	0.0000	0.0743	0.0743	0.0000	0.2027	5.2	0.0	0.1	0.1	0.0	15.4	0.0044	0.0000	0.0001	0.0001	0.0000
500	0.4201	0.4526	0.6699	0.6475	0.2084	0.2199	75.6	1.8	2.9	10.1	6.2	14.2	0.3626	0.0091	0.0223	0.0744	0.0148

Outages Caused by Defective Equipment

	Frequency (per 100 km.a)					Mean Duration (h)					Unavailability - %				
KV	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
60	1.5660	0.1964	0.2100	0.5696	0.3149	11.1	5.4	4.8	21.0	14.4	0.1991	0.0122	0.0115	0.1367	0.0518
138	0.3435	0.0742	0.1165	0.0949	0.0204	12.3	26.8	22.0	17.8	17.8	0.0484	0.0227	0.0292	0.0192	0.0042
230	0.0000	0.0171	0.0535	0.1784	0.0463	0.0	8.2	8.4	48.3	72.8	0.0000	0.0016	0.0051	0.0984	0.0385
360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
500	0.0000	0.0108	0.0108	0.0000	0.0000	0.0	0.1	0.1	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000

Outages Caused by Lightning, Weather, and Vegetation

	Frequency (per 100 km.a)					Mean Duration (h)					Unavailability - %				
KV	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
60	2.2330	1.6094	1.6212	2.1450	4.2812	8.6	9.1	4.8	12.8	13.8	0.2189	0.1672	0.0888	0.3133	0.6722
138	1.6561	0.3772	0.6197	0.2807	0.8415	3.8	8.3	8.5	13.2	17.0	0.0717	0.0359	0.0601	0.0424	0.1632
230	0.1573	0.0609	0.1173	0.0332	0.1204	5.5	22.4	0.2	5.6	0.0	0.0099	0.0156	0.0003	0.0021	0.0000
360	0.0743	0.0000	0.0743	0.0000	0.0000	5.2	0.0	0.1	0.0	0.0	0.0044	0.0000	0.0001	0.0000	0.0000
500	0.2847	0.2655	0.4507	0.6281	0.1836	1.1	0.7	3.7	1.2	0.3	0.0036	0.0021	0.0191	0.0088	0.0006

Note 1. All indices in the table exclude terminal equipment related outages.

Note 2. All data is captured on a calendar year basis.

Note 3. CEA data is not available at the specific cause level.

Table 8-2. Equipment Related Sustained Forced Outage Indices of BCTC Transmission Equipment

Fig. 8.3 Equipment-Related Sustained Forced Outage Indices of BCTC Transmission Equipment

Cable-Related Outages of Transmission Cables (all causes)

	Frequency (per 100 km.a)						Mean Duration (h)						Unavailability - %				
KV	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006
60	0.0000	0.0000	0.0000	0.0000	0.0000	0.0141	0.0	0.0	0.0	0.0	0.0	337.1	0.0000	0.0000	0.0000	0.0000	0.0000
138	0.0000	0.8906	0.0000	0.0000	0.0000	0.0165	0.0	123.4	0.0	0.0	0.0	250.6	0.0000	1.2542	0.0000	0.0000	0.0000
230	2.7435	6.4701	0.0000	1.6095	0.8573	0.0162	176.3	5.5	0.0	707.5	1509.7	611.9	5.5200	0.4070	0.0000	12.9987	14.7757
360	N/A	N/A	N/A	N/A	N/A	0.1290	N/A	N/A	N/A	N/A	N/A	70.8	N/A	N/A	N/A	N/A	N/A
500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0107	0.0	0.0	0.0	0.0	0.0	3.6	0.0000	0.0000	0.0000	0.0000	0.0000

Transformer-Related Outages of Transformers (all causes)

	Frequency (per a)						Mean Duration (h)						Unavailability - %				
KV	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006
60	0.0109	0.0163	0.0407	0.0108	0.0267	0.0450	131.8	30.7	59.0	90.6	159.3	332.4	0.0164	0.0057	0.0274	0.0112	0.0485
138	0.0109	0.0253	0.0505	0.0253	0.0072	0.0588	50.5	84.8	33.0	31.8	677.6	242.6	0.0063	0.0245	0.0190	0.0092	0.0554
230	0.0354	0.0396	0.0495	0.0099	0.0588	0.0573	896.6	460.0	55.2	2.0	153.9	218.5	0.3618	0.2079	0.0310	0.0002	0.1033
360	0.2222	0.4444	0.0000	0.0000	0.0000	0.0528	179.9	57.3	0.0	0.0	0.0	164.1	0.4563	0.2906	0.0000	0.0000	0.0000
500	0.0000	0.0635	0.0000	0.0000	0.0000	0.0494	0.0	6.0	0.0	0.0	0.0	218.4	0.0000	0.0040	0.0000	0.0000	0.0000

Circuit Breaker-Related Outages of Circuit Breakers (all causes)

	Frequency (per a)						Mean Duration (h)						Unavailability - %				
KV	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006	CEA's (01-05)	2002	2003	2004	2005	2006
60	0.0067	0.0153	0.0245	0.0368	0.0208	0.0435	508.6	133.3	251.1	93.9	735.5	533.9	0.0389	0.0233	0.0703	0.0395	0.1749
138	0.0173	0.0172	0.0216	0.0302	0.0256	0.0544	19.6	33.2	42.4	40.5	253.6	212.7	0.0039	0.0065	0.0104	0.0139	0.0742
230	0.0590	0.0439	0.0764	0.0423	0.0682	0.0655	114.6	42.5	132.9	187.0	168.4	219.1	0.0772	0.0213	0.1159	0.0904	0.1310
360	1.0000	0.1930	0.0000	0.0000	0.0000	0.0712	964.9	142.2	0.0	0.0	0.0	226.6	11.0150	0.3130	0.0000	0.0000	0.0000
500	0.0647	0.0715	0.0778	0.0652	0.0703	0.1054	393.3	314.0	118.7	209.1	87.6	134.7	0.2905	0.2563	0.1054	0.1557	0.0703

Note 1. All indices in the table exclude terminal equipment related outages.
Note 2. 500 kV Transformer indices for 2004 to 2006 exclude the outages of step-up transformers in BCH generation stations.
Note 3. All data is captured on a calendar year basis.
Note 4. CEA data is not available for Unavailability for Transformers and Circuit Breakers.

8.5 Operational Response to Intertie Congestion[38]

This performance measure considers BCTC's operation of the transmission interties with Alberta and the US. These interties are significant for trade and there is abundant data available on their use.

The measure is defined as the percent of congested hours when less than 90% of the maximum theoretical capacity of the transmission intertie was available and the operating limit on the intertie was a limit caused by the operating state of the BC transmission system, where:

(a) "Congested hours" are hours in which 90% or more of transmission path's TTC for that hour was actually used,

(b) "Limit caused by the operating state of the BC transmission system" means that limitations on the BC side of the intertie were responsible for establishing the transmission capacity limit of the intertie for that hour. In practice the lower of the BC and adjoining system limits will establish the operating limit for the hour, and

(c) "Maximum theoretical capacity" is the transmission capacity on a path if all transmission circuits and equipment were in service.

A determination is made for every hour of the month for each of the four intertie paths (inbound and outbound with Alberta and the US). Performance for each hour is determined as shown in Figure 8-6.

[38] Managing congestion is a complex challenge because congestion has causes beyond BCTC's control, such as market conditions that encourage electricity trading as well as limits and actual transfer loadings on neighbouring systems.

Figure 8-6. Calculating Operational Response to Intertie Congestion

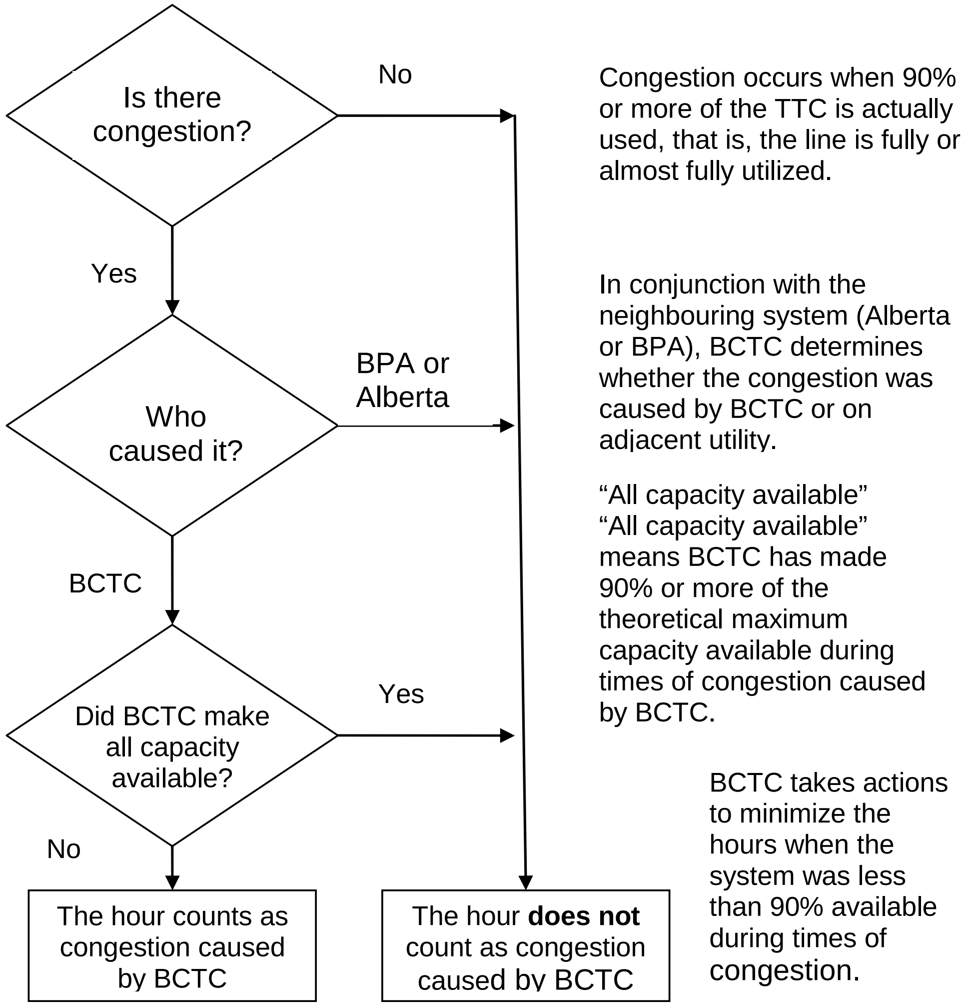
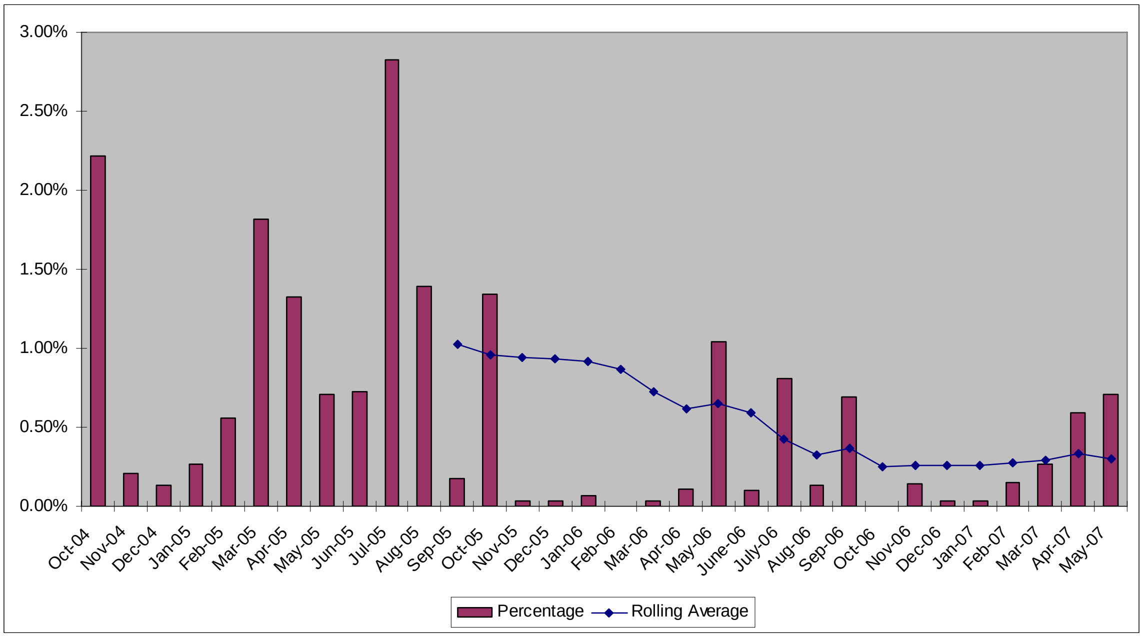


Figure 8-7 presents results of this measure for the period October 2004 through May 2007. As evidenced by the twelve-month rolling average line, BCTC's performance has improved since the establishment of this measure in early calendar 2006.

Figure 8-7. Operational Response to Intertie Congestion Oct 2004 to May 2007



APPENDIX 1

DEFINITIONS

Abnormal operating conditions: The conditions that exist when transmission facilities are out of service, emergency conditions exist, construction or commissioning of transmission facilities occur or situations when transmission facility maintenance cannot be coordinated with generation outages.

ACE, or **Area Control Error**, is the difference between the actual and scheduled interchange which is scanned and calculated at least every four seconds.

Adequacy is the ability of the electric system to meet peak demand of customers at all times, taking into account any scheduled and reasonably expected unscheduled outages of system elements.

AGC, or **Automatic Generation Control** is equipment used at Control Centers (such as SCC) to operate sufficient generating capacity in each Control Area (such as the BC Control Area) to meet its obligation to continuously balance its generation and interchange or inter-area schedules to its loads, and provide proper contribution to the Interconnection for frequency regulation.

Alternating current: Electric current that reverses at regular intervals and has alternating negative and positive voltage.

Ampere: The basic unit of measurement for the strength of an electric current.

Ancillary services: Services required to support the safe, reliable and stable operation of the interconnected system and maintain reliability.

Apparent power: Voltage multiplied by current, normally measured as megavolt amperes (MVA).

Available Transfer Capability (ATC): Unit of measure for the transfer capability remaining in the physical transmission network for further commercial activity, over and above committed uses.

Base load: The minimum amount of electricity required over a period of time at a steady rate.

Blackout: Loss of all electrical load within a given area.

Brownout: The reduction of electrical voltages caused by customer demand being higher than anticipated or by the failure of the generation, transmission or distribution system. A brownout results in lights dimming and motor-driven devices slowing down.

Bulk electric system: The portion of the electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 60kV or higher."

Bus: A group of conductors that serve as a common connection for two or more system elements.

Capacity: The amount of electricity that a transmission facility can transfer at any given time.

Capacitor bank: A set of electrical devices used to maintain or increase transmission voltage by providing reactive power.

Cascading: The uncontrolled and successive loss of system elements triggered by an incident at one location. Cascading results in widespread service interruption that cannot be restrained from spreading beyond an area.

Circuit: A conductor or a system of conductors through which electric current flows and can be automatically segregated by circuit breakers or fuses.

Circuit breaker: A protective switch which automatically interrupts the flow of an electric current in case of an overload, electrical fault, or short circuit.

Conductor: A substance or body, usually in the form of a wire, cable or busbar, that allows a current of electricity to pass continuously along it.

Committed Use: Committed Use can consist of native load, prudent reserves, existing commitments for purchase/exchange/deliveries/sales, existing commitments for transmission service and other pending potential uses of transfer capability at the time of ATC determination. It consists of:

- Transmission Service requirements as per the OATT Tariff to meet supply of domestic (native) load from the points of supply (Generators) for the declared range of generation allocation by network customers, plus
- Point to Point transmission service contracts for exports/imports, plus
- Pending Applications for NITS or PTP transmission service.

Congestion: Congestion occurs when the amount of transfer capacity requested by customers exceeds the existing capacity of the circuit or system.

Connection: The physical junction (e.g., transmission lines, transformers, switch gear, etc.) between two electric systems permitting the transfer of electric energy.

Constraint: A restriction on a transmission system or segment of a transmission system that limits the ability to transmit power between various locations. A path rating establishes the limits of power flow across defined paths often defined as the total transfer capability. The path rating is established taking into account physical limitations, such as the thermal limits of a transmission elements; local voltage and stability restrictions, or contingency limits that are established to assure secure operations in the event of an unexpected failure of a transmission elements or a generation facility.

Contingency: An event occurring on the transmission system that results in the loss of a system element.

“largest single generation contingency” means the loss of an element that would result in the largest loss of generation measured in MW. This contingency includes more then one generator if a single elements outage could result in a prolonged outage of associated generators i.e., a combined cycle turbine outage may result in the outage of an associated steam generator or a interconnection transformer may result in the outage of more than one generator.

“single contingency” - The loss of a single system element under any operating condition or anticipated mode of operation. Single contingency events include the outage of a generator, single transmission circuit or a transformer.

“multiple contingency” - The loss of two or more system elements caused by unrelated events or by a single low probability event occurring within a time interval too short (less than ten minutes) to permit system adjustment in response to any of the losses.

Control area: An electric power system or combination of systems managed through a common control system.

Criteria: The standards on which a judgment or decision may be based.

Current: Flows of electricity passing through a conductor, measured in amperes. Current can either be alternating (AC) or direct (DC).

Cycle: The single complete series of changes in voltage and current direction of an alternating electric current. The standard used in North America is 60 cycles per second. One cycle is equal to 1/60th of a second or 17 milliseconds.

DC (direct current): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Demand: The rate at which electric power is delivered to or by a system; it is generally expressed in kilowatts (kW) or megawatts (MW).

Average demand: The electric energy delivered over any interval, when expressed in kilowatts or megawatts, it is determined by dividing the total energy by the units of time in the interval.
Coincident demand: The sum of two or more demands that occur in the same time interval (e.g., peak load hour)
Peak demand: The maximum instantaneous demand on a power system. This is normally the hourly maximum demand.

Derating: Reducing the energy or capacity rating of a piece of equipment to reflect the fact that it can operate only below its original design rating because of site conditions, a deficiency or its physical condition. A derating can be temporary or permanent.

Dispatch: The monitoring and regulation of an electrical system to provide coordinated operation; the sequence in which generating resources are called upon to generate power to serve fluctuating loads.

Dispatchable: A supply or demand resource whose output can be adjusted for short-term variations in load or resource balance due to weather changes, unit outages, market price changes and non-power considerations.

Double Circuit: A transmission line having two separate circuits on a single structure.

Dynamic VAr control devices: A device that can rapidly vary its reactive power output in response to control signals.

Economic dispatch: A method of managing the operation of generation and transmission facilities to produce the most cost-effective result. Economic dispatch most commonly involves the selection of the lowest-cost available generating units.

EENS, Expected Energy Not Served, MWh/year: Expected energy not served (or Expected energy not supplied) (EENS) is an index or measure of reliability of a system due to single and multiple system contingencies, which is calculated as a probabilistic average MWh in a time period, usually a one year basis. It is dependent on the assumed reliability model of the system and the reliability data for the individual system elements.

EENS studies are useful for comparing the expected reliability performance of systems with different system reinforcement options and/or operational alternatives.

Electro-mechanical Stability: The condition of operation of an AC electrical system based on all generators operating in synchronism; that is, at the same frequency and in-phase with each other and able to withstand normal disturbances that could otherwise cause instability. The instability can occur within a fraction of a second or minutes. It can result in the electrical breakup of the transmission system into several sections and a widespread interruption of the electrical load or blackouts. See also **Transient Stability.**

Element: Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit breaker, bus section or transmission line. An element may be comprised of one or more components. A fault on an element usually results in the clearing of one protective zone by circuit breakers.

Emergency rating: The rating, as defined by the facility owner, that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand for short periods of time.

Fault: An event occurring on an electric system where abnormally high current flows resulting in the operation of a protection device or such as a short circuit, or a total interruption of an electrical circuit.

Firm Export: The assured sale of a contracted amount of energy and/or capacity to utilities or customers located outside the boundaries of BC.

Firm load: The load that BCTC will use reasonable best efforts to supply without interruption.

Firm Transmission: Transmission service that is reserved and/or scheduled with a priority that will not be interrupted for economic reasons.

Forced outage: An unplanned component failure (immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Generation: The process of producing electric energy by transforming other forms of energy such as steam, heat or falling water. Also, the amount of electric energy produced, expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Gigawatt: a thousand megawatts or one million kilowatts.

Gigawatt hour: One million kilowatt-hours—an amount of electric energy that will serve about 100 residential customers for one year.

Grid: The layout of an electrical transmission system.

Heavy Load Hours (HLH): Generally speaking, this refers to the time of day on a system that would be considered peak demand.

Impedance: The opposition in an electrical circuit to the flow of alternating current (AC). The ratio of electromotive force to the effective current.

Inadvertent flow: The inadvertent flow over the scheduled transmission path. This unscheduled flow is a result of the continuously varying imbalance between generation, load and scheduled interchanges, and is also due to system disturbances. For example when a BCHydro generating unit is tripped this will result in an instantaneous variation in the BC-US and BC-Alberta path flows to supply the load in BC until other generators respond with increased output to supply the power which was previously carried by the tripped generator.

Interchange: Electric power or energy that flows between British Columbia and other jurisdictions such as Alberta or Washington State.

Interconnected system: A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Intertie: A transmission line that interconnects the Transmission system with other utilities and jurisdictions outside of B.C. Used interchangeably with tie line.

Kilowatt: One thousand watts; the commercial unit of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Light Load Hours (LLH): Generally speaking, the term for the time of day on a system that could be considered off peak.

Limiting element: The device in a system that has the lowest energy rating, thereby setting the maximum amount of energy that can be transferred.

Load: The amount of electricity required by a customer or group of customers as measured by an electrical metre.

Load centre: The region where the majority of electricity customers are located.

Load forecast: The expected customer electricity requirements that will have to be met by the electrical system in future years.

Load shedding: Removal of pre-selected customer demand from a power system, as a result of the occurrence of an abnormal condition, in a effort to maintain the integrity of the system and minimise overall customer outages.

Unscheduled Flow:

The unscheduled flow over a parallel transmission path which carries a portion of the flow scheduled on the scheduled transmission path**.** For example, when energy is scheduled to flow from Montana to Seattle there is an unscheduled flow through the BC Hydro system which is in parallel with the actual scheduled path for the flow (from Boundary to Nelway to Selkirk to Ingledow to Custer).

Unscheduled flow on circuits other than those of the scheduled transmission path is an inherent characteristic of interconnected AC power systems. Schedules need to be arranged such that the effect of unscheduled flow does not cause transfer capability limits to be exceeded on other transmission paths.

Mega VAr" or **"MVAr:** 1 million VArs or 1000 kiloVArs of reactive power.

Most critical generator: The generator outage that results in the worst system performance during subsequent outages and includes additional generators if a single element outage could result in a prolonged outage of associated generators i.e., a combined cycle turbine outage may result in the outage of an associated steam generator or an interconnection transformer may result in the outage of more than one generator.

Must Run Units: A specific generating unit that has been designated by the system operator to be on line or on the grid to insure the flow of electricity. This must run unit is outside of economic dispatch and may or may not be a system's most efficient unit. A unit may be designated as must run for operating reasons that may include system reliability, voltage control or system stability.

MVA: Mega Volt Amperes. See **Apparent Power**.

MW: Megawatt(s) or means 1 million watts or 1000 kilowatts of real electrical power.

MWh: Megawatt hour(s). A unit of energy equal to the product of 1000000 joules/second (one megawatt) multiplied by 3600 seconds (one hour).

MCR: (Maximum Continuous Rating): The maximum output a plant can sustain on a continuous basis and prescribed conditions.

N-1: A single system contingency event involving the loss of one component.

N-2: A double system contingency event involving the loss of two components.

NERC: The North American Electric Reliability Council.

Non-firm transmission service: Point-to-point transmission service that is scheduled and paid for on an as available basis and is subject to interruption.

Non-spinning reserve: Generating units that are not connected to the system but are capable of coming on line within a specified time, or interruptible load that can be removed from the system in a specified time.

Normal operating conditions: Conditions where all transmission facilities are available for service including generators.

Operating reserves: The generation capability above that required for system demand to provide for regulation, load forecasting errors, equipment forced and scheduled outages and local area protection.

Operator: The party in control of the physical operation and maintenance of a well or other facility.

Outage: Periods, both planned and unexpected, during which power system facilities (generating unit, transmission line or other facilities) cease to provide generation, transmission or the distribution of power.

Over frequency: The abnormal operating state or system condition that results in a system frequency above the normal 60-hertz.

Path: A transmission line or set of lines that carry energy from one region to another.

Path rating: The rating assigned to the transmission facility when it was placed in service and rated in accordance with reliability standards. Related to transfer capability.

PCR: (peak continuous rating) means the maximum rating a generator can produce for a prescribed period of time and conditions.

Peak demand: The maximum load during a specified period of time.

Phase-shifting transformer: Also called phase angle regulators, these devices are a special kind of transformers that induce a power flow into a circuit, in order to increase or decrease the power loading of that circuit by inserting a voltage phase angle difference.

Planned outage: The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g. for annual overhaul, inspection, testing).
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POD (Point Of Delivery): A conceptual point of delivery from the transmission system. A POD is the point at which energy is deemed to be delivered from the transmission system to the customer.

PLC (Power Line Carrier) systems: These are communication systems used on some 230kV and extensively on 138 kV and 60 kV transmission lines for line protection, station supervision, telemetry and voice communications. A PLC system consists of PLC terminal, a line tuning unit, coupling capacitor and line trap. PLC's are used where a low channel requirement exists and economics do not warrant an alternative solution.

PTP (point-to-point): The transmission of power from one point to another point.

Post transient: The state of equilibrium of a power system after a transient event.

Power factor: The power factor is the ratio of active power (kW) to **apparent power** (kVA) in a circuit. It varies between 0 and 1, and is normally given in percent (0 to 100%).

Power Transfer Capability: The power that can be transferred over a particular section of a transmission system in a reliable manner.

Radial transmission: A transmission system that is not networked and does not provide multiple parallel flow paths.

Radial customer: A customer served from an electric system in which the electrical service is through a single transmission element.

Reactive power: Reactive power is the power required to maintain the flow of electrical energy and maintain voltages at acceptable levels.

Reinforcement: Improvements in the electrical system to maintain or increase reliability and security of supply, or increase power transfer capability.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system adequacy and security.

> <u>Adequacy:</u> The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> <u>Security:</u> The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reliability criteria: A set of standards and principles used to design, plan, operate, and assess the adequacy of an electric system and refers to the BCTC Reliability Criteria except where otherwise noted.

Reliability Must-Run Generation (RMR): Generation resources in a given area constrained to operate at a minimum specified MW output level in order to maintain system security. In BC, reliability must run generation resources are essentially located in the coastal generation region, which includes the Vancouver Island and Lower Mainland areas.

Remedial action scheme (**RAS**)**:** Protection schemes designed to perform pre-planned corrective measures following a system disturbance to ensure an acceptable level of performance or equipment protection. Most of these schemes provide high speed automatic system switching actions such as generation shedding, load shedding and switching station reactive power devices.

Rights-of-way: The land rights acquired by a utility to allow the construction and operation of electrical transmission or distribution facilities.

Safety net system: A control system that protects the system from widespread cascading outages and loss of load. Systems include under frequency load shedding, and under voltage load shedding.

Single pole trip and reclose (SPT&R): A transmission circuit protection system which is capable of opening only the faulted phase of a circuit for single phase faults and successfully reclosing after the fault has been cleared.

Spinning reserve: Unused capacity available from units connected to and synchronised with the grid available to respond instantly to system requirements.

Stability: The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Stability limit: The maximum power flow possible through some particular point in the system while maintaining stability, during both normal and defined contingencies, in the entire system or the part of the system to which the stability limit refers.

Statcom: A device which provides instantaneous and continuously variable reactive power in response to grid voltage transients, enhancing the grid voltage stability.

Steady state: The operation of a power system with no disturbances or after regaining equilibrium after a disturbance.

Standard: Something established by authority, custom, or general consent as a model or example.

Substation: Facility equipment that switches, changes or regulates electric voltage. An electric power station which serves as a control and transfer point on an electrical transmission system. Substations route and control electrical power flow, transform voltage levels, and serve as delivery points to industrial customers.

Summer rating: The rating a piece of equipment is given when summer ambient weather conditions prevail.

Switching station: A facility for switching electrical elements.

Synchronism: The timing of alternating current generators so that their voltage waves go through their maximum and minimum values at exactly the same rate.

System: Integrated electrical facilities that may include generation, transmission, distribution, protection, control and communications facilities.

System Stability: The ability of all parts of an electrical system to remain synchronised following an electrical disturbance such as the interruption of a transmission line. See also **Transient Stability.**

Terminal Station: The station at the end of a high voltage transmission line or cable circuit.

Thermal rating: The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Tie line: A circuit connecting two or more systems and used interchangeably with intertie.

Total Transfer Capacity (TTC): The total amount of power that can be transferred reliably over a transmission circuit or path.

Transfer capacity: The ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW).

Transformer: An electrical device for changing electricity from one voltage to another.

Transient: The period when a power system is moving from one state of equilibrium to another (post transient) state.

Transient stability: A transient event can be a lightning strike, line fault, or equipment failure resulting in a short circuit. Transient instability occurs when, due to a short-circuit, some generators accelerate and others decelerate so that the usual stabilising forces cannot restore the generators to synchronous operation. The result of transient instability can be widespread blackouts. Transient phenomena can occur very quickly (typically in less than a second) due to a transient event.

Transmission: The network of high voltage lines, cables, transformers and switches used to move electrical power from generators to the distribution system and to interconnect different utility systems and independent power producers together into a synchronised network. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission circuit: A set of wires energized at transmission voltages extending beyond a substation which has its own protection zone and set of breakers for isolation.

Transmission line: A set of structures, wires and insulators that together make up one or more transmission circuits.

Transmission losses: The power lost in transmission between one point and another. It is measured as the difference between the net power passing the first (delivery) point and the net power passing the second (receiving) point.

Transmission reliability margin (TRM): The amount of transmission transfer capability set aside to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Trip: The disconnection or breaking of a circuit, usually in context of an automatic interruption of the circuit such as the opening of a circuit breaker.

Underfrequency: The abnormal operating state or system condition that results in a system frequency below the normal system operating frequency of 60-hertz.

VArs: Volt-amp reactive, a measure of reactive power.

Voltage collapse: A catastrophic voltage drop in a region where the transmission and distribution system is incapable of supplying the load. A system enters a state of voltage collapse or instability when an increase in load, system disturbance or change causes voltage to drop quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage collapse may take anywhere from a few seconds to minutes.

Voltage control: The control of transmission voltage adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage instability: A system state in which an increase in load, disturbance, or system change causes voltage to decay quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage decay may take anywhere from a few seconds to tens of minutes. Unabated voltage decay can result in angular instability or voltage collapse.

Voltage limits:

<u>Normal Voltage Limits</u> The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

<u>Emergency Voltage Limits</u> The operating voltage range on the interconnected systems that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage recovery: The nature of voltage returning to an equilibrium state after a transient event.

Voltage stability: The ability of the electrical transmission system to withstand the failure of a system element such as a line or transformer without **voltage collapse** at the receiving (customer) end of the system.

Watt: The basic unit of electric power equal to one joule per second.

WECC: The Western Electricity Coordinating Council.

Wheeling: The movement of electricity from one system to another over transmission facilities of the intervening systems.

Winter rating: The rating a piece of equipment is given when winter ambient weather conditions prevail.

APPENDIX 2
STATION ACRONYMS

ABA	ALBREDA-TRANS MOUNTAINS
ABF	ABERFELDIE G.S.
ABP	ABBOTSFORD POWER SMART CENTER (closed)
ABT	ABBOTSFORD SUBSTATION
ABW	ALBRIGHT & WILSON AMERICAS (NOW SPC
ABY	ALERT BAY G.S.
ACK	ASHTON CREEK SUBSTATION
ACL	ACLAND ANPRODOME (VHF) REPEATER
ADC	ARNOTT DC TERMINAL
ADL	ADAMS LAKE SUBSTATION
AFP	APOLLO FOREST PRODUCTS
AFT	ASHCROFT SUBSTATION
AHM	ANAHIM LAKE D.G.S.
AIA	ABBOTSFORD INTERNATIONAL AIRPORT
AIR	AIYANSH REPEATER
AKO	ALKOKOLEX
ALC	ALICE LAKE REPEATER SITE
ALD	ALDERGROVE SUBSTATION
ALG	ALEX GRAHAM (VHF)
ALH	ARROW LAKES HYDRO G.S.
ALN	ALCAN
ALP	ALPINE SUBSTATION
ALR	MOUNT ALLARD
ALT	ALTA LAKE MICROWAVE REPEATER STN.
ALU	ALOUETTE GENERATING STATION
ALZ	ATCHELITZ SUBSTATION
AMC	AMERICAN CREEK CAPACITOR STN.
AMX	AMAX OF CANADA
AN2	ANNACIS ISLAND SUB #2
ANC	AQUILA NETWORKS
ANN	ANNACIS ISLAND SUBSTATION
ANP	ATSUKI NYLON PLANT
AON	AFTON-OPERATING CORP.
AOT	AHOUSAT DGS (DISMANTLED)
APP	PACIFICA PAPERS
APT	CANADIAN AUTOPARTS TOYOTA
ARD	ARROW DAM SUB. (DISMANTLED)
ARL	ARROW RESERVOIR (LOWER)
ARM	ARMSTRONG SUBSTATION
ARN	ARNOTT SUBSTATION
ARW	ARROW LAKE RESERVOIR (UPPER)
ASH	ASH RIVER G.S.(ELSIE LAKE)
ASK	AH-SIN-HEEK DGS
ATH	ATHALMER SUBSTATION
ATK	POINT ATKINSON
ATL	ATLIN D.G.S.
AVO	AVOLA SUBSTATION

AWH	ARROWSMITH REPEATER
AWL	AINSWORTH OSB SUBSTATION
AWT	ANNACIS ISLAND WASTEWATER TREATMENT PLANT
AXC	ALEXANDER CREEK SUBSTATION
AYH	AIYANSH SUBSTATION
BAB	BABINE LAKE SUBSTATION
BAD	BALD MOUNTAIN
BAL	BALFOUR SUBSTATION
BAM	BAMFIELD DGS #2 (DISMANTLED)
BAR	BARRIERE SUBSTATION
BBD	BOSTON BAR D.G.S.
BBE	BOUNDARY BAY ELECTRODE
BBH	BOSTON BAR HYDROELECTRIC GEN-IPP
BBN	BAMBERTON SUB. (DISMANTLED)
BBR	BOSTON BAR SUBSTATION
BBS	Big Bend Substation
BBY	BURNABY MOUNTAIN CONTROL CENTER
BCC	BC CHEMICALS
BCH	BC Hydro System
BCI	BUCKEYE CANADA INC.
BCK	BRITT CREEK SWITCHING STATION
BCL	B.C. COAL (renamed ElkView Coal EV1)
BCM	B.C.CHEMICAL CHLORATE #4
BCR	BC RAIL
BCS	BCH SECURITY
BCT	BC Timber (renamed Skeena Cellulose)
BDC	BOULDER CREEK
BDD	BOUNDARY PLANT/PROJECT
BDM	BRENDA MINES
BDR	BOULDER MICROWAVE STN.
BDW	BRANDYWINE IPP
BDY	BOUNDARY SUB
BEA	BEAR MOUNTAIN
BEC	BEAR CREEK (SEE JOR)
BEL	BELLA BELLA DGS
BGA	BRIDGE RIVER AREA
BGB	BIG BAR REPEATER STATION
BGC	BRIDGE RIVER CONTROL
BGR	BEAR RIDGE REPEATER
BGS	BURRARD GENERATING STATION
BGY	BINGLEY MOUNTAIN (VHF) REPEATER
BHQ	BOUNDARY HEADQUARTERS
BIG	BIG EDDY DYKES
BIS	BISSETT
BKL	BROCKLEHURST SUBSTATION
BKR	BAKER MICROWAVE REPEATER STN.
BKY	BUCKEYE CANADA INC.(RENAMED BCI)
BLA	BELLA COOLA DGS
BLD	BURNS LAKE POWER DISTRICT
BLH	BULLHEAD MICROWAVE STATION

BLK	BOUNDARY LAKE
BLM	BULLMOOSE MINE
BLR	BELL COPPER-MACLAREN FOREST PRODUCT
BLS	BROWN BEAR LAKE D.C.P.
BLU	BLUE RIVER SUBSTATION
BLW	BARLOW SUBSTATION
BLZ	BLIZZARD MICRO. REPEATER STATION
BMM	BULLMOOSE MOUNTAIN (VHF) REPEATER
BMN	BEAR MOUNTAIN (VHF) REPEATER
BMP	BINGHAM PUMPS (SULZER)
BMR	BOSTON BAR REPEATER
BND	BARNARD SUBSTATION
BNI	BOWEN ISLAND
BNT	BURNETT ROAD TERMINAL STATION
BOD	BODWELL SUB. (DISMANTLED)
BOM	BOARD MILL
BOR	BORDER
BOT	BOTANIE MOUNTAIN (VHF) REPEATER
BP1	Ballard Power Systems
BP2	BALLARD POWER PLANT
BPA	BONNEVILLE POWER
BQR	BOB QUINN REPEATER
BR1	BRIDGE RIVER G.S. #1 & TERZAGHI DAM
BR2	BRIDGE RIVER G.S. #2
BRA	BRALORNE SUBSTATION (DISMANTLED)
BRC	BYRON CREEK COAL-CORBIN CREEK RES.
BRD	BRILLIANT (WKP) COMINCO/BCH EXPAN.
BRG	BUTLER RIDGE (VHF) REPEATER
BRK	BEAR CREEK HYDRO
BRL	BROWN LAKE Hydro Electric Plant
BRM	BULL RIVER MINERAL
BRN	BURNS LAKE SUB.
BRP	BC RAIL POLE (SETON LAKE)
BRU	BRUCE PEAK MICROWAVE STATION
BRX	BRILLIANT EXPANSION
BSS	BOSS MOUNTAIN SUBSTATION
BTA	BRITANNIA SUBSTATION (DISMANTLED)
BTL	BUTTLE RESERVOIR
BTS	BRILLIANT TERMINAL STATION
BUL	BULKLEY AREA TRANS. SYSTEM
BUT	BURRARD THERMAL SUBSTATION (see BGS for Gen Stn)
BVC	BEAVER COVE SUBSTATION
BVY	BEAVERLEY SUBSTATION
BWD	BRENTWOOD SUBSTATION
BWN	BOWEN ISLAND MICROWAVE STATION
BXR	BAXTER (WAS KNOWN AS CK1)
BYD	BURRARD YARROW SHIPYARD
BZA	BONANZA MOUNTAIN REPEATER STATION
CAL	Callaghan Creek IPP
CAM	CAMBIE SUBSTATION
CAP	CAPILANO SUBSTATION

CAR	CAMBIE ROAD (RENAMED 'CAM')
CAT	MOUNT CARTIER SEISMOGRAPH (VHF) REP
CBC	CARBON CREEK (VHF) REPEATER
CBH	CAMPBELL HILL REPEATER STATION
CBK	CRANBROOK SUB
CBL	CAMPBELL RIVER SUB
CBN	CLAYBURN SUBSTATION
CBP	CARIBOO PULP & PAPER SUBSTATION
CBR	CAMPBELL RIVER SYSTEM
CBY	CRANBERRY LAKE RADIO REPEATER
CCB	CAPE COCKBURN CABLE TERMINAL
CCD	COMINCO COPPER DIVISION
CCG	CLYDE COATES CO-GENERATION IPP
CCP	CENTRAL COAST POWER CORPORATION
CCR	COQUITLAM CENTRE VAULT
CCW	CACHE CREEK WOODCHIPS.GEORGIA PAC.
CFE	CRESTBROOK FOREST INDUSTRIES (ELKO)
CFI	CROWN FOREST INDUSTRIES(FRASER ML)
CFM	CANADIAN FOREST PRODUCTS MDF PROJ.
CFT	CROFTON MILL SUBSTATION
CHA	CHASE (VHF) A.T.B. REPEATER
CHC	CHAPMAN CAMP (PREVIOUSLY KM2)
CHF	CHIEF LAKE SUBSTATION
CHG	CHINGEE (VHF)
CHI	CHINA CREEK
CHK	CHILLIWACK SUBSTATION
CHL	CHARLIE LAKE RADIO STATION
CHN	CHEMAINUS REPEATER
CHP	CHAPMANS CAPACITOR STN.
CHR	CHUWANTEN MTN REPEATER
CHS	CHASE SUBSTATION
CK5	CHEEKYE 500kV SUBSTATION YARD
CKB	CHECKERBOARD SLOPE
CKP	CRANBROOK POWER SMART CENTER - Closed
CKY	CHEEKYE SUBSTATION
CLA	CLAYTON FALLS GENERATING STATION
CLB	COLEBANK SUBSTATION
CLD	COLWOOD SUBSTATION
CLL	CONTINENTAL LIME (PAVILLION)
CLN	CLINTON SUBSTATION
CLT	COULTER MOUNTAIN REPEATER STATION
CLV	CLEVELAND DAM SUBSTATION
CLW	CLEARWATER SUBSTATION
CMB	COAST MOUNTAIN BUS CO. LTD.
CMC	COMOX DAM
CMH	CONUMA RIVER HATCHERY-FISHER.& OCNS
CML	CAMPBELL RIVER LODGE
CMM	Cummins BC (Cummins Western Canada)
CMN	CHEMAINUS SAWMILL (DISMANTLED)
CMO	COAL MOUNTAIN OPERATIONS
CMR	CAMERON LAKE REPEATER

CMS	CHEAKAMUS GENERATING STATION
CMT	CRAIGMONT SUBSTATION (DISMANTLED)
CMX	COMOX SUBSTATION
CNB	CN BOSTON BAR
CNG	CANADIAN NATIONAL GISCOME
CNH	CANADIAN MOUNTAIN HOLIDAYS
CNL	CANAL FLATS SUBSTATION
CNM	CANOE MOUNTAIN (VHF) REPEATER
CNP	CROWN PACKAGING LTD. (renamed NAC)
CNR	CANADIAN NATIONAL RAIL
CNT	CROWSNEST-ALBERTA NATURAL GAS
CNY	CANYON POWER IPP
COC	CANADIAN OXY CHEMICAL-HARMAC
COF	COFFEE CREEK SUBSTATION
COH	COMOX HARBOUR
COK	COMO LAKE SUBSTATION
COM	CLOWHOM GENERATING STATION
COP	CANADIAN OXY INDUSTR. CHEM.(SEE NXC
COR	CORRA LINN (WKP)
COS	CANADIAN OXY-SQH CHLORINE
COU	COURSIER DAM-WALTER HARDMAN STORAGE
COX	COMOX RIVER NR COURTENAY
CPC	COLUMBIA POWER CORPORATION
CPG	CPR GOLDEN
CPH	CROFTON PUMP HOUSE
CPM	COPPER MOUNTAIN MICRO REPEATER STN
CQD	COQUITLAM DAM
CQM	COQUITLAM SUBSTATION
CRB	COLUMBIA RIVER DEVELOPMENT
CRC	CRESTBROOK FOREST IND.(CANAL FLATS)
CRD	CANREED SUBSTATION
CRK	CREEKSIDE CAP.STN.
CRN	CARSON MICROWAVE STN.
CRO	CROWSNEST (TRANSALTA)
CRP	CARPENTER LAKE RESERVOIR
CRQ	CARQUILLE SUBSTATION
CRR	REVELSTOKE GS
CRS	CRESTBROOK FOREST IND. SKOOKUMCHUCK
CSN	CAMOSUN SUBSTATION
CSQ	CATHEDRAL SQUARE SUBSTATION
CST	COASTAL CS AREA
CTE	Coteay Creek
CTF	CATFACE REPEATER
CTL	COTTLE HILL MICROWAVE STN.
CTY	COURTENAY SUBSTATION (DISMANTLED)
CUS	CUSTER (BPA)
CVN	CHEVRON CANADA SUBSTATION
CVP	COLUMBIA VALLEY PULP SUBSTATION
CWD	CHETWYND SUBSTATION
CYP	CYPRESS SUBSTATION
DAN	MOUNT DAINARD SEISMOGRAPH (VHF) REP

DAW	DAWSON CREEK SUBSTATION
DBG	DOMINION BRIDGE
DBY	DUNCAN BAY SUBSTATION
DCK	DOG CREEK
DCN	DUNCAN
DCR	DUNCAN ANPRODOME (VHF) REP-DROP
DCS	DECOSMOS REPEATER
DCV	DEEP COVE SUBSTATION
DCY	D'ARCY MICROWAVE STN.
DDM	DUNCAN DAM
DEC	DECEPTION CONE (VHF) REPEATER
DEL	DELTA SUBSTATION
DFD	DARFIELD-TRANS.MOUNTAIN
DFN	DUFFERIN SUBSTATION
DGB	D.G. BELL (WKP)
DGN	DRAGON MICROWAVE STN.
DGR	DAL GRAUER SUBSTATION
DIL	DIANA LAKE SUBSTATION
DKY	DUNKLEY LUMBER
DLD	DONALD REPEATER
DLK	DEASE LAKE D.G.S.
DLS	DENNIS LAKE D.C.P.
DMI	DOMAN INDUSTRIES
DMR	DUNSMUIR SUBSTATION
DMU	DUNSMUIR RADIO REPEATER SITE
DND	DND ESQUIMALT
DOM	DOME MOUNTAIN (VHF) REPEATER
DOR	DORAN MOUNTAIN TOP REPEATER SITE
DOW	DOWNIE SLIDE
DPS	DOWNIE PEAK RIDGE SEISMOGRAPH
DPT	DELTAPORT CONTAINER TERMINAL
DRV	DUAL OR DOUBLE DUAL RADIAL VAULTS
DSR	DEASE LAKE REPEATER
DSY	DAISY LAKE (CHEAKAMUS) HEADWORKS
DTR	DORAN TAYLOR
DUG	DOUGLAS STREET SUBSTATION
DUK	DUKE POINT POWER IPP
DUN	DUNSMUIR OFFICE TELECONTROL EQUIPMENT
DUT	DUTCHMAN'S RIDGE
DVC	DEVILS CANYON REPEATER,TELECONTROL
DWN	DOWNTON RESERVOIR
EBT	ENGLISH BLUFF TERMINAL
EDO	ELDORADO MOUNTAIN (VHF) REPEATER
EDR	EDDONTENAJON REPEATER
EFD	ELKFORD SUBSTATION
EFM	ELK FALLS MILL-NORSKE SKOG
EFT	ELKFORD TAP STATION
EKA	EUREKA ANPRODOME (VHF) REPEATER
EKC	EAST KOOTENAY CONTROL CTR.
EKG	EAST KOOTENAY GENERATION
EKN	ERICKSON REPEATER

EKO	ENDAKO SUBSTATION
EKT	EAST KOOTENAY THERMAL
EKW	EKWAN CELL SITE
ELF	ELK FALLS REPEATER STATION
ELH	ELAHO RIVER
ELK	ELKO GENERATING STATION
ELL	ELLIOTT DAM (SEE JOR)
ELM	ELSIE LAKE MOUNTAIN TOP REPEATER
ELR	ELK RIVER HEADPOND
ELS	ELSIE LAKE INTAKE
EMC	ELCO MINING CO
EMW	ELECTRA MICROWAVE STATION
EN1	ENDERBY NO.1 OLD SUB (SEE END)
END	ENDERBY SUBSTATION
EPG	EDMONDS DIESEL PARALLEL GENERATOR
EPM	EPSOM
EPS	EAGLE PASS SEISMOGRAPH
EQU	EQUITY MINING
ERC	ERIC CREEK
ERS	MOUNT ERSKINE
ESC	ESCO FOUNDRY
ESM	EBURNE SAWMILLS-CAN.FOREST PROD.
ESQ	ESQUIMALT SUBSTATION
ESS	Emerald Switching Station (TeckCominco)
ETC	EAST TWIN HYDRO
EUR	EUROCAN SUBSTATION
EV1	ELKVIEW COAL (PREV. KAISER COAL)
EVP	EVANS PRODUCTS -name change to LPE
EWL	ELSWORTH LOGGING
EXR	EXETER SUBSTATION
FBC	FIBRECO
FCC	FLETCHER CHALLENGE CANADA,MACKENZIE
FCK	FOX CREEK SUBSTATION
FCL	FIBERGLASS CANADA LTD.SCOTT PAPER
FCN	FUNCTION JUNCTION SUBSTATION
FCO	FEDERATED CO-OPERATIVES (PREV. CNU)
FDC	FORDING COAL (RENAMED 'FRO')
FFI	FINLAY FOREST INDUSTRIES
FGS	FAUQUIER-ARROW LAKE GAUGE STATION
FHS	FOOTHILLS SUBSTATION
FIH	FAITH ANPRODOME (VHF) REPEATER
FIN	FINLAY RIVER ABOVE AKIE RIVER
FIR	FIR STREET RECTIFIER STATION
FJ2	FORT ST.JOHN #2 SUBSTATION
FJN	FORT ST JOHN SUBSTN.
FKR	FORREST KERR RUN OF RIVER
FLD	FIELD SUBSTATION
FLG	FRED LAING MICROWAVE (VHF) REPT.
FLR	EXSTALL REPEATER
FLS	FALLS RIVER GENERATING STATION
FM1	FORT ST JAMES NO.1 SUB.

FM2	FORT ST JAMES NO.2 SUBSTATION
FMC	FMC - PRINCE GEORGE
FMM	FOUR MILE MOUNTAIN REPEATER VHF/UHF
FMR	FIRE MOUNTAIN REPEATER
FMT	FAIRMONT SUBSTATION
FNE	FERNIE SUBSTATION
FNG	FORT NELSON GENERATING STATION
FNL	FORT NELSON (VHF) REPEATER
FNN	FORT NELSON DGS NO. 1
FRC	FURRY CREEK SUBSTATION
FRF	FRASER RIVER FIBREBOARD (see MDF)
FRH	FIRTH LAKE SUBSTATION
FRI	FURRY CREEK IPP
FRK	FREDERICK REPEATER
FRO	FORDING COAL-FORDING RIVER OPERATIO
FSR	FRASER LAKE SUB.
FSS	FRASER LAKE SAWMILLS-LEJAC
FST	FORT STEELE SUBSTATION
FTH	FIRTH MICROWAVE STATION
FVW	FOREST VIEW SUB/FVW AREA
GAR	GARRISON MOUNTAIN (VHF) REPEATER
GBR	GIBRALTER MINE-MARGUERITE
GBW	GIBRALTER WELLS
GCL	GREAT CENTRAL SUBSTATION
GDC	GALIANO DC STATION
GDF	GOLDSTREAM AERIAL FERRY (VHF) RPTR.
GDK	GEORGE DICKIE SUBSTATION
GDN	GOLDEN SUBSTATION
GDS	GOLDSTREAM MICROWAVE SITE
GDT	GOLDSTREAM TRAM
GHS	GORDON HEAD SUBSTATION
GIB	GIBSONS LANDING SUBSTATION
GIL	GULF ISLAND LOOP SCHEME
GLB	GILLIES BAY
GLD	GOLD RIVER SUB.
GLM	GILMORE ST. TELECONTROL
GLN	GLENANNAN SUBSTATION
GLO	GALIANO RIDGE
GLR	GLENMORE SUBSTATION
GLS	GALIANO SUBSTATION
GLT	GLOUCESTER SUBSTATION
GMC	G.M.S. CONTROL
GMR	GARDNER MICRO. REPEATER STN.
GMS	GORDON M. SHRUM G.S.(WAC BENNETT)
GMT	GORDON M. SHRUM TRAILER
GNO	GALIANO TERMINAL
GNR	GLENANNAN MICROWAVE REPEATER STN.
GOW	GOWARD SUBSTATION
GPT	GRIEF POINT SUBSTATION
GRC	GALIANO RECLOSER
GRD	GOLD RIVER G.S.

GRH	GREEN HILLS-FORDING COAL
GRP	GOLD RIVER PULPMILL (PREV. TAH)
GRR	GREEN RIVER SUBSTATION
GRS	GROUSE MICROWAVE REPEATER STN.
GRT	GOLD RIVER REPEATER SITE
GRV	GRAVEL PIT (RENAMED 'SSY')
GRY	MOUNT GREY REPEATER SITE
GSC	GENSTAR CEMENT LTD. (RENAMED TCL)
GSM	GOLDSTREAM MINE SUBSTATION
GSP	GVRD SAPPERTON PUMPS
GST	GOLDSTREAM TAP
GSY	GLOSSY MOUNTAIN (VHF) RPTR (SEE CBH
GTC	GUILDFORD TOWN CENTRE
GTP	GEORGE TRIPP SUBSTATION
GUI	GUICHON CAPACITOR STATION
GVH	GVRD IPP (renamed SEE - Seegen IPP)
GVL	GAVIN LAKE SUBSTATION
GVR	GREENVILLE RADIO REPEATER
HAL	HALPIN (PREVIOUSLY KM1)
HAM	HAMILTON MICROWAVE REPEATER STN.
HAR	HARRISON REPEATER STN (FORMERLY BEAR)
HAW	HAYWARD LAKE
HAY	HAYWARD LAKE RADIO REPEATER
HCK	HAT CREEK THERMAL DEVELOPMENT
HCL	HAT CREEK LIQUEFACTION PLANT
HCR	PRINCE GEORGE PULP #2 HCR
HCT	HILLCREST SUBSTATION
HDC	HEBER DIVISION
HDW	HOLDSWORTH REPEATER SITE
HEB	HEBER RIVER DIVERSION DAM
HEN	HENDRIX
HFP	HOUSTON FOREST PRODUCTS SUB.
HFY	HEFFLEY CREEK SUBSTATION
HGR	HELLS GATE MICROWAVE RPTR
HHP	HUDSON HOPE
HHT	HUDSON HOPE TRANSMISSION
HKS	HKUSAM (VHF)
HLD	HIGHLAND SUBSTATION
HLK	HUGH L. KEENLEYSIDE (ARROW DAM)
HLL	HALL LAKE SUBSTATION
HLN	HOLLYBURN SUB.
HLR	HALL LAKE MICROWAVE REPEATER STN
HLT	HILL AVENUE TERMINAL STATION
HMC	HARMAC-PACIFIC INC.
HMH	HUNDRED MILE HOUSE SUBSTATION
HML	HUCKLEBERRY MINE PROJECT
HMR	HOPE REPEATER
HNY	HANEY SUBSTATION
HOM	HOMATHKO RIVER DEVELOPMENT
HOP	HOPE SUBSTATION
HPA	HORNE PAYNE ANNEX

HPI	HARMAC PACIFIC INC. (See HMC)
HPL	HIGH POWER LAB
HPN	HORNE PAYNE SUBSTATION
HRD	HARVIE ROAD SUBSTATION
HRF	HAYWARD RECREATION FACILITY
HRG	HOWSER RIDGE REPEATER
HRN	MOUNT HORNE REPEATER STN
HRO	HARO STREET RECTIFIER STATION
HRS	HORSEY RADIO REPEATER SITE
HSB	HORSESHOE BAY SUBSTATION
HSK	HUSKY OIL
HSP	HOWE SOUND PULP AND PAPER
HSR	HOWSER RIDGE REPEATER STATION
HSS	HILL STREET SUBSTATION
HST	HASTINGS EAST RECTIFIER STATION
HSY	HORSEY SUBSTATION
HTN	HUNTINGDON RADIO STN (DISMANTLED)
HTR	HOTNARCO MOUNTAIN REPEATER VHF/UHF
HTV	HUNTINGDON VHF SITE
HUS	HOUSTON SUBSTATION
HVC	HIGHLAND VALLEY COPPER
HWD	HAREWOOD SUBSTATION
HXN	HIXON SUBSTATION
HYS	HAYES SUBSTATION
HZN	HAZELTON SUBSTATION
ICG	ISLAND COGENERATION PLANT
ICP	INTERCONTINENTAL PULP
IFM	INTERNATIONAL FOREST PRODUCTS
ILD	ILLECILLEWAET DYKES
ILL	ILLECILLEWAET SUB.
IMR	INSTRUMENT MODULE REPAIR SHOP
IND	INDUSTRIAL (WAS KNOWN AS CK2)
ING	INGLEDOW SUBSTATION
INV	INVERMERE
IOC	IOCO SUB-ESSO PETROLEUM
IPH	ISLAND PHOENIX
IPM	ISLAND PAPER MILL
IPR	ISLE PIERRE SUB.
IPS	INTERPROV. PIPE & STEEL CORP
IRD	INVESTMENT RECOVERY DEPT (DISPOSAL)
IRR	IRON RIVER REPEATER
ISK	ISKUT RIVER DEVELOPMENT
ITO	INTALCO ALUMINUM COMPANY
IVR	INVERMERE REPEATER STATION
JAR	JARVIS MICROWAVE REPEATER STATION
JCL	Jones Creek below Laidlaw Bridge
JHC	JOHN HART CONTROL.
JHM	JOHN HART (SURGE TANK)
JHN	JOHN HART GS
JHS	JOHN HART SUBSTATION
JHT	JOHN HART GEN. STN.

JLK	WAHLEACH POWER TUNNEL - JONES LAKE
JLN	JOHN LAWSON SUBSTATION
JOD	JORDAN DIVERSION DAM
JOE	JOSEPH CREEK SUBSTATION
JOR	JORDAN RIVER G.S.
JPT	JINGLE POT SUBSTATION
JRI	JAMES RICHARDSON INTERNATIONAL LTD.
JUL	JEUNE LANDING SUB.
KAB	KABAU ANPRODOME (VHF) REPEATER
KAL	KALUM SUBSTATION
KAS	KASLO SUBSTATION
KBL	KINBASKET LAKE
KBY	KIMBERLEY SUBSTATION
KC1	ELKVIEW COAL (OBSOLETE USE EV1)
KCD	KOOTENAY DIVERSION
KCL	KOOTENAY CANAL DEVELOPMENT
KCS	KITIMAT COPPER SMELTER
KDS	KENNEDY SUBSTATION
KDY	KENNEDY CAPACITOR STN.
KEN	KENT SUBSTATION
KGG	KINGSGATE SUB.
KGH	KEOGH SUBSTATION
KGP	KWOEN 230KV SUBSTATION
KGT	KEOGH GAS TURBINE
KI1	KIDD NO.1 SUBSTATION
KI2	KIDD NO.2 SUBSTATION
KIR	KING ISLAND REPEATER
KIT	KITIMAT TRANS. SYSTEM
KKT	KITKATLA DIESEL GENERATING STATION.
KLO	KASLO MOUNTAIN TOP REPEATER
KLS	KEENLEYSIDE POWERPLANT PROJECT
KLW	KELOWNA (WKP)
KLY	KELLY LAKE SUBSTATION
KMI	KEMESS SOUTH MINE PROJECT
KMO	KEMANO (ALCAN)
KNS	KAINS LAKE
KNT	KNIGHTON (PREVIOUSLY KM5)
KOK	KOKISH RIVER DEVELOPMENT
KPD	KIMBERLEY POWER DISTRICT
KRD	KINGS ROAD SUBSTATION
KRH	KAISER HOSMER
KSA	KASLO REPEATER STATION
KSD	STILES SUBSTATION (previously Kimberly Stiles)
KSH	KOKSILAH SUBSTATION
KSP	KINGS PEAK (VHF)
KST	KITSAULT SUB.
KSY	KAMLOOPS STORAGE YARD.
KTC	KANELK TRANS COMPANY
KTG	KEATING SUBSTATION
KTR	KITIMAT RADIO REPEATER
KVS	KINGSVALE SUBSTATION

KWD	KAMWOOD SUBSTATION
KWY	KINGSWAY RECTIFIER STATION
LAC	LAC DES ROCHE
LAJ	LAJOIE GENERATING STATION
LAP	LOUISIANA PACIFIC
LB1	LAKE BUNTZEN G.S. #1 (Dam)
LB2	LAKE BUNTZEN G.S. #2 (POWER INTAKE)
LBD	LAKE BUNTZEN DAM
LBH	LONG BEACH SUBSTATION
LBO	LOWER BONNINGTON (WKP)
LBP	LAKE BUNTZEN PUMPHOUSE & REC. AREA
LBR	LIBBY RESERVOIR (LAKE KOOCANUSA)
LBY	LIONS BAY SUBSTATION
LCC	LINE CREEK COAL
LCD	LOWER COLUMBIA DEVELOPMENT
LCL	LOWER CAMPBELL RESERVOIR
LCN	LAKE COWICHAN REPEATER (VHF)
LCR	LIONS CREEK
LCW	LAKE COWICHAN SUBSTATION
LDR	LADORE FALLS G.S.
LDY	LADYSMITH SUBSTATION
LEE	F.A. LEE SUBSTN (WKP)
LF1	LAFARGE CEMENT NO.1
LF2	LAFARGE CEMENT NO.2
LGL	LOGAN LAKE SUBSTATION
LGM	LIGNUM SAWMILL
LGN	LANGDON SUBSTATION (TAU)
LGP	LAVINGTON GLASS PLANT
LGS	LADORE FALLS (RENAMED 'LDR')
LGW	LIGNUM AT WILLIAMS LAKE
LHS	LARCH HILL REPEATER STATION
LIB	LIBBY DEVELOPMENT (U.S.)
LIK	LIKELY REPEATER STATION
LKL	LAKELSE SUBSTATION
LLD	LORNEX LOW LEVEL DAM
LLH	LAC LA HACHE SUB (DISMANTLED)
LLK	LOGAN LAKE RADIO REPEATER SITE
LLT	LILLOOET SUBSTATION
LMA	LOWER MAINLAND TRANSMISSION SYSTEM
LMC	LOWER MAINLAND CONTROL CENTER
LMM	LIME MOUNTAIN (VHF) REPEATER
LMT	LOWER MAINLAND TRANSMISSION
LNG	TILSBURY ISLE.LNG.PLANT
LNL	LONG LAKE IPP
LOH	LOUGHEED SUBSTATION
LRA	LANGLEY PRODUCTION
LRD	LIARD RIVER DEVELOPMENT
LRP	LANTIC REAL PROPERTY LTD.PARTNERSHP
LSD	LOVELAND SADDLE DAM
LTN	LYTTON DIESEL GENERATION STATION
LTZ	LANTZVILLE SUBSTATION

LU1	LUMBY NO.1 SUBSTN (DISMANTLED)
LU2	LUMBY NO.2 SUBSTATION
LWT	LONGWORTH (VHF)
LYN	LYNN VALLEY SUBSTATION
LYT	LYTTON SUB
LYW	LYTTON WOODWASTE IPP
MAB	MA-BUTTE MICROWAVE STATION
MAC	MACDONALD MOUNTAIN REPEATER STN.
MAD	MAD CREEK
MAM	MAMQUAM G.S.
MAN	MAINWARING SUBSTATION
MAR	MASSET REPEATER
MAS	MASSET DIESEL G.S.
MAT	MATHESON MOUNTAIN REPEATER STN.
MBC	MOUNT BECHER
MBD	MCBRIDE POWER DISTRICT
MBH	MOUNT BLENHEIM RPTR
MBL	MCMILLAN BLOEDEL-CAN.WHITE PINE
MBO	MARACAIBO TERMINAL
MBR	MCBRIDE HILL REPEATER
MCA	MICA CREEK DEVELOPMENT
MCC	MICROWAVE CONTROL CENTRE
MCF	MITSUBISHI CHOPSTICK FACTORY
MCG	MCGREGOR RIVER DIVERSION
MCH	MCNAIR CREEK IPP
MCK	MCCULLOCH CREEK
MCL	MICHEL SUBSTATION
MCM	MCMAHON COGENERATION PLANT
MCO	CARIBOU MOUNTAIN REPEATER VHF/UHF
MCP	MILLER CREEK POWER
MCR	MISERY CREEK GENERATING STATION
MDF	MEDIUM DENSITY FIBRE PLANT
MDH	MACDONALD RANCH
MDN	MERIDIAN SUBSTATION
MDR	MICA DUTCHMAN RIDGE (VHF) REPEATER
MDS	MOLYBDENUM SUBSTATION
MER	MEZIADIN REPEATER
MEZ	MEZIADIN SUBSTATION
MFE	MORFEE SUB (ALEXANDRA)
MGT	MARGUERITE SUBSTATION
MHA	MOUNT HALL (ADAS) REPEATER
MHX	METHANEX CORPORATION
MID	MAYNE ISLAND DEPOT
MIN	MINETTE SUBSTATION
MIS	MISSION SUBSTATION
MKS	MICA/KOOTENAY COMMUNICATION SYSTEM
MLC	MICA LITTLE CHIEF SLIDE (VHF) REPT.
MLN	MCLELLAN SUBSTATION
MLR	MICA LITTLE CHIEF RIDGE (VHF) REPT.
MLS	MCLEESE CAPACITOR STN.
MML	MOUNT MILLIGAN MINE PROJECT

MMR	MOUNT MORSE REPEATER
MMS	MCLEESE MICROWAVE STATION
MNC	Mount Cook
MNM	MAYNARD MOUNTAIN (VHF)
MNR	MONROE (BPA)
MNX	METHANEX CORPORATION - See MHX
MO1	MOBILE SUB NO.1
MO2	MOBILE SUB NO.2
MO3	MOBILE SUB NO.3
MO4	MOBILE SUB NO.4
MOM	MONKMAN
MON	MONASHEE SUBSTATION
MOR	MORRISSEY MTN. ANPRODOME (VHF) RPTR
MOS	METRO STATION
MPH	MCPHEE
MPN	MCPHERSON ANPRODOME (VHF) REPEATER
MPY	MURPHY CREEK DEVELOPMENT
MRE	MORFEE MOUNTAIN MICROWAVE STN.
MRF	RENAMED 'BKY' BUCKEYE CANADA INC.
MRG	MAPLE RIDGE SUBSTATION
MRR	MORRISSEY RIDGE MICROWAVE STATION
MRT	MERRITT SUBSTATION
MS2	MISSION 2
MSA	MALASPINA SUBSTATION
MSF	MILE 64 (VHF) REPEATER
MSN	MISSION MOUNTAIN MICROWAVE STATION
MSV	MOUNT SAVONA MICRO. REPEATER
MSZ	MISSEZULA MOUNTAIN (VHF) REPEATER
MTB	MOBILE TRANSFER BUS
MTD	MOUNT DOUGLAS
MTE	MONTE LAKE SUBSTATION
MTG	MONTAGUE TERMINAL
MTH	MOUNT HALOWELL
MTL	METALINE - BONNEVILLE
MTM	MOUNT MURRAY (VHF) REPEATER
MTN	MILLIGAN MOUNTAIN SUBSTATION
MTO	MINTO MICROWAVE REPEATER STN.
MTP	MOUNT POLLEY
MUA	MURRIN #2 SUBSTATION (SWITCHYARD)
MUR	MURRIN #1 SUBSTATION
MVL	MARYSVILLE SUBSTATION
MVR	MOREHEAD VALLEY RANCH HYDRO INC.
MWA	MOUNT WARBURTON PIKE
MWG	MERRILL WAGNER (WILLIAMS LK)
MWN	MCEWAN SUBSTATION
MYE	MOYIE SUBSTATION
MYI	MOYIE (VHF) REPEATER
MYR	MURRAY RIDGE (VHF)
NAE	NORTH AMERICAN ENERGY SYSTEMS CORP.
NAK	NAKUSP SUBSTATION
NAS	NASS REPEATER

NAZ	NAZCO REPEATER
NBF	NABOB FOODS
NCA	NORTH COAST PRODUCTION AREA
NCC	NORTHERN CONTROL CENTER
NCK	NECHAKO SUBSTATIOIN
NCR	NORTH COAST REGION
NCS	NORTHERN CUSTOMER SERVICE
NCT	NILE CREEK TERMINAL
NDA	NEW DENVER REPEATER STATION
NDN	NADEN (HMCS) SUBSTATION
NDR	NEW DENVER SUBSTATION
NDV	NEW DENVER MOUNTAIN TOP REPEATER
NEL	NEWELL SUBSTATION
NEX	NEXEN CHEMICALS CANADA LTD.(NANAIMO
NFD	NORTHFIELD SUBSTATION
NGL	SOLEX GAS LIQUIDS LTD. (WAS NGL)
NGS	NAKUSP - ARROW LAKE GAUGE STATION
NGT	NEWGATE SUBSTATION
NHS	NORTHWOOD HOUSTON SAWMILL
NIC	NICOLA SUBSTATION
NID	NORTH VI DISTRIBUTION
NIP	NORTH ISLAND POWER CORPORATION
NIR	NICOMEN REPEATER
NKA	NAKUSP REPEATER STATION
NKL	NICOMEKL SUBSTATION
NKM	NAKUSP MARINA SUBSTATION
NLN	NELSON TOWER
NLV	NECHAKO LUMBER VANDERHOOF
NLY	NELWAY SUBSTATION
NMN	NORTH MAYNE ISLAND RECLOSER
NMR	NINE MILE REPEATER
NMT	NEWMONT (RENAMED 'SCO' SIMILCO)
NNO	NANAIMO STORAGE YARD
NOR	NORGATE SUBSTATION
NOS	NETHERLANDS OVERSEAS SAWMILL
NRG	NEWSTECH RECYCLING COQUITLAM
NRS	NORTHERN REGION SUBSTATION
NSS	NANAIMO SAFETY SHOP
NTC	NEWSTECH RECYCLING COQUIT (SEE NRG)
NTL	NATAL SUBSTATION
NUR	NEWCASTLE RIDGE REPEATER SITE
NVR	NORTH VANCOUVER SUBSTATION
NWP	NORTHWOOD PULP AND PAPER
NWR	NEW WESTMINSTER SUB.
NXC	NEXEN CHEMICALS LTD. PARTNERSHIP
OCT	OCELOT - METHANEX (RENAMED MNX)
OFD	OLDFIELD SUBSTATION
OKR	OAKRIDGE RECTIFIER STATION
ORD	ORENDA
OSA	OOTSA LAKE (VHF)
OSP	OSPIKA

OVR	OLIVER
OXY	CANADIAN OXY
OYR	OYSTER RIVER SUBSTATION
PAC	PORT ALBERNI COGENERATION PROJECT
PAL	PORT ALBERNI SUBSTATION
PAM	PORT ALICE MILL
PAR	PARMIGAN CREEK
PAV	PAVILION SUBSTATION
PC1	PACIFIC CENTRE NORTH
PC2	PACIFIC CENTRE SOUTH
PCA	PATRICIA SUBSTATION
PCC	P&C NORTH (CONWAY)
PCH	POCAHONTAS (VHF)MICROWAVE STATION
PCI	PACIFIC CASCADE HYDRO INC.
PCN	PEACE CANYON G.S. (SITE #1)
PCP	PETRO-CANADA PRODUCTS.
PCT	PORT CLEMENTS SUBSTATION
PDR	PENDER ISLAND RECLOSER
PED	PORT EDWARD SUBSTATION
PEL	PEMBERTON LINE ROOM
PEM	PEMBERTON SUBSTATION
PEN	PENNASK ANPRODOME (VHF) REPEATER
PEX	PETRO CANADA TAYLOR (RENAMED 'MGP')
PFD	PANEL AND FIBRE DIVISION (CFP)
PGG	PRINCE GEORGE SUB
PGP	PRINCE GEORGE PULP & PAPER
PGS	PORT ALBERNI GENERATION PROJECT (renamed VIG)
PGT	PIONEER GRAIN TERMINAL(RENAMED JRI)
PHD	PACIFIC VENEER
PHI	PHILLIPS CANYON DEVELOPMENT
PHM	PORT HARDY MOUNTAIN.(VHF)
PHR	PENDER HARBOUR SUBSTATION
PHY	PORT HARDY SUB
PIK	PIKE LAKE SUBSTATION
PIN	PINGSTON GS (IPP)
PKL	PORT KELLS SUBSTATION
PKR	PARKER ISLAND TERMINAL
PLP	PRINCETON LIGHT & POWER SUBSTATION
PLT	PLATEAU MILLS
PMD	PORTAGE MOUNTAIN DEVELOPMENT (SEE GMS)
PML	PORT MCNEILL SUBSTATION
PMM	PTARMIGAN MOUNTAIN (VHF) REPEATER
PMS	PITT MEADOWS
PMT	PEMBERTON MOUNTAIN REPEATER
PND	PEND D'OREILLE RESERVOIR
PNE	PACIFIC NATIONAL EXHIBITION
PNP	POINT NO POINT REPEATER STN.
PNS	PINE STREET SUBSTATION
PNT	PATTERSON TOWER
POC	POCATERRA GENERATING STATION
POW	POWELL RIVER SUBSTATION

PPR	PACIFIC PRESS (renamed PNG)
PPS	PORTAGE PASS SUBSTATION
PRA	PUNTLEDGE RV. GAUGE 6
PRB	PUNTLEDGE RV. GAUGE 8
PRC	PARK ROYAL SHOPPING CENTRE
PRD	PRINCE RUPERT DISTRICT
PRF	PORTABLE RECTIFIER
PRG	PRINCE RUPERT GRAIN
PRI	PRINCETON SUBSTATION
PRK	PARKLAND (WAS KNOWN AS CK3)
PRN	PORT RENFREW
PRO	PROMONTORY MOUNTAIN (VHF) REPEATER
PRR	PROPHET RIVER VHF
PRS	PARSNIP (FINLEY FOREST IND)
PRT	PRINCE RUPERT THERMAL G.S.(SEE RPG)
PRW	PORT RENFREW REPEATER STN (VHF)
PSN	PARSON SUBSTATION
PSS	PRODUCTION SYSTEM STORE(STORE 4049)
PTC	PORT CLEMENTS SWITCHING STN.
PTH	PORT HARDY DIESEL G.S.
PTL	POWERTECH LABS (PREVIOUSLY RDL)
PTN	PTARMIGAN MOUNTAIN (VHF REPEATER)
PTO	PORTEAU SUBSTATION
PTR	POINT ROBERTS SUBSTATION
PTS	PINETTE & THERRIEN SAWMILLS
PUD	PUNTLEDGE INTAKE DIVERSION DAM
PUN	PUNTLEDGE G.S.(COMOX DAM)
PUR	PURCELL POWER PROJECT
PVG	PRINCE GEORGE VEHICLE GARAGE
PVL	PARKSVILLE SUBSTATION
PVN	PEAVINE (VHF)
PVO	PREVOST SUBSTATION
PVW	PINEVIEW SUBSTATION
PWP	PEACE WOOD PRODUCTS
QCC	QUEEN CHARLOTTE CITY
QCH	QUEEN CHARLOTTE ISLAND DIESEL GEN.
QCI	QUEEN CHARLOTTE ISLAND REGION
QCP	QUEEN CHARLOTTE POWER CORPORATION
QIN	QUINSAM RIVER AT ARGONAULT BRIDGE
QLB	QUALICUM BEACH TERM. (RENAMED NCT)
QLC	QUALICUM BEACH SUBSTATION
QNL	QUESNEL SUBSTATION
QNR	QUINSAM RIVER FISH FLOW
QNT	QUINTETTE
QRP	QUESNEL RIVER PULP
QSM	QUINSAM MINES
QUD	QUINSAM DIVERSION DAM
QUI	QUINSAM RIVER DIVERSION
RBF	RED BLUFF SUBSTATION
RBK	ROBERTS BANK PORT DEVELOPMENT
RBL	RAINBOW LAKE

RBV	ROBSON VALLEY POWER
RBW	RAINBOW SUBSTATION
RCK	ROCK CREEK ANPRODOME (VHF) REPEATER
RDL	RESEARCH & DEVELOPMENT LAB (SEE PTL)
RDM	RADIUM SUBSTATION
REE	REES CREEK
REP	REVELSTOKE PASSIVE
REV	REVELSTOKE G.S. (aka - Columbia River Revelstoke)
RIM	RICHMOND SUBSTATION
RLD	RUTLAND (WKP)
RMB	RUMBLE BEACH IPP
RMH	RICHMOND HOSPITAL
RO2	ROYAL NO.2 SUBSTATION
RON	RONAYNE REPEATER
ROS	ROSEDALE SUBSTATION
ROY	ROYAL OAK
RPG	PRINCE RUPERT G.S.
RPT	ROCKY POINT
RRK	RED ROCK MICROWAVE STN.
RSC	RIVERSIDE,SODA CREEK MILL
RSR	RICHMOND STEEL RECYCLING
RSW	RIVERSIDE AT WILLIAMS LAKE
RTI	RIDLEY TERMINALS INCORPORATED
RUP	RUPERT SUBSTATION
RUS	RUSKIN GENERATING STATION
RUT	RUTHERFORD CREEK IPP
RVS	RIVERSIDE FOREST PRODUCTS
RVW	RIVERVIEW SUBSTATION
RY1	RAYONIER #1
RY2	ROYAL SUBSTATION NO. 2 (SEE RO2)
RYC	RUBY CREEK SUBSTATION
S12	STORE 12
S2S	SOOKE NO.2 SUBSTATION
SAI	SALMON INLET I.P.P. (RENAMED SCG)
SAL	SALTSPRING SUBSTATION
SAM	SALMON ARM SUBSTATION
SAN	SAN JUAN REPEATER
SAR	SALMON RIVER DIVERSION DAM
SAT	SAHTLAM SUBSTATION
SBH	SHUTTY BENCH
SBR	SPENCES BRIDGE SUBSTATION
SC2	SCOTT PAPER MISSION
SCA	STRATHCONA G.S.
SCC	SYSTEM CONTROL CENTRE
SCG	SECHELT CREEK GENERATING STATION
SCI	SCAIA MICROWAVE REPEATER STN.
SCK	SODA CREEK SUBSTATION
SCM	SICAMOUS SUBSTATION
SCN	SURREY CONSTRUCTION
SCO	SIMILCO SUBSTATION (PREV. 'NMT')
SCP	SCOTT PAPER

SCS	SURREY SERVICE CENTRE SITE SERVICES
SCT	SCOTT SUBSTATION
SCZ	SCUZZY CREEK G.S.
SDM	SHOULDER MOUNTAIN (VHF)
SDS	SARDIS
SEA	SEA ISLAND SUBSTATION
SEC	SECHELT SUBSTATION
SEE	SEEGEN IPP
SEL	SELKIRK SUBSTATION
SEV	SEVEN MILE DEV. (PEND D OREILLE)
SEY	SEYMOUR ARM ANPRODOME (VHF)REPEATER
SFI	STAVE FALLS INTAKE GATE
SFL	STAVE FALLS GENERATING STATION
SFN	STAVE FALLS NEW GENERATING STATION
SFY	STAVE FALLS SWITCHYARD (see SFN)
SGD	GENERATION MTCE-SURREY
SGR	SUGAR LAKE (SHUSWAP FALLS G.S.)
SHA	SHAWNIGAN LAKE SUB.
SHD	SHEPPARD
SHE	SHELPAC (ELCO)
SHL	SHELLBURN SUBSTATION
SHN	SHELPAC (NATAL)
SHO	SHADOW RESERVOIR
SHP	SHEPHERD REPEATER
SHR	SHERATON MICROWAVE REPEATER STN.
SHU	SHUSWAP FALLS G.S.(WILSEY,SUGAR LKE
SIC	SOUTHERN INTERIOR CONTROL
SIG	SOUTH ISLAND GENERATION
SIL	SILVERDAISY
SIP	SALMON INLET POWER CORPORATION.
SIR	SALMON INLET MICROWAVE RPTR STN.
SIS	3 SISTERS REPEATER,TELECONTROL
SIT	SITE 1, (RENAMED 'PCN')
SKA	SKEENA SUBSTATION
SKC	SKEENA CRAFT
SKL	SKEENA CELLULOSE SUBSTATION
SKM	SKAGIT MTN REPEATER-DROPPED FROM PLAN
SKR	SKEENA RIVER REPEATER
SKT	SINKUT MICRO REPEATER STN.
SKU	SKOOKUMCHUCK SUBSTATION
SLC	SOUTH SLOCAN (WKP)
SLE	SALE MICROWAVE REPEATER STN.
SLK	STAVE LAKE CORRECTION CAMP
SLM	SALMON RIVER DIVERSION
SLN	SALMON RIVER DIV. NR CAMPBELL RIVER
SLR	SANDSPIT REPEATER
SLS	SUNDANCE LAKES
SMC	SEVEN MILE CONSTRUCTION (DISMANTLED
SMH	SEVENTY MILE HOUSE SUBSTATION
SMO	SALMO REPEATER,TELECONTROL
SMR	SOUTH MAYNE ISLAND RECLOSER

SMS	SUMAS MOUNTAIN MICROWAVE STATION
SMW	SUMAS WAY SUBSTATION
SNE	SANSUM NARROWS ELECTRODE
SNK	SUKUNKA SWITCHING STATION
SNP	STIKINE NATION POWER CORPORATION
SNY	SIDNEY SUBSTATION
SOK	SOUTH OKANAGAN SUB. (renamed VAS)
SON	SETON GENERATING STATION
SOO	SOOKE SUBSTATION
SOR	SOO RIVER I.P.P.
SPA	SPERLING ANNEX RECTIFIER STATION
SPC	STERLING PULP CHEMICALS (renamed ERW)
SPD	SPARWOOD SUBSTATION
SPG	SPERLING SUBSTATION
SPH	SPANISH MOUNTAIN (VHF)
SPL	STEEPLES SUBSTATION
SPN	SPILLIMACHEEN G.S.
SPR	SPROAT ANPRODOME (VHF) REPEATER
SPT	SANDSPIT D.G.S.
SQA	SQUAMISH CHLOR ALKALI
SQH	SQUAMISH SUBSTATION
SRF	SETON RECREATION FACILITY
SRG	SLOCAN RIDGE MICROWAVE REPEATER STN
SRR	SALOOMPT MOUNTAIN REPEATER VHF/UHF
SRS	SMITHERS SUBSTATION
SRY	SURREY SUBSTATION
SSA	SILVER STAR ANPRODOME (VHF) REPEATER
SSM	SEVENTY-SIX MILE HOUSE
SSR	SILVER STAR MICROWAVE REPEATER STN.
SSS	SYSTEM SPARE STORAGE FACILITY
SSY	SOUTH SURREY REPEATER SITE
STA	SATURNA RECLOSER
STC	SITE C DEVELOPMENT (PEACE RIVER)
STG	STEWART (DGS) ... PLEASE SEE 'STW'
STH	SPLINTER HILL REPEATER
STI	STIKINE RIVER DEVELOPMENT
STK	STIKINE DISTRICT
STL	SPATSUM-LORNEX
STN	STRATHCONA REPEATER STN.
STO	SORRENTO SUB.
STP	STEEL BROTHERS (PAVILLION)
STR	STAVE FALLS RECREATION FACILITY
STS	STAVE LAKE SUBSTATION
STV	STEVESTON SUBSTATION
STW	STEWART SUBSTATION
SUA	SUGAR LAKE (VHF) REPEATER
SUT	SUTTON REPEATER
SVA	SAVONA SUB (230 KV T/S)
SVG	SURREY VEHICLE GARAGE
SVH	SEVEN HILLS REPEATER STATION
SVS	SILVERSMITH P&L

SVY	SALMON VALLEY SUBSTATION
SWL	SWAN LAKE (VHF) REPEATER
SWP	SASKATCHEWAN WHEAT POOL
SYH	STRAWBERRY HILL SUB.
SYP	SURREY PLACE SHOPPING CENTRE
SZM	SPUZZUM SUBSTATION
TAC	TACHICK SUBSTATION
TAH	TAHSIS PULP MILL (RENAMED GRP)
TAK	TAKAMA FOREST PRODUCTS
TAU	TRANS ALBERTA UTILITIES
TAY	TAYLOR SUBSTATION
TBI	TILBURY ISLAND
TBN	TIMBERNORTH (MACKENZIE)
TBR	TABOR MICROWAVE STN.
TBT	TSAWWASSEN BEACH TERMINAL
TBW	TIMBERWEST (MACKENZIE)
TBY	TAYLOR BAY TERMINAL
TCK	TELEGRAPH CREEK D.G.S.
TCL	TILBURY CEMENT LTD.
TCR	TELEGRAPH CREEK REPEATER
TEL	KITCHENER TELECONTROL
TER	TERRACE SUBSTATION
TFM	TELECOM FACILITIES MANAGEMENT
TFP	TAKLA FOREST PRODUCTS,FORT ST.JAMES
TFS	TOFINO SUBSTATION
TGD	TERRACE GENERATION DIESEL.
THC	THORNHILL CREEK GENERATING STATION
THR	THUNDER MOUNTAIN REPEATER SITE
THY	THYESTES REPEATER
TII	TREE ISLAND INDUSTRIES
TIL	TOLKO INDUSTRIES LTD. - LAVINGTON
TIM	TIMOTHY MICROWAVE STATION
TIR	TEXADA ISLAND REACTOR
TIS	TISDALL SUB STORAGE YARD
TKA	TAKLA LAKE (VHF)
TKC	TELKWA COAL
TKL	TAKLA LANDING
TKP	TELKWA PASS TELEMETRY
TKR	TELKWA REPEATER
TKW	TELKWA SUBSTATION
TLR	TUMBLER SUBSTATION
TMM	TRANS MOUNTAIN OIL MCMURPHY
TMO	TRANS MOUNTAIN OIL VEDDER
TMT	TRANS MOUNTAIN OIL KAMLOOPS
TMW	TRANS MOUNTAIN OIL WAHLEACH
TNO	TELECOM NETWORK OPERATIONS
TOK	TOLKO INDUSTRIES - HEFFLEY Creek Div.
TOM	MOUNT THOMPSON SEISMOGRAPH (VHF)REP
TPH	TELKWA PASS D.C.P.
TPL	TRAPLINE MICROWAVE REPEATER STN.
TPY	TOPLEY SWITCHING STN.

TRH	THORNHILL SUBSTATION
TRI	TRIUMPH (RENAMED 'UNS')
TRN	TRINCOMALI TERMINAL
TRR	TAYLOR RIVER REST AREA
TRZ	TERZAGHI DAM-IN BRIDGE RIVER COMPLX
TSC	TERRACE SKEENA CELLULOSE
TSK	BLACK TUSK MICROWAVE STATION
TSL	TSABLE REPEATER
TSM	TAHSIS SAWMILL
TSO	TSOLUM RIVER NR COURTENAY
TSS	TADANAC (WKP)
TSV	TAHSIS VILLAGE SUBSTATION
TSW	TSAWWASSEN SUBSTATION
TTC	TERRACE TELECONTROL
TUK	TUKTAKAMIN MICRO REPEATER STN.
TWN	TOWNSITE-CBK(CRANBROOK) (PREV. KM4)
TXB	TEXACO (BOUNDARY LAKE)
TXE	TEXADA ISLAND EAST CABLE TERMINAL
TXL	TYAX LAKE SUBSTATION
TXW	TEXADA ISLAND WEST CABLE TERMINAL
TYN	THYNNE MICROWAVE REPEATER STN.
UCL	UPPER CAMPBELL RESERVOIR
UCO	UCONA RIVER
UCV	UPPER COLUMBIA VALLEY
UFR	UPPER FRASER SUB.
UMH	UPPER MAMQUAM IPP
UNS	SOUTH CAMPUS (TRIUMPH)
UTA	UTAH MINE
VAC	VERNON ARMY CAMP REPEATER STATION
VAL	VALEMOUNT DIESEL (DISMANTLED)
VAS	VASEUX LAKE TERMINAL STATION
VBM	VAVENBY MOUNTAIN (VHF) REPEATER
VBY	VAVENBY SUBSTATION
VCC	VERNON CONTROL CENTRE
VCR	VICTORIA REPEATER
VCT	VANCOUVER ISLAND TERMINAL REPEATER
VDC	VANCOUVER ISLAND DC TERMINAL
VDF	VANDERHOOF SUBSTATION
VDK	VANCOUVER DRY DOCK COMPANY LTD.
VES	VANCOUVER ENERGY SYSTEMS.
VGP	VICTORIA GAS PLANT
VIC	VANCOUVER ISLAND CONTROL
VIT	VANCOUVER ISLAND TERMINAL
VLM	VALEMOUNT 138 KV
VNA	VANANDA
VNT	VERNON TERMINAL
VPD	VICTORIA POWER DISTRICT
VPE	VANCOUVER POLICE DEPT/BCH EMERGENCY
VVW	VALLEYVIEW SUBSTATION
WAB	WABI MOUNTAIN (VHF) REPEATER
WAH	WAHLEACH GENERATING STATION

WAN	WANETA GENERATING STATION
WAX	WANETA EXPANSION
WBK	WESTBANK SUBSTATION
WCE	WESTCOAST ENERGY (RENAMED WEI)
WCF	WESTCOAST CELLUFIBRE INDUSTRIES
WCS	WESTERN CANADA STEEL
WCT	WEST COAST TAYLOR (RENAMED 'NGL')
WCV	WINTER COVE
WDN	WALDEN NORTH
WDS	WOODS LAKE SUBSTATION
WDW	WELDWOOD (METRO)
WEI	WESTCOAST ENERGY
WEL	WELLS REPEATER STATION
WES	WESTAR MINING LIMITED (RENAMED KC1)
WEY	WEYERHAEUSER PULP MILL STATION
WFN	WEST COAST TRANSMISSION
WFQ	WEST FRASER SAWMILL
WFR	WOODFIBRE - WESTERN PULP LTD.
WGS	WHATSHAN G.S.
WHL	WHATSHAN LAKE
WHN	WALTER HARDMAN G.S.
WHY	WHALLEY SUBSTATION
WI1	WESTERN INTEGRATED #1
WIG	WAHLEACH JONES LAKE-INTAKE GATE
WIL	WILSEY DAM
WIN	WINSOR SUBSTATION
WIT	WESTERN INTEGRATED TECHNOLOGY
WL2	WILLIAMS LAKE NO.2
WLB	WILLIAMS LAKE BASE STATION
WLF	WOLFENDEN MTN. REPEATER SITE
WLM	WILLIAMS LAKE SUBSTATION
WLT	WALTERS SUBSTATION
WMR	WAHLEACH REPEATER SITE
WMS	WESMAN STEWART
WNK	WHONNOCK SUBSTATION
WNR	WESTMIN RESOURCES
WOK	WOKAS LAKE PEAK REPEATER
WOL	WOLF RIVER
WOS	WOSS SUBSTATION
WP1	WESTPORT INNOVATIONS 1
WP2	WESTPORT INNOVATIONS 2
WPM	WEST PINE MED.DENSITY FIBRE
WPN	WEST PINE MDF PLANT
WPS	G.V. WATER DIST. CAPE HORN PUMP STN
WQL	WELDWOOD (QUESNEL)
WRK	WHITE ROCK SUBSTATION
WSE	WESTERN STATE ELECTRIC DISCONNECT
WSM	WOSS MOUNTAIN (VHF)
WSN	WILLISTON SUBSTATION
WSP	WESCUP SUBSTATION
WSR	WOSS

WSS	WARFIELD (WKP)
WST	WEST STODDART PLANT
WTB	WARTENBE (VHF) REPEATER (SEE WAB)
WTL	WESTSHORE TERMINALS LTD.
WVN	WOLVERINE (VHF)
WWD	WESTWOLD SUBSTATION
WWI	WESTAR WATSON ISLAND (RENAMED SKL)
WWL	WELDWOOD (WILLIAMS LAKE)
WWQ	WELDWOOD (QUESNEL) #2
YAL	YALE MICROWAVE REPEATER STN.
YAR	YARROWS
YHD	YELLOWHEAD SUBSTATION
YRK	YORK SUBSTATION
YVR	VANCOUVER INTERNATIONAL AIRPORT
ZZC	ZZ CREEK (renamed to MEA - Mears Creek)

APPENDIX 3

CAPITAL PROJECT MAPS

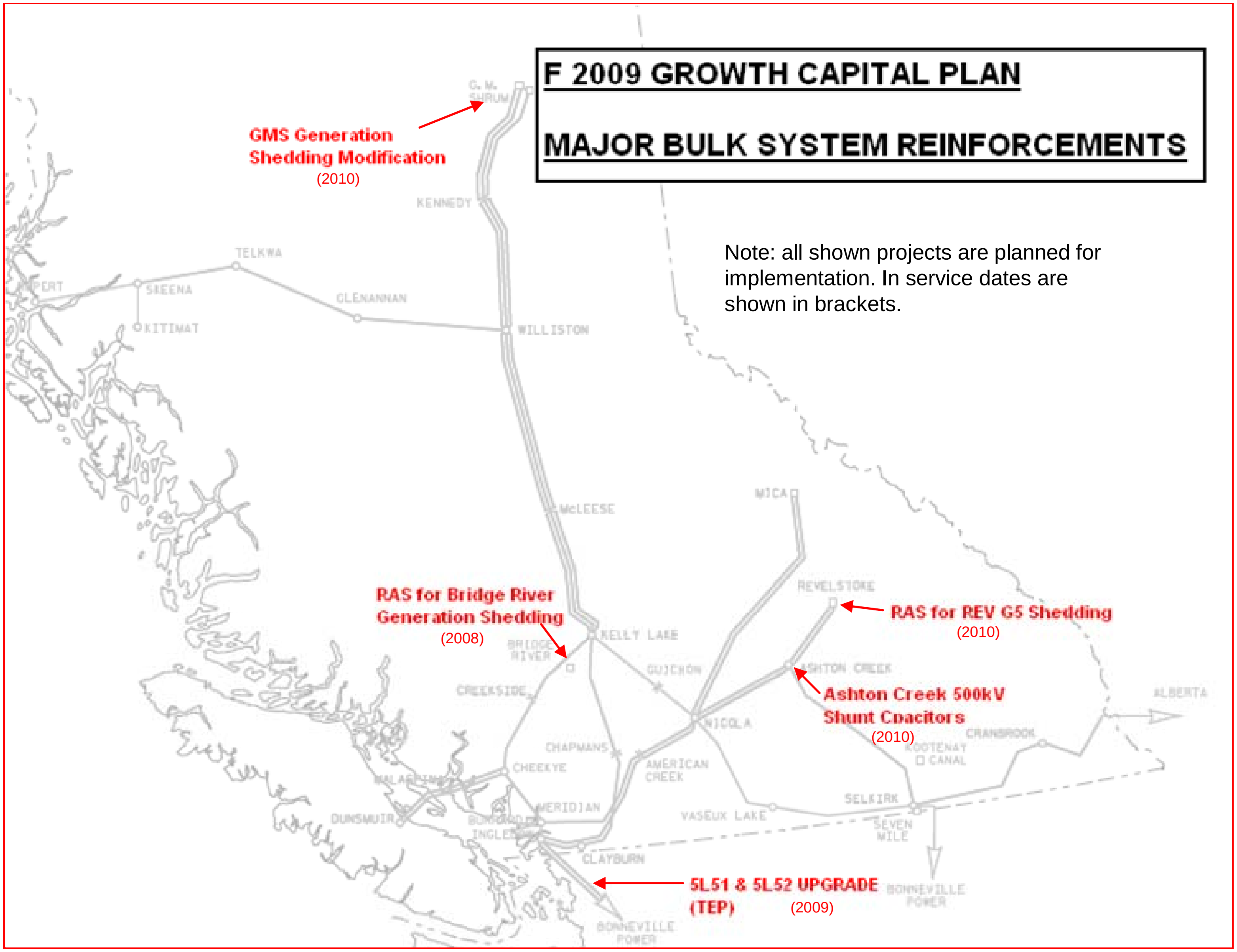


Fig A3 - 1 Growth Projects Planned for the Bulk System

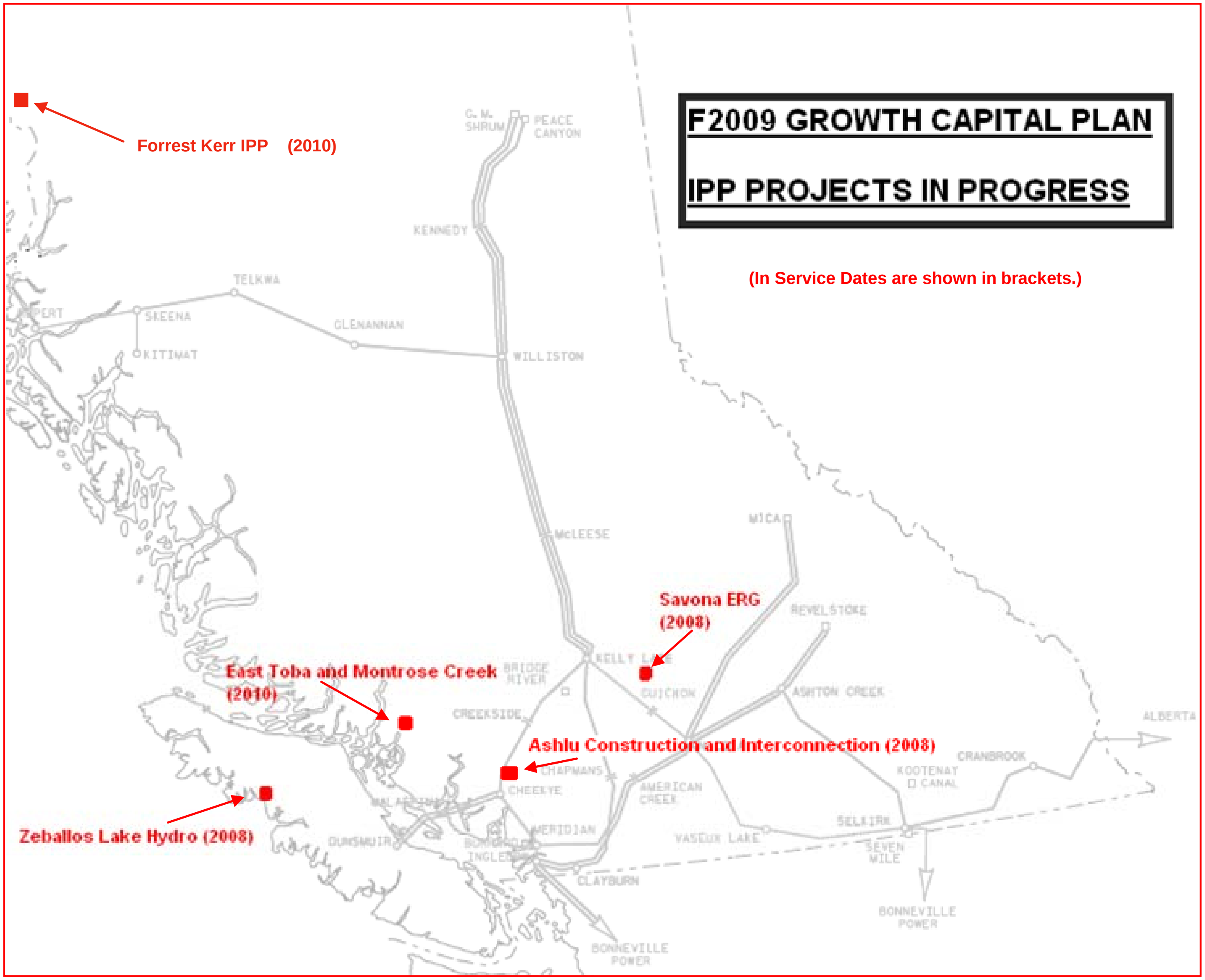


Fig A3 – 2 IPP Projects in Progress

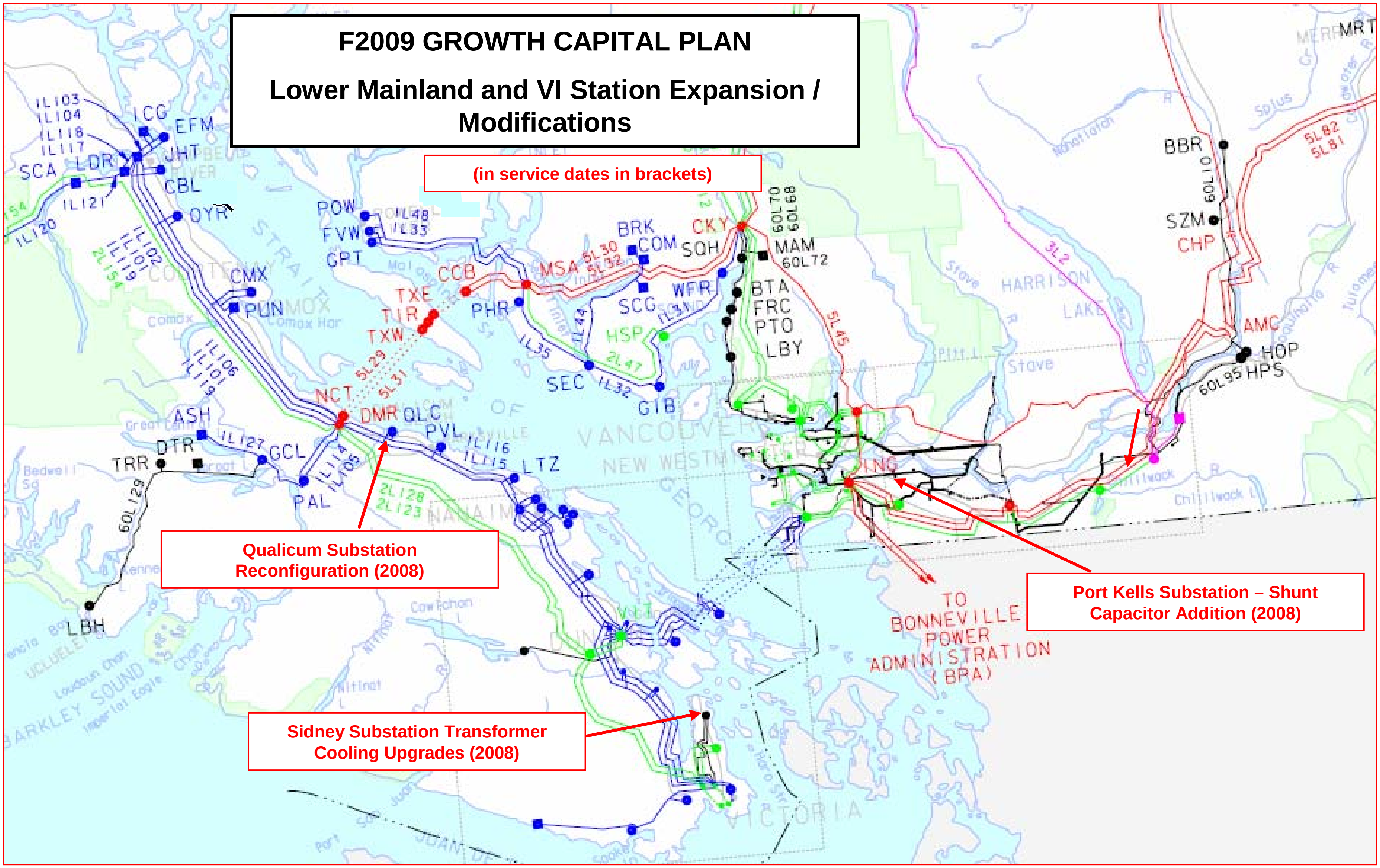


Fig A3 - 3 Lower Mainland and Vancouver Island Station Expansion / Modification Projects

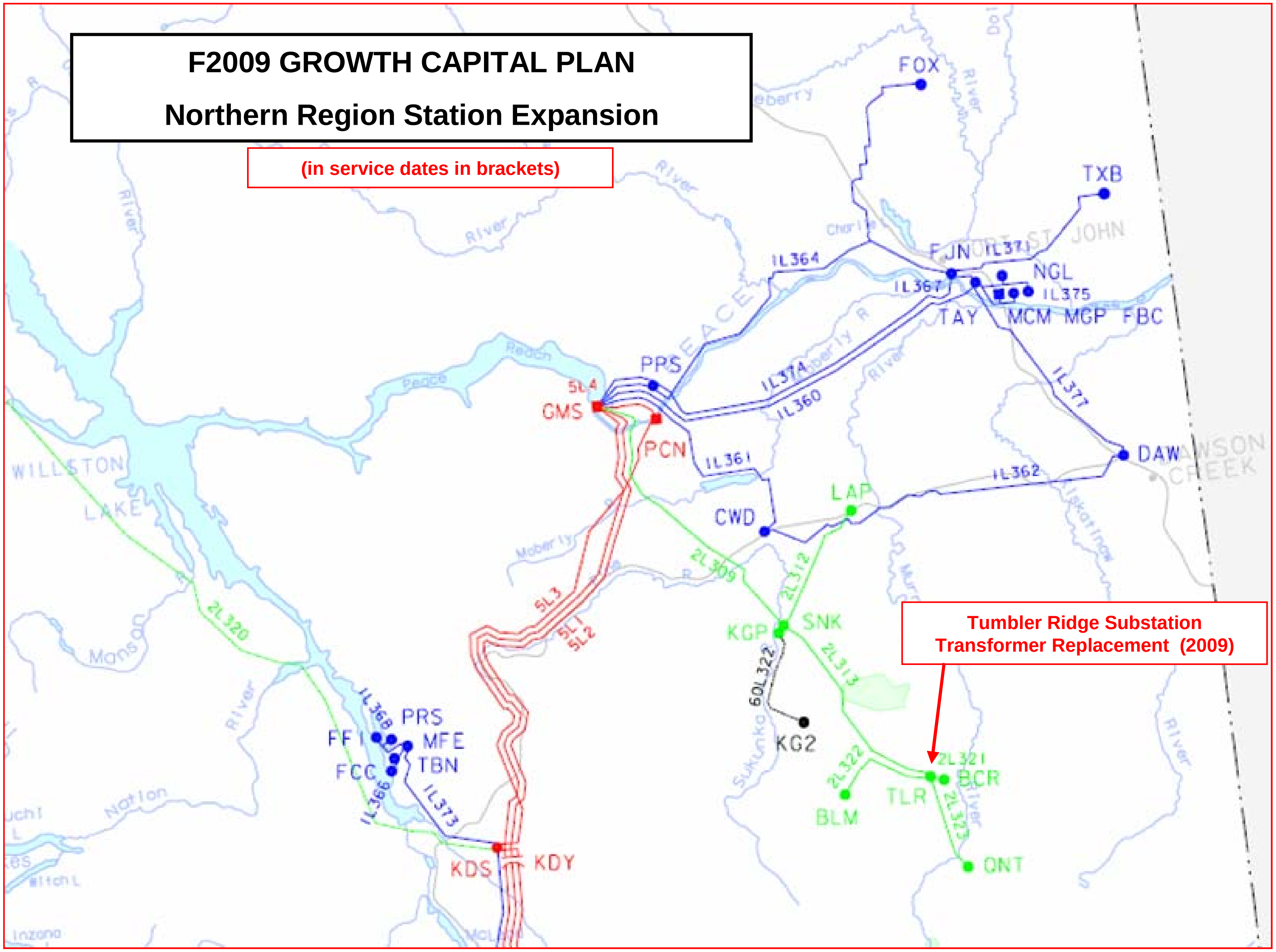


Fig A3 - 4 Northern Region Station Expansion Project

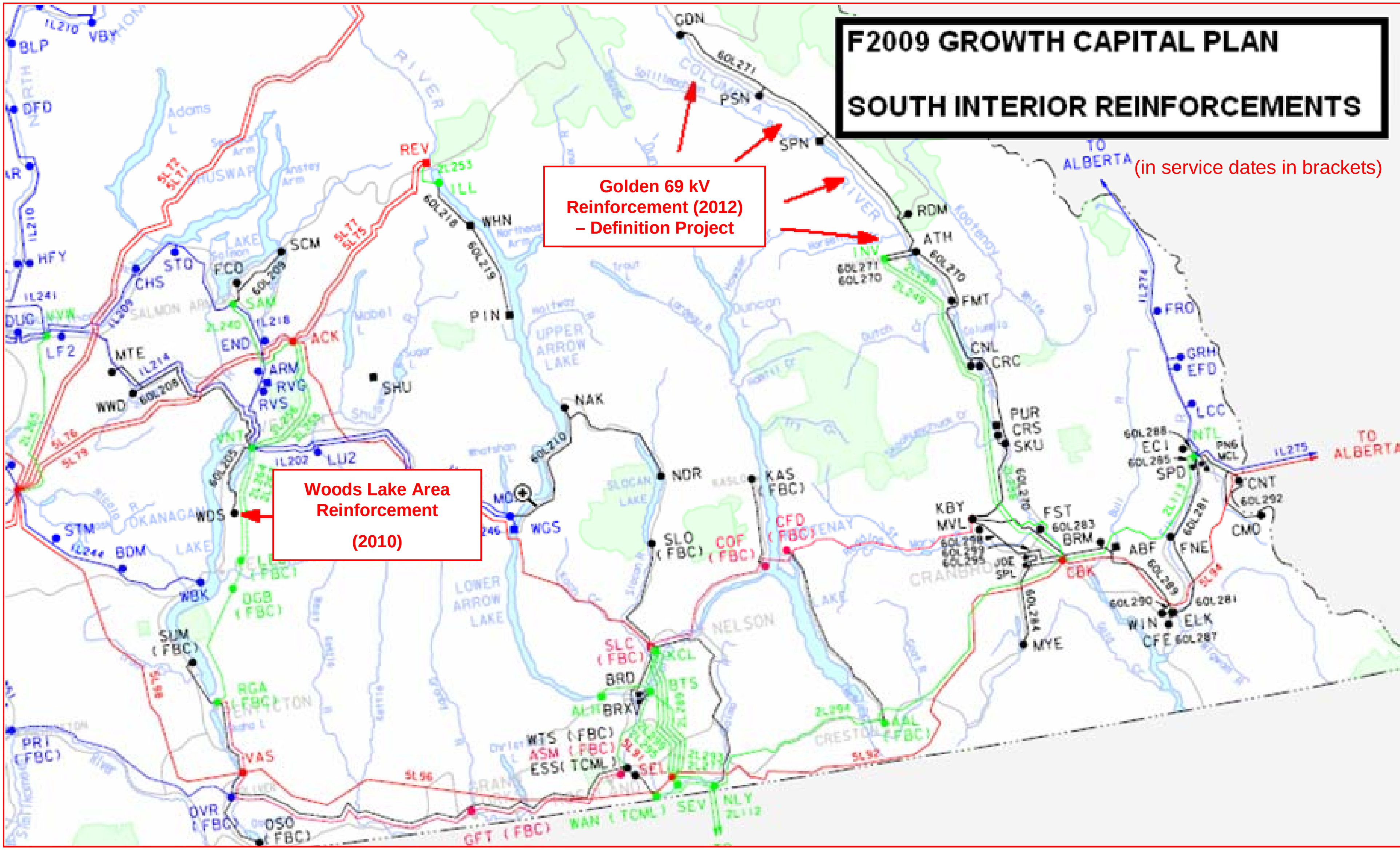


Fig A3 - 5 South Interior Regional System Reinforcement Projects

Appendix C

Growth Planning Standards

1 GROWTH PLANNING STANDARDS

BCTC is a member of the Western Electricity Coordinating Council (WECC), which is a regional member of the North American Electric Reliability Council (NERC). BCTC plans and operates the transmission system in accordance with NERC planning and operating standards, augmented by WECC. The NERC/WECC Planning Standards establish the criteria within which members plan and operate their systems. Regional differences (economics, geography, weather, etc.) often dictate that more detail is required in each utility's planning and operating criteria, which direct their individual planning while still conforming to the NERC/WECC Planning Standards.

In the aftermath of the August 2003 blackout in the northeast, NERC has undertaken to update and augment its Planning Standards and Operating Policies into new NERC Reliability Standards. Under the FERC directions, these new standards became mandatory in the United States in June 2007. WECC may suggest NERC add more mandatory standards to address WECC concerns. BCTC is currently reviewing the NERC Reliability Standards, and plans to file a BCTC Reliability Standards document with the Commission in the spring of 2008.

BCTC applies the NERC/WECC Planning Standards to ensure reliability in the planning of the transmission system. NERC defines reliability as comprising both adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The NERC/WECC Planning Standards detail the system performance criteria used to address these two objectives. These criteria are based on many years of experience by utilities across North America as to the general level of reliability expected by customers, relative to the cost of achieving this reliability. These criteria also take into consideration that operators will require time to adjust their systems to a secure operating condition following a system event. Protection systems and Remedial Action Schemes are often required to meet these criteria.

The BC transmission system is interconnected with three other systems: the Alberta Electric System Operator (AESO) to the east, Bonneville Power Authority (BPA) to the south, and FortisBC internally. WECC members have mutually agreed to apply performance standards with respect to the impacts that each system can have on its neighbours. Specifically, the WECC Planning Standards state:

> WECC Member Systems shall comply with the WECC Disturbance-Performance Table of Allowable Effects on Other Systems… To the extent permitted by NERC Planning Standards, individual systems or a group of systems may apply standards that differ from the WECC specific standards … for internal impacts. If the individual standards are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance. If these standards are more stringent, these standards may not be imposed on other systems. This does not relieve the system or group of systems from WECC standards for impacts on other systems.

The system performance requirements of the NERC/WECC Planning Standards are summarized in Table B-1. These standards, and BCTC's own standards, which together represent the performance requirements for the transmission system, are described in more detail in the following pages.

Table 1. Summary of NERC and WECC Planning Standards

	Event Category	Contingency Description	Mean Time Between Failure (Actual Category Performance)	Loss of Load or Curtailed Firm Transfers	Thermal Limits	Voltage Stabilit y	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
1	A	All facilities in service		All loads served.	All facilities within applicable ratings				
2	B	Includes most single contingencies (n-1)	0 to 3 years	No loss of firm loads except on radial systems and local networks served by the affected facility. System adjustments and curtailment of firm transfers permitted to prepare for the next contingency.	All facilities within applicable ratings	Voltage stable at 105% of path rating	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load busses.	Not below 59.6 Hz for 6 cycles or more at a load bus.	Not to exceed 5% at any bus.
3	C	Some single contingencies. Most double contingencies (n-2)	3 to 30 years	Planned/controlled interruption of loads, generators, and firm transfers permitted.	All facilities within applicable ratings	Voltage stable at 102.5% of path rating	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below 59.0 Hz for 6 cycles or more at a load bus.	Not to exceed 10% at any bus.
4	D	Some double contingencies initiated by very low probability events. Some multiple contingencies (>n-2). Multiple contingencies	30 to 300 years Greater than 300 years	No cascading loss of loads. Evaluate for risks and consequences Evaluate for risks and consequences	Evaluate for risks and consequences				

1.1 Thermal Limits

Excessive current flowing through a transmission line will heat the conductor and associated hardware to a temperature which can damage the conductor or cause it to sag too close to the ground, causing a public safety issue. Similarly, overloading of substation transformers, circuit breakers, and other equipment can damage this equipment, resulting in long outage times until this equipment can be repaired. To ensure that these conditions do not occur, the line current must be planned and operated to stay within the rated capacity.

The thermal ratings used for planning and operating purposes are specific to individual equipment characteristics, asset condition, and ambient conditions. Individual circuit and equipment ratings are used in all planning studies. In some cases, short-term overload ratings are established. These allow the operator to maintain schedules for a reasonable length of time after an outage to implement remedial action measures or to re-dispatch generation and avoid having to immediately limit the transfer because of thermal restrictions.

1.2 Voltage Limits and Voltage Stability

The transmission system must be able to maintain acceptable voltages after the failure of one or more elements. Immediately following a system disturbance voltages will swing as the system readjusts to a new stable operating point. Once the system has stabilized, operating voltages will normally be different than prior to the disturbance. Excessive voltage deviations may cause voltage sensitive system elements and other customer equipment to disconnect from the system, or in some cases, damage to equipment.

Voltage stability is the ability of the transmission system to settle at a stable voltage after the failure of system element(s). An unstable system would demonstrate voltage collapse at the receiving end of the system (load end), which would lead to local load loss and could lead to widespread blackouts. Very low voltages can damage equipment, such as motors, due to overheating caused by the resulting high current flow.

To achieve voltage stability, sufficient reactive power sources need to be available to serve the pre-disturbance reactive load plus the extra reactive power required following the loss of the transmission element(s) in a system disturbance. Reactive power is not suitable to be transferred over long distances, and it is preferable to provide reactive resources distributed throughout the system under normal conditions. Voltage levels are managed with equipment such as capacitors, reactors, static VAr compensators (SVC), and other types of reactive equipment. Generators also provide reactive power that is used to control voltages on the system.

1.3 Underfrequency Limits (Minimum Transient Frequency Standard)

Frequency deviations occur following system disturbances. The WECC system is operated at a frequency of 60 Hz. Immediately following a disturbance, frequencies will vary until the system adjusts to a new stable operating point. As the total connected generator output changes in response to the disturbance, the system frequency will gradually return to 60 Hz.

One of the WECC standards establishes a limit on the dip in frequency for various contingencies. BCTC has adopted, for internal impacts only, a less stringent standard than the WECC standard. This exception is solely for the loss of the BC to US interties when importing from the US. This decision was made because adoption of the WECC standard (for internal purposes) would result in a significant reduction to the historical import limit of 2000 MW from the US. The risk of this event actually occurring is very low and the consequence of this greater frequency dip is acceptable. The trigger event for this underfrequency risk is a double circuit outage on the short interconnections between Vancouver and Blaine, Washington. Furthermore, BCTC can selectively reduce the import limit during higher-risk conditions (e.g., lightning activity in a geographic area that could lead to this contingency) to mitigate the risk of the underfrequency dip. Based on discussions with its Alberta and BC stakeholders, BCTC chose the minimum allowable frequency dip to be 58 Hz within the BC system. This is one Hz lower than the WECC standard of 59 Hz. WECC recommends that it is prudent to prevent dips from falling below 58 Hz. BCTC continues to meet the WECC standard of 59 Hz in terms of impacts on its neighbours.

1.4 Transient and Dynamic Stability

Transient stability is the condition in which, following a system disturbance, a generator or group of generators will return to pre-disturbance rotational speed and will not lose synchronism with the integrated system. Transient stability depends upon the physical characteristics of the generators themselves, the controls and excitation systems on these generators, their connections to the system, and the whole power system.

After a disturbance, the generators' output in one area will oscillate against the generators' output in other parts of the large area interconnected system. The interconnected system must have sufficient damping so that power oscillations dissipate quickly and the system remains dynamically stable. WECC requires installation and use of power system stabilizers on individual generating units to provide this damping.

1.5 Safety Nets

The power system, with many interconnected facilities in different geographic areas, is occasionally challenged by unexpected combinations of operating conditions and multiple disturbances. To mitigate the potential impact of these types of disturbances, BCTC has put in place various "safety nets". Some of these safety nets are WECC requirements, while others have been put in place at BCTC's initiative. Examples of such safety nets follow.

1.5.1 Underfrequency Load Shedding

WECC has identified the amount of load and the underfrequency trip levels which should be incorporated in an underfrequency load-shedding program. The purpose of this "safety net" is to deliberately trip loads during a severe underfrequency situation, the outcome of which is that the frequency in that area should increase towards the required 60 Hz.

1.5.2 No Generation Shedding for Single Contingency Events

BCTC's policy is to avoid the use of generation shedding for first contingency events, when all facilities are in service. This is based on a number of factors including:

(a) Impact on generation equipment – Excessive generation shedding can lead to advanced ageing of the generator units.

(b) Generation shedding for single contingencies on the transmission system compromises system reliability and could impact capacity reserve requirements.

(c) Generation shedding reduces the flexibility for generation dispatch.

(d) A deferral of system reinforcements by using generation shedding forgoes the benefits that can occur from reinforcements in one part of the system providing secondary benefits in another part of the system.

Some exceptions to this general policy are made if the amount of shedding is less than the largest unit on the transmission system, and the required investment to avoid the shedding cannot be justified.

BCTC will accept generation shedding for a double contingency and for a single contingency if one element is already out of service. BCTC has adopted this policy so that the transmission system is more robust and is able to depend on generation shedding for less common and more severe events.

1.5.3 Over-Voltage Line Tripping

The transmission system has many expensive pieces of equipment that can be damaged by excessive voltages. For example, underground cables in Metro Vancouver and the submarine cables to Vancouver Island can be severely damaged if exposed to excessively high voltages. Because of this, a staged protection scheme has been implemented which trips 500 kV lines at specific increasing levels of over-voltage. This system is intended to backup other specific measures that are taken to control voltages to acceptable levels for well-defined contingencies that may occur on the system.

Tripping a single line reduces system voltages due to two phenomena. First, because 500 kV lines have some capacitance which tends to support system voltages, the removal of a line will reduce a source of capacitive reactive power and the voltage will fall somewhat. Second, tripping one line also increases the reactive power demand by putting more current onto the remaining lines. The demand for reactive power is proportional to the square of the current on the remaining lines and this is a non-linear effect. Consequently, the reactive power required to maintain a given level of voltage is higher after a line trips than it was before and the sources of reactive power are lower. The net result of these two phenomena is that the voltage stabilizes at a lower value than it had before the line tripping occurred. One alternative to the reliance on line tripping is to install additional reactors on the system.

BCTC's planning policy is that the line over-voltage protection scheme shall not be triggered when the system responds to a single (N-1) or double (N-2) contingency. To effect this standard, BCTC requires that sufficient voltage control equipment be installed so that the 500 kV lines do not trip on over-voltage protection for N, N-1, or N-2 contingencies.

Appendix D

Risk Matrices

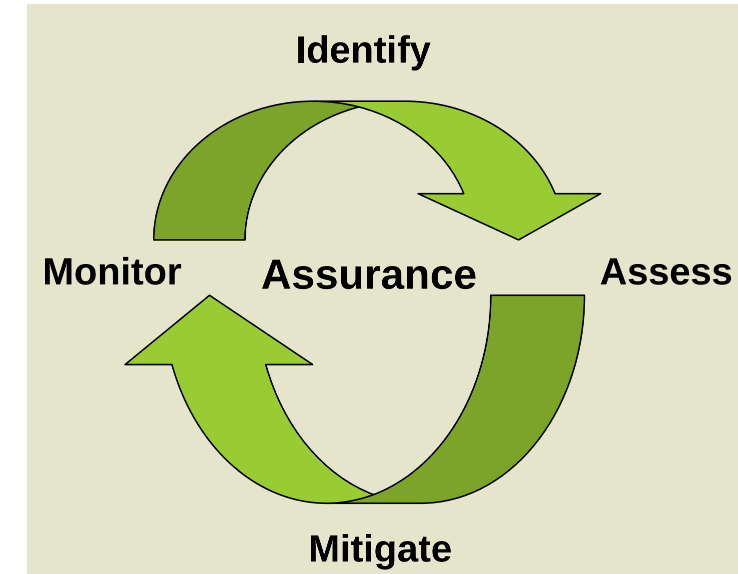
BCTC Corporate Risk Matrix

LIKELIHOOD GUIDELINES	LIKELIHOOD OF OCCURRENCE						
90%	(9 in 10) or greater likelihood that event will occur within next year.	5	Moderate	Moderate	High	Extreme	Extreme
50%	(1 in 2) or greater likelihood that event will occur within next year.	4	Guarded	Moderate	High	Extreme	Extreme
10%	(1 in 10) or greater likelihood that event will occur within next year.	3	Guarded	Moderate	Moderate	High	Extreme
1%	(1 in 100) or greater likelihood that event will occur within next year.	2	Low	Guarded	Moderate	Moderate	High
<1%	<1% (1 in 100) likelihood that event will occur within next year.	1	Low	Low	Guarded	Guarded	High
IMPACT CRITERIA			1	2	3	4	5
Safety			First aid injury/illness	Medical aid injury/illness	Lost time injury/ temporary disability	Permanent disability	Fatality (ies)
Financial			Impact totaling < $500,000	Impact totaling $500,000 - $1 Million	Impact totaling $1 Million - $5 Million	Impact totaling $5 Million - $10 Million	Impact totaling ≥ $10 Million
Reliability			One of: < 250,000 customers hrs lost or < 2 GWh of energy not served or delivered.	One of: 250,000 – 1 million customers hrs lost or 2 -7 GWh of energy not served or delivered.	One of: 1 - 3 Million customer hrs lost or 7 - 20 GWh of energy not served or delivered.	One of: 3 Million - 7 Million customer hrs lost or 20 - 50 GWh of energy not served or delivered.	One of: ≥ 7 Million customer hrs lost or ≥ 50 GWh of energy not served or delivered.
Market Efficiency			Customers and rate payers lodge complaints to BCTC	BCTC customers and rate payers lodge complaint to Government or the Utilities commission	Government or BCUC enquiry conducted into BCTC practices and policies	Government or BCUC impose strategic and operational changes upon BCTC	Failure to deliver required level of service resulting in loss of license to operate
Relationships			External opposition resulting in short term delays or minor modifications to work plans.	External opposition affecting BCTC's ability to implement its work plans is constrained and/or substantive modifications of its work plans are required.	External opposition resulting in increased regulatory oversight; shareholder scrutiny and/or restricted access to work sites.	External opposition resulting in increased regulatory/ legislative/court action or government intervention resulting in a loss of responsibilities impacting BCTC's corporate mandate, including restricted access to major project sites.	External opposition resulting in loss of license to operate and/or imposed corporate restructuring
Organization & People			Negligible impact on service delivery and staff.	Impacts the efficiency or effectiveness of some services, but would be dealt with internally.	Portions of the organization experience unexpected attrition or reduced attraction factors.	The ability to achieve the corporate goals is threatened or there is a significant increase in the cost of service.	Unexpected loss of multiple critical staff including senior leadership and the ability to deliver critical services.
Environment			Non-reportable environmental incident	Reportable environmental incident with short term mitigation (<1year)	Reportable environmental incident with long term mitigation (> 1year)	Reportable environmental incident with regulatory fines and mitigation possible.	Reportable environmental incident with regulatory prosecution and/or uncertain mitigation.

Severity Classification	
Extreme	Must be managed through a detailed plan by an Executive.
High	Detailed research and planning required at senior management; Executive attention is required.
Moderate	Management responsibility must be specified; Manage by specific monitoring or response procedures.
Guarded	Managed by routine procedures - regular monitoring required.
Low	Managed by routine procedures.

Enterprise Risk Management (ERM) at BCTC

ERM is a common process for everyone in the organization to make use of when making decisions. The framework below describes the main ERM phases. Prior to using this **Risk Matrix** you should have identified the relevant risks in the identify phase. This Risk Matrix forms part of the 'Assess' phase. The phases in the ERM framework are described below.



Identify all potential risks (threats) and opportunities related to achievement of organizational and departmental level business objectives.

Assess risks in terms of impact and likelihood. **In this phase you analyse the risk impact by utilizing the accompanying Corporate Risk Matrix.**

Mitigate risks with control activities and insurance programs. Identify control activities in place to manage risk and identify gaps requiring improvement action plans.

Monitor risk profile of inherent and residual risks, impact of changes to risk profile and risk appetite.

Provide **Assurance** that control activities are effective through either management self-assessment or internal audit program.

BCTC Project Deferral Risk Matrix

Consequence						
CATEGORY	**0**	**1**	**2**	**3**	**4**	**5**
Financial	Combined financial impact totaling $0 to <$50K	Combined financial impact totaling $50K to <$500K	Combined financial impact totaling $500K to <$1 Million	Combined financial impact totaling $1 to <$5 Million	Combined financial impact totaling $5 Million to <$10 Million	Combined financial impact totaling >= $10 Million
Reliability	• TSAIDI – incremental Outage Duration hrs: 0-<15 • Distribution Customer Hrs – Incremental: 0-<14,167 • TRI- % decrease in TRI:0-<1.75% • EENS – MWh: 0-<10	• TSAIDI – incremental Outage Duration hrs: 15-<30 • Distribution Customer Hrs – Incremental: 14,167 -<28,333 • TRI- % decrease in TRI:1.75-<3.70% • EENS – MWh: 10-<100	• TSAIDI – incremental Outage Duration hrs: 30-<45 • Distribution Customer Hrs – Incremental: 28,333 -<42,500 • TRI- % decrease in TRI:3.70-5.65% • EENS – MWh: 100-<200	• TSAIDI – incremental Outage Duration hrs: 45-<60 • Distribution Customer Hrs – Incremental: 42,500-<56,667 • TRI- % decrease in TRI:5.65-<7.6% • EENS – MWh: 200-<1000	• TSAIDI – incremental Outage Duration hrs: 60-<75 • Distribution Customer Hrs – Incremental: 56,667-<70,833 • TRI- % decrease in TRI:7.60-<9.55% • EENS – MWh: 1000-<2000	• TSAIDI – incremental Outage Duration hrs: >= 75 • Distribution Customer Hrs – Incremental: >= 70,833 • TRI- % decrease in TRI: >= 9.55% • EENS – MWh: >= 2000
Market Efficiency	Combined Market Efficiency impact totaling = $0-<$50K resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $50K to <$500K resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $500K to <$1 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $1 to <$5 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $5 to <$10 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling >= $10 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits
Asset Condition	• OEM Support/Availability of Spares: 0 to <1 • Asset health score 0.00 to <1.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.0 to <1.1	• OEM Support/Availability of Spares: 1 to <2 • Asset health score 1.00 to <2.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.1 to <1.2	• OEM Support/Availability of Spares: 2 to <3 • Asset health score 2.00 to <3.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.2 to <1.3	• OEM Support/Availability of Spares: 3 to <4 • Asset health score 3.00 to <3.67 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.3 to <1.4	• OEM Support/Availability of Spares: 4 to <5 • Asset health score 3.67 to <4.34 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.4 to <1.5	• OEM Support/Availability of Spares: >=5 • Asset health score >=4.34 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: >=1.5
Relationships	Impact is negligible	External opposition resulting in limited increase in complaints and/or external lobbying	External opposition resulting in significant increase in complaints and/or external lobbying	External opposition resulting in increased regulatory and shareholder oversight/scrutiny	External opposition resulting in increased regulatory/ legislative/court action or government intervention resulting in a loss of responsibilities impacting BCTC's corporate mandate	External opposition resulting in loss of license to operate and/or imposed corporate restructuring
Environment & Safety	Impact is negligible	• First aid injury/illness • Non-reportable environmental incident	• Medical aid injury/illness • Non-reportable environmental incident – mitigation required	• Lost time injury/temporary disability • Reportable environmental incident – mitigation not required	• Permanent disability • Reportable environmental incident – mitigation required and possible	• Fatality (ies) • Reportable environmental incident – mitigation required but uncertain
Probability						
Likelihood of Occurrence	< 0.1 % (<1 in 1000) likelihood that event will occur within next year.	0.1% (1 in 1000) likelihood that event will occur within next year.	1% (1 in 100) to <10% (1 in 100) likelihood that event will occur within next year.	10% (1 in 10) to <50% (1 in 2) likelihood that event will occur within next year.	50% (1 in 2) to <90% (9 in 10) likelihood that event will occur within next year.	90% (9 in 10) or greater likelihood that event will occur within next year.

BCTC Project Risk Matrix (DRAFT FOR DISCUSSION)

LIKELIHOOD GUIDELINES	LIKELIHOOD OF OCCURRENCE						
90 %	(9 in 10) or greater likelihood that event will occur within the project life-cycle (Risk should be incorporated into project plan)	5	Moderate	Moderate	High	Extreme	Extreme
50 %	(1 in 2) or greater likelihood that event will occur within the project life cycle.	4	Guarded	Moderate	High	Extreme	Extreme
10 %	(1 in 10) or greater likelihood that event will occur within project life cycle.	3	Guarded	Moderate	Moderate	High	Extreme
1 %	(1 in 100) or greater likelihood that event will occur within project life cycle.	2	Low	Guarded	Moderate	Moderate	High
<1 %	<1% (1 in 100) likelihood that event will occur within project life cycle.	1	Low	Low	Guarded	Guarded	High
IMPACT CRITERIA			1	2	3	4	5
Safety			First aid injury/illness	Medical aid injury/illness	Lost time injury/ temporary disability	Permanent disability	Fatality (ies)
Financial			Impact totaling <5% of project cost	Impact totaling 5-10% of project cost	Impact totaling 10-15% of project cost	Impact totaling 15-20% of project cost	Impact totaling >20% of project cost
Reliability			One of: <30,000 customers hrs lost or <200 MWh of energy not served	One of: 30,000 - 45,000 customers hrs lost or 200 - 300 MWh of energy not served	One of: 45,000 - 60,000 customer hrs lost or 300 - 400 MWh of energy not served	One of: 60,000 - 75,000 customer hrs lost or 400 - 500 MWh of energy not served	One of: ≥ 75,000 customer hrs lost or ≥ 500 MWh of energy not served
Market Efficiency			Customers and rate payers lodge complaints to BCTC	BCTC customers and rate payers lodge complaint to Government or the Utilities commission	Government or BCUC enquiry conducted into BCTC practices and policies	Government or BCUC impose strategic and operational changes upon BCTC	Failure to deliver required level of service resulting in loss of license to operate
Relationships			External opposition resulting in short term delays or minor modifications to work plans	External opposition affecting BCTC's ability to implement its work plans is constrained and/or substantive modifications of its work plans are required.	External opposition resulting in increased regulatory oversight; shareholder scrutiny and/or restricted access to work sites.	External opposition resulting in increased regulatory/ legislative/court action or government intervention resulting in a loss of responsibilities impacting BCTC's corporate mandate, including restricted access to major project sites.	External opposition resulting in loss of license to operate and/or imposed corporate restructuring
Organization & People			Negligible impact on service delivery and staff.	Impacts the efficiency or effectiveness of some services, but would be dealt with internally.	Portions of the organization experience unexpected attrition or reduced attraction factors.	The ability to achieve the corporate goals is threatened or there is a significant increase in the cost of service.	Unexpected loss of multiple critical staff including senior leadership and the ability to deliver critical services.
Environment			Non-reportable environmental incident	Reportable environmental incident with short term mitigation (<1year)	Reportable environmental incident with long term mitigation (> 1year)	Reportable environmental incident with regulatory fines and mitigation possible.	Reportable environmental incident with regulatory prosecution and/or uncertain mitigation.

Project Management Methodology

Project Risk Management	Identification	Study: Opportunity Analysis	Study: Preferred Option	Definition	Execution	Measure
Define Objectives	Have the strategic objectives of the need been defined?	NA	NA	Have the project objectives been defined?	NA	NA
Identify risks	NA	For each option, identify the internal and external risks that could impact the selection of the preferred option.	For the preferred option conduct a more detailed risk identification exercise for the definition phase.	Create a **risk log** with a listing of risk events for the execution phase.	As project progress occurs the project manager shall identify additional risks.	NA
Assess risks	NA	Assess the risks as they relate to the options under review (see **Project Risk Matrix**)	Conduct limited risk assessment for the definition phase of the preferred option.	Assess the detailed risks for the project from a project execution standpoint (see **Project Risk Matrix**).	Assess any new risks identified as additional project information arises (see **Project Risk Matrix**).	NA
Mitigate risks	NA	Develop high level mitigation plan for identified risks within each option & compare residual risk and cost of mitigation	Develop detailed mitigation plans for identified risks within the preferred option for the definition phase	Develop mitigation plans for each project execution risk considering mitigation strategy and cost.	Develop specific mitigation plans for each risk after considering strategy and cost.	NA
Monitor risks	NA	NA	NA	Set up the **Risk Log** review strategy for the execution phase.	Periodically review **Risk Log**.	Ensure ongoing operational project related risks are communicated management, and monitored.

Severity Classification

Extreme	Must be managed through a detailed plan by Senior Management.
High	Detailed research and planning required by the project manager; Senior Management attention is required.
Moderate	Management responsibility must be specified; Manage by specific monitoring or response procedures.
Guarded	Managed by routine procedures – regular monitoring required.
Low	Managed by routine procedures.

Example Risk Categories

Cost	Risks related to the total cost of the project, including organizational costs related to implementation.
Schedule	Risks related to the amount of time required to complete the project
Scope	Risks related to the size and nature of the project in its final form versus what was anticipated in the project design.
Regulatory	Risks related to the regulatory approval process (BCUC, environment or other)including the time and schedule implications of the approval process, up to and including the ultimate recovery of costs in rates)
People	Risk related to appropriate staffing, scheduling, professional experience for the project, including contractors and employees.
Performance	Risks related to the ultimate performance of the project upon completion. This includes performance of the asset/solution/process versus its original design as well as value realization versus initial design/justification assumptions.

Appendix E

MMK Consulting Report – BC Hydro Construction Cost Trends and Outlook

MMK CONSULTING

— BC HYDRO —

CONSTRUCTION COST TRENDS AND OUTLOOK

Prepared for:

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September 17, 2007

Contents

1. Introduction and Executive Summary

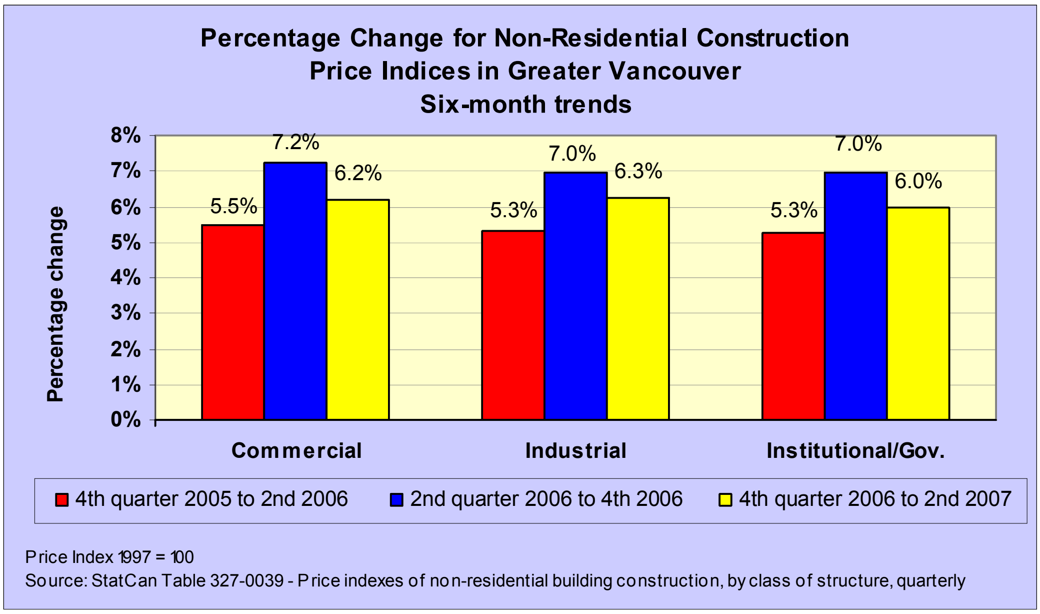
This report is the second of four semi-annual reviews of construction cost trends in British Columbia, and the implications for BC Hydro's cost inflation[1] allowances on future major construction projects[2].

1.1 General trends

The general non-residential construction industry in BC continues to experience strong levels of building activity, led by commercial construction. While the value of industrial building permits in BC in the first six months of 2007 is down from the same period in 2006, strong markets in Alberta and Ontario continue to put pressure on industrial construction in BC.

Price indices continue to increase sharply for non-residential construction in BC. Industrial construction price levels in Vancouver rose 6.3% between the fourth quarter of 2006 and second quarter of 2007. This rate of increase was down from the previous six months, but up from the same period in the preceding year.

Exhibit 1a — Changes in non-residential construction price indices in the past three six-month periods - Greater Vancouver



[1] Unless otherwise indicated, the term "cost inflation" refers to upward construction price trends *specifically* in the non-residential, industrial and electric utility industries (rather than to general price inflation in the overall economy).
[2] This report also updates three previous (December 2005, July 2006, and March 2007) MMK reports for BC Hydro.

1.2 Trends in the electric utility industry

In the Canadian electric utility industry, reported price index increases through 2006 have been much lower for electric utility transmission/distribution construction than for overall industrial construction. While Statistics Canada's price index for industrial construction increased by 28.7% between 2003 and 2006, its construction price indices for distribution-related electric utility construction (distribution systems, transmission lines and substations) increased only by a cumulative total of 4.8% to 6.8% over three years. (No data are available yet for 2007.)

In the United States, equipment price indices for electric power and specialty transformer manufacturing have increased approximately 42% over three years, compared with 8% for turbine and power transmission equipment manufacturing[1]. US industry publications are also forecasting high levels of transmission and distribution construction activity over the next few years.

On balance, we expect that the Canadian electric utility transmission/distribution construction price indices for 2007, when they become available in 2008, will show significantly higher increases than for 2006 and prior years. Going forward, we expect future price index trends in transmission/distribution to be subject to the same type of cost inflation pressures experienced by power generation and other heavy construction projects.

1.3 Price trends by cost component

While component cost trends have been mixed during the first half of 2007, there has been a general tendency towards less volatility than was experienced in 2005 and 2006 – albeit at significantly higher price levels in many cases.

While component cost trends are important contributors to cost inflation in the BC industrial construction industry, they are only partial indicators of the total impact of prices, since they do not account for market-driven (supply and demand) cost inflation pressures.

1.4 Regional trends in BC

While regional BC price index data is not available, construction activity levels provide an indication of regional cost inflation pressures.

Based on the available data on construction activity levels (building permit values, construction industry employment trends), the greatest market-driven regional cost inflation pressures are being experienced in Vancouver Island, Northeast BC and the Lower Mainland.

[1] See section 3.4, Exhibit 3d.

1.5 Other agencies' estimates and forecasts

Other agencies have a wide range of approaches to estimating and forecasting construction cost inflation:

- **BTY Group,** a Canadian construction project management firm, significantly reduced its cost inflation forecast between December 2005 and December 2006, and is now projecting BC construction cost increases of 6% in 2007, 5% in 2008, and 3% in each of 2008 and 2009.
- **US ENR (Engineering News Record)** is forecasting a 2.7% increase in its US-based "Construction Cost Index" in 2007, reflecting modest expectations for materials cost increases. (The ENR figure is a composite of labor, materials, and other component costs, and does not directly measure construction price trends.)
- **Rider Levett Bucknall** reports that its US selling price index ("what the market will bear") increased 2.3% in the first quarter of 2007, and its annual cost inflation rate is projected to be 7.5%.
- **BC Ministry of Advanced Education** has developed (September 2006) annual cost inflation guidelines of 15% for 2007, 12% for 2008, 9% for 2009, and 8% for 2010.
- **BC Ministry of Transportation** has adopted (September 2006) annual cost inflation expectations of 5.2% (construction costs) and 10% (property acquisition costs).
- **Statistics Canada** (as discussed earlier) has recorded price index increases for industrial construction in the range of 10% to 14% annually, and increases for industry-specific electric utility distribution construction price indices in the range of 2% to 4% annually.

1.6 Cost inflation outlook for BC Hydro

For **heavy construction**, there are some signs of softening in component price indices. However, both the BC construction industry and the Canadian industrial construction industries continue to show high activity levels and price inflation. Accordingly, for 2007 to 2010, our recommended cost inflation allowance range is unchanged at 4% to 6% annually. For 2011 through 2015, our recommended range is 3% to 4% annually, up slightly from our March report.

For **transmission, stations and distribution**, based on the recent strength of US equipment price indices, confirmed by the recent experiences of BC Hydro staff, we expect future Canadian cost inflation pressures for transmission, stations and distribution to be much stronger than in the past few years. Accordingly, we have increased our recommended cost inflation ranges for transmission, stations and distribution construction to bring them into line with those for heavy construction and power generation.

In summary, our recommended cost inflation allowances, for all major construction projects, are 4% to 6% for 2007 through 2010, and 3% to 4% for 2011 through 2015.

Exhibit 1b — Recommended construction cost inflation allowances

Previous report vs. this update		2007 to 2010	2011 to 2015
Mar. 2007	• Generation (heavy construction)	4% to 6%	2.5% to 4%
	• Utility transmission/distribution	2% to 4%	2% to 4%
Sep. 2007	• All construction projects	4% to 6%	3% to 4%

The recommended allowances:

- Are for "hard" construction costs only, and do not include "soft" costs such as design and project management.
- Assume that BC Hydro takes appropriate cost mitigation measures to dampen the impact of cost inflation through procurement strategies, value engineering, and other cost mitigation initiatives.
- Assume that the strong construction market in BC between 2003 and 2007 will continue through 2010, and that the market will have a "soft landing" in 2010 and 2011 as market demand and supply forces come more into balance.

2. General Price and Activity Level Trends

This chapter presents overall price and activity level trends for non-residential and industrial construction.

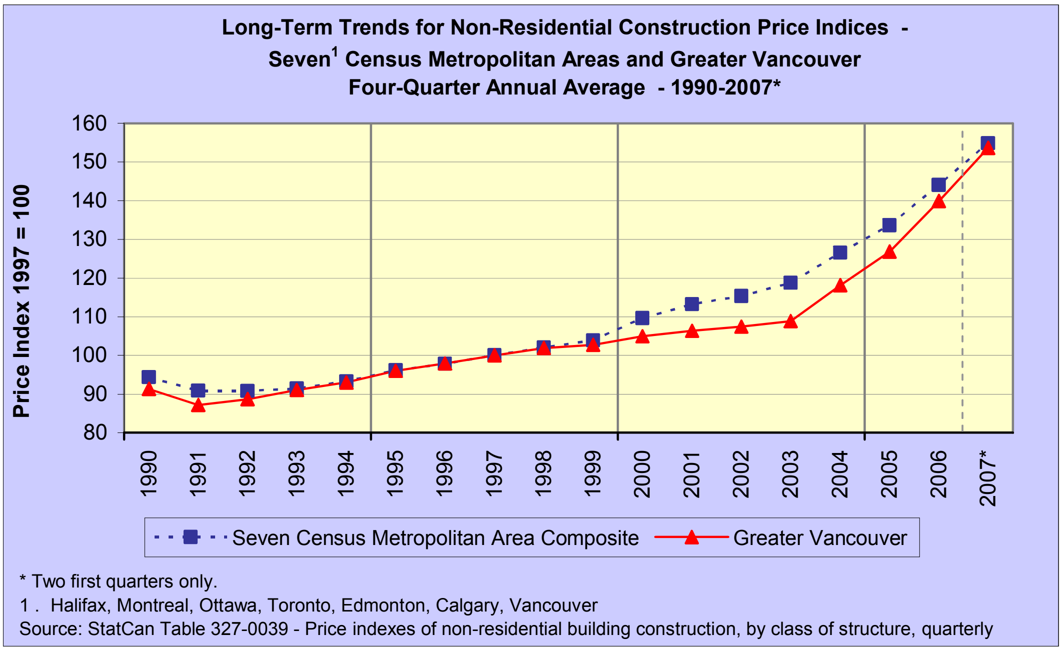
2.1 Non-residential construction price index

a) Annual trends

Non-residential construction price index[1] trends for Greater Vancouver, as well as the composite index for seven Canadian metropolitan areas, are illustrated in Exhibit 2a. For Vancouver, price index trends were stable between 1992 and 2003, increasing approximately 1.9% per year. However, the situation changed dramatically starting in 2004, and the Vancouver non-residential price index increased by an average of approximately 9% per year over the past four years.

The seven Canadian metropolitan areas' price index increased more rapidly than the Vancouver index between 1999 and 2003, but has increased less rapidly since 2003.

Exhibit 2a — Long-range construction cost trends in the non-residential sector



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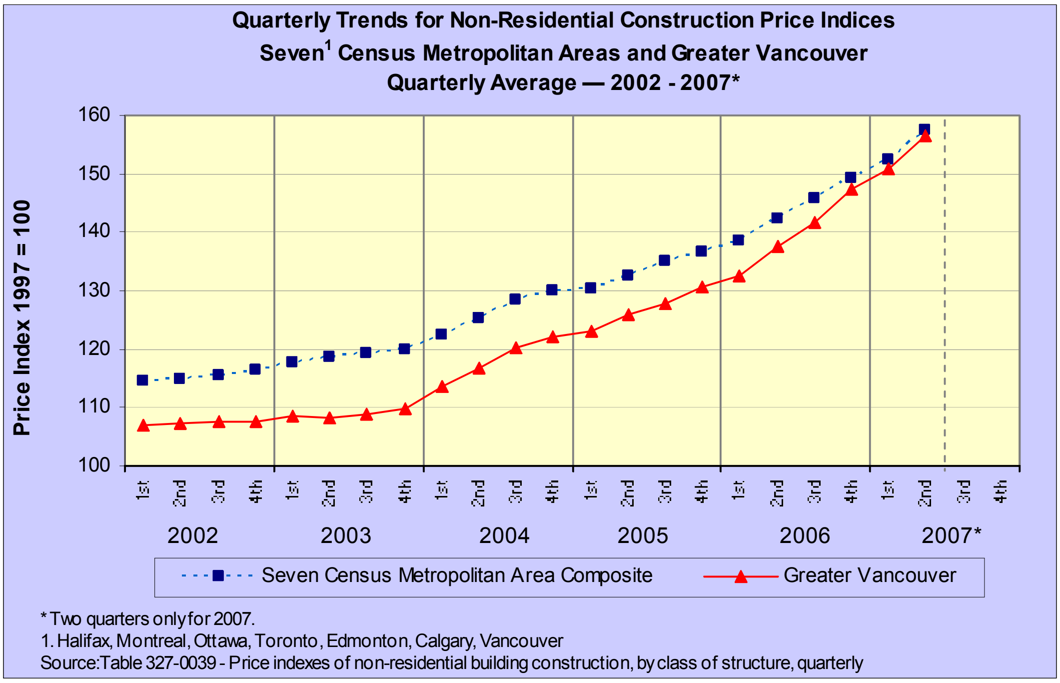
[1] The non-residential construction price index (NRBCPI) is defined by Statistics Canada as "…a quarterly series measuring the changes in contractors' selling prices of non-residential building construction (i.e. commercial, industrial and institutional)". It includes both general and trade contractors' work, but excludes the cost of land, land assembly, design, development and real estate fees.

b) Quarterly trends

As illustrated in Exhibit 2b, the change in Statistics Canada's price index trends dates from the first quarter of 2004.

Exhibit 2b — Short-term quarterly trends for non-residential construction price indices



For BC Hydro, the Vancouver index is more relevant to smaller locally-sourced Lower Mainland projects, while the seven-CMA average is more relevant to larger nationally-sourced projects.

Recent rates of increase in Vancouver have been higher than the composite of Canadian Metropolitan Areas, as shown in Exhibit 2b[1].

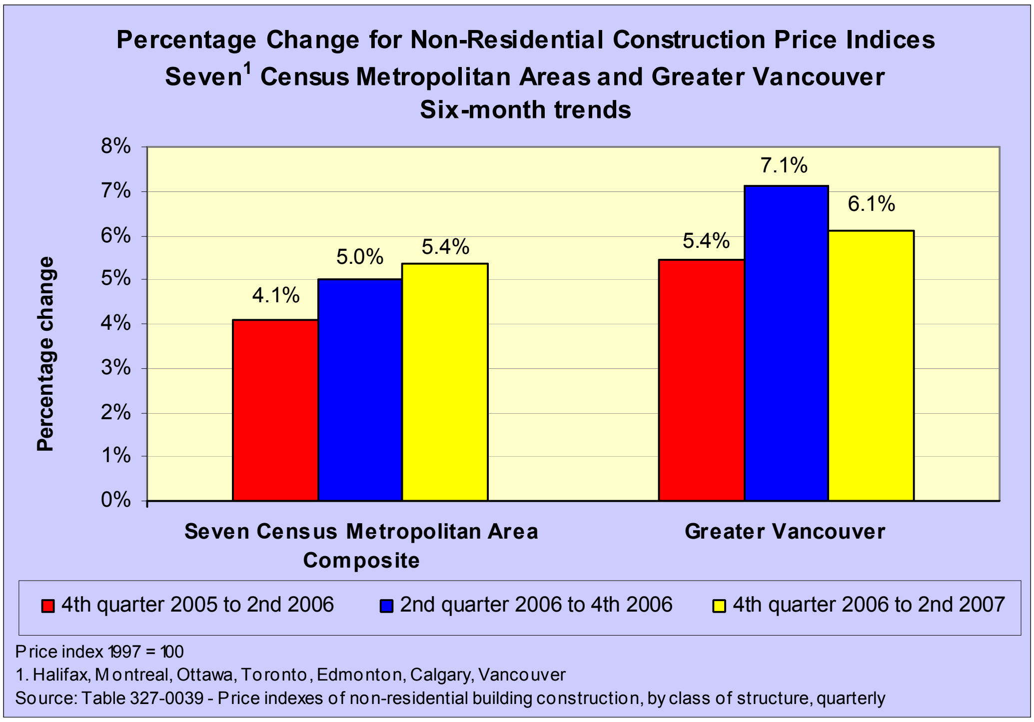
---

[1] Although the seven-city CMA price index using 1997 as the base year, is still slightly higher than the Vancouver price index, the Vancouver price index has been catching up and is now less than one point below the CMA's index.

c) *Six-month trends (since previous report)*

Over the six months from the fourth quarter of 2006 to the second quarter of 2007, the Vancouver price index increased 6.1% compared to 5.4% for the CMA average. Both rates of increase were higher than for the same time period in 2006, although the Vancouver rate was down from the immediately preceding six months.

Exhibit 2c — Changes in non-residential construction price indices in the past two six-month intervals



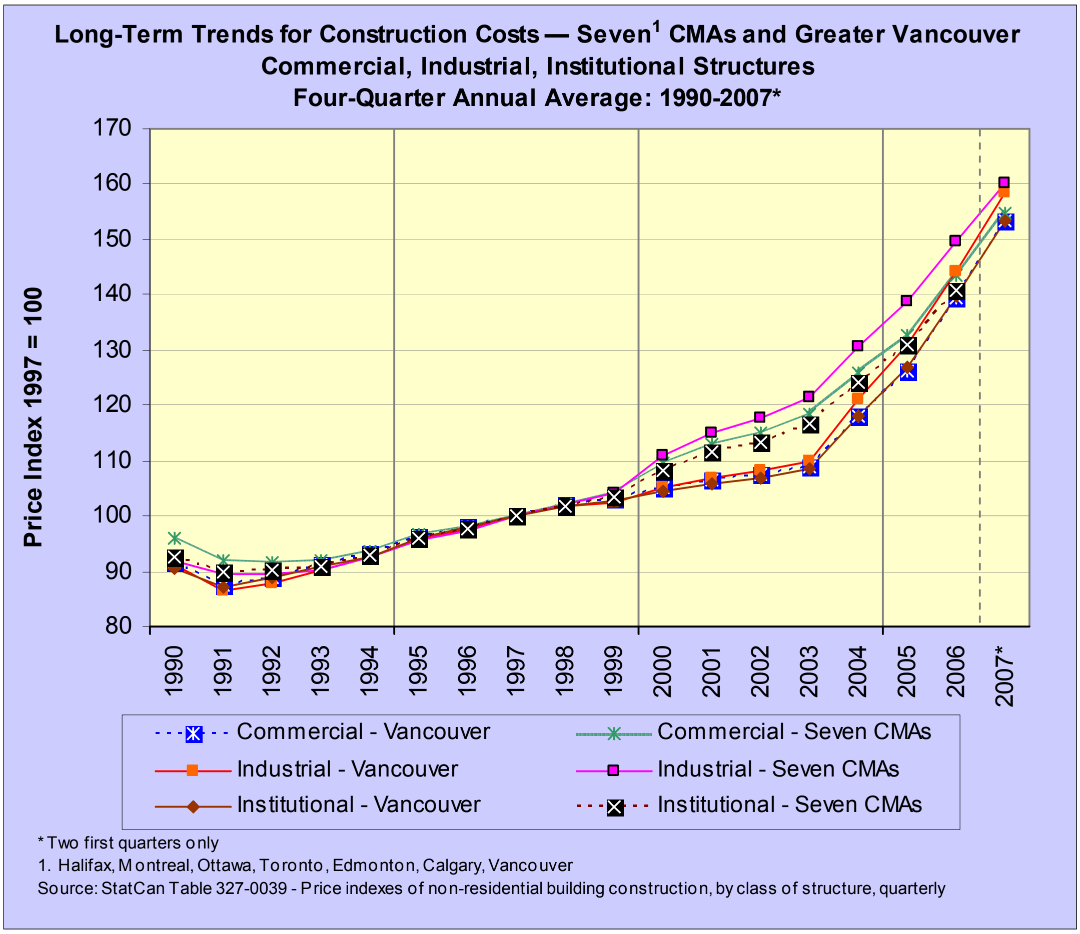
Annually, (Q2-06 to Q2-07), Statistics Canada's non-residential construction price index increased by 14.3% for Greater Vancouver and 10.7% for the CMA composite.

2.2 Commercial, industrial, and institutional

a) Annual trends

Statistics Canada's non-residential construction price index may be broken out into commercial, institutional/government and industrial construction (of most interest to BC Hydro). Exhibit 2d illustrates long-term annual trends for each of these subgroups, for both Greater Vancouver and the seven-city CMA[1] composite.

Exhibit 2d — BC Construction non-residential price index trends, by sector



Since 1997, long-term non-residential price index increases have been slightly higher for industrial construction, both for the seven-city CMA composite and for Greater Vancouver.

b) Quarterly trends

As illustrated in Exhibit 2e, similar rates of price index increase have occurred for all three categories of non-residential building structures in Vancouver.

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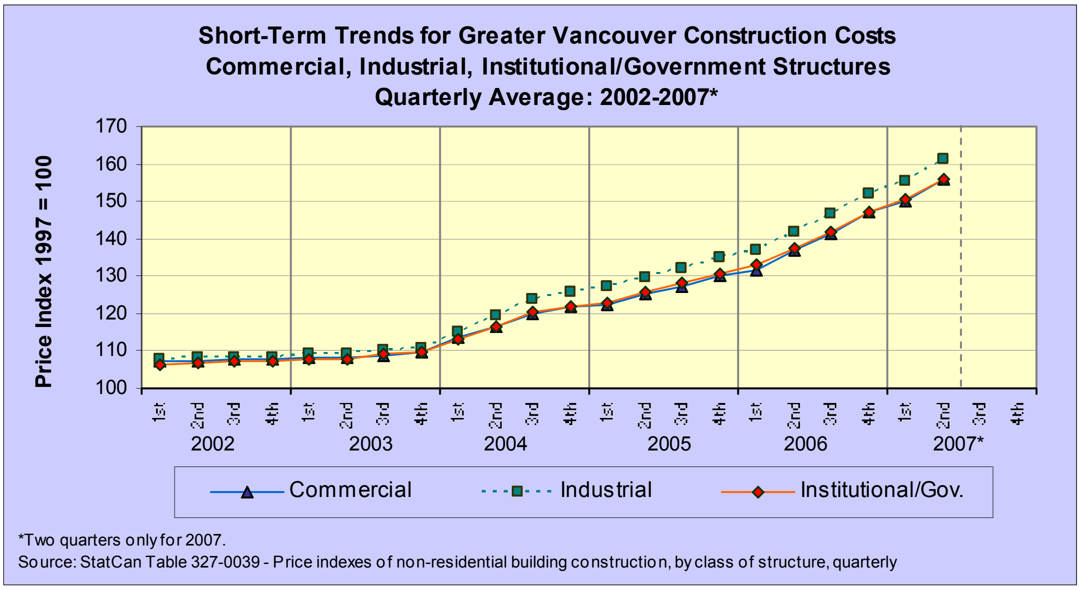
[1] Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver

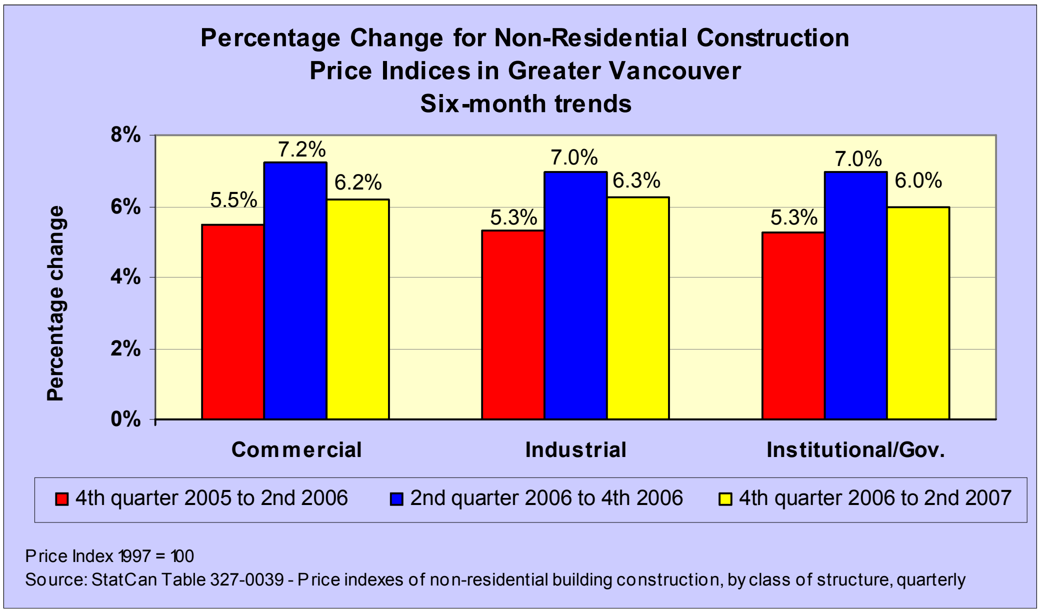
Exhibit 2e — Short-term quarterly trends for different types of building structure



c) *Six-month trends (since previous report)*

As illustrated in Exhibit 2f, recent six-month price index trends are reported by Statistics Canada as being similar for all three types of non-residential construction. Rates of price index increases continued to be strong in the first half of 2007 — down from the second half of 2006, but up from the same six-month period in 2006.

Exhibit 2f — Changes in non-residential construction price indices in the past three six-month periods - Greater Vancouver



2.3 General construction activity trends

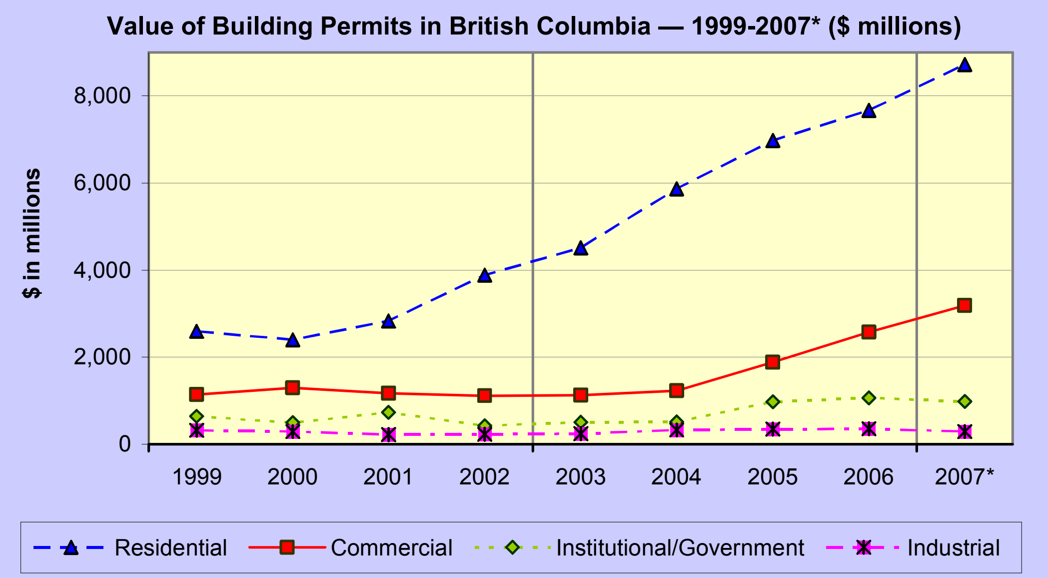
a) Annual trends

As illustrated in Exhibit 2g, the value of building permits has increased dramatically in BC since 2001, driven in initial years by residential construction, and also in more recent years by commercial construction[1].

Exhibit 2g — Value of building permits ($ million) by sector, 2000 to 2007

	Annual trends								Six-month data (Jan -Jun)		
	2000	2001	2002	2003	2004	2005	2006	Change 05-06 (%)	Jan-Jun 2006	Jan-Jun 2007	Change 06-07 (%)
Residential	2,403	2,830	3,888	4,514	5,869	6,979	7,669	9.9%	3,633	4,360	20.0%
- as % of total	53.5%	57.1%	68.7%	70.6%	73.9%	68.5%	65.7%		66.8%	66.1%	
Non-residential											
▪ Industrial	296	221	230	244	328	346	358	3.5%	165	148	-10.7%
- as % of total	6.6%	4.5%	4.1%	3.8%	4.1%	3.4%	3.1%		2.4%	2.1%	
▪ Commercial	1,297	1,171	1,117	1,130	1,228	1,886	2,576	36.6%	1,077	1,594	48.0%
- as % of total	28.9%	23.6%	19.7%	17.7%	15.5%	18.5%	22.1%		24.5%	23.9%	
▪ Institut./Govt	496	732	424	506	514	980	1,067	9.0%	607	493	-18.8%
- as % of total	11.0%	14.8%	7.5%	7.9%	6.5%	9.6%	9.1%		7.9%	7.1%	
BC Total	4,492	4,955	5,659	6,394	7,939	10,191	11,670	14.5%	5,483	6,594	20.3%

Source: StatCan Table: 26-0006 - Building permits, by type of structure and area, seasonally adjusted, monthly.



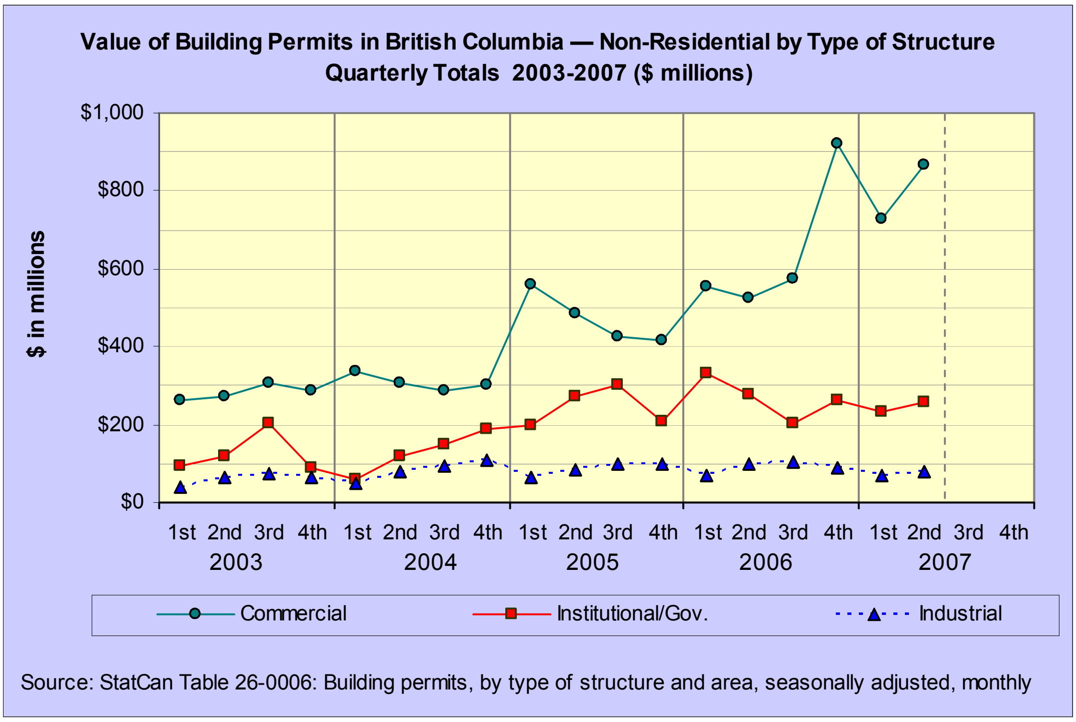
* Six-month data for 2007 has been pro-rated to 12 months.
Source: StatCan Table 26-0006: Building permits, by type of structure and area, seasonally adjusted, monthly

[1] BC Hydro and some other agencies (MoTH, BCTC, etc.) do not require building permits for industrial construction.

b) *Quarterly trends – Commercial, institutional, industrial*

As shown in Exhibit 2h, the value of non-residential building permits in BC has varied significantly on a quarterly basis for commercial construction, and to a lesser extent for institutional/government construction.

Exhibit 2h — Quarterly trends of BC non-residential building permits values, by type of structure



Industrial building activity, the sector most relevant to BC Hydro, has shown the greatest stability in terms of activity levels.

c) *Trends since previous report*

As illustrated in Exhibit 2g and 2h, growth in commercial construction activity continues to dominate the non-residential market, with the value of commercial building permits in BC up 48% for the first half of 2007 over the same period in 2006, far outweighing the declines in industrial and institutional/government building permit values.

Industrial building permit values in BC have actually declined during the first half of 2007, although the decrease is more than offset by the increase in Alberta for the same period (see following section).

2.4 Price and activity trends — BC vs. Ontario/Alberta

BC Hydro's contract bidders for major projects tend to be large firms that operate at the national level. All contractors are affected, directly or indirectly, by trends for major projects in other provinces, particularly in Ontario and Alberta.

2.4.1 Price trends – Non-residential construction

a) Annual trends

Exhibit 2i compares annual trends for non-residential construction costs in Toronto, Calgary and Vancouver. In 2004 and 2005, annual increases were highest in Vancouver. In 2006, cost inflation rates in Calgary were nearly doubled those in Toronto and higher than in Vancouver.

Exhibit 2i — Annual non-residential construction cost trends— Toronto, Calgary, Vancouver

	Toronto		Calgary		Vancouver	
	Index	Change	Index	Change	Index	Change
2002	119.4	-	115.8	-	107.5	-
2003	123.8	3.7%	119.4	3.1%	108.8	1.3%
2004	132.0	6.6%	127.4	6.7%	118.2	8.6%
2005	139.0	5.3%	136.1	6.9%	126.9	7.3%
2006	148.3	6.7%	153.7	12.9%	139.9	10.3%

Source: StatCan Table 327-0039: Price indices of non-residential building construction, by class of structure, annually.

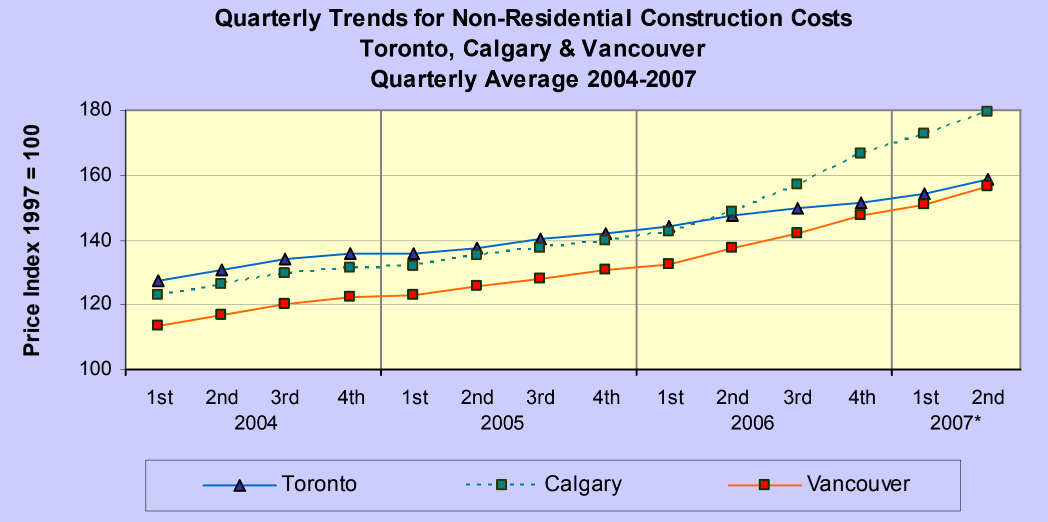
b) Recent trends

Exhibit 2j illustrates quarterly cost inflation rate trends in recent years for non-residential construction. (Results are similar for industrial construction only.) As Exhibit 2j shows, rates of increase have diverged sharply over the past 12 months (Q2 2006 to Q2 2007):

	12-month increase in price indices	
	Non-residential	Industrial only
• Calgary	20.6%	20.0%
• Toronto	7.6%	8.1%
• Vancouver	13.7%	13.7%

Vancouver's 12-month price index increase has been much higher than that of Toronto, but much lower than that of Calgary.

Exhibit 2j – Quarterly trends for total non-residential construction costs – Toronto, Calgary and Vancouver

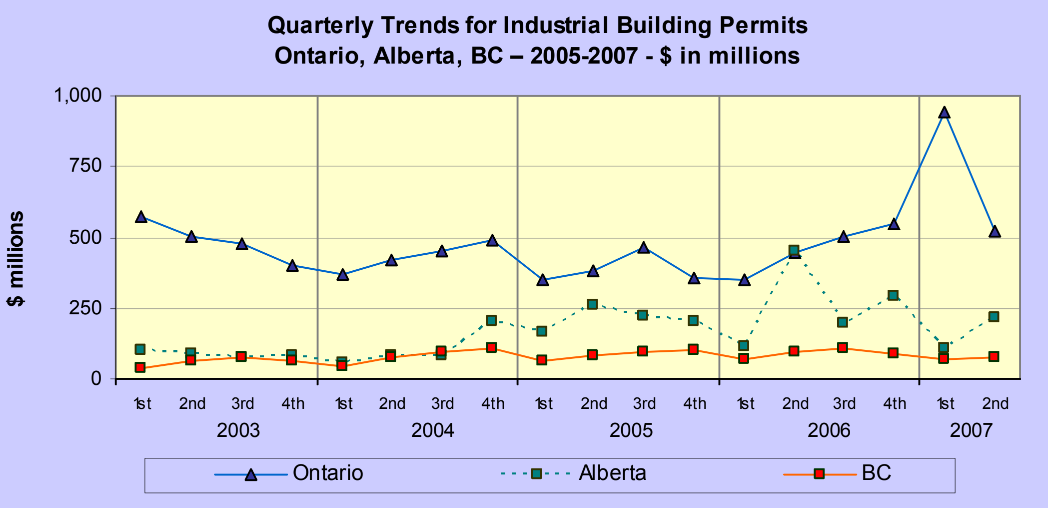


Source: StatCan Table 327-0039 - Price indexes of non-residential building construction, by class of structure, quarterly

2.4.2 Activity level trends

Quarterly trends in the value of building permits are illustrated in Exhibit 2k.

Exhibit 2k – Quarterly activity trends — Ontario, Alberta, BC



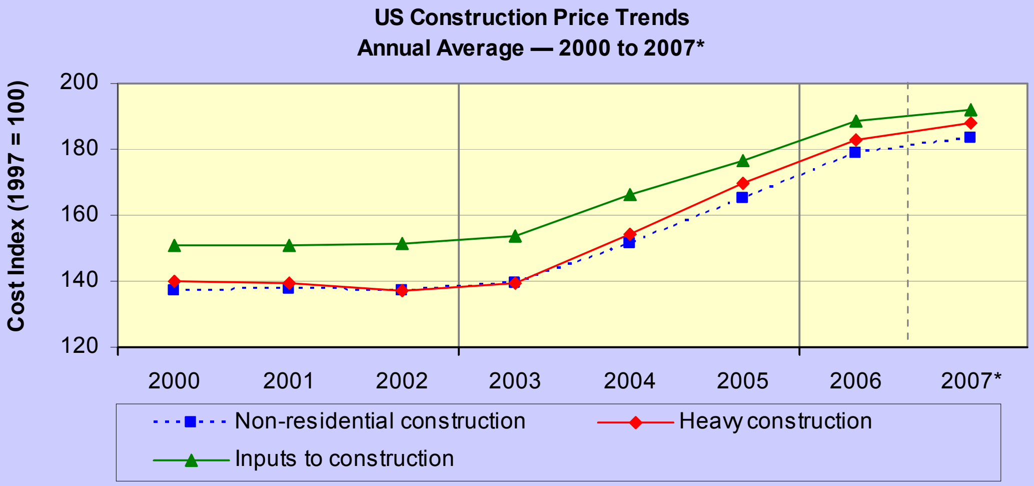
Source: StatCan Table 26-0006: Building permits, by type of structure and area, seasonally adjusted, quarterly

The data indicate a significant increase in industrial construction activity in Alberta, starting in 2004, and also the significance of the Ontario industrial construction industry. While industrial construction activity levels in BC have been relatively flat, the strength of the Alberta and Ontario markets has put price pressure on BC industrial construction projects.

2.5 US construction price trends

Between 2000 and 2003, US Bureau of Labor Statistics (BLS) data indicate flat annual price increases in US non-residential and heavy construction. In 2004, prices started to escalate at a higher rate, increasing 7.1% to 10.6% annually.

Exhibit 21
(i) US annual construction price trends



* Six-month average
Source: US Department of Labour Statistics, Producer Price Index: Non-residential construction BMNR; heavy construction BHVY; Inputs to construction WPUSOP2200

(ii) US annual price indices and percentage change

	Non-residential		Heavy construction		Inputs to construction	
	Index	Change	Index	Change	Index	Change
2000	137.1	-	139.8	-	138.9	-
2001	137.9	0.6%	139.6	-0.1%	139.1	0.1%
2002	137.0	-0.7%	137.3	-1.6%	138.3	-0.6%
2003	139.7	2.0%	139.4	1.5%	140.8	1.8%
2004	151.7	8.6%	154.2	10.6%	151.8	7.8%
2005	165.1	8.8%	169.5	9.9%	163.7	7.8%
2006	178.6	8.2%	182.6	7.7%	175.4	7.1%
2007[1]	183.3	2.6%	188.3	3.1%	179.6	2.4%

1 Six-month average
Source: US Department of Labor Statistics, Producer Price Index.

For the first six months of 2007, price indices are up between 2.4% and 3.1% over the 2006 annual average.

2.6 Conclusion — General activity and price trends

In summary, the non-residential construction industry in BC continues to experience strong levels of activity, led by commercial construction. While the value of industrial building permits in BC in the first six months of 2007 is down from the same period in 2006, strong markets in Alberta and Ontario continue to put pressure on industrial construction in BC.

Price indices continue to increase sharply for non-residential construction in BC. Industrial construction price levels in Vancouver rose 6.3% between the fourth quarter of 2006 and second quarter of 2007. This rate of increase was down from the previous six months, but up from the same period in the preceding year.

3. Price and Activity Trends — Electric Utility Industry

This chapter presents price index information that is particularly relevant to the Canadian electric utility industry.

3.1 Canadian electric utilities price trends

Exhibit 2a presents the Statistics Canada price index data for Canada-wide electric utility costs with respect to:

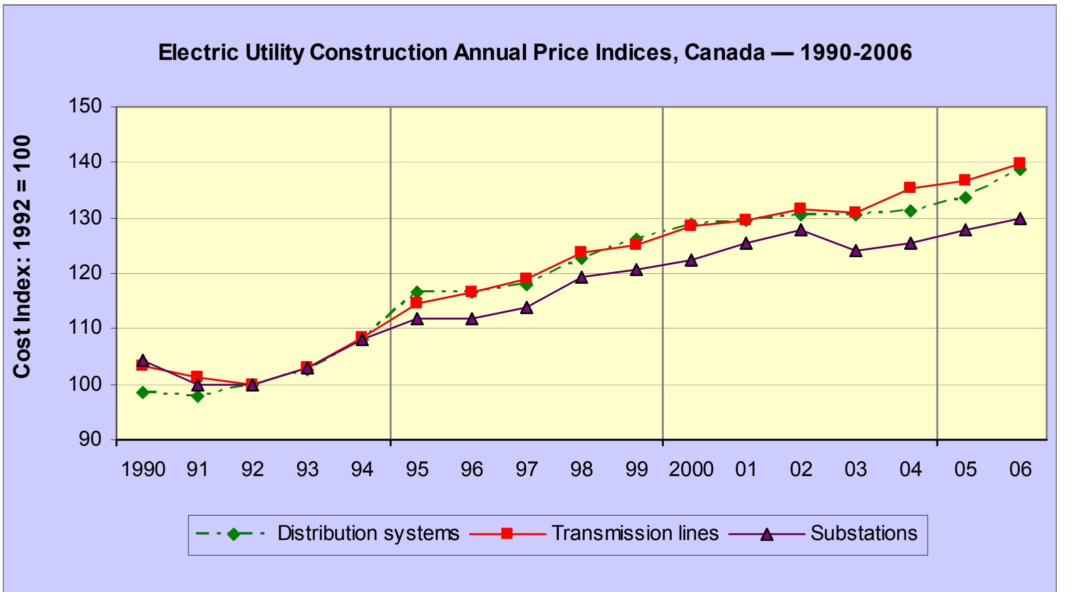
(1) distribution systems,

(2) transmission lines, and

(3) substations.

The long-term Canada-wide index trends for electric utility construction are significantly lower than for the broader industrial construction price index.

Exhibit 3a — Electric utility construction price trends – Canada



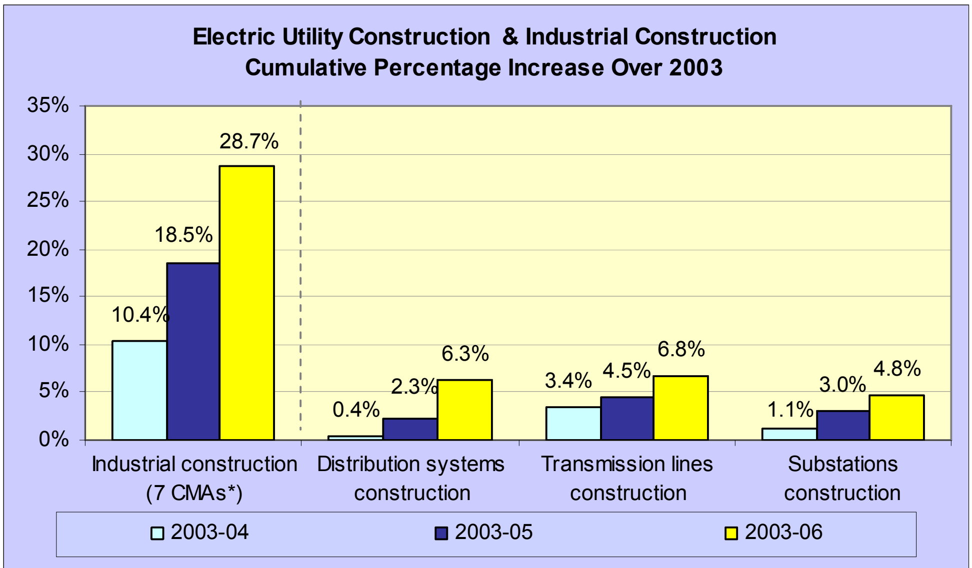
Sources: StatsCan: Table 327-001 - Electric utility construction price indexes (EUCPI), annual (Index, 1992=100)

Data on quarterly trends are not available, as Statistics Canada cost indices for electric utility construction costs are only reported on an annual basis.

3.2 Comparison — Electric utility vs. industrial construction

Exhibit 3b compares three-year cumulative trends in Statistics Canada's electric utility construction indices to cumulative trends in the industrial construction price index.

Exhibit 3b – Comparison of general industrial construction price index with electric utility indices



*Seven CMAs; Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver.
Sources: Statistics Canada - Table 327-0039 - Price index of non-residential building construction, by class of structure, 4-quarter annual average, 7 CMAs; Table 327-001-Electric utility construction price indexes (EUCPI), Canada, annual.

Since 2003, Statistics Canada's distribution system, transmission, and substation indices have increased by 4.8% to 6.8%, far less than the 28.7% increase in industrial construction price indices during the same period.

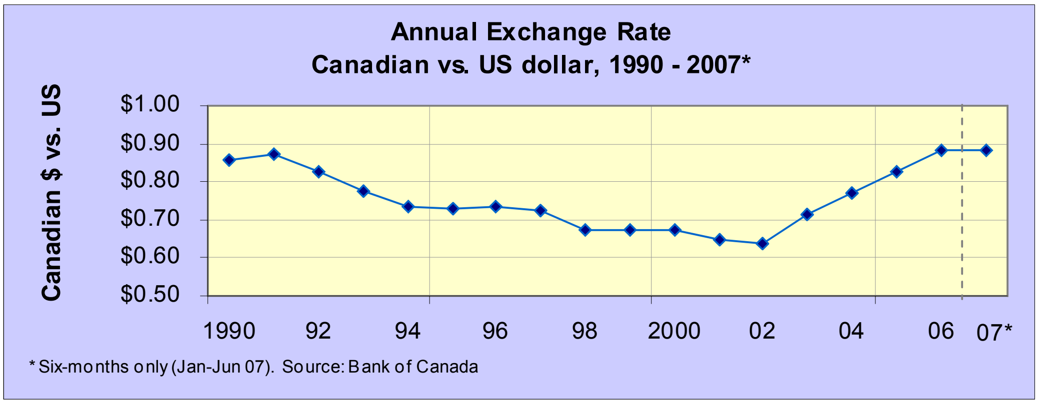
3.3 Factors contributing to low recent-year electric utility construction price increases in Canada

One factor that has likely contributed to the lower cost inflation trends for electric utility construction is the specialized nature of this construction segment. There may be less ability of firms to cross over into other industry sectors where activity levels have increased dramatically.

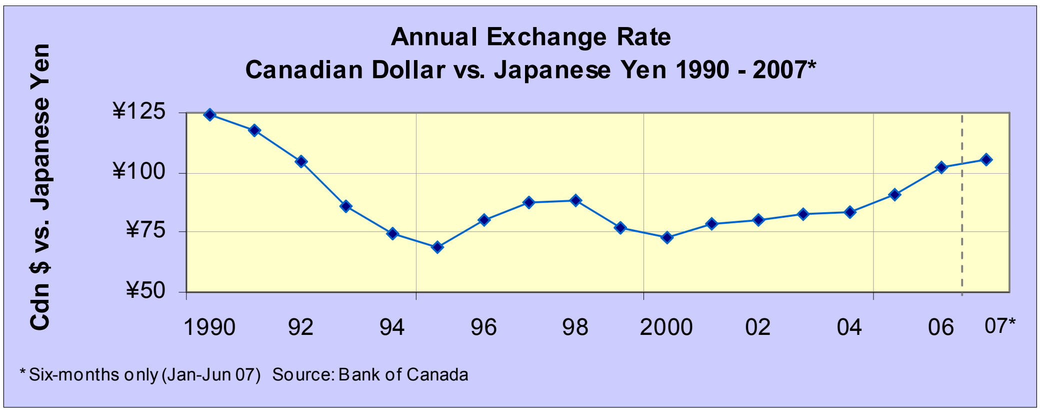
Another contributing factor may be the structure of the Canadian electric utility industry, with a limited number of larger utilities, that may make it easier for these utilities to resist upward price pressures.

Another contributing factor is the rising value of the Canadian dollar in recent years, as illustrated in Exhibit 3c. A strengthening Canadian dollar tends to lower the cost of purchasing imported[1] electric utility materials (e.g. cables, etc.) and equipment (e.g. transformers), on which the Canadian electric utility construction industry relies heavily.

Exhibit 3c – Long-term annual exchange rate:
(i) Canadian vs. US dollar



(ii) Canadian dollar vs. Japanese Yen



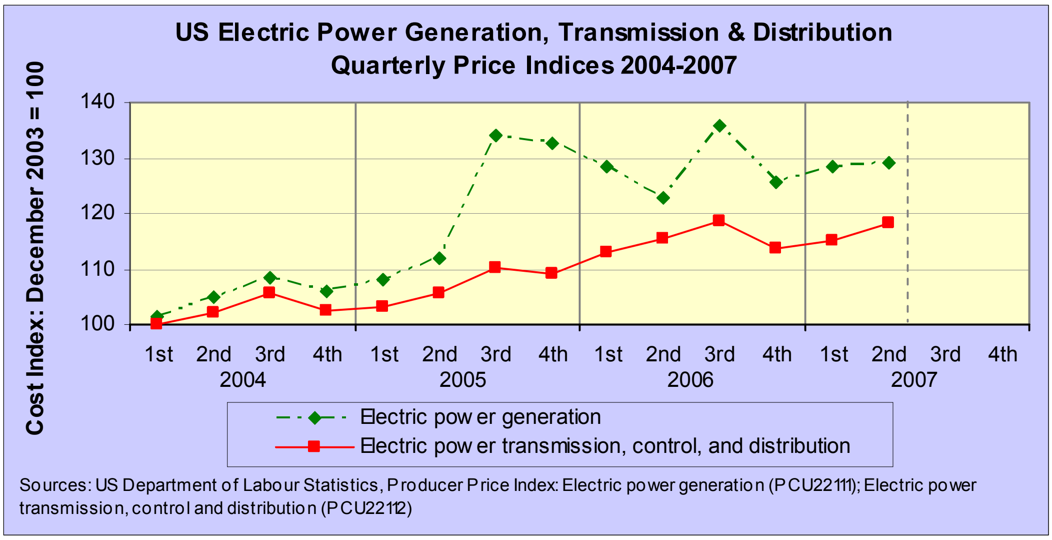
[1] With respect to its Industrial Producer Price Index, Statistics Canada has estimated that "if the impact of the exchange rate [shift relative to US dollar] had been excluded, producer prices would have risen 1.7% instead of falling 0.3% between July 2006 and July 2007."

3.4 Recent US electric utility trends

a) Price trends — Generation, transmission and distribution systems

Recent quarterly US price trends of electric power generation, transmission and distribution are illustrated in Exhibit 3d.

Exhibit 3d – US electric power generation, transmission & distribution – Quarterly trends 2004-07

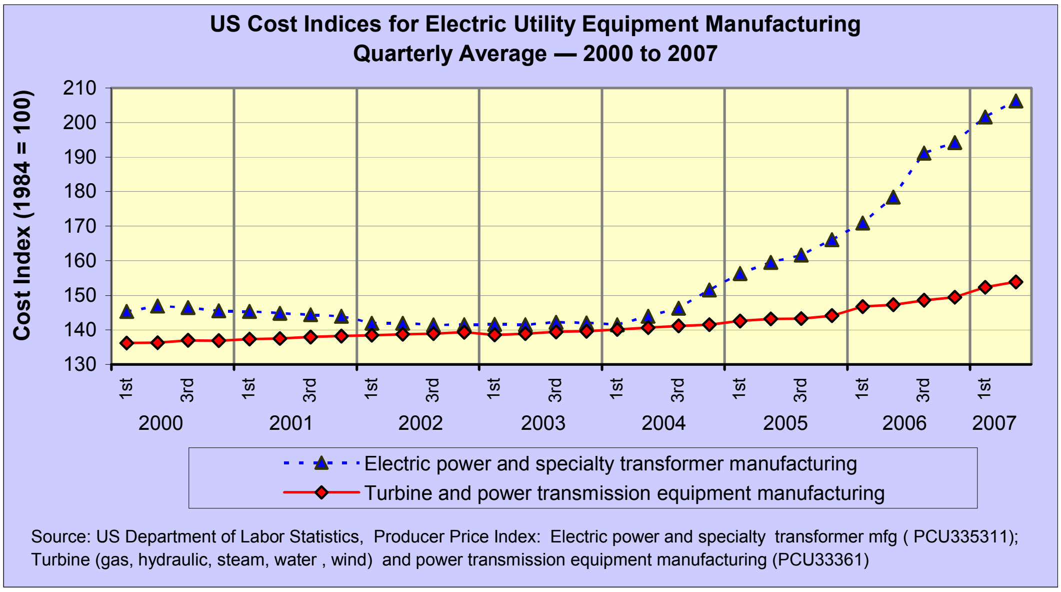


These US data relate to producer prices, and are not directly applicable to the construction industry. However, they demonstrate the relatively moderate overall upward trends for US producer prices in recent years, as well as the tendency in the US for generation price indices to have increased at higher rates than distribution price indices.

b) Price trends — US electric utility equipment manufacturing

A very different story emerges with respect to US electric utility equipment manufacturing prices. As illustrated in Exhibit 3e, US electric power and specialty transformer equipment manufacturing price indices have risen approximately 42% over the past 3 years (2nd quarter 2007 versus 2nd quarter 2004). Turbine and power transmission equipment manufacturing has increased at a much lower rate, approximately 8%, over the same period.

**Exhibit 3d – US electric utility equipment manufacturing
Quarterly trends 2004-07**



c) Construction activity trends — US transmission and delivery

There is also general industry consensus in the US that electrical construction activity is increasing significantly. According to the Edison Electric Institute:

> "The [US electric utilities] industry has been investing and will continue to invest in the nation's transmission infrastructure at levels not seen in 30 years …. From 2006-2009…, the industry is planning to invest $31.5 billion… nearly a 60% increase over the amount invested from 2002-2005." [1]

These activity level estimates and projections help to explain the rapidly increasing manufacturing price index trends illustrated in Exhibit 3d.

3.5 Recent BC Hydro purchasing experience

BC Hydro staff members confirm that, in recent months, they have experienced very significant increases in manufacturers' prices for materials and equipment purchases relating to BC Hydro's transmission, stations and distribution projects. They report materials and equipment purchase costs of up to 25%-30% above those expected, consistent with the US price index data illustrated in Exhibit 3d.

These reported increases are in strong contrast to the situation noted in our previous reports, where Canadian data and BC Hydro's own experiences were both pointing to lower cost inflation pressures for transmission/distribution projects than for power generation projects.

[1] Source: "Energy Data Alert", Edison Electric Institute, December 2006, as quoted in Engineering News Report, February 19, 2007, page 10.

3.6 Conclusion — Electric utility construction price and activity trends

In Canada, price index increases have been much lower in recent years for electric utility transmission/distribution construction than for overall industrial construction. While the Statistics Canada price index for industrial construction increased by 28.7% between 2003 and 2006, its construction price indices for distribution-related electric utility construction (distribution systems, transmission lines and substations) increased only by a cumulative total of 4.8% to 6.8% over three years. (Because Statistics Canada reports these indices on an annual basis only, no data are available yet for 2007.)

In the United States, equipment price indices for electric power and specialty transformer manufacturing have increased approximately 42% over three years, compared with 8% for turbine and power equipment manufacturing. US industry publications are also forecasting high levels of transmission and distribution construction activity over the next few years.

On balance, we expect that the Canadian electric utility transmission/distribution construction price indices for 2007, when they become available in 2008, will show significantly higher increases than for 2006 and prior years. Going forward, we expect future price index trends in transmission/distribution to be subject to the same type of cost inflation pressures experienced by power generation and other heavy construction projects.

4. Price Trends — By Cost Component

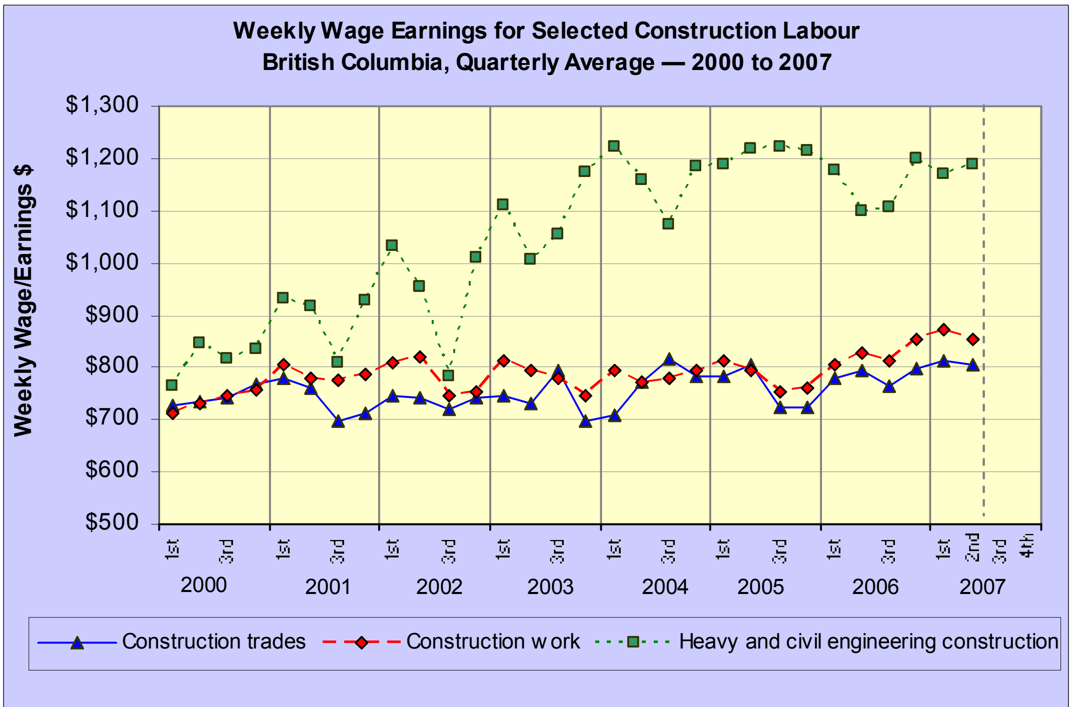
This chapter analyzes price index trends in many of the component cost factors (labour, materials, fuel, etc.) that underlie industrial construction cost estimates and contractor bid prices.

4.1 Construction labour

a) Quarterly trends in wage earnings

As illustrated in Exhibit 4a, average wage earnings for construction trades and workers have not increased at the same rate as construction cost indices in recent years.

Exhibit 4a — Weekly wage earnings for selected construction labour in British Columbia



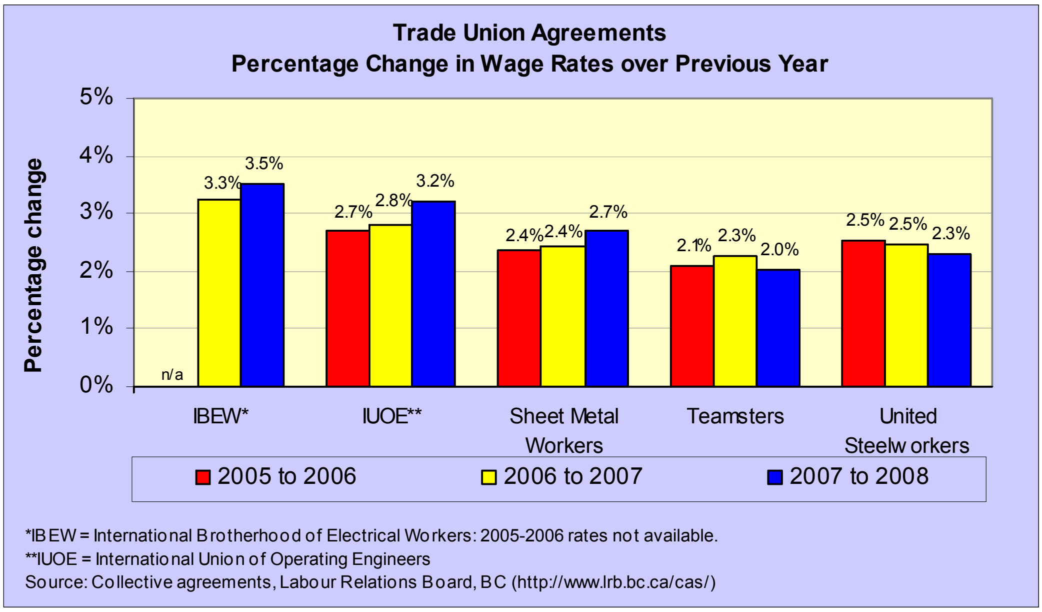
Source: Statistics Canada Tables: 282-0069 and 282-0071: Weekly wage rate (LFS), BC, construction trades V2576579; BC construction V1575891; Table 281-0026: Weekly earnings (SEPH), BC, Other heavy and civil engineering construction V21639054

These trends appear at first glance to be inconsistent with anecdotal industry sources, which report very significant increases in wages paid for similarly qualified labour. One possible explanation of these results is that the rapid growth of the BC construction industry has resulted in a decline in average experience levels, partly masking the increase in wage earnings for equally qualified individuals.

b) Trade union wage rate agreements

A number of collective agreements were renewed in BC in 2006. As illustrated in Exhibit 4b, annual wage rate increases (excluding benefits and other adjustments) are generally in the range of 2.0% to 3.5% annually.

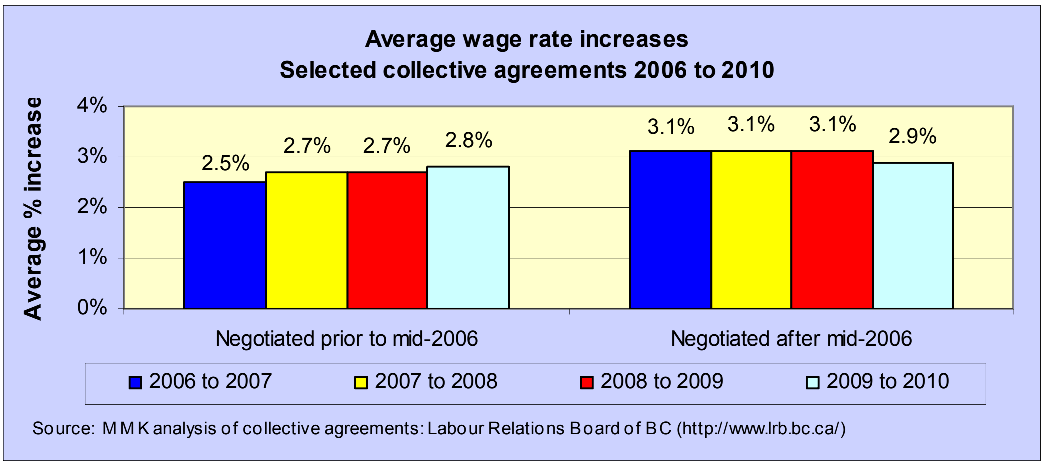
Exhibit 4b — Wage rate increases for sample union trade positions



c) Recent trends in union wage raises

Exhibit 4c illustrates the trends in size of collective agreement wage increases in recent months. For collective agreements negotiated in the second half of 2006, trends show average annual wage increases that are modestly higher than wage increases negotiated in earlier agreements.

Exhibit 4c — Recent years wage rate increases for sample union trade agreements

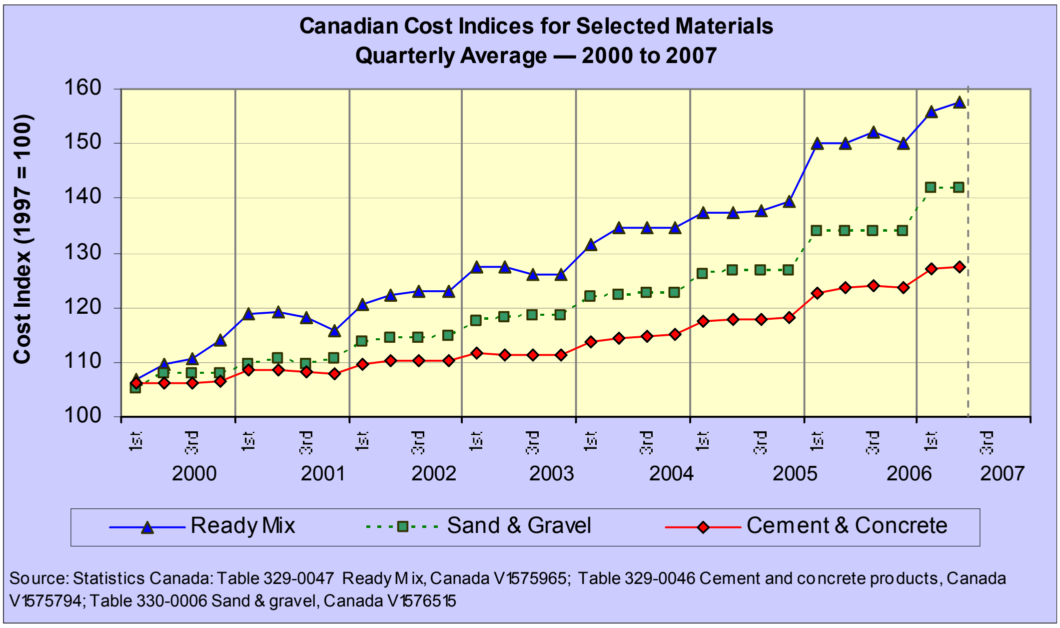


4.2 Concrete materials

a) Quarterly trends in recent years

Concrete materials price indices have been trending steadily upwards over the past few years, as illustrated in Exhibit 4d.

Exhibit 4d — Cost indices for selected construction materials



b) Recent trends

As illustrated in Exhibit 4d, concrete materials price indices have increased 3.1% to 5.7% between fourth quarter of 2006 and the second quarter of 2007, with most of the increase coming in the first quarter of 2007.

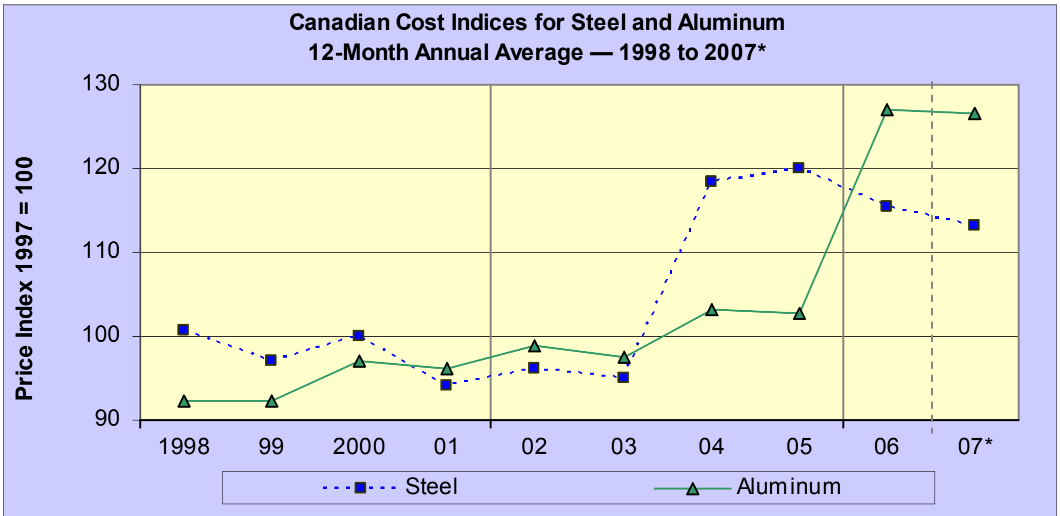
The increase in early 2007 was not as sharp as in early 2006 (up 7% to 10% over the first half of 2005), but is still strongly upwards.

4.3 Metal prices[1]

a) Annual trends

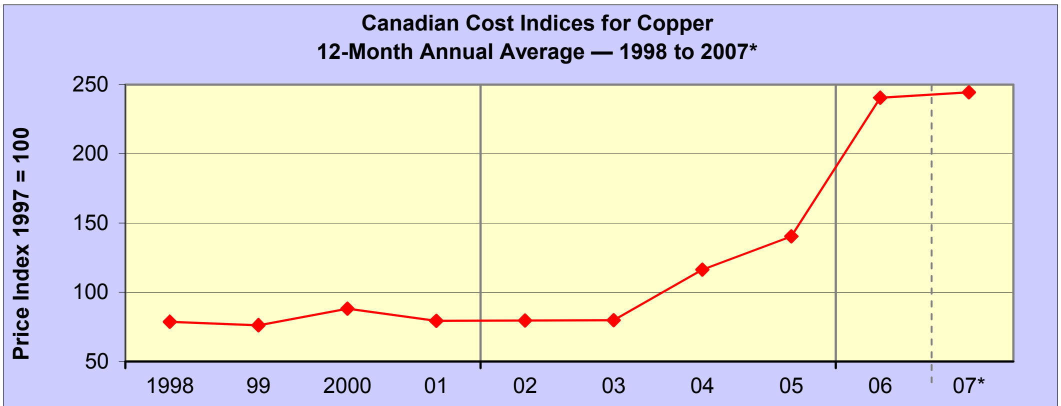
Exhibit 4e illustrates annual Canadian trends in steel, copper and aluminum.

Exhibit 4e — Selected metal cost trends – Canada
(i) Steel and aluminum



*Six-month average for 2007 (Jan-Jun 2007)
Source:StatsCan: Table 329-0044: Primary aluminum products V1575263; Table 329-0038: Iron and steel mills & ferro-alloy manufacturing V3822696

(ii) Copper



*Six-month average for 2007 (Jan-Jun 2007)
Source:StatsCan: Table 329-0044: Copper and copper alloys in primary form V1575281;

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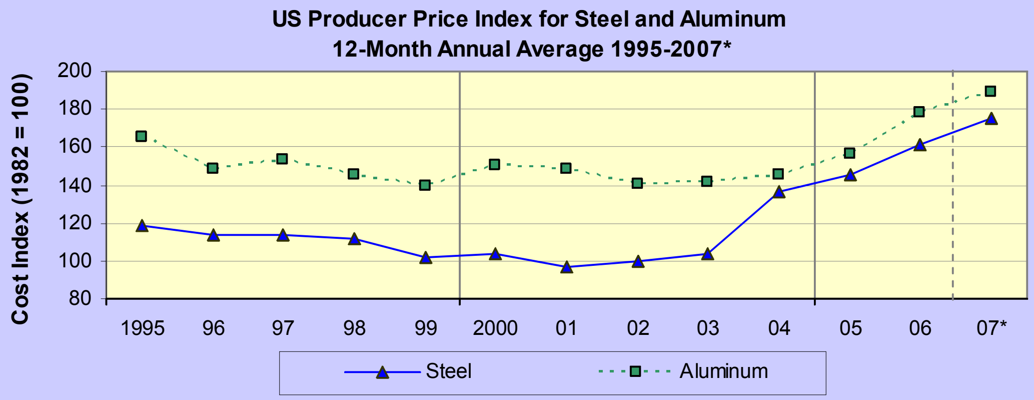
1 Caution should be used in assessing the implications of metal price trends for electric utility construction costs. Metal commodity prices may not be indicative of the short and medium term trends in the cost of metal materials used in major utility construction projects, since these trends may be outweighed by industry-specific supply and demand trends.

For these three metals:

- **Copper** has experienced the greatest price increases since 2003, especially between 2005 and 2006. The first half of 2007, copper prices averaged close to 2006 average levels.
- **Steel** experienced a two-year increase of more than 25% between 2003 and 2005, before flattening in 2006.
- **Aluminum** prices rose moderately throughout 2005, before increasing sharply in 2006 and flattening in the first half of 2007.

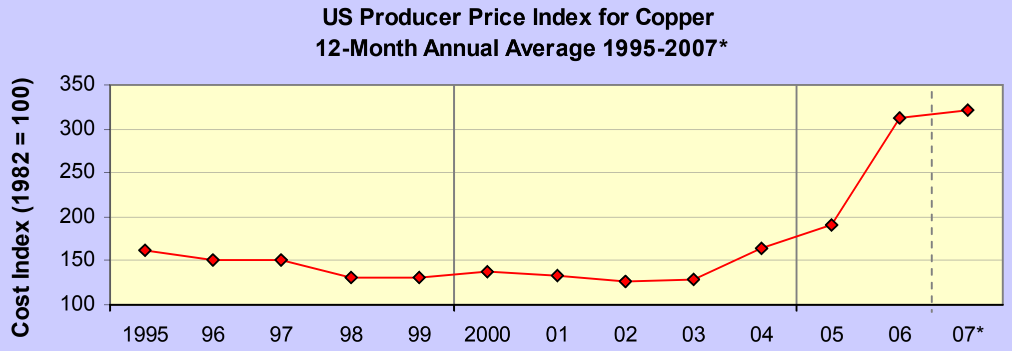
US price index trends (Exhibit 4f) are similar to Canadian trends.

Exhibit 4f — US producer price index for selected metal products
(i) Steel and aluminum



*Six-month average (Jan-Jun) for 2007
Source: US Bureau of Labor Statistics Data —Producer Price Index Industry Data: Aluminum sheet, plate & foil manufacturing (PCU331315). Iron and steel mills (PCU331111)

(ii) Copper

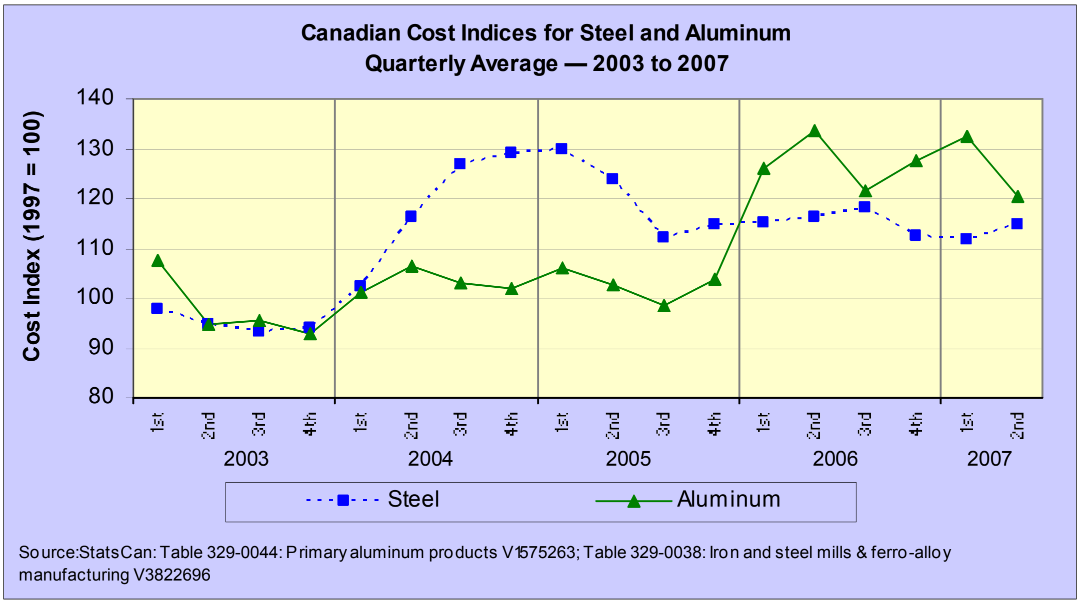


*Six-month average (Jan-Jun) for 2007
Source: US Bureau of Labor Statistics Data —Producer Price Index Industry Data: Copper rolling, drawing & extruding (PCU331421).

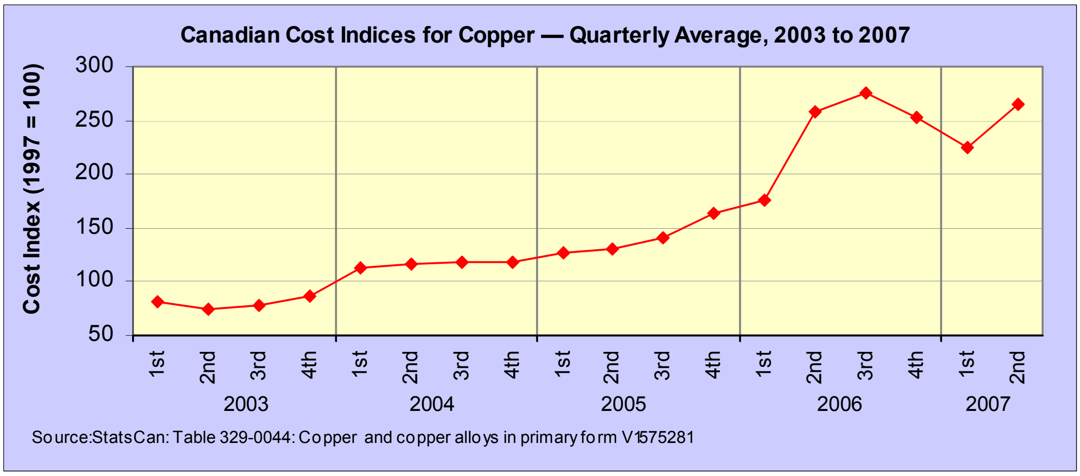
b) *Recent trends*

Quarterly cost index trends for steel, aluminum and copper are illustrated in Exhibit 4g.

Exhibit 4g — Canadian cost indices for selected metals
(i) Steel and aluminum



(ii) Copper



Copper prices rebounded in the second quarter of 2007, following a decline between the third quarter of 2006 and first quarter of 2007. Prices have recently been at or near all-time highs, following the dramatic increases in early 2006.

Aluminum prices continued to be strong the first half of 2007, at or close to record 2006 levels, following the significant increase in prices between 2005 and 2006. In the US, aluminum prices were at record highs in the first half of 2007.

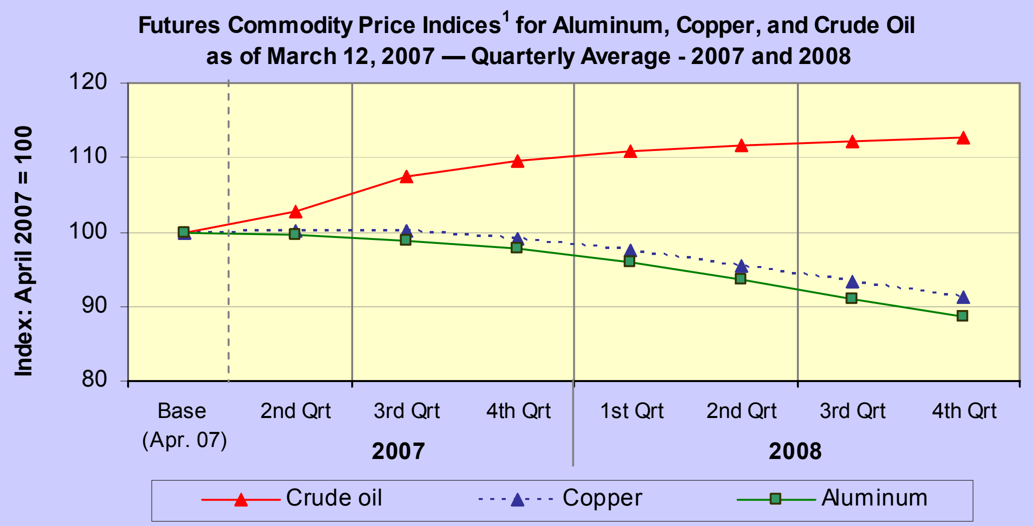
Steel prices also continued to be strong during the first half of 2007, at or close to record 2006 levels.

4.3.2 Changes in Futures markets

a) Previous outlook (February 2007)

Exhibit 4h illustrates the futures prices as recorded by the Futures New York Mercantile Exchange (NYMEX) on February 1, 2007, for aluminum, copper and crude oil, (translated to a common index).

Exhibit 4h — Futures commodity price indices, based on the Futures New York Mercantile Exchange



1 Indices calculated by MMK, using April 2007 Futures prices as the base of 100.
Source: TFC Commodity (http://w w w .tfc-charts.w 2d.com/marketquotes/CL.html): COMEX Copper High Grade; Comex Aluminum, NYMEX Crude Oil (Light)

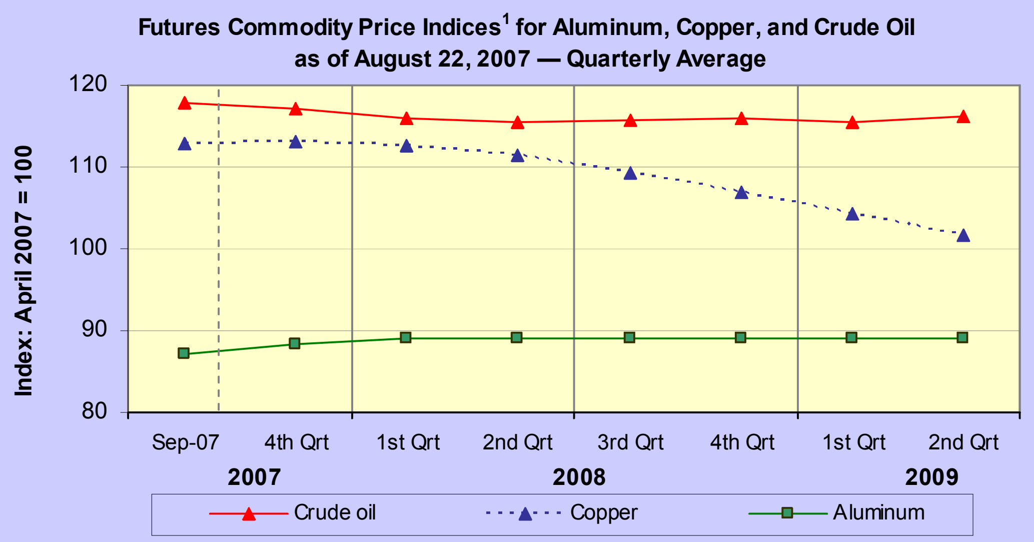
As of March 12, 2007, the market was expecting the following price changes by the fourth quarter of 2008:

- **Crude oil** – projected to <u>increase</u> from US $58 to $66.
- **Copper** – projected to <u>decrease</u> from US $2.85/lb to $2.53/lb.
- **Aluminum** – projected to <u>decrease</u> from US $1.23/lb to $1.05/lb.

b) Updated outlook (August 2007)

Exhibit 4i illustrates futures commodity prices as of August 2007.

Exhibit 4i — Futures commodity price indices, based on the Futures New York Mercantile Exchange



1 Indices calculated by MMK, using September 2007 Futures prices as the base of 100.
Source: TFC Commodity (http://futures.tradingcharts.com/): COMEX Copper High Grade; Comex Aluminum, NYMEX Crude Oil (Light)

As of August 2007, the market was expecting future prices to change as follows from the last quarter of 2007 to the first half of 2009:

- **Crude oil** – projected to remain stable at approximately $US 69.
- **Copper** – projected to decrease from US $3.21/lb to $2.85/lb.
- **Aluminum** – projected to increase slightly from US 1.07/lb to $1.10.

c) Interpretation of futures markets trends

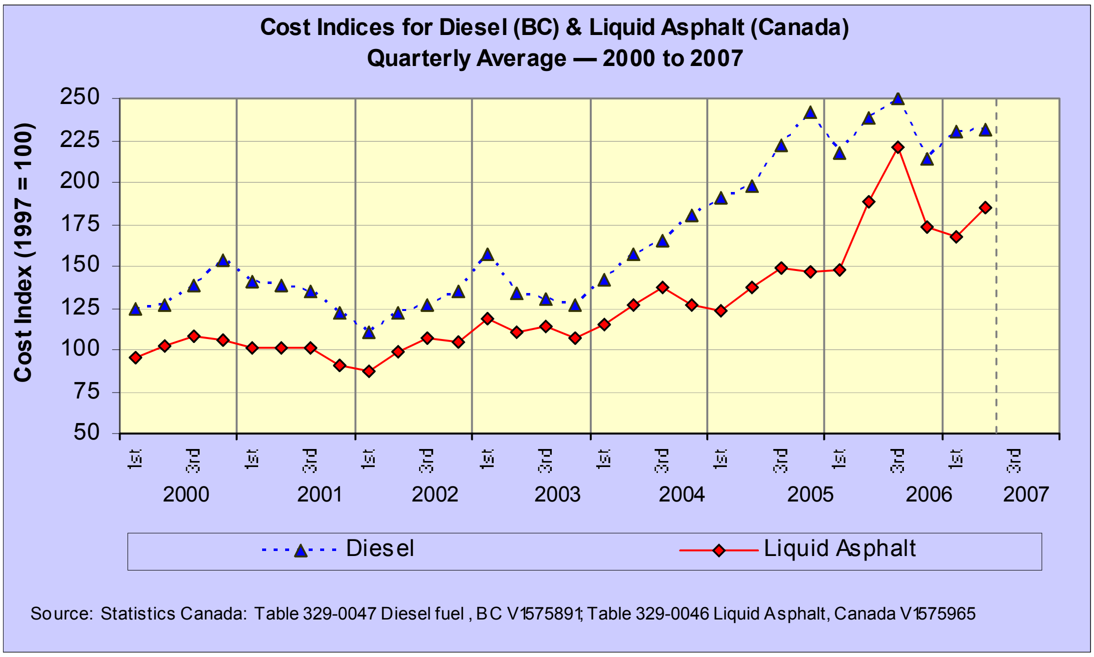
The market expectations in August 2007 are for more stable commodity price trends than were expected in March – albeit at higher general price levels than foreseen in March.

4.4 Diesel fuel and asphalt

a) Recent trends

Quarterly price index trends for diesel fuel and asphalt are illustrated in Exhibits 4j.

Exhibit 4j — Cost indices for diesel and liquid asphalt



Diesel fuel prices declined seasonally between the third and fourth quarter of 2006, before rebounding during the first quarter of 2007. Prices in mid 2007 are slightly lower than the record highs established in 2006.

Asphalt prices declined seasonally between the third quarter of 2006 and first quarter of 2007. Prices during the second quarter of 2007 were close to 2006 second-quarter levels.

b) Outlook in August 2007

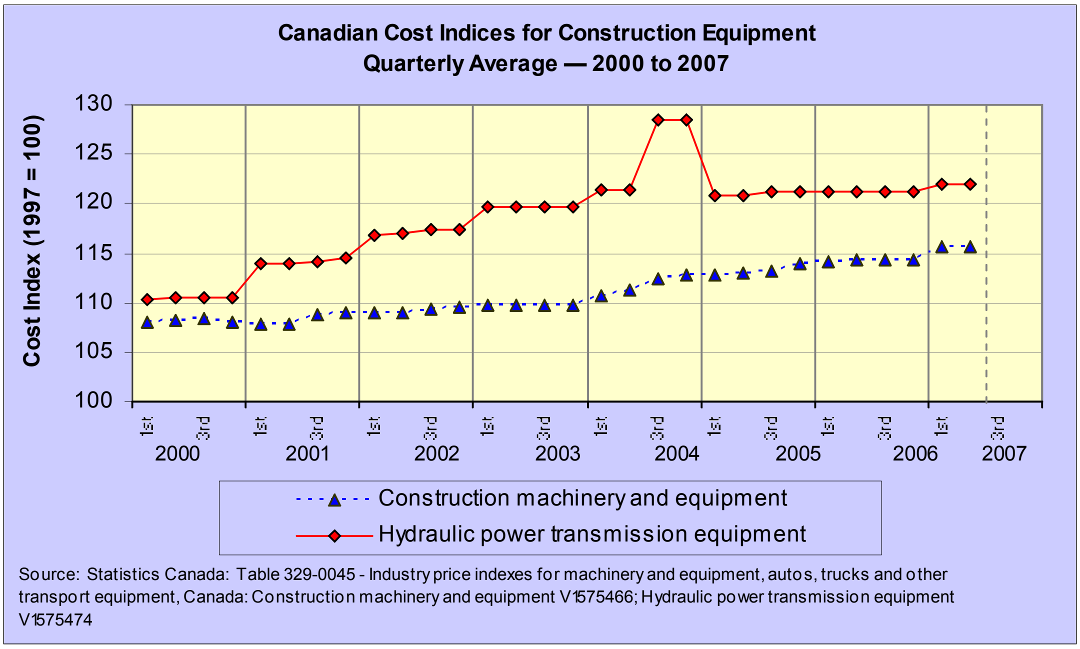
As previously illustrated in Exhibit 4i, the New York Mercantile Exchange Futures market expects the price of crude oil to remain stable around US $69/barrel over the next several quarters.

4.5 Construction machinery & equipment

a) Quarterly trends in recent years

As illustrated in Exhibit 4k, for construction machinery and equipment, and for hydraulic power and transmission equipment, price indices have been increasing slowly in recent years. Results for 2007 are slightly higher than in recent years, but are still modest in relation to increases in other indices.

Exhibit 4k — Cost indices for construction equipment



4.6 Oil & gas drilling/extraction and mining costs

a) Annual trends

Exhibit 41 illustrates price trends for selected US oil, gas and mining indices. (These indices relate to the cost of drilling/extracting/mining activity, rather than the value of the product.)

Exhibit 41 — US producer price index for selected mining activities

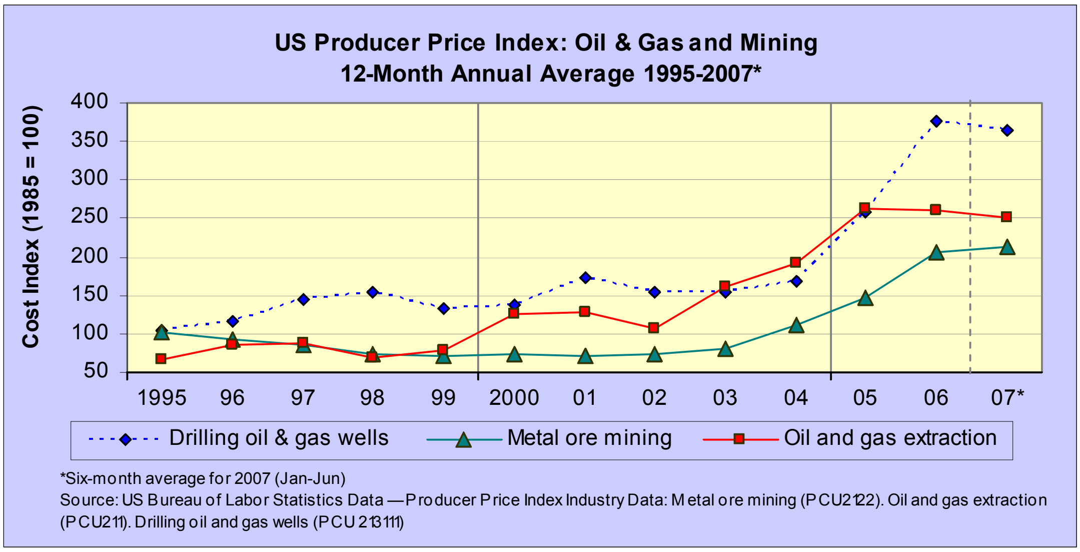


Exhibit 4e illustrates that:

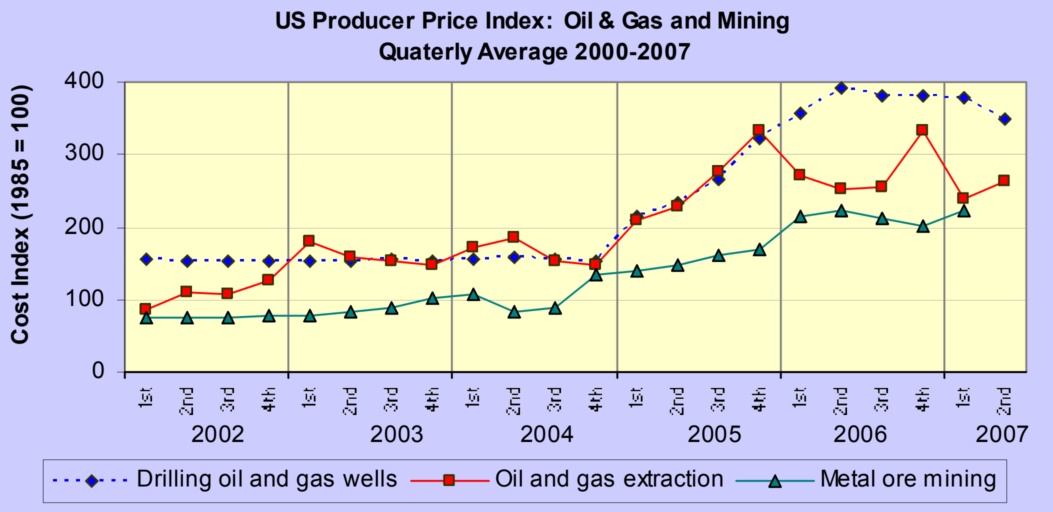
- **Oil and gas drilling** price indices have more than doubled between 2003 and 2006.
- **Metal ore** mining price indices were flat between 1998 and 2003, but have more than doubled between 2003 and 2006.
- **Oil and gas extraction** price indices also more than doubled between 2003 and 2005, before flattening between 2005 and 2006.

b) Recent trends

Quarterly trends are illustrated in Exhibit 4m:

- **Oil and gas drilling** prices indices declined in the first quarter and second quarters of 2007
- **Oil and gas extraction** price indices declined significantly in the first quarter of 2007, but recovered to mid-2006 levels in the second quarter.
- **Metal ore** mining price indices decreased in the first quarter of 2007, but increased in the second quarter to 2006 peak levels.

Exhibit 4m — Price indices in the US mining and oil & gas industry sectors



Source: US Bureau of Labor Statistics Data —Producer Price Index Industry Data: Metal ore mining (PCU2122). Oil and gas extraction (PCU211). Drilling oil and gas wells (PCU213111)

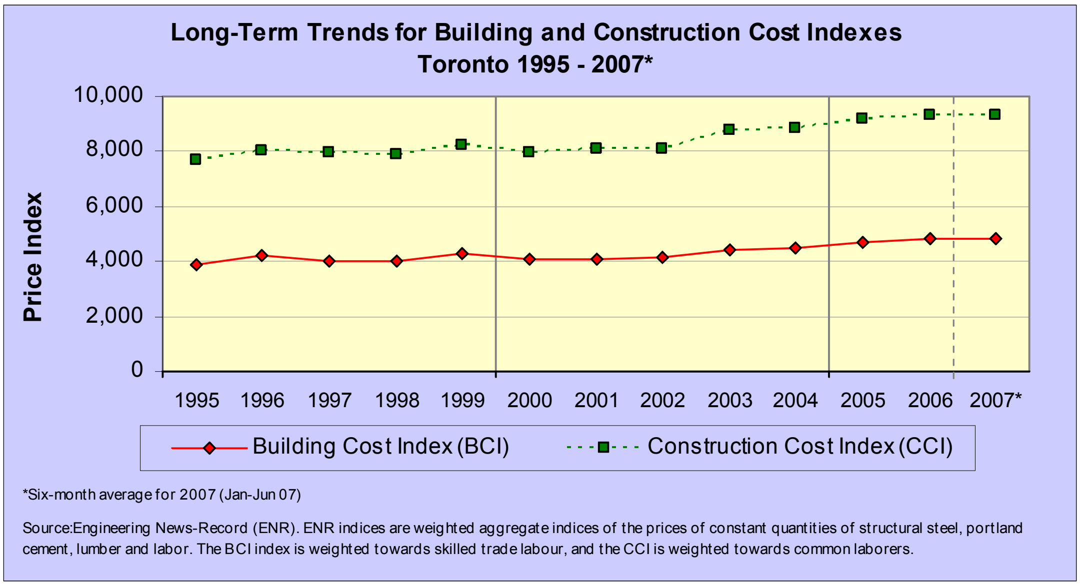
4.7 ENR composite measure of construction cost components

Engineering News Record (ENR) publishes two composite indices of construction cost components, for a number of cities in the US and Canada, including Toronto: the Building Cost Index (BCI), and the Construction Cost Index (CCI) [1].

As illustrated in Exhibit 4n, ENR construction cost inflation rates for Toronto show moderate increases in recent years, and less than 1% over the past six months.

These indices do not take into account factors such as profit margins, insurance costs, employee bonuses and incentives, lower productivity levels related to labour shortages, etc. They are therefore only partial indicators of construction cost trends.

Exhibit 4n - ENR construction cost indices for Toronto 1995-2007



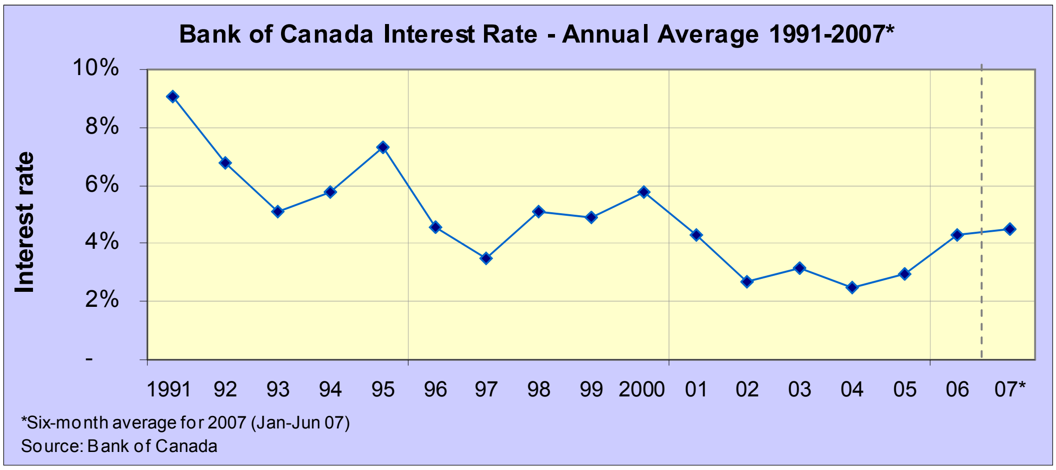
[1] ENR indices are weighted aggregate indices of the prices of constant quantities of structural steel, portland cement, lumber and labor. The BCI index is weighted more towards skilled trade labour, and the CCI is weighted more towards entry-level laborers.

4.8 Trends in interest rates

a) *Longer-term annual trends*

Long-run trends in the Bank of Canada interest rate are illustrated in Exhibit 4o. They demonstrate the historically low interest rates that have prevailed during the past few years. Rates increased in 2006, but are still relatively low in relation to historical levels of the past two decades. Many observers have identified the low cost of borrowing as a driver of the residential and non-residential construction boom in British Columbia and across Canada.

Exhibit 4o — Long-term Bank of Canada interest rates



b) *Recent trends*

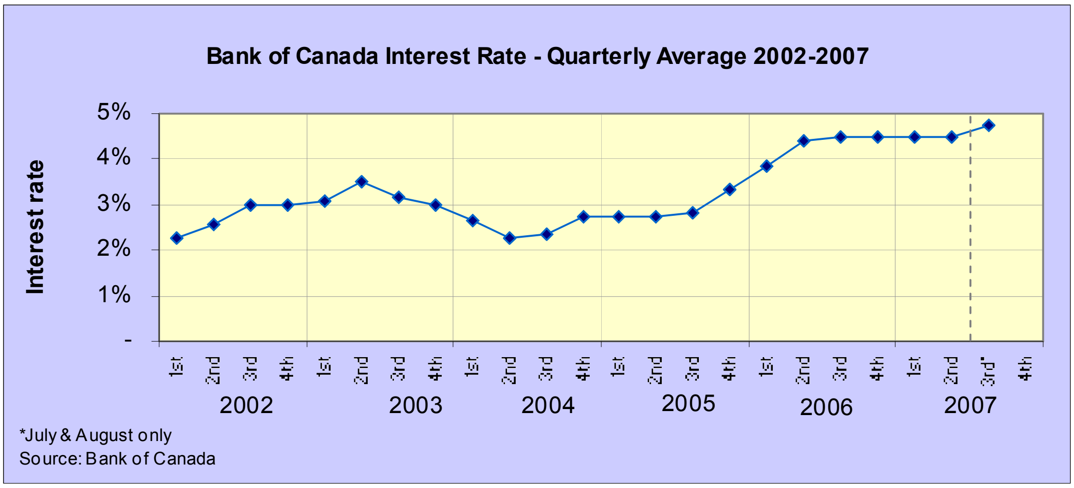
Quarterly interest rate trends, shown in Exhibit 4p, illustrate the upturn in interest rates in late 2005 and early 2006. These increases affect non-residential construction prices in two ways:

- **Cost impact on contractors.** Interest rate increases add to the contractor's cost of doing business, especially where the contractor's business is financed through debt instruments (operating lines of credit, loans on capital equipment, etc.).

- **Demand impact.** Interest rate increases also add to the owner's costs, especially where these costs are debt-financed. Higher interest rates will tend to dampen the demand for construction activity, encouraging greater price competition.

Based on the construction boom of the past few years, the demand impacts of interest rates shifts appear to outweigh the contractor cost impacts, at least in a low interest rate environment.

Exhibit 4p — Quarterly Bank of Canada interest rates



The Bank of Canada interest rate remained stable between the second quarters of 2006 and 2007, before being increased to 4.75% in July 2007.

4.9 Conclusion — Component cost trends

While component cost trends have been mixed during the first half of 2007, there has been a general tendency towards less volatility than was experienced in 2005 and 2006 – albeit at much increased price levels.

While component cost trends are important contributors to cost inflation in the BC industrial construction industry, they are only partial indicators of the total impact of prices, since they do not account for market-driven (supply and demand) cost inflation pressures.

5. BC Regional Trends

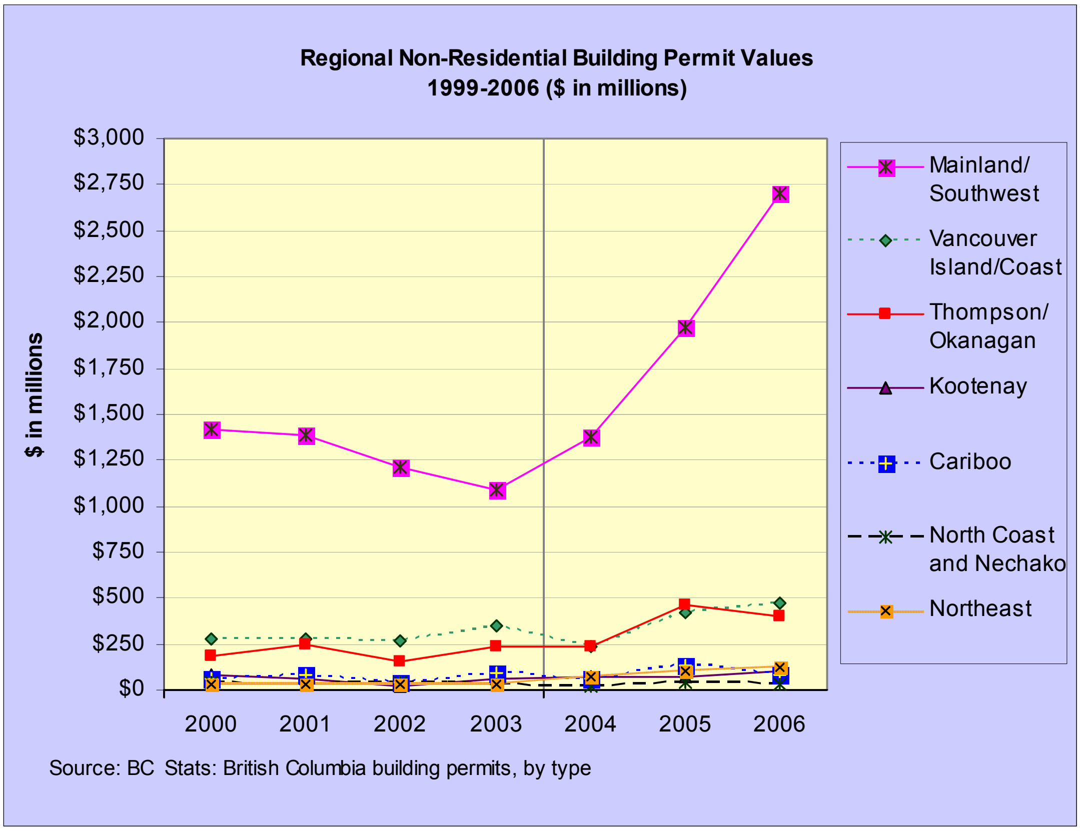
Regional construction price indices are not kept by Statistics Canada or BC Stats. However, regional construction activity levels provide an indirect indicator of those regions in which construction cost inflation pressures can be expected to be significant in BC.

5.1 Regional trends in construction activity levels

a) Annual trends

Regional trends in non-residential construction levels are illustrated in Exhibit 4a, based on the data contained in Exhibit 5a.

Exhibit 5a — Regional annual trends in non-residential building permit values



The Mainland/Southwest region accounts for approximately two-thirds of all non-residential construction activity in BC. This region also had the largest dollar increase in building permit values in 2006.

Exhibit 5b — BC value of building permits, by region

	2000	2001	2002	2003	2004	2005	2006	Jan-May 2006	Jan-May 2007	Change 06 vs 07
British Columbia (Total)										
Total value	4,492.0	4,954.7	5,659.4	6,394.2	7,938.7	10,191.1	11,541.1	4,303.2	5,210.6	21.1%
Non-residential										
Industrial	296.0	221.0	230.0	244.0	328.0	346.2	358.2	113.9	113.6	-0.3%
Commercial	1,297.0	1,171.0	1,117.0	1,130.0	1,228.0	1,886.4	2,491.4	847.3	1,183.0	39.6%
Institutional/Government	496.0	732.0	424.0	506.0	514.0	979.5	1,067.4	534.6	370.5	-30.7%
Total non-residential	2,089.0	2,124.0	1,771.0	1,880.0	2,070.0	3,212.1	3,917.0	1,495.8	1,667.1	11.5%
Residential	2,403.0	2,830.7	3,888.4	4,514.2	5,868.7	6,979.0	7,624.1	2,807.6	3,543.5	26.2%
Vancouver Island/Coast										
Total value	581.5	632.0	769.2	993.4	1,098.4	1,459.9	1,705.7	621.9	871.3	40.1%
Non-residential										
Industrial	29.7	34.8	16.5	33.6	18.5	20.7	31.4	11.6	15.6	34.5%
Commercial	147.6	145.1	155.2	202.5	139.1	257.4	281.9	84.6	89.2	5.4%
Institutional/Government	99.3	102.6	93.5	113.6	81.0	148.3	161.8	53.6	175.0	226.5%
Total non-residential	276.6	282.5	265.2	349.7	238.6	426.4	475.2	149.8	279.8	86.8%
Residential	304.9	349.5	504.0	643.7	859.8	1,033.5	1,230.5	472.1	591.6	25.3%
Mainland/ Southwest										
Total value	3,079.8	3,396.6	4,028.3	4,165.0	5,371.6	6,387.3	7,443.1	2,730.6	3,334.3	22.1%
Non-residential										
Industrial	194.9	150.5	162.7	129.8	198.4	187.7	227.9	72.3	63.9	-11.6%
Commercial	953.0	799.3	787.7	697.4	861.5	1,204.7	1,802.8	611.2	896.9	46.7%
Institutional/Government	269.2	433.9	257.7	262.7	315.1	582.9	672.1	365.3	148.7	-59.3%
Total non-residential	1,417.1	1,383.7	1,208.1	1,089.9	1,375.0	1,975.3	2,702.7	1,048.8	1,109.5	5.8%
Residential	1,662.7	2,012.9	2,820.2	3,075.1	3,996.6	4,412.0	4,740.4	1,681.8	2,224.7	32.3%
Thompson/ Okanagan										
Total value	397.01	531.256	515.998	774.3	963.7	1,560.7	1,551.7	629.4	712.3	13.2%
Non-residential										
Industrial	30.2	17.4	23.4	49.2	30.5	48.3	69.1	17.2	13.6	-20.9%
Commercial	96.2	159.4	94.2	116.2	135.3	293.6	209.8	93.8	162.2	72.9%
Institutional/Government	54.6	70.2	35.6	70.1	70.0	122.0	125.8	54.2	29.0	-46.5%
Total non-residential	181.0	247.0	153.2	235.5	235.8	464.0	404.6	165.2	204.8	24.0%
Residential	216.0	284.3	362.8	538.8	727.9	1,096.8	1,147.0	464.2	507.4	9.3%
Kootenay										
Total value	219.001	174.291	164.2	239.4	244.6	369.7	402.4	164.5	148.2	-9.9%
Non-residential										
Industrial	27.8	8.8	6.5	6.7	13.9	8.9	13.4	9.1	1.8	-80.2%
Commercial	44.0	18.3	13.5	28.6	33.4	22.9	33.0	12.3	9.3	-24.4%
Institutional/Government	15.3	34.7	5.0	23.5	23.8	38.6	55.7	25.3	14.1	-44.3%
Total non-residential	87.1	61.8	25.0	58.8	71.1	70.4	102.1	46.7	25.2	-46.0%
Residential	131.9	112.5	139.2	180.6	173.5	299.3	300.3	117.8	123.0	4.4%
Cariboo										
Total value	101.8	115.2	88.5	125.4	121.2	203.0	174.0	74.5	76.3	2.4%
Non-residential										
Industrial	7.5	4.0	10.2	6.5	16.2	38.0	7.2	2.4	3.9	62.5%
Commercial	22.4	21.3	25.7	52.0	32.3	30.3	39.8	8.0	11.3	41.3%
Institutional/Government	29.9	55.9	9.8	31.2	11.1	62.0	33.4	29.5	2.4	-91.9%
Total non-residential	59.8	81.2	45.7	89.7	59.6	130.4	80.4	39.9	17.6	-55.9%
Residential	42.0	34.0	42.8	35.7	61.6	72.6	93.7	34.7	58.8	69.5%
North Coast and Nechako										
Total value	57.7	45.9	46.4	41.2	33.3	61.5	63.1	21.4	21.2	-0.9%
Non-residential										
Industrial	2.2	4.1	5.9	11.4	1.5	11.8	4.5	1.1	0.5	-54.5%
Commercial	13.5	11.8	10.9	13.1	7.7	10.8	21.9	5.2	6.1	17.3%
Institutional/Government	24.3	18.3	21.3	4.0	10.9	18.8	5.2	0.5	1.3	160.0%
Total non-residential	39.9	34.2	38.1	28.5	20.1	41.3	31.6	6.8	7.9	16.2%
Residential	17.7	11.7	8.3	12.6	13.2	20.1	31.5	14.6	13.3	-8.9%
Northeast										
Total value	55.2	59.5	46.7	55.6	105.9	149.1	201.2	60.9	47.0	-22.8%
Non-residential										
Industrial	3.3	1.7	5.0	6.8	49.0	30.8	4.8	0.2	14.3	7050.0%
Commercial	20.7	16.0	19.5	19.9	18.7	66.7	102.2	32.2	8.0	-75.2%
Institutional/Government	3.5	16.6	1.5	1.3	1.9	6.9	13.4	6.2	0.0	-100.0%
Total non-residential	27.5	34.3	26.0	28.0	69.5	104.4	120.5	38.6	22.3	-42.2%
Residential	27.7	25.2	20.7	27.6	36.4	44.6	80.7	22.4	24.7	10.3%

Source: BC Stats – British Columbia building permits, by type.

b) *Recent trends*

Exhibit 5c compares percentage changes for 2005 over 2006, plus partial-year comparisons of 2007 versus 2006.

Exhibit 5c — Value of building permits, by region

	Value of non-residential building permits					
	2005 ($ M)	2006 ($ M)	Change 2005 to 2006	Jan-May 2006	Jan–May 2007	Change Jan-May 2007 vs 06
Total non-residential						
■ Vancouver Island/Coast	426	475	+11%	149.8	279.8	+87%
■ Mainland/Southwest	1,975	2,703	+37%	1048.8	1109.5	+6%
■ Thompson/Okanagan	464	405	-13%	165.2	204.8	+24%
■ Kootenay	70	102	+45%	46.7	25.2	-46%
■ Cariboo	130	80	-38%	4039.9	17.6	-56%
■ North Coast & Nechako	41	31	-24%	6.8	7.9	+16%
■ Northeast	104	121	+15%	38.6	22.3	+42%
Industrial construction						
■ Vancouver Island/Coast	21	31	+52%	11.6	15.6	+35%
■ Mainland/Southwest	188	228	+21%	72.3	63.9	-12%
■ Thompson/Okanagan	48	69	+43%	17.2	13.6	-21%
■ Kootenay	9	13	+51%	9.1	1.8	-80%
■ Cariboo	38	7	-81%	2.4	3.9	+63%
■ North Coast & Nechako	12	5	-62%	1.1	0.5	-54%
■ Northeast	31	5	-84%	0.2	14.3	>+100%

Comparing industrial construction activity over the five-month period January-May 2007 to the same period in 2006:

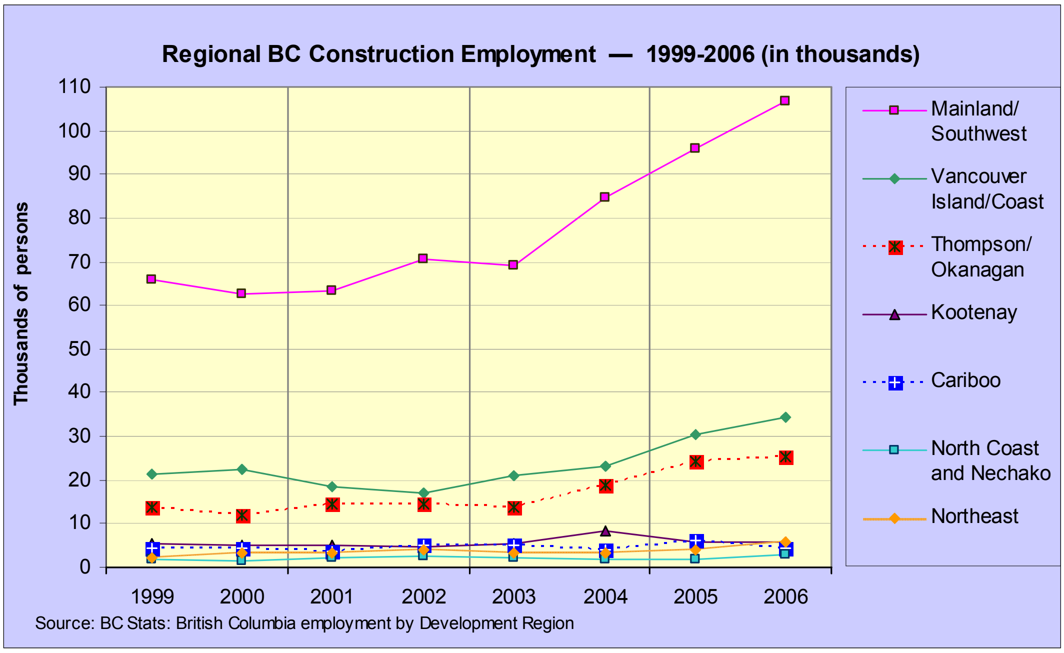
- Vancouver Island/Coast shows a 35% increase, continuing the strong upward trend between 2005 and 2006.
- The Cariboo and the Northeast regions show significant increases for early 2007, reversing the drop between 2005 and 2006.
- Industrial activity levels in the Lower Mainland/Southwest, Thompson/Okanagan and Kootenay regions show declines in early 2007 over early 2006, compared with increases in 2006 over 2005.

5.2 Regional trends in construction employment

a) Annual trends

Regional trends in construction employment are illustrated in Exhibit 5d. In absolute terms, the highest rates of growth in construction employment between 2003 and 2006 were in the BC Mainland/Southwest, Vancouver Island/Coast, and Thompson/Okanagan.

Exhibit 5d — Regional construction employment trends 1999-2006 (000s)[1]



1. See also table overleaf.

Exhibit 5d (cont'd) — Regional construction employment trends 1999-2006 (000s)

	1999	2000	2001	2002	2003	2004	2005	2006	% change 2005 to 2006
British Columbia									
Construction employment	114.3	111.1	110.7	118.1	119.8	144.0	168.0	185.3	10.3%
- % of total employment	6.0%	5.8%	5.8%	6.0%	5.9%	7.0%	7.9%	8.4%	
Vancouver Island/Coast									
Construction employment	21.2	22.4	18.5	17.1	20.9	23.0	30.3	34.4	13.5%
- % of total employment	6.4%	6.8%	6.0%	5.4%	6.5%	6.9%	8.7%	9.3%	
Mainland/Southwest									
Construction employment	65.8	62.6	63.4	70.4	69.2	84.6	95.8	106.9	11.6%
- % of total employment	5.8%	5.4%	5.4%	5.8%	5.5%	6.6%	7.3%	7.9%	
Thompson/Okanagan									
Construction employment	13.7	12.0	14.6	14.3	13.6	18.8	24.1	25.3	5.1%
- % of total employment	6.6%	5.7%	6.9%	6.9%	6.2%	8.2%	9.9%	9.8%	
Kootenay									
Construction employment	5.3	5.0	5.1	4.6	5.5	8.3	5.8	5.8	-0.6%
- % of total employment	7.6%	7.1%	7.2%	6.9%	8.2%	12.4%	8.4%	8.2%	
Cariboo									
Construction employment	4.4	4.5	3.7	4.9	4.9	4.1	6.2	4.3	-30.6%
- % of total employment	5.4%	5.7%	4.7%	6.3%	6.3%	5.1%	7.7%	5.2%	
North Coast and Nechako									
Construction employment	1.9	1.5	2.3	2.6	2.2	1.9	1.8	2.9	59.3%
- % of total employment	4.1%	3.2%	4.9%	5.8%	4.9%	4.5%	3.9%	6.7%	
Northeast									
Construction employment	2.1	3.1	3.1	4.0	3.4	3.4	3.9	5.7	47.0%
- % of total employment	6.8%	9.7%	9.5%	12.0%	9.7%	10.2%	11.4%	16.4%	

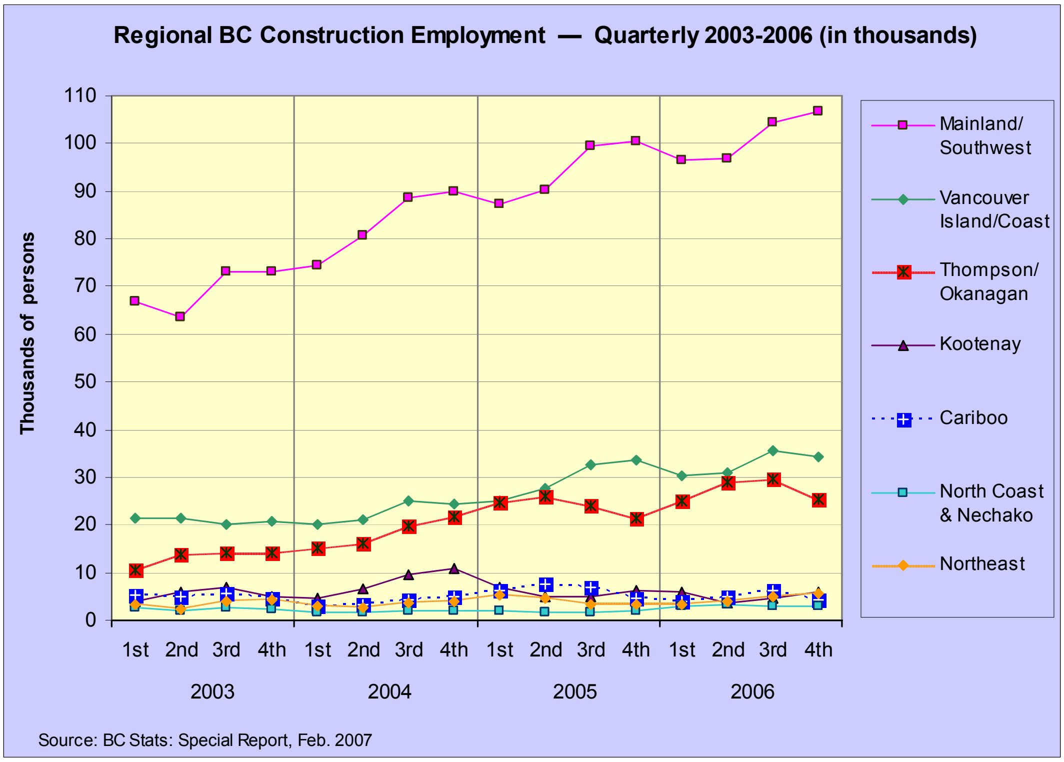
In percentage terms, construction employment in 2006 was up in all areas except Kootenay (flat) and Cariboo (down -31%).

b) Recent trends

Quarterly construction employment trends for 2003-06 are illustrated in Exhibit 5e.

(Quarterly construction employment is not yet available on a regional basis for early 2007.)

Exhibit 5e – Regional BC construction employment



In **Mainland/Southwest**, quarterly trends in 2005/06 were similar to those in 2005 — a seasonal decline in the first quarter, followed by an increase throughout the balance of the year. However, the seasonal trends in 2006 occurred at an overall employment level approximately 8% higher than in 2005.

In **other regions**, Vancouver Island/Coast returned to normal seasonal downward trends after having had no downturn during winter 2004/05, and in Thompson/Okanagan construction employment increased in the first quarter of 2006 after dropping in the fourth quarter of 2005.

5.3 Conclusions — Regional trends

Based on the available data on construction activity levels (building permit values, construction industry employment trends), the greatest market-driven regional cost inflation pressures are for Vancouver Island, Northeast BC and the Lower Mainland.

6. Other Agencies' Estimates and Forecasts

This chapter briefly outlines some approaches undertaken by other agencies in estimating historical construction cost inflation and/or in forecasting future trends, where we have used the information in developing recommendations for BC Hydro. These approaches are illustrated in Exhibit 6a and are described in the following pages.

Exhibit 6a – Other agencies' cost inflation estimates and forecasts

Cost inflation estimates/forecasts		2006	2007	2008	2009	2010	2011-2015
BTY	BC Lower Mainland construction						
	• December 2005	11%	10%	10%	9%	8%	
	• December 2006	11%	5-7%	5%	3%	3%	
ENR (US)	Component cost Index						
	• Building Cost Index (BCI)	3.9%	3.5%[1]				
	• Construction Cost Index (CCI)	4.1%	3.7%[1]				
RLB (US)	Selling price index						
	• US	10.4%	9.9%[2]				
	• Seattle	n/a	12.9%[2]				
BC MoT	Construction cost allowances						
	• Property acquisition		10.0%	10.0%	10.0%		
	• Construction costs		5.2%	5.2%	5.2%		
BC AVED	Construction cost allowances	15%	15%	12%	9%	8%	
YVR	Construction cost allowances		8%	6%	5%	3.5%	2.5%
StatsCan	Industrial construction						
	• Seven CMAs	7.8%	9.6%[3]				
	• Vancouver	10.3%	13.7%[3]				
	Electric utility construction						
	• Distribution systems	4.0%	n/a				
	• Transmission lines	2.3%	n/a				
	• Substations	1.8%	n/a				

1 August 06 to August 07
2 July 1/06 to July 1/07
3 June 06 to July 06

6.1 BTY Group

BTY Group is a Canadian-based construction project management consulting firm that periodically issues cost inflation forecasts. BTY's December 2005 newsletter forecast that construction cost inflation in the BC Lower Mainland would be 11% in 2006, 10% in each of 2007 and 2008, 9% in 2009, and 8% in 2010. These estimates were subsequently revised downwards in a BTY December 2006 newsletter which forecast construction cost inflation of 6% (5% to 7%) in 2007, 5% in 2008, and 3% in each of 2009 and 2010.

6.2 ENR composite cost index

As discussed earlier, Engineering News Record (ENR), a US-based McGraw-Hill industry publication, publishes two US indexes—a "Building Cost Index" and a "Construction Cost Index".

- ENR's US **Building Cost Index** (BCI) is more heavily weighted towards materials costs. Based on relatively modest materials cost inflation expectations (ranging from -9% for softwood lumber to +9% for asphalt paving), ENR is forecasting a 0.7% increase in its Building Cost Index for 2007, versus an estimated actual increase of 2.6% in 2006. In August of 2007, ENR reports a Building Cost Index increase of 1.6% since December 2006. If this trend continues, the annual BCI increase for 2007 will be around 2.4%, higher than ENR projections in December 2006.

- ENR's US **Construction Cost Index** (CCI) is more heavily (79%) weighted towards labour costs. In late 2006, ENR is forecasting a 2.7% increase in this index for 2007, slightly down from the 3.2% increase in 2006. ENR's Building Cost Index increased by 1.5% between December 2006 and August 2007. If this trend continues, the annual CCI increase for 2007 will be around 2.3%, lower than ENR projections in December 2006.

It should be noted that these indices do not take into account contractors costs such as profit margins, insurance costs, employees bonuses and incentives, lower productivity levels related to labour shortages, etc.

6.3 Rider Levett Bucknall (RLB) "selling price" index

Rider Levett Bucknall (RLB) is a US/UK firm specializing in construction project management, cost consulting and advisory services that publishes a construction "selling price[1]". RLB's most recent quarterly cost report estimates:

- That its <u>overall</u> US construction cost index (based on bid prices) increased by 9.9% for the year July 1/06 to July 1/07.

- That its <u>Seattle</u> construction cost index increased by 12.9% during the same period.

[1] The "selling price" index is an estimate of what the market will bear. It tracks the true bid cost of construction, including contractor/subcontractor overhead costs and fees (profit).

6.4 Conference Board of Canada report

The Conference Board of Canada's summer 2007 report on Canadian industrial outlook[1] forecasts that both revenues and costs in the construction industry will increase 10% in 2007. It warns however, that by 2008 labour and materials costs will start to surpass revenue. Profit levels are expected to fall every year through 2011 (to 2.3% from 4.3%), but will still be considered high by historical standards — in the range of 1.8% over the past 15 years.

A major cause of projected reduced profit margins is the rising cost of labour, resulting from the labour shortage which compels contractors to hire less-skilled workers (lower productivity), and pay higher wages, bonuses and benefits, driving overall labour costs upward.

6.5 BC Ministry of Transportation (MoT)

This BC Ministry has an annual capital budget in the range of $650-$700 million. Capital projects range widely in size, from small projects costing a few hundred thousand dollars up to major projects of hundreds of millions. Projects may be cost-shared with other levels of government (municipality, federal), with cost inflation risk typically being assumed by the party that is responsible for construction.

Because many of the larger contracts are "design-build", it is often difficult to separate cost factors from design and cost estimating factors in assessing the impact of cost inflation. A previous MMK study for the Ministry estimated that cost inflation of cost components (asphalt, equipment, labour, etc.) can explain approximately 15%-17% of increases between 2003 and 2005, before allowing for market forces.

MoT's strategies for mitigating cost inflation pressures include:

- Breaking larger projects into smaller tenders, to encourage bidding by a wider range of contractors.
- Spacing of tender closing dates, to make it easier for contractors to bid on several projects.
- Making scope adjustments, to at least partially offset cost inflation pressures.
- Clarifying and revising contract language, to make projects less risky for bidders and to share risk where appropriate.

In mid-2006, the Ministry revised its project estimating system to explicitly include cost inflation allowances for various types of project. Annual cost inflation allowances have been established as follows:

- 5.2% annually for project planning & design, project management and construction.
- 10% annually for property acquisition costs.

[1] Conference Board of Canada: Canadian Industrial Outlook: Canada's Non-Residential Construction Industry — Summer 2007.

6.6 BC Ministry of Advanced Education (AVED)

In 2006, the Ministry of Advanced Education (AVED) issued cost inflation estimates and projections for construction projects as follows:

- 14% for 2003
- 15% for 2004
- 16% for 2005
- 15% for each of 2006 and 2007
- 12% for 2008
- 9% for 2009
- 8% for 2010

These figures represent a significant increase from previous AVED cost inflation allowances, which in 2003 had been established as being in the range of 3% to 4.25%.

6.7 Vancouver International Airport (YVR)

We also understand (from BC Hydro) that Vancouver International Airport is using the following construction cost inflation allowances:

- 8% for 2007
- 6% for 2008
- 5% for 2009
- 3.5% for 2010
- 2.5% for 2011-2015

6.8 Statistics Canada

As discussed earlier in detail, Statistics Canada industrial price index data indicate that industrial construction cost inflation in Vancouver has been in the general range of 10% to 14% annually over the past eighteen months.

On the other hand, Statistics Canada's price index for electric utility transmission and distribution was in the range of 2% to 4% for 2006 (data for 2007 not yet available), indicating that cost inflation for industry-specific electric power delivery systems has been significantly lower than for general industrial construction.

6.9 Summary — Other agencies' estimates and forecasts

Other agencies have a wide range of approaches and results, both in estimating recent price index inflation and in developing future cost inflation allowances.

This wide range illustrates the different approaches to measuring cost inflation, different expectations about the duration of the current construction boom, and different approaches in determining how generously to allow for cost inflation pressures.

7. Cost Inflation Outlook for BC Hydro

This final chapter assesses the outlook for BC Hydro's allowances for future major construction projects.

7.1 Trends since last report

The cost inflation allowances recommended in our March 2007 report are illustrated in Exhibit 7a. In our March report, we noted that "a number of industry participants and observers have expressed their views that cost inflation pressures and expectations have begun to ease in the past six months…"

Six months later, while there is some evidence of weakening of some cost component indices, general construction price indices themselves do not yet show a significant weakening of upward price pressures for industrial construction in general.[1]

Within the industry, US-based utility equipment price indices, particularly for transmission and distribution equipment, have risen significantly over the past few years. Anecdotally, BC Hydro staff are reporting significant price increases for imported transmission and distribution materials and equipment in recent months, despite the increase in value of the Canadian dollar. This is a significant shift from earlier reports, where BC Hydro's experience more closely matched the relatively low Canadian price index movements for transmission and distribution construction.

7.2 Recommended cost inflation allowances for BC Hydro

Our recommended cost inflation allowances are illustrated in Exhibit 7a:

- **Heavy construction (power generation)** — While there are some signs of softening in component price indices, the BC construction industry and the Canadian industrial construction industries continue to show high activity levels and price inflation. Accordingly, for 2007 to 2010, our recommended cost inflation allowance range is unchanged at 4% to 6% annually. For 2011 through 2015, our recommended range is 3% to 4% annually, up slightly from our March report.

- **Transmission, stations and distribution** — Given the recent strength of US equipment price indices, combined with the experiences of BC Hydro staff, we expect the cost inflation pressures for transmission, stations and distribution to be similarly strong as for heavy industrial construction. Accordingly, we have increased our recommended cost inflation ranges for transmission, stations and distribution construction to bring them into line with those for heavy construction and power generation.

In summary, our recommended cost inflation allowances, for all major construction projects, are 4%-6% for 2007-2010, and 3%-4% for 2011-2015.

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[1] Data released by Statistics Canada in September 2007 indicate a short-term decline in new building permits in British Columbia between June 2007 and July 2007. However, it is premature to conclude whether this indicates a shift in medium-term trends.

Exhibit 7a — Recommended construction cost inflation allowances

Previous report vs. this update		2007 to 2010	2011 to 2015
Mar. 2007	• Generation (heavy construct.) • Utility transmission/distribut.	4% to 6% 2% to 4%	2.5% to 4% 2% to 4%
Sep. 2007	• All construction projects	4% to 6%	3% to 4%

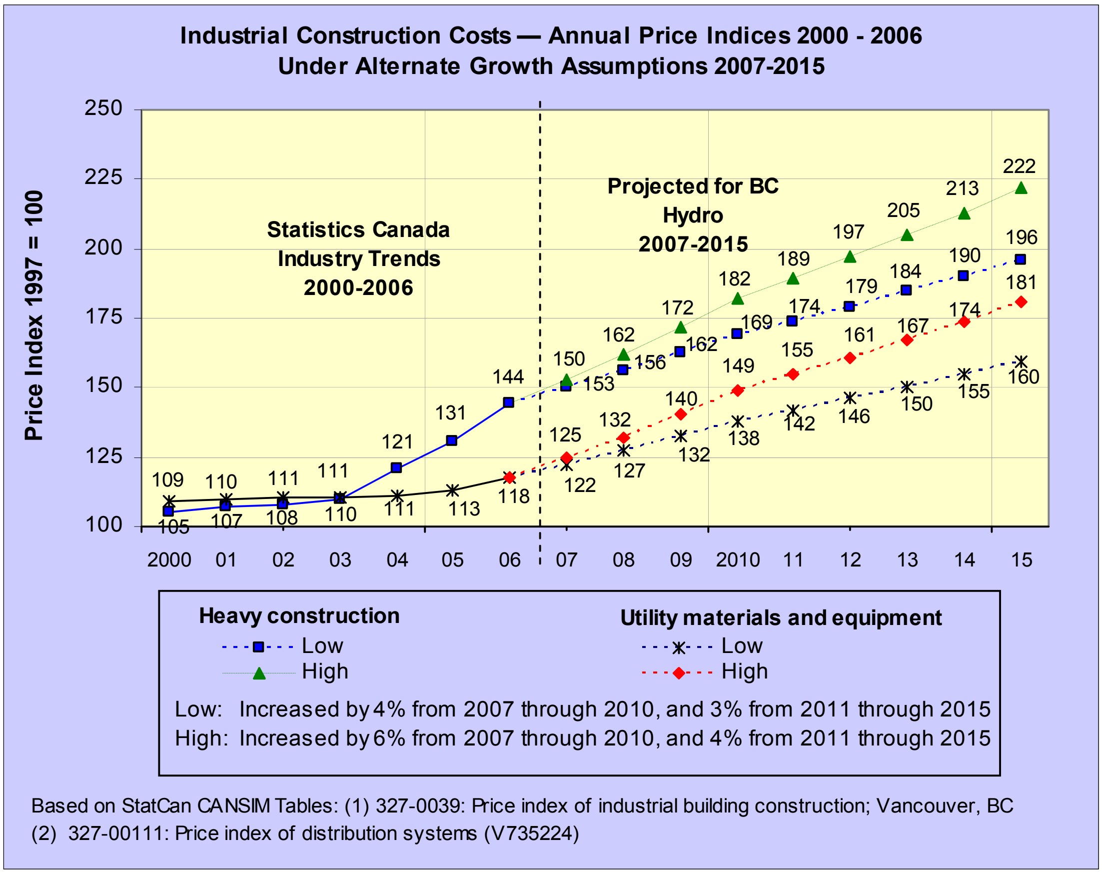
7.3 Future price index projections

These recommended ranges, applied to the relevant price indices, are illustrated in Exhibit 7b:

- For power generation and other heavy construction projects, the annual allowances have been applied to Statistics Canada's Vancouver industrial construction price index.

- For transmission and distribution projects, the allowances have been applied to the Canadian Electric Utility Annual Price Index (index numbers re-stated to make the 1997 base year consistent with the broader industrial construction price index).

Exhibit 7b — Future industrial construction price index projections, for recommended range of cost inflation allowances



7.4 Interpretation of recommended allowances

The recommended allowances are for BC Hydro "hard" construction costs only, and exclude other "soft" project cost elements such as project design, administrative overheads, environmental mitigation, property acquisition, and other non-construction costs.

The recommended allowances also assume that the strong construction market in BC between 2003 and 2007 will continue through 2010, and that the market will have a "soft landing" in 2010 and 2011 as market demand and supply forces come more into balance.

The recommended allowances are also based on the assumption that BC Hydro takes appropriate cost mitigation measures to dampen the impact of construction cost inflation, through procurement strategies, value engineering and other cost mitigation initiatives.

All forecasts and allowances are by their nature uncertain, and we cannot represent that any of the projections in this report will be realized in whole or in part.

Appendix F

Two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor Banks at Ashton Creek Substation – Project Justification Report

Two 500 kV-250 MVAr

Mechanically Switched Shunt Capacitor Banks

at Ashton Creek Substation

Project Justification

Revision 0

Report No. SPPA 2007- 87
December 2007

British Columbia Transmission Corporation
Transmission System Planning

Table of Contents

DISCLAIMER OF WARRANTY, LIMITATION OF LIABILITY

This report was prepared by BCTC solely for the purposes described in this report, and is based on information available to BCTC as of the date of this report. Accordingly, this report is suitable only for such purposes, and is subject to any changes arising after the date of this report.

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Executive Summary

This report provides the justification for installing two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks at Ashton Creek Substation. It updates previous reports on the Ashton Creek Shunt Capacitor reinforcement by including more information on the West of Selkirk Cut-plane seasonal flows, Available Transfer Capability (ATC) for pre-contingency and post-contingency flows on this cut-plane, and generation shedding.

The Commission approved the project Definition Phase in its decision on BCTC's F2008 Capital Plan[1]. The definition phase completed the preliminary engineering design, provided a cost estimate (+/-10% accuracy), and a project plan.

Without the reinforcement, there is a shortage of ATC during the winter season. No ATC is available when the load level is 88% of the peak load. The ATC is between negative 200 MW during the lightest load period and positive 106 MW during the maximum peak load period during the winter season.

Without any reinforcements there is also a shortage of ATC during the freshet season. The ATC is between negative 583 MW during the lightest load period and negative 364 MW during the maximum peak load period. To manage this ATC shortfall, a combination of long-term reinforcements and short-term operational re-dispatch is used.

Two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks at Ashton Creek substation are required to accommodate the Revelstoke Unit 5 and the addition of generation in the South Interior East area by 2010. This is the lowest-cost solution to meet this need and prevent system voltage collapse under first single-contingencies, such as an outage on 5L91, 5L96, or a 5L98.

[1] Commission Order No. G-69-07 dated June 15, 2007.

1 Introduction and Purpose

This report provides the justification for installing two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks at Ashton Creek Substation. It updates previous reports on the Ashton Creek Shunt Capacitor reinforcement by including more information on the West of Selkirk Cut-plane seasonal flows, Available Transfer Capability (ATC) for pre-contingency and post-contingency flows on this cut-plane, and generation shedding.

The Commission approved the project Definition Phase in its decision on BCTC's F2008 Capital Plan.[2] The Definition Phase completed the preliminary engineering design, provided a cost estimate (+/-10% accuracy), and a project plan.

2 Cost Estimate

The South Interior system reinforcements identified in BCTC's SI Development Plan include two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks at the Ashton Creek Substation with an expected in-service date of August 31, 2010. The project capital cost is provided in Table 1.

Table 1: Cost Estimate (+/- 10% Accuracy)

	Total	Prior Years	F2009	F2010	F2011
Transmission Capital	$19.8M	$0.25M	$1.55M	$13.2M	$4.7M

3 Justification

These two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks are mainly driven by system integration of Revelstoke Unit 5 in 2010 and the addition of generation in the South Interior East area by 2010 including Brilliant Expansion (127 MW) and the new run-of-river generator, Canada – Glacier/Howser/East project (108 MW).

The Commission issued a CPCN to BC Hydro for Revelstoke Unit 5 (REV G5) in 2007[3] and this unit is expected to enter service in August 2010. One 500kV-250 MVAr Mechanically Switched Shunt Capacitor bank at Ashton Creek Substation was identified as the transmission requirement to accommodate the REV G5 system integration. This shunt

[2] Commission Order No. G-69-07 dated June 15, 2007.
[3] Commission Order No. G-8-07 dated July 12, 2007.

capacitor bank will provide essential voltage support to Ashton Creek Substation and Revelstoke generating station and assist in maintaining the transfer capability on the transmission system from Selkirk Substation to Nicola Substation.

The South Interior East (SIE) is one of largest provincial hydro-generation regions. These resources are needed to serve the peak loads during the winter but they also have important characteristics during other periods. For example, the water inflows are predominantly from snowmelt and these inflows typically increase rapidly during the spring freshet. These inflow characteristics and the water storage capability in SIE determine the seasonal generation dispatch patterns in a year. The SIE region is also connected to the Alberta system and the US through various interties. These interties provide reliability benefits and opportunities for trade and the Nelway intertie receives 3/14ths of the Canadian Entitlement (CE) when this resource is returned to BC. Over the next ten years it is expected that new resources with about 58 MW in Winter Dependable Capacity and about 407 MW in Maximum Continuous Rating capacity will be added in the region.

The transfer demands at the West of Selkirk Cut-Plane vary within a broad range for different system load levels in different seasons. Two transmission planning strategies are applied to address the different transmission requirements at different system conditions. In winter, the SIE area generation surplus (with Dependable Capacity Generation and winter peak load) is needed to serve the provincial system peak load. Therefore, in winter, the West of Selkirk Cut-Plane needs to have adequate transfer capability to deliver the regional generation surplus both before and after a single-contingency event.

During the freshet season, the area generation surplus reaches a peak under light load conditions. It is likely that sufficient generation reserves are available in the rest of the system for meeting loads; therefore, the constraints in the SIE transmission system for N-1 contingency should not cause load curtailment during this period. However, these could result in lost energy from water spills or lost opportunities for inter-utility trade.

The Eastern Inter-tie, consisting of 2L112 from Nelway to Boundary, has a significant impact on the West of Selkirk Cut-Plane. A portion of the CE, nominated in the 2004 NITS Application, is received at this intertie and adds to the flows across this cut-plane. To reasonably stress the West of Selkirk Cut-Plane in the system study, 257 MW and 100 MW of power imports were taken into account in winter and summer, respectively, under system normal conditions.

The Eastern Inter-tie also provides temporary support after an outage. Therefore, pre-contingency (or non-firm) TTC is estimated for a short time period during a transmission outage. However, if the transmission outage cannot be restored in a short time (about one hour), generation re-dispatch is required to recover the power flow at the Eastern Intertie to the pre-contingency schedule. As such, post-contingency TTC is applied to show the firm transfer capability at the West of Selkirk cut-plane during a permanent transmission outage.

Table 2 shows the Available Transfer Capability (ATC) for the West of Selkirk Cut-Plane for the winter and summer season, and before and after shunt capacitor reinforcements are added to the system. The ATC is calculated for the pre-contingency and post-contingency transfer capability.

Table 2: Available Transfer Capability Analysis at West of Selkirk Cut-Plane

Available Transfer Capability (ATC)		Transfer Capability (TTC)	Existing System Configuration with REV5 in-service				After Installing one Shunt Capacitor at ACK substation				After Installing two Shunt Capacitors at ACK substation			
			Pre-contingency transfer capability limited by voltage stability, Non-firm TTC		Post-contingency transfer capability linited by voltage stability, Firm TTC		Pre-contingency transfer capability limited by voltage stability, Non-firm TTC		Post-contingency transfer capability linited by voltage stability, Firm TTC		Pre-contingency transfer capability limited by voltage stability, Non-firm TTC		Post-contingency transfer capability linited by voltage stability, Firm TTC	
			Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Committed Use (CU)			1870	1990	1660	1770	1990	2060	1780	1850	2190	2320	1910	2000
Winter Peak Load Condition (100%)	Post-contingency	1554	----	----	106	----	----	----	226	----	----	----	356	----
Winter Light Load Condition (80% -- average)	Post-contingency	1729	----	----	-69	----	----	----	51	----	----	----	181	----
Winter Light Load Condition (65%)	Post-contingency	1860	----	----	-200	----	----	----	-80	----	----	----	50	----
Summer Heavy Load Condition (70%)	Pre-contingency	2014	----	-24	----	-364	----	46	----	-284	----	306	----	-134
Summer Light Load Condition (45%)	Pre-contingency	2233	----	-243	----	-583	----	-173	----	-503	----	87	----	-353

Note: When Post-contingency CU is calculated from Pre-contingency, 120 MW should be added because L11w is transfer-tripped out.

With system reinforcements that are approved and/or expected to be complete before fall 2010 in the South Interior, including the addition of the 500 kV T4 transformer in Selkirk Substation (SEL) and the 230 kV system upgrade in the FortisBC system, the post-contingency TTC at the West of Selkirk Cut-Plane, dominated by voltage stability, is about

1660 MW[4] in winter. In this season, most generation units in SIE would be dispatched to their winter dependable capacities to serve system winter peak loads.

The maximum flows can occur during the off-peak load periods during the winter season. Table 2 shows that without any reinforcements, the post-contingency ATC is between negative 200 MW during the lightest load period and positive 106 MW during the maximum peak load period. There is no ATC available when the load level is 88% of the peak load and therefore there is a shortage of ATC during the winter season. There should be some operational flexibility to dispatch the surplus SIE generation during the peak winter season. For example, there will be a total of 1200 hours of restriction on the SIE generation from 88% of peak load to the average winter peak load (80% of the peak load). Adding one shunt capacitor would increase the post contingency ATC to negative 80 MW and 226 MW under the same conditions. Adding the second shunt capacitor would increase the post-contingency ATC to 50 MW and 356 MW, which would fully relieve the shortfall in ATC. Therefore, the two Ashton Creek Shunt Capacitors provide sufficient ATC over generation and load values during the winter season.

During freshet, most generation units would be dispatched to their Maximum Continuous Ratings (MCR), even during the light system load conditions, to avoid spilling water. These seasonal generation characteristics result in very high transfer demand at the West of Selkirk Cut-Plane only during the freshet, which is forecast to be around 2233 MW in 2010. The transfer demands are mainly contributed by existing hydro plants in SIE (owned by BC Hydro, Fortis BC and CPC), the return of the CE at the Eastern Inter-tie (scheduled 100 MW to be returned to BC in the summer), Brilliant Expansion (120 MW), and the new run-of-river generator, Canada – Glacier/Howser/East project. In summer, the pre-contingency TTC, measured as maximum loading capability at the West of Selkirk Cut-Plane at system normal condition, is about 1990 MW, limited by voltage stability. Accordingly, there will be about 243 MW in transfer capability shortage after a single transmission contingency which, if not addressed, would lead to a voltage collapse. The addition of the two shunt capacitors would increase the pre-contingency ATC to between 87 MW during the lightest load period and 306 MW during the heavy summer peak load period. The two shunt capacitors prevent voltage instability during the winter and freshet seasons.

[4] This value is the **post-contingency** TTC for the West of Selkirk Cut-Plane in **the winter season**. These are new TTC values that have been determined in this report update to determine the strength of the system to provide firm TTC during the winter season. The TTC values calculated in report SPA 2006 -117 “South Interior Cut-Plane Reinforcement – Justification Report are **pre-**

However, Table 2 also shows that without any reinforcements, the post-contingency ATC is between negative 583 MW during the lightest load period and negative 364 MW during the maximum peak load period. To manage this shortfall, a combination of reinforcements and operational re-dispatch are used. Adding one shunt reactor would increase the post-contingency ATC to negative 503 MW and negative 284 MW under the same conditions. Adding the second shunt capacitor would increase the post-contingency ATC to negative 353 MW and negative 134 MW. In order to recover the power transfer at the Eastern Intertie to a preset schedule, up to 353 MW of SIE generation would likely have to be re-dispatched if the forced outage cannot be restored in a short time.

4 Reinforcement Alternatives

As described in the *South Interior Cut-Plane Reinforcement Justification Report* filed with the Commission in Appendix C of BCTC's 2008 Capital Plan, BCTC evaluated a large number of alternatives. This report adds an analysis of the do nothing and generation shedding options.

4.1 Ashton Creek Shunt Capacitor Banks

The addition of shunt capacitors at ACK provides the least TTC necessary to meet the transmission demand at the least cost. The two proposed Mechanically Switched Shunt Capacitor banks would increase the West of Selkirk TTC to 2320 MW, which would be capable of meeting the new transfer requirement in the freshet time to prevent system collapse when the export capability at the Eastern Intertie is available. However, if the forced transmission outage cannot be restored in a short time and the power transfer at the Eastern Intertie has to be recovered to the pre-disturbance amount (importing 100 MW), about 353 MW of generation would still need to be curtailed. As mentioned in the South Interior Cut-Plane Reinforcement Justification Report, one of these two Mechanically Switched Shunt Capacitor banks is also critical to support Revelstoke G5 system integration and effective for post-contingency voltage controls at Ashton Creek and Revelstoke plant; the second MSC bank will improve the transfer capability at West of Selkirk cut-plane to accommodate new generation integrations in SIE, such as the Brilliant Expansion and Canada – Glacier/Howser/East project.

contingency TTC values for the freshet season. The pre-contingency TTC is higher than the post-contingency TTC because of the temporary support afforded by the Nelway intertie.

4.2 Do nothing

Without new capacitor bank installations at Ashton Creek,

i) After REV G5 is in service, 5L96 contingency will cause low voltage concerns at Ashton Creek substation, the generation in Revelstoke may be limited under some system operating conditions; and

ii) Due to the shortfall of transfer capability at West of Selkirk cut-plane, generation outputs will need to be curtailed especially during freshet season to protect the transmission system from voltage instability.

4.3 Generation Shedding

Another option considered is to shed generation in the SI region for first contingencies. Generation shedding is not the preferred option to alleviate voltage stability limitations caused by a single contingency because the generation[5] is lost to the system after the contingency and this approach to system reinforcement will lead to a weaker system in the long term.

Generation shedding is effective in maintaining the stability of the system by quickly removing generation at the source end of the transmission system after a fault on any of the transmission lines, thus removing the constraint. If the system is not connected to a large network, the frequency will decline and under-frequency load shedding will reduce the load to obtain a lower load resource balance. In this instance, load is lost which does not meet the single contingency criteria of maintaining load service under single contingency events. However, the BC system is connected to the US and Alberta systems, and frequency does not decline significantly after generation shedding because of the large size of the integrated system. The US and the Alberta systems temporarily provide replacement power for some of the generation that was shed and the service to the load is maintained.

The intertie flow must be reduced to pre-outage schedule and this is done by dispatching reserves on the BC system from another region of the system. For outages on the SI system, the reserves will be delivered from the Peace or Mica

[5] Both real power and reactive power are lost to the system.

generation. However, generation reserves are intended for generation maintenance and forced outages and not for single contingency outages of transmission lines.

Therefore, the generation shedding option depends upon the replacement power from neighbouring utilities, which may or may not be available, and in any event those utilities are not obligated to supply BC's firm loads. Shedding for first contingencies would increase the frequency of this support and would add a significant burden on the neighbouring utilities in the long run. Also, BC's generation reserves are determined under the assumption that the bulk transmission system is reliable and meets the single contingency criteria without loss of load or generation. Therefore, firm loads require firm generation and transmission reinforcements.

While the main planning criteria is the ability of the system to withstand a single contingency and reliably serve the load, the system must also be stable after the next single contingency, double contingencies and maintenance outages. For example, generation flows on the 500 kV network should be maintained after the first single contingency especially during winter peak loads, to maintain secure transmission service. Generation shedding is used to maintain high flows after a permanent forced outage[6] in anticipation of the next contingency. Also it is used to keep the system from cascading when it is in the normal state and a sudden double contingency[7] occurs. Shedding is also used to enable non-firm transfers that can be interrupted after the first contingency. In these n-1-1, and n-2 scenarios, generation shedding is a legitimate and economic option[8] because the requirement to maintain load service after the second outage is not required. These events are relatively rare and while the US system does provide replacement generation, there is an understanding amongst utilities to provide this occasional support. Not providing reinforcements for first contingencies would increase the impact on neighbouring utilities for second contingencies because the system would be weaker and more shedding would be required for second contingencies.

[6] This is commonly referred to as an n-1-1 forced outage. The first single contingency is the n-1 forced outage and the next outage is the n-1-1 forced outage. Good single contingency planning not only considers the first contingency but also the next single contingency if firm service is to be maintained after a permanent outage but before the next outage. The required performance is not to allow cascading but generation and load may be lost after the second outage.

[7] This is commonly referred to as an n-2 outage. This is the sudden loss of two lines in the system. The required performance is not to allow cascading but large amounts of generation and load may be lost with large impacts on neighbouring utilities.

[8] Utilities usually cannot afford reinforcements for n-1-1 outage during peak load periods and n-2 second contingencies. Yet, the consequences of these rare events which are cascading and blackouts must be managed and prevented. The only practical tool is generation and load shedding and these options must be reserved for these situations.

Providing reinforcement facilities for resource additions on the 500 kV systems provides for a secure and robust system over the long term. Generation shedding on the 500 kV system is available to provide planning and operational flexibility to maintain high flows after a permanent outage in anticipation of the next contingency, sudden double contingencies, additional economy transfers, and temporary transfer capability for uncertainties related to resources, load growth, and project delays in reinforcements. In short, generation shedding for N-1 events would increase the risk of cascading the system, increase the complexity of system operations, and reduce the flexibility for operation and maintenance significantly.

4.4 Series Compensation in 5L91 and 5L98

50% series compensations of 5L91 and 5L98 would provide 2380 MW transfer capability on the West of Selkirk cut-plane, which can meet the transfer requirements in 2010 and provide better voltage profile in Selkirk and Vaseux Lake Substations. However, the cost is about $ 51.9 million and is much higher than the cost of the proposed Ashton Creek Shunt Capacitor Banks.

5 Conclusion

Two 500 kV-250 MVAr Mechanically Switched Shunt Capacitor banks at Ashton Creek substation are required to accommodate the REV G5 and the addition of generation in the SIE area by 2010. This is the lowest-cost solution to meet this need and prevent system voltage collapse under first single contingencies, such as an outage on 5L91, 5L96, or 5L98.

During the freshet period and without the reinforcement, the amount of ATC shortfall is 583 MW and this exceeds the largest generation unit size (500 MW) on the system. Adding the proposed reinforcement prevents voltage instability and reduces this amount of generation loss to be within a manageable size.

Appendix G

Goto Sargent Report –
F2008 Q1 Project Forecast Update Report on Forecast Sensitivities

GOTO•SARGENT

Report to System Planning and Asset Management Group
British Columbia Transmission Corporation

Fiscal Year 2008, Q1 Project Forecast Update
Report on Forecast Sensitivities

To: Ginette Handfield, P. Eng., MBA
Manager, Corporate Capital Planning Process

Introduction

The System Planning and Asset Management Group are responsible for approximately 400 projects currently in definition or execution phase. At the end of Q1, F '08, on 30 June 2007, the forecast Annual Project Cost and Life Project Cost will be updated. This Report will identify the sensitivities in the forecast update, and assess the level of confidence BCTC should have in the Life and Annual Forecast numbers for projects currently with a "Planned" or "Approved" EAR Status.

The Report is presented in the following sections:

Executive Summary	*Presenting a summary of findings and recommendations*
Methodology – Selection of Projects for Review	*Description of the criteria applied to identify projects presenting highest potential risk to forecast accuracy, and select projects for review*
Methodology – Identification of Forecast Sensitivities	*Description of data obtained and methods employed to obtain general understanding of project status, identify how the F 08, Q1 forecast update was developed and assess the risk to the forecast accuracy*

Forecast Sensitivities for Projects Reviewed	*Description of the risks to forecast identified in the projects reviewed and assessment of impact*
Assessment of Overall Forecast Sensitivity	*The characteristics that impact the risk profile of each project are identified and used to provide a general assessment of overall forecast sensitivity*
Forecast Review Issues	*A note of areas of investigation potentially relevant to forecast sensitivity that were not pursued in preparing this report generally due to time constraints*
Identification of Other Issues for further Investigation	*A listing of issues identified during the review, not directly connected with forecast sensitivity, that could benefit from further investigation, with preliminary description of further actions*

Report Prepared 10 July 2007

Goto Sargent Inc.

Gordon Goto Meredith Sargent

Executive Summary

This report contains an assessment of the sensitivities in the Q1 F'08 forecast update, and gives an opinion on the level of confidence BCTC should have in the Life and Annual Forecast numbers for the project portfolio. Time and practical constraints required a sampling methodology. 11 projects presenting highest potential risk to forecast accuracy were selected for detailed review. Investigation of performance of these projects identified common issues and systemic problems. These findings were extrapolated to provide a qualitative assessment of overall sensitivities in the Q1 F'08 forecast update.

The assessments and recommendations in this report are made from Goto Sargent's perspective – the perspective of managing projects for cost and schedule performance. It is recognized that this perspective may not align completely with the complex objectives of a crown utility corporation[1].

Selection of Projects for Detailed Review

Selection criteria were applied to eliminate projects which, because of state of completion or capital value, represent minimal risk to overall forecast. Selection criteria were applied to ensure a spread of projects across Program Managers and Service Providers. Projects were included from the asset classes with highest contribution to F'08 forecast cost. Projects were selected from Growth and Sustain programs, and from both station and transmission business lines.

Review Findings – Forecast Sensitivities and Risk Factors

The projects selected for detailed review are listed here with findings on risk to Annual and Life Forecasts:

Project	Project Name	Risk to Forecast
1110163	Mission & Matsqui Area – 69 kV reinforcement	Low risk to forecast as contingencies in June 2007 forecast are significant. Continued close monitoring required.
601806	500 kV CB Replacements 2007/2008	Low risk to forecast, tracking well with remaining contingency
600054	MICA GIS Switching Equipment	Assessed potential for $1M deterioration, much of that in F'08
1106926	Barnard 12 kV Feeder Section Addition	Assessed potential for $2M deterioration, most within F'08

[1] Brief background on Gordon Goto and Meredith Sargent, Principles of Goto Sargent responsible for preparing this report, is attached.

Project	Project Name	Risk to Forecast
601901	Ashlu Creek Water – IPP Execution	Low risk to forecast, remaining risks should be contained within existing contingency
600082	Hope 25kV Conversion	Some risk to forecast presented by intended design concept change, impact not quantified.
BCTC602379	East Toba and Montrose Creek Hydroelectric Project (IPP Plutonic Power Corp)	Estimate supporting current forecast is summary level, order of magnitude quality, without nominated contingency. Significant risk to forecast.
1110839	Cable Life Extension Program & Enhance 5L29/31 Subcable	Unable to make meaningful assessment of risk to forecast.
601799	Oil Spill Containment, Cable Termination Sites	Considered low risk to forecast because of nature of project.
602381	Upper Stave & Kwasla (Cloudworks)	Contingencies and escalation allowances in SNC estimate result in low risk to forecast.
602193	Gibraltar Mine Load Increase	Some risk to forecast due to civil construction and electrical installation costs.

The detailed review of the projects listed above provided data and insight into the main risk factors in the project portfolio. The following characteristics of projects were identified as presenting risk to forecast:

- Escalation in construction cost, and availability of resources;
- Novel equipment, and long lead times;
- Land acquisition costs and delay, geotechnical and topographical features of land not known early;
- Schedule delay (variety of causes);
- Scope change, including late design concept changes;
- Variance from original estimate (including as a result of miscommunication or misunderstanding of meaning of estimate class).

The identification of risk factors was used to estimate the overall sensitivity of the Q1 F'08 Forecast Update.

Assessment of Overall Forecast Sensitivity

Projects in the portfolio were classified as carrying insignificant (eliminated from further analysis), low, medium or high risk to F'08 Annual Forecast. The classification was based on using basic project information to identify the likely presence of the main risk factors listed above. The risk factors were given a weighting in the calculation of an overall risk 'score' for each project in the portfolio.

Overall risk to the F'08 Annual Forecast is assessed at +13%.

A qualitative assessment of risk to annual forecast was made. The calculation is summarized in the table below:

Risk	+ %	Number of Projects	Total Value of Annual Forecast less Actual YTD (excluding CPCN)	Annual Forecast Sensitivity
High	30	10	$46,635,789	$13,990,737
Medium	20	91	$101,712,901	$20,342,580
Low	10	16	$19,907,504	$1,990,750
Forecast Sensitivity				**$36,324,067**
Total Annual Forecast (all projects in portfolio excluding CPCN)(source May Cost Report)				$273,160,780
Overall Forecast Sensitivity as % of Total Annual Forecast[2]				13%

Recommendations

Improvement in the level of confidence that BCTC should have in the forecast, and in the efficient execution of projects, will require:

Better Estimates
EAR and Project Budget estimating quality must be of a consistent, understood standard.

Better Tools
Project Management tools available are not used to provide information that allows proactive management of projects, or an accurate real-time status of projects.

Disciplined Execution
Project Management practices, cost and schedule forecasting, risk analysis and development of risk management strategies, project reporting and implementation of project controls require improvement, standardization and disciplined implementation.

End of Executive Summary

[2] Total Annual Forecast excludes the internal projects (related to IT, Facilities Management etc.) which appear on the May Cost Report but which are not part of the Projects Portfolio being reviewed.

Methodology – Selection of Projects for Review

Time and practical limitations prevent detailed review of all projects in the portfolio. A method was developed to select projects for detailed review, which would provide a reliable insight into the forecast sensitivity in the whole portfolio. The method is described below.

BCTC requested that the projects for review include at least the following criteria:

1. From "Sustain" projects, one 'Stations' and one 'Transmission' project;
2. From "Growth" projects, EAR # 1110163 – Mission & Matsqui Area, plus other approved projects spread across stations/transmission;
3. One project in late definition phase or early execution phase;
4. Ensure projects to be audited include at least one project managed under BCTC agreement with SNC Lavalin, one project with IPP involvement, and one project managed internally by BCTC.

The following additional criteria have been applied to identify projects for review which could have the greatest impact on the accuracy of the Annual Forecast:

1. Projects with zero Actual Cost were eliminated. Projects where (Actual Cost/Life Forecast) % is less than 15% have been eliminated from the review. Our ability to predict how well costs are being forecast when work has not yet commenced or has yet to progress into procurement is limited. We recognize that these projects still present a risk to the accuracy of the forecast. Our methodology is to identify systemic problems in forecasting where we have data on which to base our review. Any systemic problems on initial estimating should be identified in our review, and the likely impact of those problems on projects in early stages can be estimated.

2. Projects where (Actual Cost/Life Forecast) % is greater than 75% have been selected. Unless the project is in a state of significant cost overrun, these projects are expected to have sufficiently progressed for most costs to be known and committed, and therefore costs which are still forecast or 'unknown' to be minimal. A check was done on the assessed progress on each large (Life Forecast greater than $1 million) project in this group to identify whether the project had a significant cost overrun before eliminating these projects from detailed review.

3. Projects where the Life Forecast is less than $1 million have been eliminated. Any single project in this group, even if the forecast is inaccurate, is unlikely to have a material impact on total forecast capital requirements. The risk to forecast accuracy for these projects as a group, arising because of systemic problems, can be estimated.

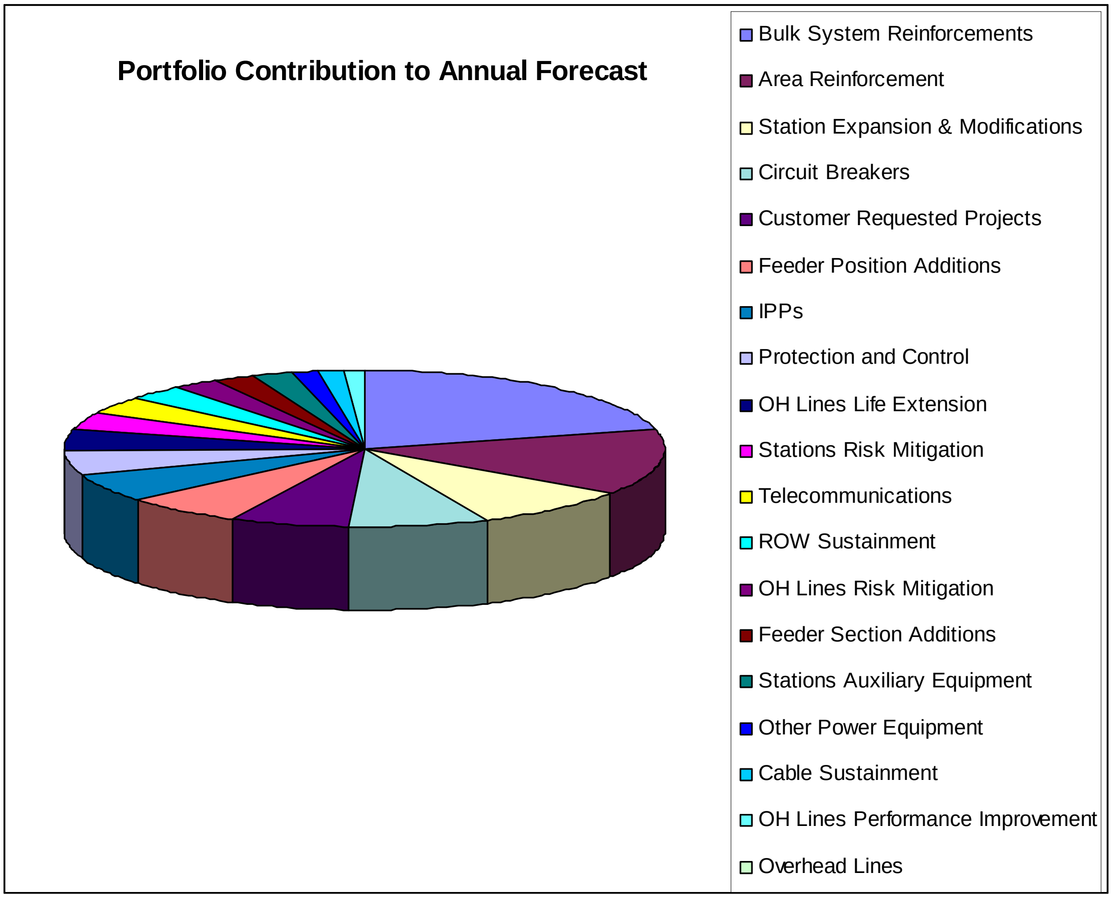
4. Projects where the Annual Forecast for F08 is less than $1 million have been eliminated. Any single project in this group, even if the forecast is inaccurate, is unlikely to have a material impact on total forecast capital requirements.

5. As requested, CPCN projects have been eliminated.

To identify systemic issues we need to review a range of projects from different asset portfolios, and preferably with different Program Managers (at BCTC) and Project Managers (at the Service Provider).

The forecast annual cost for each asset portfolio was calculated. The “Bulk System Reinforcement” portfolio has the highest forecast cost for F08, however as most of the value in this portfolio is in CPCN projects that were eliminated from the review, no projects were selected for detailed review from this portfolio. “Area Reinforcement”, “Station Expansion Modifications” and “Circuit Breakers” represent the following highest forecast annual cost contributors, so projects have been selected from each of these portfolios. Projects have also been selected from the “IPPs”, “Feeder Section Additions” and “Cable Sustainment” portfolios.

The following chart shows the ranked portfolio contributions to the annual forecast.



Projects reviewed included those under the responsibility of three of the BCTC Program Managers and 13 Project Managers from Service Providers including 12 from BC Hydro and 1 from SNC Lavalin.

To accommodate the selection criteria described above, 11 projects were selected for review. The selected projects are set out in Table 1.

Table 1 – Projects Reviewed

Project No	Project Name	Asset Class	Program
1110163	Mission & Matsqui Area - 69 kV reinforcement	Stations - System Reinforcement	Growth
601806	500 kV CB Replacements 2007/2008	Stations - Switching Equipment	Sustain
600054	MICA GIS Switching Equipment	Stations - Switching Equipment	Sustain
1106926	Barnard 12 kV Feeder Section Addition	Stations - Feeder Additions	Growth
601901	Ashlu Creek Water – IPP Execution	Transmission - IPP New Interconnections	Growth
600082	Hope 25kV Conversion	Stations - Station Expansion and Modifications	Growth
BCTC602379	East Toba and Montrose Creek Hydroelectric Project (IPP Plutonic Power Corp)	Stations - IPP New Interconnections	Growth
1110839	Cable Life Extension Program & Enhance 5L29/31 Subcable	Transmission - U/G & Submarine Cable Life Extension	Sustain
601799	Oil Spill Containment, Cable Termination Sites	Stations - Cable Reliability Improvements	Sustain
602381	Upper Stave & Kwasla (Cloudworks)	Stations – IPP New Interconnections	Growth
602193	Gibraltar Mine Load Increase	Stations – Customer Requested Projects	Growth

Methodology – Identification of Forecast Sensitivities

Data from the following sources was obtained for each of the projects reviewed:

- Info PM Project Variance Report including committed costs;
- AMP Project Cost Report detailed to task level;
- Investment Justification submissions;
- Interviews with BCTC Program Managers;
- Interviews with BC Hydro and SNC Lavalin Project Managers.

Project Cost and Progress data from Info PM and AMP was used to develop:

- Comparison of commitments vs. forecast vs. approved budget;
- Broad breakdown of costs, project management/design/equipment and materials/construction;
- Comparison of AC/EAC% vs. reported % complete.

Interviews with Program Managers and Project Managers were used to assess:

- Knowledge of project plans and project reporting procedures;
- Knowledge of details of projects and major project issues;
- Current status, assessment of progress and forecasting;
- Understanding of the basis of original estimates;
- Specific concerns related to completion of projects and how those concerns are reflected in forecasts;
- Proportion of project costs in equipment and nature of equipment;
- Proportion of project costs in construction and nature of construction.

Forecast Sensitivities for Projects Reviewed

1110163 – Mission/Matsqui Area 69 kV reinforcement

The June 2007 cost forecast shows a deterioration of $13.8M (34%) since December 2006 and a deterioration of $16.0M (39%) as compared to EAR approval in December 2005. This appears to have been caused by several factors – inaccurate EAR estimate, scope changes, cost escalation and decreased productivity. With the available information, it is difficult to determine the actual contribution of each of the factors to the deterioration in forecast. Further review of the estimating methodology and cost detail beyond what is available in Info PM is required. This would enable a better assessment of the forecast, associated risks and quantification of contingencies.

The June 2007 cost forecast represents a **decrease** in equipment costs since EAR approval of 39% and an **increase** in construction costs of 210%. This would indicate that although the cumulative equipment scope has decreased, the construction costs have escalated considerably since EAR approval. Also, since the most recent forecast in December 2006, the construction costs have increased by 17% overall mainly due to a $2.1M claim for delay and soil at Mt Lehman Substation and escalation of construction and materials for the Clayburn – Mission 60kV Circuit Replacement.

Based on our interviews with the Program Manager and Project Manager, the June 2007 forecast reflects complete designs, actual equipment costs and firm construction costs with the exception of the Mission Bridge cable support design in the Clayburn – Mission 60 kV Circuit Replacement which is still in progress. The commitment level shown in AMP (57%) does not reflect the level of progress described. It is assumed that there is a lag in data entry and/or equipment and construction contract awards are still pending.

The June 2007 cost forecast has a contingency of $2.3M. Considering the level of outstanding commitments, the uncertainty with the Mission Bridge design, the possibility of future contractor claims and further schedule and cost creep, the contingency level appears to be justified.

Based on the level of completion and certainty of cost information, the June 2007 cost forecast for this project is considered to be reasonable as is the current Annual Forecast for the project. This project should be monitored closely to ensure that remaining issues are resolved in a timely manner and opportunities for claims from the EPC contractor are minimized.

601806 – 500 kV CB Replacements 2007/2008

Of the 11 CB replacement projects in this year's program, there are nominal increases in construction costs for 5 of them. This is due to the escalation in construction since the EAR approval in July 2006. This poses a minor risk to the current Annual Forecast as construction is a small proportion of these projects, equipment costs are based on a 5 yr blanket order, other costs are tracking well and there remains a contingency.

Based on our interviews with the Program Manager and Project Manager, one replacement project is complete at Dunsmuir, one at Cranbrook and Skeena is starting in mid July.

600054 – Mica GIS Switching Equipment

The work has been split in 2 phases and is currently in the middle of phase 1. The EPC scope forms the majority of the project cost and has been awarded for both phases of work. The costs have been reflected in the forecast but there remains a $600K discrepancy between the commitment and forecast for the EPC scope. There is a contingency of $83.6K remaining. With the remaining work in both Phases and the current level of committed costs, a deterioration of Life Forecast in the $1M range is likely on this project. The $600K discrepancy noted above is likely to result in a significant portion of the $1M deterioration impacting the F 08 Annual Forecast, assuming Phase 2 commences this year.

1106926 – Barnard 12kV Feeder Section Addition

The June 2007 cost forecast shows a deterioration of construction costs of 53% since the EAR approval in May 2005. Since the latest forecast update in May 2007 there has been a deterioration of 14% in construction costs. The latest forecast also indicates that equipment commitments exceed forecast by $1M and there is no remaining contingency.

Based on our interviews with the Program Manager and Project Manager, the design is complete, all equipment has been ordered and construction contracts have been awarded. A new EAR approval will be submitted due to the increased costs.

It is estimated that a further deterioration of forecast in the range of $2M will be experienced on this project due to forecasting delays and residual risk, most within F 08.

601901 – Ashlu Creek Water – IPP Execution

Based on our interviews with the Program Manager and Project Manager, Phase 1 of the project has been completed and limited work has been executed for Phase 2. Phase 2 involves transmission upgrade, P&C and Telecom. Phase 2 will require a survey in order to determine the scope of transmission upgrade required. The forecast assumes a "worst case" upgrade scope.

The estimate basis and project plan were updated in May 2007. Although there was deterioration in overall cost of 17% since EAR approval, the remaining construction scope is not a significant proportion of the work. With the recent estimate update, the assumed scope and the remaining contingency, the risk to the forecast is minimal.

600082 – Hope 25kV conversion

Based on our interviews with the Program Manager and Project Manager, this project is undergoing a change to the implementation plan due to revised customer requirements. The initial assessment of the Project Manager is that the change will not have a significant affect on the project cost forecast.

602379 – East Toba and Montrose Creek

A copy of the BC Hydro estimate dated April 3 2007 and defined as "EAR Level Cost Estimate" was reviewed. It should be noted that the BCTC requirement for "EAR Quality" is an estimating quality of +/-10% with expected accuracy 9 times out of 10 according to Project Management Standard EST-01. The cost estimate provided does not meet the BCTC EAR Quality requirement. BC Hydro provided an estimate with a stated accuracy outside of the BCTC EAR quality requirement, described as "EAR Level Cost Estimate spreadsheets", which contributes to misunderstanding.

The estimate reviewed can be described as summary level, order of magnitude quality. There is insufficient detail to review the estimate basis but in reviewing the attached Cost Estimate Synopsis, there are potentially significant risks to the cost that would normally need to be resolved prior to seeking capital expenditure approval. A few of these are: property acquisition cost ($150,000 included), ROW cost, terrain, geotechnical review, construction inflation (appears low but the base level in Info PM is not identified), reuse of existing shield design.

Based on our interview with the SNC estimator, the SNC work is in the early stages. The estimating effort is just starting and the initial site visit is being organized. To achieve the current ISD, early start of design/order of the transformer is required due to the current delivery schedules. An estimate was not available for review.

602381 – Upper Stave & Kwasla (Cloudworks)

This project provides a basis for comparison of estimating methods and approach between BC Hydro and SNC Lavalin. BC Hydro prepared an EAR level cost estimate on 10 April 2007, described as a “preliminary design – planning level estimate”. The basis for the estimate was a one line diagram, scope notes and information from planning and discipline engineers. SNC Lavalin delivered an estimate on 22 June 2007, described as having estimate accuracy of 15%.

A comparison of the estimated project costs shows that the estimates are within 3% of each other. The following adjustments were made to equalize scope and cost basis:

- $360,000 deducted from BC Hydro cost for estimated cost of System Performance Assessment, assumed not included in SNC Lavalin scope (refer page 15 “Service Scope, Activities and Deliverables” of the SNC Lavalin estimate);
- Escalation of $2,015,733 deducted from SNC Lavalin and $625,328 deducted from BC Hydro;
- $510,000 added to BC Hydro, to adjust for a spreadsheet error that omitted “Civil Materials” from estimate total;
- Contingency of $6,090,000 deducted from SNC Lavalin estimate. BC Hydro estimate did not show contingency, but contingency was included in the Project Plan prepared by BC Hydro.

Adjusted on this basis, BC Hydro Project Cost is $24,532,300 and SNC Lavalin Project Cost is $25,294,330.

We were later informed by BC Hydro that their estimate was prepared in a short time-frame to support the IPP Call for Tender process. BC Hydro applied construction inflation amounts based on the March 2007 MMK Report.

Based on our interview with the SNC estimator, local and site visits have taken place and the initial estimate is based on spread footings with added contingency to cover geotechnical risk. SNC have performed a risk analysis (not provided) but the risk analysis was not used to establish contingencies. Contingencies established are generally consensus-based and cover off “worst case” risk. A contractor has been consulted for information on construction and materials costs and related escalation and contingencies. Escalation factors are based on trend analysis of major PO’s (5%-10%) and the current construction market (15%/yr). Work in the next two months will concentrate on telecom risk by establishing radio path/microwave channel and +/- 10% overall estimate. Early work to design/order the transformer and reactor are required to meet the ISD (Aug 2009).

The escalation allowance and contingencies in the SNC estimate are reasonable, but further work is required before the estimate is at the BCTC EAR level of +/- 10% accuracy.

1110839 – Cable Life Extension Program

We were unable to meet with the Project Manager. BCTC Program Manager was unable to provide up to date information on progress or current issues. A review of the Investment Justification document prepared in March 2006 identifies schedule and obtaining competitive bids from contractors as the most likely risks. A potential increase in the cost of the program of $5M if project initiation is delayed is identified in the financial risk analysis. Further information is required to provide a meaningful assessment of the risk presented to forecast from this project.

601799 - Oil Spill Containment

We were unable to meet with the Project Manager. BCTC Program Manager advises that this program is funded year to year, to retrofit concrete sumps in manholes to capture oil spills before draining to the storm water sewers. BCTC Program Manager was unable to provide up to date information on progress or current issues. Further information is required to provide a meaningful assessment of the risk presented to forecast, however the project is considered to be low risk.

602193 – Gibraltar Mines Load Increase

The June 2007 cost forecast represents a deterioration in project cost of 38% since EAR estimate approval in February 2007. The majority of the cost increase has been due to an increase in equipment costs caused by scope change and acceleration. This forecast includes firm equipment costs so any increase in major equipment costs is of limited risk. The design is still in progress so none of the construction costs are based on a Tender document or firm quote. The forecast has been increased by $300 K to cover likely increases in construction costs, based on assessments made by BC Hydro and the civil engineer. Earthworks and civil construction will likely be sole sourced to the contractor working for Gibraltar Mines, as the contractor has a concrete batch plant already at the site. Provided the contractor is monitored to ensure competitive pricing, this approach should be the lowest cost alternative. The electrical works will be open tender and significant risk of cost escalation. Telecom and P&C estimates have recently been updated, they however only represent a small proportion of the forecast. We assess an exposure to the risk of cost escalation, mainly in construction and associated materials, perhaps in the order of $500 K. There is a remaining contingency of $285.7K.

Key Financial and Progress Data for Projects Reviewed

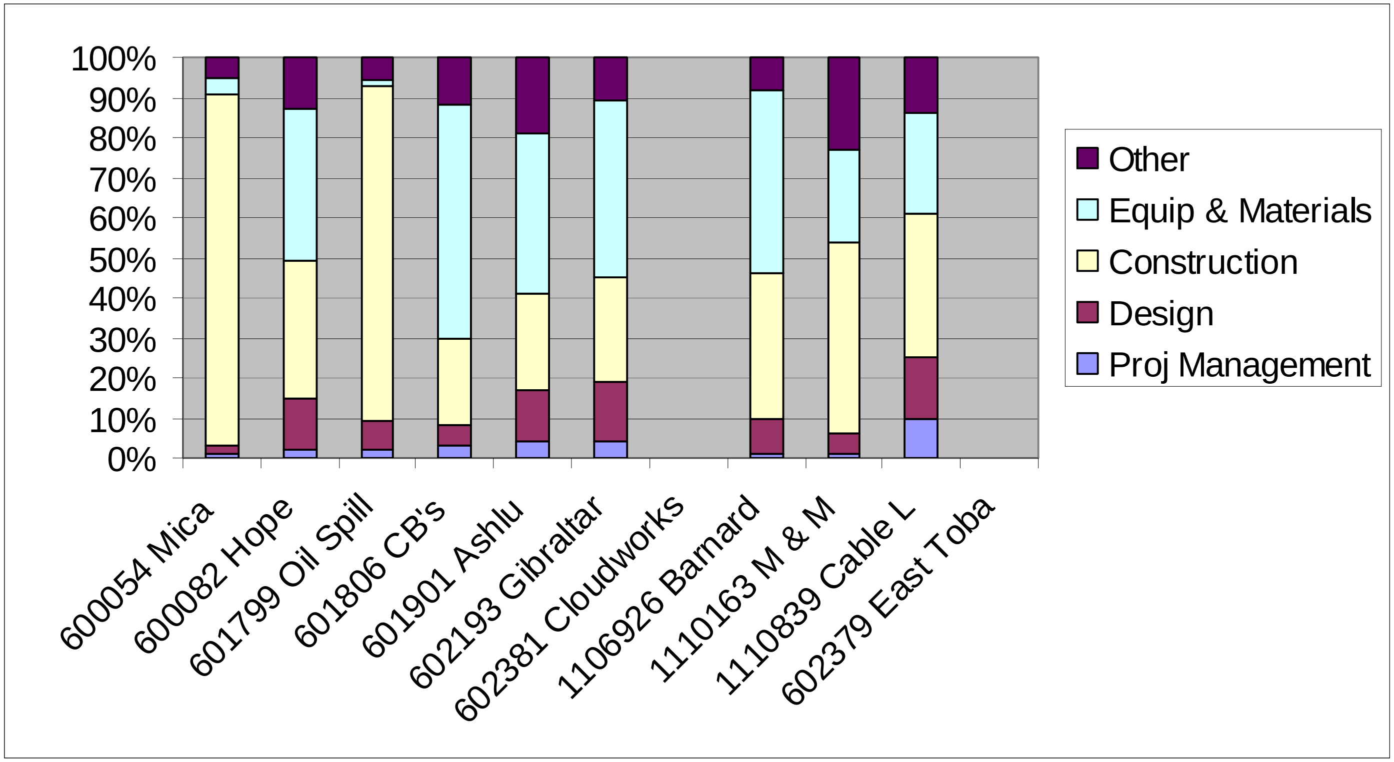
The key financial and progress data for each of the projects reviewed is set out in the following:

- Table 2 – Projects Reviewed: Key Data
- Table 3 – Projects Reviewed: Cost Split.

Table 2 – Projects Reviewed, Key Data

Project No.	Project Name	Approved	Forecast	Committed	AC	EAC	AC/EAC	% Complete	Annual Forecast
BCTC602379	East Toba and Montrose Creek Hydroelectric Project (IPP Plutonic Power Corp)								1,680,200
1110839	Cable Life Extension Program & Enhance 5L29/31 Subcable	2586.1	1931	1552.3	1,336,495.32	2,302,830.05	58.04%	62.63%	1,397,896
1110163	Mission & Matsqui Area - 69 kV reinforcement	44792.2	56897.3	28603.6	12,851,437.69	41,341,611.04	31.09%	36.40%	35,088,700
1106926	Barnard 12 kV Feeder Section Addition	5960.6	6239.2	6361.9	1,593,772.41	5,734,500.31	27.79%	30.53%	5,098,995
602381	Upper Stave & Kwasla (Cloudworks)								5,098,995
602193	Gibraltar Mines Load Increases	4038.3	5568.7	1394.5	79,882.21	3,912,039.39	2.04%	5.11%	4,567,124
601901	Ashlu Creek Water - IPP Execution Addition Execution Work	3205.4	3215.9	574.3	683,593.90	3,961,736.38	17.25%	18.37%	3,614,147
601806	500 kV CB Replacements 2007/2008	7552.2	7659.9	6130.1	4,087,455.92	8,333,811.33	49.05%	43.77%	7,410,149
601799	Oil Spill Containment, Cable Termination Sites	1477.7	1549.4	1112	1,101,198.71	1,883,148.21	58.48%	47.08%	1,041,520
600082	Hope 25kV conversion	2816.9	2836.2	768.5	508,425.77	2,644,652.78	19.22%	24.16%	2,779,771
600054	MICA GIS Switching Equipment	959.1	9667.5	9812.9	3,240,232.96	9,718,016.31	33.34%	32.38%	7,140,784

Table 3 – Projects Reviewed, Cost Breakdown



Note: 600054 "Construction" includes EPC Contract Cost.
1110163 "Construction" includes EPC Contract Cost for Mount Lehman Sub-project.

Assessment of Overall Forecast Sensitivity

To provide an assessment of overall forecast sensitivity, the findings from review of certain projects have to be extrapolated across the entire project portfolio. The overall assessment is essentially qualitative. Although a quantitative assessment is given, its accuracy is limited. Systemic risks to forecast have been identified and assumptions made as to their presence in a project, but those risks have not been quantified taking into account the particular issues on projects not reviewed. Discrete, 'one off' risks arising on any project have not been identified or quantified.

The projects in the entire project portfolio were classified as carrying low, medium or high risk to forecast on the basis of the existence of identified risk characteristics described in Table 4 below.   Characteristics with a "high" influence were weighted more heavily in the analysis. There was insufficient data to enable an assessment to be made of the quality or age of the EAR estimate, or the likelihood and magnitude of changes in scope.

The detailed review of 11 projects identified the following characteristics as having highest influence on the risk any project presents to the forecast:

Table 4 – Project Forecasting Risk Characteristics

Characteristic	Issues	Influence on Accuracy of Forecast
Equipment purchased under blanket PO	Pricing certainty	High positive
Novel Equipment	Reinforcement Projects; Bulk System Reinforcement Projects; Pricing uncertain; Basis for estimate;	Medium negative
Equipment/materials with long lead times	Pricing uncertainty (mitigate where stores supply); Knock on impacts of delay in construction/installation; Premium pricing to reduce lead times; SNC finding transformer lead times 18 months.	Medium negative

Characteristic	Issues	Influence on Accuracy of Forecast
Program Type (ongoing annual program)	High productivity; Low transaction costs for each item through repetition; Quality data to update annual forecasts; Growth projects – costs more predictable for Feeder Additions and Transformer replacements/upgrades;	High positive
Proportion of Costs in Construction	Highest escalation in costs; Highest uncertainty in availability of resources; BC Hydro field as back-up resource; Current experience is civil construction and lines construction have highest escalation; SNC data indicates 10 - 20% pa escalation factor for construction in Western Canada.	High negative
Geotechnical / Topographical	Early stage of design on which estimates based more likely to change; Potential for delay to construction/installation if unfavorable site conditions encountered;	Medium negative
Land Acquisition	Addition or expansion projects; Site conditions and topographical conditions are unknown when estimate prepared; Potential for delay to construction/installation; BC Hydro land group provide land pricing to SNC Lavalin.	Medium negative
Quality of EAR Estimate	Level of project definition; Preparation effort;	High positive or negative
Age of EAR Estimate	Updating for current escalation data;	High positive or negative
Change in Schedule	Resource and productivity issues; Knock on from other characteristics;	High negative
Change in Scope	Involvement of external stakeholders in design/planning; Planning concept changes; Potential delay; Potential site changes;	High negative

The following projects were not included in the classification of the entire project portfolio:

1. Projects with Annual Forecast less than $250,000. These projects as a group have a low influence on overall forecast accuracy. Forecast deterioration on all the projects, in a 'worst case' scenario, would impact the overall forecast accuracy by less than 10%.
2. Projects with completion reported at 90% or above. It is assumed that at 90% completion the likelihood of significant forecast variation is very low. The challenge to this assumption would be unanticipated major claims.

Classification of projects as presenting overall low, medium or high risk to the F 08 Annual Forecast resulted in the following:

Risk	Number of Projects	Total Value of Annual Forecast (excluding CPCN)
High	10	$52,152,225
Medium	91	$123,286,490
Low	16	$20,873,336

Qualitative Assessment of Risk to Annual Forecast

A qualitative assessment of the risk to annual forecast expressed in dollars is based on classifying 'high' risk as +/- 30% of forecast value (after deduction of YTD Actuals), 'medium' risk as +/- 20% forecast value (after deduction of YTD Actuals), and 'low' risk as +/- 10% of forecast value (after deduction of YTD Actuals). The quantification of risk into the 30/20/10 ranges is based on observed deteriorations in the projects reviewed.

Commitments

Ideally, commitments for the year would also be deducted from the Annual Forecast amount, to derive the proportion of Annual Forecast Cost not 'locked in'. The BCTC Accounting System does not support commitment accounting. As a result, the only commitment figures obtainable are through InfoPM. InfoPM reporting of commitments is at project task level and is a 'life' commitment number. It is not possible to establish the proportion of the commitment number that is expected to be spent in the current year. We compared the commitments against actuals on some of the projects reviewed in detail. The commitment number is usually significantly higher than the actuals, in most cases reflecting that construction contracts have been entered into. A project by project review of planned cash flow may be required to establish the proportion of commitments for the current year. The cash flow reports we have received are not detailed enough to support this analysis. The information required may be in InfoPM, but the understanding of the PE Administrator is that although cash flow forecasts are generated by InfoPM, BC

Hydro Project Managers have differing methodologies for updating progress and schedule. The recording of changes, commitments and the timing of generation of Change Notices for approval impacts the cash flow generated by InfoPM.

We note that even where commitments are taken into account, some assessment should be made as to the risk of additional cost for scope included in the commitment, arising through the same list of risk factors identified earlier in this Report.

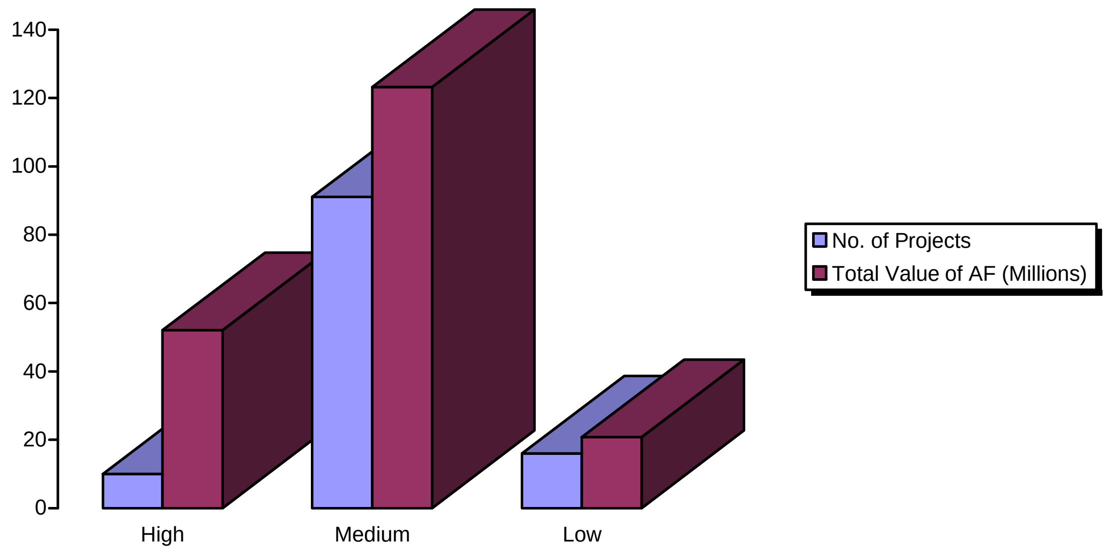
If commitments for the current year could be obtained and included in the calculation, a reduced potential variance on forecast would be expected.

Calculations

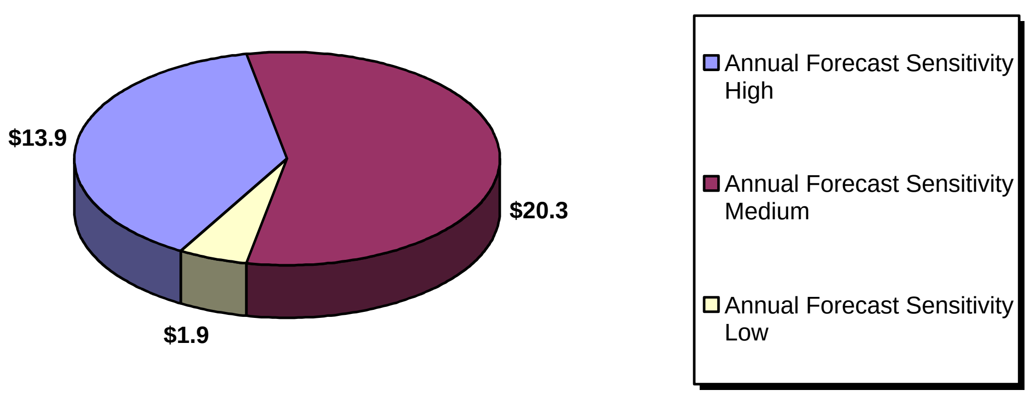
Risk	**+/- %**	**Number of Projects**	**Total Value of Annual Forecast less Actual YTD (excluding CPCN)**	**Annual Forecast Sensitivity**
High	30	10	$46,635,789	$13,990,737
Medium	20	91	$101,712,901	$20,342,580
Low	10	16	$19,907,504	$1,990,750
Forecast Sensitivity				**$36,324,067**
Total Annual Forecast (all projects in portfolio excluding CPCN)(source May Cost Report)				$273,160,780
Overall Forecast Sensitivity as % of Total Annual Forecast[3]				13%

The following charts are graphical representations of the previous table.

[3] Total Annual Forecast excludes the internal projects (related to IT, Facilities Management etc.) which appear on the May Cost Report but which are not part of the Projects Portfolio being reviewed.



Forecast Sensitivity Worst Case Cost Allocation



A full quantitative analysis of forecast sensitivity is possible with more complete data; however the nature of the analysis is such that the increase in quality of the analysis may not justify the effort required. A positive only variance is given, based on the limited indication of trends from the projects reviewed

Issues/Data For Further Review

Certain areas of investigation were not pursued prior to preparing this Report, either because of time restrictions, or because the personnel or data required was not readily available within the timeframe.

These areas of investigation are listed below, with an indication of the type of information sought and its importance to the recommendations and outcomes.

Data/Issue	**Type of Information/Task**
BC Hydro Financial Analysis Tools	BC Hydro has a program to develop project financial analysis tools, including Earned Value and Variance Reports. Interviewing those responsible for the development of the program may provide more information on how earned value is measured and its reliability as a project controls indicator for BCTC Program Managers.
Accuracy of Progress Reporting	Spot check project progress, by objective data (deliverables completed) against PM's assessment. Review PM's submitted progress reports for quality.
Review of Cable Life Extension and Oil Spill Containment Projects	Interview Project Managers. Oil Spill Containment Project shows a significant (11%) variance between AC/EAC% and reported % Complete requiring explanation. Project Managers at BC Hydro not available for interview on short notice.
Resource Planning	Interviews with BCTC Program Managers, and review of data available on Info PM and AMP, indicates that estimates and schedules are prepared without task level resource planning, and that resource planning and resource loaded schedule tools are not available. Interviews with estimators and more detailed interviews with project managers would indicate how resources are taken into account in project planning and management.
Variance Trends	A 'one off' variance in actuals from forecast flags one type of problem in project management. A continual slippage of actuals against forecast flags another type of problem. The review of the history of forecast vs. actuals would indicate if continual slippage is a problem on any projects. A method for obtaining historical cost reports has not been established, as the history is not retained in AMP. The capability exists in InfoPM but is not routinely reported to BCTC.

Data/Issue	Type of Information/Task
BC Hydro estimating methods	BCTC Project Management Standard EST-01 Estimate Classification defines the class of estimate required at certain project phases, and broadly describes the accuracy and effort level required to achieve the estimate class. In reviewing the Project Plans for Mission/Matsqui Area 69 kV Reinforcement, Gibraltar Mine Load Increase and the Replacement of 11 – 500 kV Airblast Circuit Breakers at 4 subs, there appears to be a significant gap between the BCTC expectation (as expressed in the Standard) of an EAR Quality Estimate and the estimates and information evident in the Project Plans. It is apparent that there are situations where insufficient time is allocated for estimating in the definition phase. Where BC Hydro nominates an estimate accuracy level outside of the EAR quality +/- 10%, the estimate is still described as EAR level or quality. Interviews with BC Hydro estimating personnel, and review of estimating tools and systems would allow an assessment of how closely BC Hydro estimates conform to BCTC class expectations.
Estimate Detail	All cost estimates reviewed lacked sufficient detail to enable a review of how estimates were built up. The estimate detail provided does not describe the data used. Review of the estimate detail would enable a stronger assessment of estimate quality to be made.
Development of Contingencies	General information was obtained on methods used for development of contingencies, and implementation of other risk management/mitigation strategies. Review of contingency calculations on particular projects, review of the BC Hydro @ Risk contingency development tool, review of risk assessments and tracking the implementation of risk management strategies identified in the Project Plans would allow a level of confidence in overall risk management to be assessed.
Scope Changes	Change control procedures, and their effectiveness in early identification of scope changes and prevention of wasted work, were not investigated.

Identifications of Issues for Further Investigation

During our review, we observed general practices and systems and gathered general information on management of the projects and project portfolio. Some of the issues are incidental to the forecast, but are noted below for your consideration.

Issue	**Recommendation**
Program Manager, Project Manager, Lead Engineer Responsibilities	In interviews with various project personnel, roles and responsibilities were not consistently known. It would be beneficial to provide the applicable Project Management Standard to clearly communicate roles and responsibilities, and enable alignment of participants from project Kick-off.
Key Project Personnel	The number of personnel changes made for the few projects being reviewed was higher than expected. Consider nominating key personnel on major projects with changes only by Senior Management approval. There is usually a high variability in the capabilities of PM's to progress engineering projects.
Project initiation process, role of BCTC	The Project Initiation process is not consistent. Some Program Manager's refer to being "handed" projects without involvement in investment justification and planning. The APM group involvement in preliminary phases, development of scope notes/project plan/preliminary estimate and other material supporting Investment Justification is not consistent.

Accurate communication of estimate classification	The meaning, parameters and methods applicable to a particular estimate classification are not clear. It is not clear whether typical estimating methods for +/- 10% accuracy are being used. Typical methods include take offs on all major equipment/materials (over $10K), pricing from vendors (min. budget quality) and pricing from Construction contractors (min. budget quality) to establish construction pricing. BC Hydro Engineering estimating methods have not been reviewed. Cost estimates reviewed were those available through AMP. All cost estimates reviewed lacked sufficient detail to enable a review of how estimates were built up. A detailed estimate should be provided for major projects, signed off by Project and Program Managers and made available as a reference document to assess changes and assist in auditing.
Project Management Tools	In reviewing the information available to BCTC Program Managers in AMP, it appears to be a financial reporting tool and not suitable for monitoring/managing projects. Even with the financial based system, reporting of commitments does not seem consistent, reducing the reliability of commitments data to track progress. Progress measurement is by project manager's assessment based on somewhat subjective data, or financial data that could be misleading. The cost based system has no scheduling or resource management capabilities. The systems and/or reporting to BCTC Program Managers do not provide historic data, so managers are unable to analyze trends, and BC Hydro Project Managers do not report on or analyze trends. The ability of Program Managers to audit information provided by Project Managers is limited. If systems are being updated, a project management system that will interface with the accounting system may be beneficial for major projects.

	The capabilities of InfoPM were reviewed (subsequent to the initial work done to prepare this Report) with BC Hydro and trending and other capabilities of the system were demonstrated. BC Hydro is improving the capabilities of InfoPM. Project Managers should consistently utilize the capabilities available in InfoPM and the relevant Project Management data should be mapped to AMP so that BCTC Program Managers can effectively monitor their projects.
Project Management Procedures	We saw significant variation in the quality and frequency of reporting by Project Managers. Much of the cost and schedule 'forecasting' by Project Managers is in fact revision of costs after increased costs have been incurred, and revision of completion dates after delays have been suffered. This is not forecasting. Project execution would benefit from formal monthly project review meetings, and a requirement that Project Managers (from all service providers) report on a standard pro-forma designed to force pro-active forecasting, development of project execution strategies, ongoing risk and opportunity assessment etc.
Risk Management – development of mitigation strategies, development of contingency, contingency analysis	The risk analysis tools used by service providers in developing estimates are not consistent and do not ensure a thorough risk analysis and development of a sound risk management strategy (including contingencies). There are problems with both (i) recognition of risks and gaps in estimate, and (ii) good quantification and management strategy for recognized risks. Consider improving risk analysis and management tools and skills by implementing a 'fit for purpose' tool, supported with appropriate training.

Strategic sourcing of Construction resources	Strategies of small packages and reliance on small to medium contractors may not be best suited to the current environment. In the current construction environment, alternative contracting arrangements may provide greater interest and better outcomes than the conventional arrangements.
Implementation of current data/lessons learned in existing and new projects	The lack of estimate detail prevents an analysis of the extent to which escalation studies and up to date data have been used to estimate escalation, or whether older estimates have been reviewed in light of new data. Potentially service providers could share this data. We have not seen systematic review or analysis of bids when bids received are higher than estimate. BCTC are developing a procedure for the systematic review of projects, development of lessons learned data and best practice materials, and implementation of these into new project plans.
Claims analysis and assessment	The quality of the data supporting the ‘claim’ submitted by SNC Lavalin on Mount Lehman was very poor. We are unsure of the procedures used by service providers to rigorously assess claims and make recommendations to BCTC.
Service Provider Incentives/Penalties	In order for a cost reimbursable arrangement to achieve the expected outcomes for all parties, objectives need to be aligned. An appropriate incentive structure will align objectives while a poorly designed one will be exploited. In addition to the usual project kpi’s such as cost, schedule and safety, consider adding performance, reliability, maintainability and key personnel.

Benchmarking	BCTC has an opportunity to build a benchmarking database, with base cost information, manhours etc. This database would be a valuable resource for estimating and also for setting targets and kpi's for service providers.
BC Hydro organization	A review of the advantages and disadvantages of the change in BC Hydro from multi-discipline dedicated project teams reporting to PM, to a matrix organization with work delivered by discipline groups, should be attempted. Different organizational structures are optimal for different types of projects. The matrix structure is well suited to certain project types. Consideration should be given to treating higher risk projects differently with regards to organization of the project team.

Gordon Goto *P. Eng* is a registered professional engineer in British Columbia and a member of ASME with over 20 years experience in international engineering and construction projects. Mr. Goto held positions of Project Engineer, Project Manager, Manager of Proposals, Director of Projects and President at Aker Kvaerner Chemetics. Mr. Goto managed lump sum EPC and EP projects in Australia, India, Argentina, Brazil and Canada and implemented company project management processes – risk assessment, project controls, constructability, HSE operating system and other key standards and procedures. Mr. Goto was involved in contract negotiations, dispute resolution, strategic management and major claims. Mr. Goto had profit and loss responsibility for a business unit with annual revenues of CAD150M and 200+ employees. Mr. Goto has technical knowledge of chemical plants (sulfuric acid, chlorine, sodium chlorate, pulp bleaching chemicals) pulp and paper and mining projects.

Meredith Sargent *B. Sc. LLM* is an Australian trained lawyer with over 15 years experience in international engineering and construction projects. Ms. Sargent held positions of Director, Legal and Commercial, General Counsel and Manager Procurement at Aker Kvaerner Chemetics and senior lawyer at law firms Baker & McKenzie, Deacons and Madgwicks in Melbourne Australia. Ms. Sargent was responsible for commercial risk management of engineering and construction projects, extensive engineering and construction claims development and defense, including claims valued at over CAD50M, claims negotiations and strategic management, development of contracting strategy, negotiation and drafting of engineering and construction contracts in jurisdictions including: North America, South America, North Africa, China, South East Asia, India, Australia, Eastern Europe, UK, management of global procurement of materials, equipment and services and litigation. Ms. Sargent has knowledge of chemical plants, commercial properties, electrical utilities, P3 projects and has lectured in commercial awareness, negotiation and law for engineers.

Appendix H

Report on Infrastructure Spending, Reliability, and Customer Impacts

Response to BCUC Decision for BCTC's F2007 Revenue Requirement, Order G-139-06, and Appendix A, Item 10, Directive 13, Order G-69-07

FOREWORD

This Report has been prepared in response to Item 10 of Appendix A of Commission Order G-139-06, requiring BCTC to report on relationships of infrastructure spending, reliability metrics and customer impacts, and to consider a number of issues which could be addressed in such a report. This report is also in response to Directive 13 from Commission Order G-69-07. Directive 13 requests the status of BCTC's progress in establishing correlations amoung asset class health index values, failure rates, suspected remaining lifetimes, and impacts on reliability. BCTC understands the desire to develop a better understanding of these relationships and supports this objective as a means to aid the effective management of the assets.

BCTC recognizes the importance of reliability analysis for investment decisions and is improving its analytical and management tools to enable all BCTC decision makers to use a fact based reliability-related analysis when making investment decisions.

Transmission system reliability is impacted by a range of decisions, including Growth Capital investments, operating configurations, and sustaining maintenance and capital investments. BCTC is continuing to develop analytical tools to aid in understanding the impact of specific decisions on reliability. However, BCTC is unable to define a comprehensive model to measure the effect of all individual corporate investments or activities on reliability.

BCTC believes that the most effective response to this topic is to review the issue of reliability management from the perspective of Sustaining activities. This approach has been taken because a number of tools that analyze the impact of sustaining work on reliability have been completed or are under development and are closely aligned to the topics in Item 10. In this Report, Sustaining investment refers to Sustaining investments for maintaining the system's original design capability. This excludes investments to enhance the system's capability.

This Report addresses each of the suggested topics directly. Each section addresses the specific topics according to the order in which they appear in Item 10 and also expands on certain topics with a broader context to attempt to provide an insight into the reliability management activities that BCTC is pursuing. However, BCTC notes that this Report does not provide a complete description of all the reliability and asset management activities that BCTC is engaged in.

INTRODUCTION

BCTC's approach to reliability management from a Sustaining investment perspective involves the examination of system reliability at various levels of detail, including the contribution of component elements of the system to reliability at specific delivery points and their impact on overall system reliability. These analyses are supported by outage statistics and asset condition data which are recorded for individual pieces of equipment and for system elements.

The fundamental objective of these analyses is to determine the relative impact on reliability and the resulting customer impacts for any given investment decision. BCTC understands this to be the essence of the Commission's' interest as expressed in Item 10.

Response to Item 10(a)

"*Link changes in reliability Indices to impacts on end use customers to establish the costs and benefits of establishing specific reliability targets*"

BCTC has been able to correlate reliability index targets with impacts on end use customers for a significant number of activities. This correlation is done on a delivery point level and involves measuring contribution from all sources on the reliability performance at that point. When a specific source is identified and a program is designed to correct the problem BCTC is able to predict what the contribution to the reliability level will be. For SAIDI measurements this would be a reduction in duration of outages. The cost for that reliability improvement would be the cost of the program to implement the solution. For example an expenditure on specific outage causes like vegetation or equipment failure may be directly linked to specific reliability improvements and therefore reliability benefits.

BCTC has taken this concept further to compare the relative benefits associated with different programs at different delivery points.

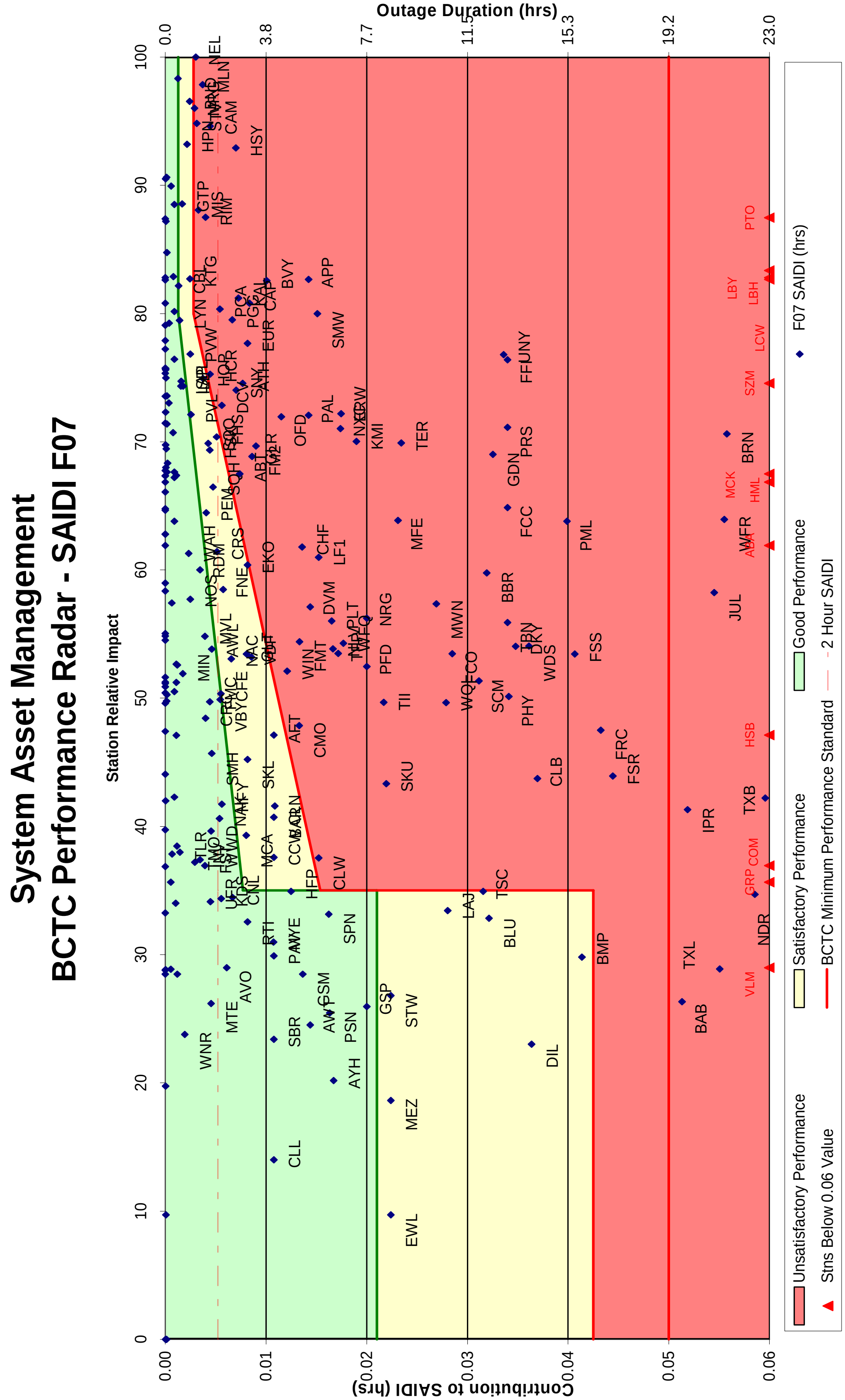
To achieve this BCTC first considered how the system is designed, operated, and maintained, and recognized that BCTC provides varying levels of reliability to different delivery points depending on the criticality of the load to different stakeholders. To ensure no customer is neglected, BCTC considers that the worst 5 % of delivery points should receive the highest priority for reliability improvement. The remaining delivery points will receive a priority rating depending on the performance gap for that point.

Each segment of the system has its own appropriate SAIDI target level and average system indices do not reflect or recognize this differentiation. Different investment options which have the same impact on a system wide SAIDI may not have the same benefit to customers as a whole. For example, for the same solution cost, a reduction of 10 hours of outages on a remote small load delivery point and 10 hours of outages to a manufacturing load where loss of production and economic benefits may occur will have different societal impacts; however, they would have the same impact on system SAIDI levels.

To address this issue, BCTC, together with BC Hydro, has developed a ranking system based on the characteristics and importance of all delivery points (currently 386) and assigned each delivery point a criticality score of low, medium, or high.[1] BCTC then calculated the relative performance (according to SAIDI statistics) of each delivery point as shown in the figure below. The following Figure 1 plots these scores which are further discussed in section 10(d).

[1] This Ranking was done in consultation with BC Hydro to incorporate BC Hydro's targets developed for its Customer Based Reliability Program.

Figure 1. Sample Performance vs. Importance of Delivery Points



With BC Hydro's assistance, BCTC developed specific reliability targets for each of the delivery points. BCTC routinely monitors delivery point performance gaps from their targets. When the gap is significant, BCTC asset managers investigate to find the cause of poor performance, determine appropriate alternative solutions, and determines the cost to close the gaps using different alternatives.

BCTC and BC Hydro can therefore compare the reliability benefits for different groups of customers by examining alternatives the different solutions to close the performance gaps at those delivery points

This approach provides a comparison between customer reliability benefits at a delivery point level for various investment decisions and it is closely aligned with the way asset managers make decisions about investments.

An example of this type of analysis was the pole top fires experienced on 60L223. In F2005 the SAIDI contribution from this problem was 0.68. The cost to bond the insulators on this line would have been approximately $1 million. However the line only serves a mine which is shut down and several obscure Highways facilities. The relative importance of this delivery point was therefore very low and the analysis demonstrated that a gain in 0.68 SAIDI by a $1 million expenditure was not warranted.

The historical level of reliability as measured by SAIDI and other traditional indices was largely a consequence of the transmission system's design when the system was relatively new and equipment rarely failed. To significantly change the performance level, new design parameters (such as wind loading levels, ice loading levels, or new network configuration) would have to be adopted and retrofitted to the system. However, as the system ages, the contribution to SAIDI from equipment failures will increase and SAIDI will deteriorate. OMA and Sustaining investments can slow the decline. To some extent, deterioration in SAIDI is also controllable by system additions or selectively improving design standards.

To set more meaningful targets which can be impacted by managing investment decisions and be used for performance measurement, BCTC has effectively removed events which would normally fall outside the original design parameters for the system. This is done by eliminating any events caused by other utilities or natural causes such as forest fires, earthquakes, and extreme weather, and which have a SAIDI impact greater or equal to 0.17 hours. This threshold was chosen because it is equal to one average month of performance since 1994 (average yearly SAIDI performance is around 2.2 hours).

BCTC now sets SAIDI performance targets by averaging the actual performance of recent years (currently the five most recent years) less an improvement factor. This improvement factor is set every year and recently has been set at 6.5%. This goal has been set to effect improvement and is also considered to be achievable at a reasonable cost.

Response to Item 10(b)

" examine the normal year-to-year variations in the reliability indices to establish the period(s) over which targets should be established and the periods over which "real" trends can be detected (statistical process control theory may be of some use here)"

BCTC analyzes actual results over a long period to help determine meaningful reliability performance targets. BCTC believes the most relevant measurement period is the last five years. This period spans enough time to reflect past asset management actions and recent events. Asset health impacts asset performance. Asset health worsens with exposure to the operating environment, age, wear and tear, and improves with maintenance and rehabilitation investments. Past investments are shown to be effective only after some history shows the asset performance meets expectations. Sufficient time is required for data to show the effectiveness of the investments. Five years is sufficient time to enable sustain and maintenance work for most assets to impact the measures. It is long enough to make data available to perform valid calculations for most delivery points.

BCTC collects causal data on every outage. In analyzing the complete data set on outages, BCTC sums the contribution of the many outage causes at the aggregated system level and trends them over time. BCTC also breaks down causes to individual sub-causes and aggregates their contribution to the system-wide performance. This enables managers to select specific corrective actions to any performance gaps related to specific causal factors. Solutions can then be implemented in a system-wide program to achieve a specific targeted overall performance improvement based on an understanding of the system wide contribution of each causal factor to performance. Based on causal analysis and by identifying opportunities to reduce the threat, a program or solution may be designed.

Examples of performance targeted programs include:

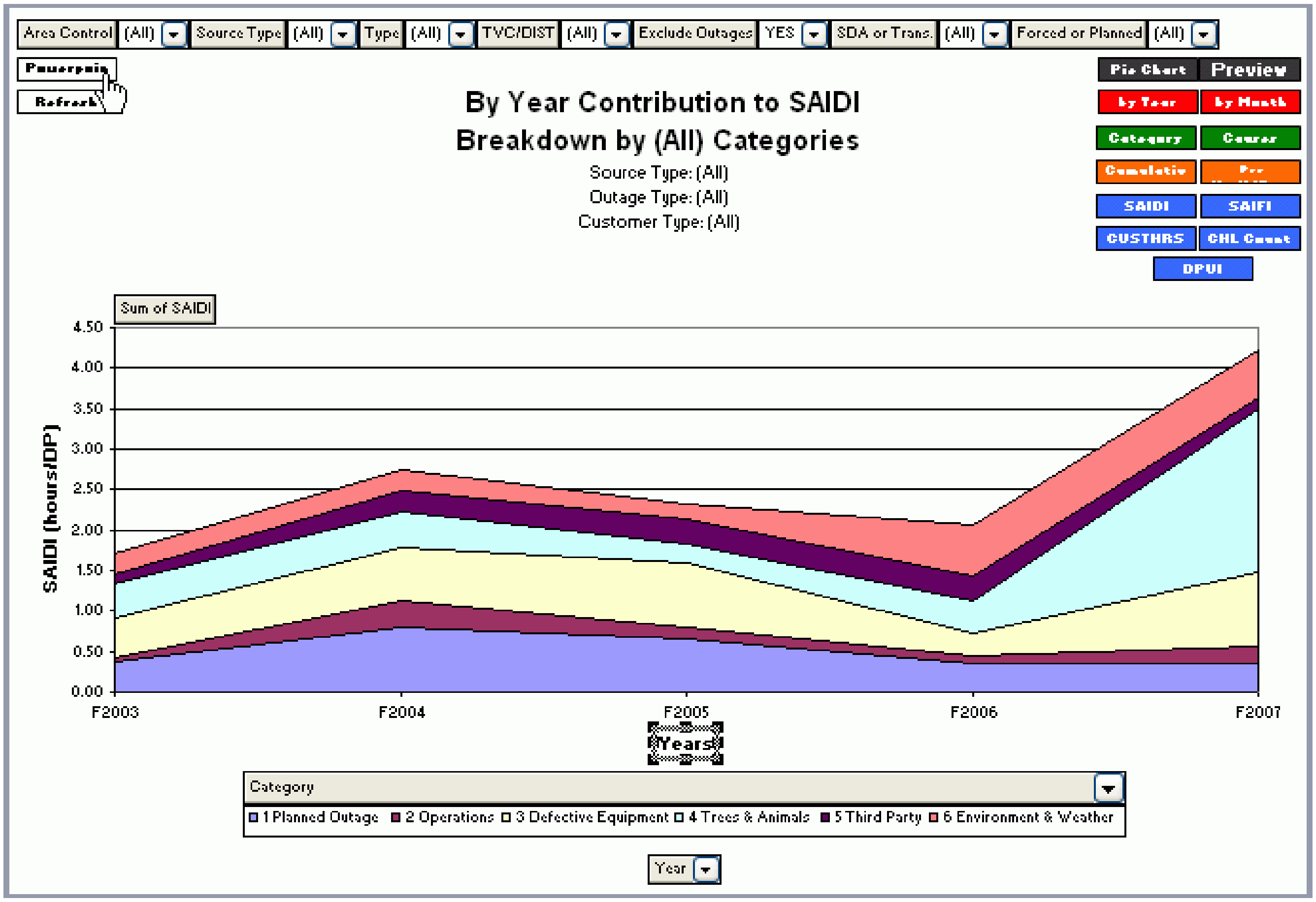
1. an animal mitigation program[2];
2. a motor vehicle accident program; and
3. a lightning mitigation program.

This performance trending process uses graphical displays to assist managers to predict future performance issues requiring attention. Figure 2 shows a sample display. BCTC does this type of analysis on many performance metrics.

BCTC uses this process to link changes in reliability indices with activities (and therefore costs) associated with some of the outage categories (e.g., defective equipment, trees and animals, etc.). Some subcategories of outage causes (e.g., external utilities, weather, etc.) are less controllable and cannot be addressed by short-term investments. For these causes the linkage of short-term investments to reliability index performance is weaker and resolution of these causes to improve system wide performance would take large investments over a long time to change the basic design level of the system to withstand large external factors.

[2] For an example of the analysis involving animal mitigation please see attachment A

Figure 2. Sample: Total System Outage Time by Causes



BCTC applies statistical theory to examine reliability trends and is working to improve that methodology. Currently, BCTC examines trends on a monthly and annual basis. As mentioned above, BCTC compares performance to targets based on the average of the previous five years of data and applies an improvement factor to the target. This improving target reflects the BCTC commitment to continuously improving reliability over time.

Statistical process control (SPC) normally depends on natural variations being small such that errant trends can be identified quickly. However, BCTC's statistics are influenced by large, random events. Due to the nature of these events, BCTC cannot use traditional SPC models for monitoring system performance.

For planning purposes, the bulk system is subdivided into four systems:

1. The Northern System
2. The South Interior System
3. The Interior to Lower Mainland (ILM) System
4. The Lower Mainland to Vancouver Island (LM-VI) System

Response to Item 10(c)

"Determine whether system-wide metrics or more localized (e.g., substation by substation) metrics are appropriate as investment triggers and/or inputs to project prioritization tools"

As discussed in BCTC's response to Item 10(a), BCTC believes investment requirements must be identified and analysed at both the local level and at a system wide level. This provides a comprehensive view as well as a local view. This enables understanding of how the particular asset or delivery point is impacted and whether the problems identified in analyzing a particular event are occurring in isolation or are common on a system wide basis. It also enables BCTC to compare and prioritize initiatives to address similar problems at different delivery points. Therefore, the metrics used to compare how the delivery points and the system are impacted must be done on a local and a system wide metric basis. This ensures consistency when comparing investment decisions.

System wide metrics are also useful for:

1. gauging longer term trends;
2. comparison to both internal and external industry benchmarks if those benchmarks are calculated on the same basis;
3. setting overall company strategies; and
4. identifying emerging issues.

Response to Item 10(d)

"Propose a clear priority-setting mechanism for expenditures on existing infrastructure and provide examples of how those mechanisms are to be employed"

BCTC uses a number of mechanisms to differentiate between various investments when it evaluates portfolio expenditures to address existing and expected performance gaps in the existing infrastructure. This allows managers to prioritize investments based on the objectives used. For example, an investment program might be planned to maximize SAIDI improvements or to produce the most cost effective renewal, or some weighted combination of objectives.

The following list identifies the major steps taken in prioritizing Sustaining investments, each of which is discussed in the subsequent paragraphs. There are a number of subordinate and supporting steps for each that are not discussed here to keep this response relatively brief.

1. Identify delivery point performance and the relative criticality (incorporate changes due to customer additions or changes in system configuration by either BCTC or BCH).
2. Identify and analyse causes of performance gaps (either positive or negative).
3. Analyse causes on a system wide basis and determine response options and costs.
4. Prioritize resolution options based on the objectives of the company.

The above steps construct a portfolio to optimally address areas of the system or business practices which under-perform or do not meet standards or regulatory requirements. Many detailed sub-processes determine the relative severity of the issue with respect to its impact on performance metrics and cost.

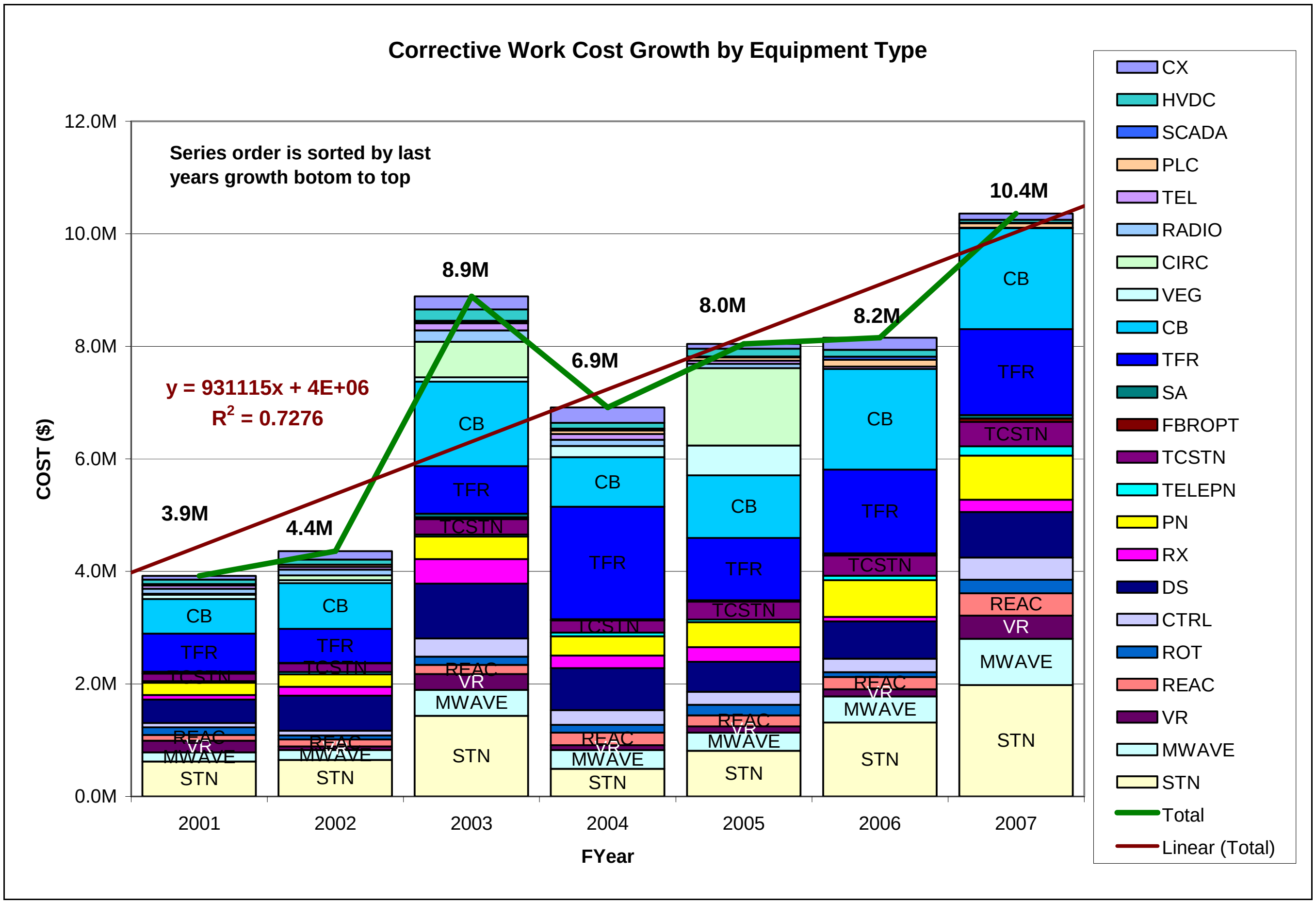
The first step in this differentiation is to identify the relative importance of the various delivery points and measure their performance relative to target levels (see Figure 1 in the response to Item 10(a)). When all delivery points have been plotted, a number of different analyses can be performed. For example, Figure 1 shows different target levels are assigned based on the criticality of the delivery point. This is illustrated by the green, yellow, and red blocks delineated on Figure 1. The target level is the Green line and is set at different levels depending on the criticality of the delivery point. All delivery points within the green block meet or exceed target levels. All delivery points within the yellow block are within limits of normal variation from the target levels (the summation of the green and yellow blocks will produce the target level) and all delivery points in the red block fall below target levels. Delivery points which fall below the red line have a performance level which falls outside a normal asset management objective. The line is arbitrarily set to display the worst 5 percent of performance. This target reflects BCTC's commitment to improving the reliability over time. These poor performers will typically have been the result of some catastrophic failure and require immediate attention. BCTC also sets service performance criteria for its employees and service providers based on how well each of these target levels is achieved.

Step 2 identifies the various contributors to problems as shown in Figure 2 in the response to Item 10(b) above. This step targets the various causes of poor performance and highlights alternative solutions to improve delivery point performance.

Step 3 has many analytical activities in it. It examines the past experience of corrective work, reports on investment in past maintenance (including corrective, preventive, and condition based work, costs and frequency), and trends these parameters for specific assets or groups of similar assets. This helps managers learn about past equipment issues, successful strategies that have been used, and those that were less effective. It also helps managers predict future failure rates and maintenance costs to support asset management decisions.

An example of corrective work cost by equipment type is included in Figure 3 (the abbreviations in the legend on the chart indicate different type of asset classes).

Figure 3. Sample: Corrective Work Cost Trending



Another part of the portfolio analysis presently being developed is the creation of a leading indicator of future failure rates. This will be done by representing the current condition of all assets in a continuously updated asset health index (AHI).

BCTC has data on the fleet of all assets (in excess of 1 million asset elements), reporting from the low level of individual assets or groups of similar assets to the aggregated system-wide level of information. This data indicates the effectiveness of Sustaining investments by trending the AHI results. An AHI is more useful than age information because it is a much closer indicator of the true condition and expected remaining life of the asset. There are some assets for which age is the main determining characteristic of remaining life. However, for many of the more costly and critical assets in the system, age is only a minor factor in determining remaining life. For example, circuit breakers are affected far more by the number of high fault current operations and operating conditions than they are by the chronological age. Circuit breakers of the same vintage, in the same fleet, may have vastly different expected lives purely based upon differences in the number of fault operations and operating environment. By employing AHI, BCTC believes that it can better judge and predict the appropriate replacement times for each of the assets. Using AHI, BCTC also expects to improve its ability to forecast short term costs versus failure rates by seeing the actual end of life demographics for the different fleets of assets.

AHI helps in setting priorities. By flagging groups of assets in particularly poor condition and associating this information with their criticality and expected life, decisions can be made to repair or replace or to allow failure to occur (where preventive maintenance is too costly or the consequence of failure is too low to justify pre-emptive expenditures), so that investments for higher assurance can be made in cases where the customer impact is high. This enables reliability index improvements to be targeted at the most critical delivery points so that maximum value is returned on the marginal OMA and capital dollars of expenditure.

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An illustration of a screen for this analysis showing the risk associated with asset failures is shown in Figure 4.

Figure 4. Display of Equipment Failure Risk Assessment (using hypothetical data)

EQUIPMENT RISK MATRIX

Risk	A		B		C		D		E		Total	RISK SUMMARY		
	A1	A2	B1	B2	C1	C2	D1	D2	E1	E2				
Total	2,079	6,346	2,565	1,773	1,186	1,173	2,101	707	1,946	6,184				
EQUIPMENT FAILURE PROBABILITY 100	56	5	57	5		45	67	128	55	54	472	1261	Very High Risk	E
90	67	45	854	56	111	8	876		1	345	2363			
80	120	4,332	34	66	67	234	65	88	4	678	5688			
70	66	12	9	854		78	212	9	763	1,898	3901	3888	High Risk	D
60	234	9	582	12	44	678	54	21	65	777	2476			
50	663	87	56	65		32	99	5	5	456	1468	2,568	Medium Risk	C
40	43	78	76	375	877	8	532	45	212	88	2334			
30	53	346	99	218	45	55	33	72	766	767	2454	11,511	Low Risk	B
20	743	765	34	56		23	74	7	67	884	2653			
10	34	667	764	66	42	12	89	332	8	237	2251	6,055	V. Low	A
0	10	20	30	40	50	60	70	80	90	100	26,060			
	EQUIPMENT IMPACT													

Note: not real data for illustrated purpose only

The above figure describes how many pieces of equipment may fall in any particular category of relative failure probability and impact assessment. For example, in the upper right there are 54 pieces of equipment which have a 100 percent probability of failure within a selected timeframe and which also have been graded as having the highest impact (100). These would then be aggregated and totalled in ranges indicated by the various colors.

The priority setting mechanisms described above are in various stages of development. Other mechanisms used by BCTC include data collection and data manipulation tools such as Passport (BCTC's work management data base) and Meridium. The Meridium tool has been used to calculate the BETA (life-cycle phase of assets) value for various types of assets which is used to produce one of the inputs to the Prioritization Model. With the aid of the Prioritization Model, management can optimize a portfolio of investments to achieve the maximum value based on a number of criteria. This methodology was discussed in the F2008 Capital Plan, and is further discussed in Appendix J of the F2009 Capital Plan.

In Step 4, the Sustaining function uses this methodology to prioritize its portfolio to produce the maximum value given certain budget constraints. This methodology recognizes the cost effectiveness of projects, and assigns additional value for alignment with corporate values and risk tolerance. Prioritization involves the review of business cases in a portfolio of proposed projects to identify the highest value projects so they can be pursued, while ensuring that significant risks associated with the deferral of lower value projects are considered.

Response to Item 10(e)

"Seek feedback from customers on the impact of outages and the cost/reliability trade off"

BCTC receives feedback from end use customers through BC Hydro's Customer Based Reliability (CBR) program which examines feeder performance and conducts customer surveys to set performance target levels. BCTC incorporates these targets in its analysis of delivery point performance to determine the criticality of each delivery point. BCTC has not surveyed wheeling customers; however, BCTC measures intertie congestion to indicate how well the system responds to the needs of its wheeling customers.

Response to Item 10(f)

"ensure that the metrics used in assessing the performance of BCTC, its contractors, and its employees measure, to the greatest extent possible, controllable factors"

As discussed in the response to Item 10(a), BCTC has taken steps to normalize SAIDI indices to exclude events which are beyond the short term control of its managers or service providers. This is accomplished by eliminating events which are caused by other utilities or are weather related and have an impact on SAIDI of 0.17 hours.

Response to Item 10(g)

"Propose one or more mechanisms, by which BCTC can, over time, establish a statistical relationship between the amount and timing of infrastructure expenditures and changes in the various measures of system reliability"

In its F2008 Capital Plan, and in Section 6.4 of the 2007 State of the Transmission System Report located in Appendix B of the F2009 Capital Plan, BCTC describes a statistical analysis which established this relationship for equipment. The following is a summary.

This analysis was developed to model the effectiveness of total Sustaining capital investment towards achieving mid-term and long-term system-wide reliability targets and to predict a budget to meet a selected performance target. This model is referred to as the Sustainment Investment Model. Over the next decade this model shows it is necessary to increase Sustaining investment on average by approximately 30% compared to the past decade to maintain current levels of asset performance and reliability.

Using this model, BCTC management:

1. amalgamates all Sustaining Capital projects proposed for the upcoming Capital Plan;
2. examines the predicted reliability impact of the proposed total Sustaining investment;
3. reviews the predicted total Sustaining budgets required to maintain a range of satisfactory performance levels over a ten-year period;[3]
4. chooses a performance level target and associated budget;

[3] It also projects future investment levels required to keep up with the demographic challenges of a large percentage of the fleet of a certain age which will reach end of life in a predictable short time frame. To assist decision makers to visualize this aspect of the problem the model produces 10 decades of forecasts.

5. allocates the chosen budget into equipment categories and subcategories so that portfolio managers can compare the model budget with their portfolio of initiatives; and

6. requires portfolio managers to adjust their portfolio of projects to fit their budget level produced by the model.

This top down analysis of specific total investment level options helps prevent rate shocks and enables long term work load levelling to ensure the work is achievable. It recognizes that the performance and health of assets is dependant on their maintenance, operation, life cycle position and capital replacement rates. This relationship is captured in the Sustainment Investment Model which is used to predict the impact of capital investment on system reliability.

The model also enables BCTC to assess the impact of reduced budgets on the system performance if particular programs are trimmed back to fit a budget reduction. Where possible, individual managers can select projects with the lowest impact to defer so that the highest value projects and programs can proceed and the adjusted budget total can be adhered to with a minimum impact on reliability.

The correlation of model input data such as useful life and maintenance costs are intended to model the current BCTC system as it is currently being managed. The intent of the Sustainment Investment Model is to take current techniques and information to forecast future spending that would be required to avoid rate shocks or excessive decline in performance.

The description of this model in the 2006 State of the Transmission System Report stated that the model is based on the number of Transmission System assets reaching the end of their useful life in each decade. BCTC further stated that phase 1 of the development of this model used expert opinion and industrial practices to estimate end of useful life. Useful life is determined by experts based on a number of factors including: catastrophic failure rate, repair costs and risk based obsolescence. Information for this comes from experience, system data, industry studies and manufacturer provided data.

Phase 2 of the project development is intended to provide ongoing refinement to the model and asset management practices by using complete historical failure, and replacement cost data. To that end, BCTC has now completed verification analysis on 11 of 33 asset classes without significant deviation of the system wide result. Additional data on the remaining assets is expected to take considerable time and expense to assemble. This process is integrated to the existing routine maintenance work. However, BCTC expects that the projections will continue to reflect the BCTC sustainment expense as this data is incorporated.

The 11 asset classes that have been completed in Phase 2 are primarily the station assets. The advantage of refining station forecasts is that the data from station assets are more readily available and these assets tend to have shorter life span compared to transmission assets. Station assets accounts for a large portion of the BCTC assets reaching end of life in the near future. Transmission assets continue to have significant effect on capital expenditure due to their large contribution to the total portfolio. For the most part, transmission assets are still far from end of life. Wood pole structures are an exception to this separation and BCTC has made a significant effort to populate and verify this data which has been included in Phase 2.

Completion of Phase 2 for transmission assets is required to better forecast long term Sustaining capital (i.e., beyond 10 years). In the short term, the first ten years of Sustaining capital forecast segment, the model is not expected to change significantly.

Attachment A

Case Study:

Station Animal Outage Reduction Program

Analysis using SAM Tool

July 12, 2005

Revision 6

Asset Performance and Quality Assurance

Prepared by:

Trevor St. Germain

Rebecca Duthie

BCTC

EXECUTIVE SUMMARY

This case study is a comparison between an animal outage contact reduction programs at stations selected and prioritized using traditional methods to station selection and prioritized using the System Asset Management (SAM) tool. The aspects of the programs being compared are both the improvements to reliability and effectiveness of financial investment. The objective of SAM is to enhance or maintain system reliability while reducing costs. The SAM system focus brings high reliability in critical areas and acceptable reliability in less critical areas at lower cost. Also, the SAM will provide clear quantitative evidence to justify reliability expenditures.

The SAM tool can be used by any utility analyst or engineer without special knowledge of the system or root causes of outages. This is made possible by the capture of the knowledge base of experts in the areas of station prioritization and station performance as part of the development of SAM.

There is currently an initiative underway for the installation of bird and squirrel guards on busses and transformers to reduce outages due to animal contact. This initiative will improve reliability and reduce the cost of outages. There are 13 Distribution stations named in the initiative for F2006.

To produce a comparison initiative, we will use SAM to identify the 13 stations, with respect to reliability, to include in the Fiscal 2006 program. Also, we will objectively quantify what the improved reliability and reduced costs are expected to be. In addition, we will use a total system approach to quantify the order of priority for the stations identified in the program.

From the results of the comparison, SAM has given us the ability to either target a potential improvement to reliability nearly twice that of the current program, or reduce the costs to nearly half of the current program. A combination of improved reliability and reduced cost is possible. Thus, SAM’s objective to enhance or maintain system reliability while reducing costs is met.

In addition, the prioritization of the stations in the program is generated in the process. Also, the business decisions within the SAM program can be repeated using an objective and consistent process.

This improvement to both the precision and accuracy of business investment is made possible by the objective analysis of the SAM tool.

INTRODUCTION

Current Station Animal Outage Reduction Program

There is currently an initiative underway for the installation of bird/squirrel guards on the busses and insulation on the transformer bushing terminals/conductors to reduce system (feeder) outages due to animal contacts and reduce the risk of damage to transformers in outdoor type substations. This initiative will improve reliability and reduce the cost of outages. There are 13 Distribution stations named in this initiative for F2006.

The stations to include in the F2006 plan is often based on limited data from only a few stations then developed using personal knowledge and subjective similarities to other stations.

Distribution Stations List

CBL	Campbell River
CBN	Clayburn
ESQ	Esquiamalt
KGH	Keogh
LTZ	Lantzville
MAN	Mainwaring
MIS	Mission
MLN	McLellan
MRG	Maple Ridge
NFD	Northfield
PHY	Port Hardy
PKL	Port Kells
WHY	Whalley

Regional staff is responsible for prioritizing the 13 stations within F2006 and to execute the work. The total cost of this initiative for the Distribution stations is $347,151.

SAM Station Animal Outage Reduction Program (Case Study)

For comparison purposes, we will use SAM to identify the 13 stations, with respect to reliability, to include in the Fiscal 2006 program. The study will focus on Animal and Bird outages only. Also, we will objectively quantify what the improved reliability and reduced costs are. In addition, we will use a total system approach to quantify the order of priority for the stations identified in the program.

The SAM Tool can be used by any utility analyst or engineer without special knowledge of the system or root cause. The System Focus brings high reliability in critical areas and acceptable reliability in less critical areas at lower cost. Also, the tool will provide clear quantitative evidence to justify reliability expenditures.

BACKGROUND

At the time of the case study, it was known that the stations identified in the current program were based on selections made by a Station Animal Outage Reduction committee. The committee considered logistics and scheduling limited to within the Lower Mainland only. The committee considered reliability limited to customer-hours lost only. For the equipment to address, the blanket decision was made to cover all 12kv bushing terminals.

SAM does not consider logistics or scheduling. Though, it does consider both reliability and business criticality. SAM will take a holistic system approach to include all geographical areas and equipment types. The SAM reliability metric is based on customer-hours lost, mean time between failures, frequency of failures, and time since last failure. The business criticality takes into account number of customers, load, customer type, substation class, rate schedule, and stakeholder issues. The business criticality translates into a station relative rank that adds a useful dimension for station prioritization.

ASSUMPTIONS

Given the scope and limitations during the development of the case study, the following assumptions are made:

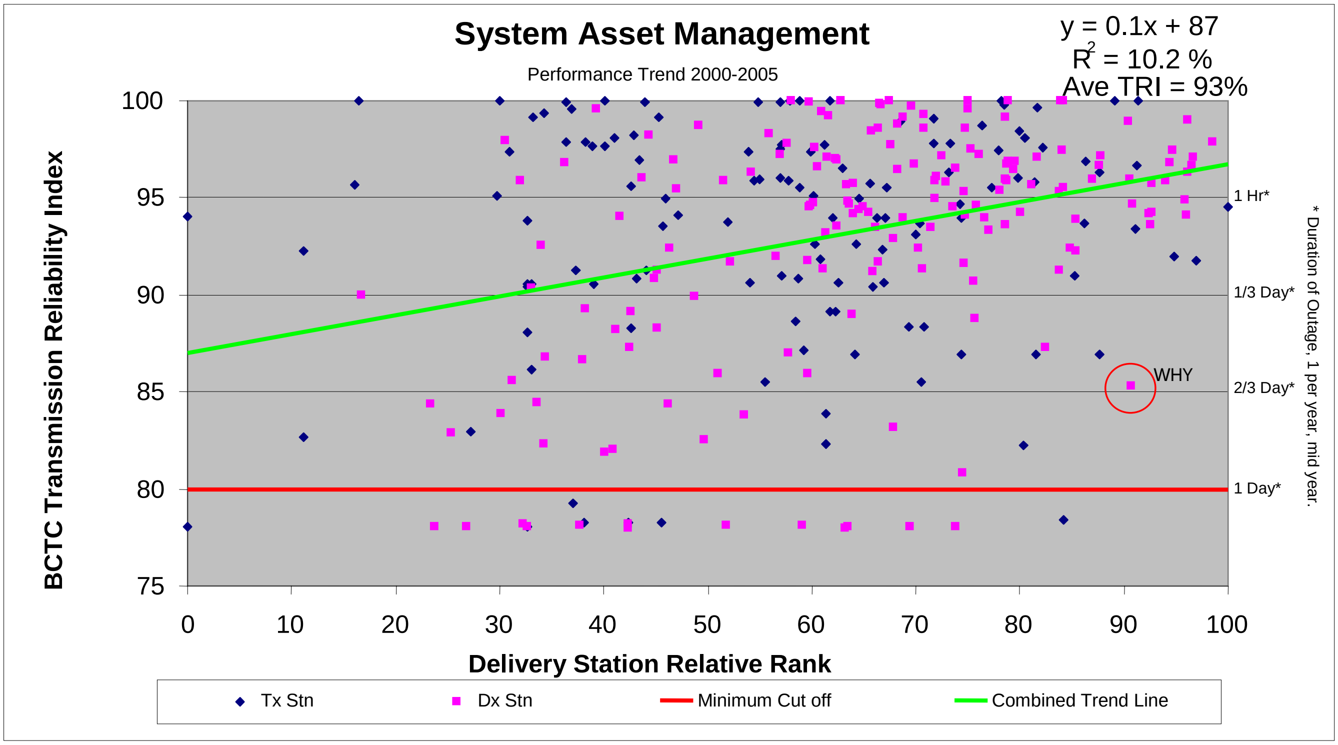
It will be assumed that all stations identified in the current program or SAM program have yet to be addressed as part of the Station Animal Outage Reduction Program.

It will be assumed that the total Station Animal Outage Reduction Program costs are the same for measures taken at the 13 stations identified by the current program or SAM program.

It will be assumed that the primary driver for the stations to be identified in either program is reliability and business criticality. The strategy is that the higher the business criticality of the station, the higher the expected reliability. I.e. the higher the relative rank, the less tolerance there is for impacts to reliability as a result of animal contact outages.

It will be assumed that the purpose of the comparison between the current program and SAM program is to show the strength of using the SAM tool to cover the reliability aspect of the decision making process.

1 **ANALYSIS**



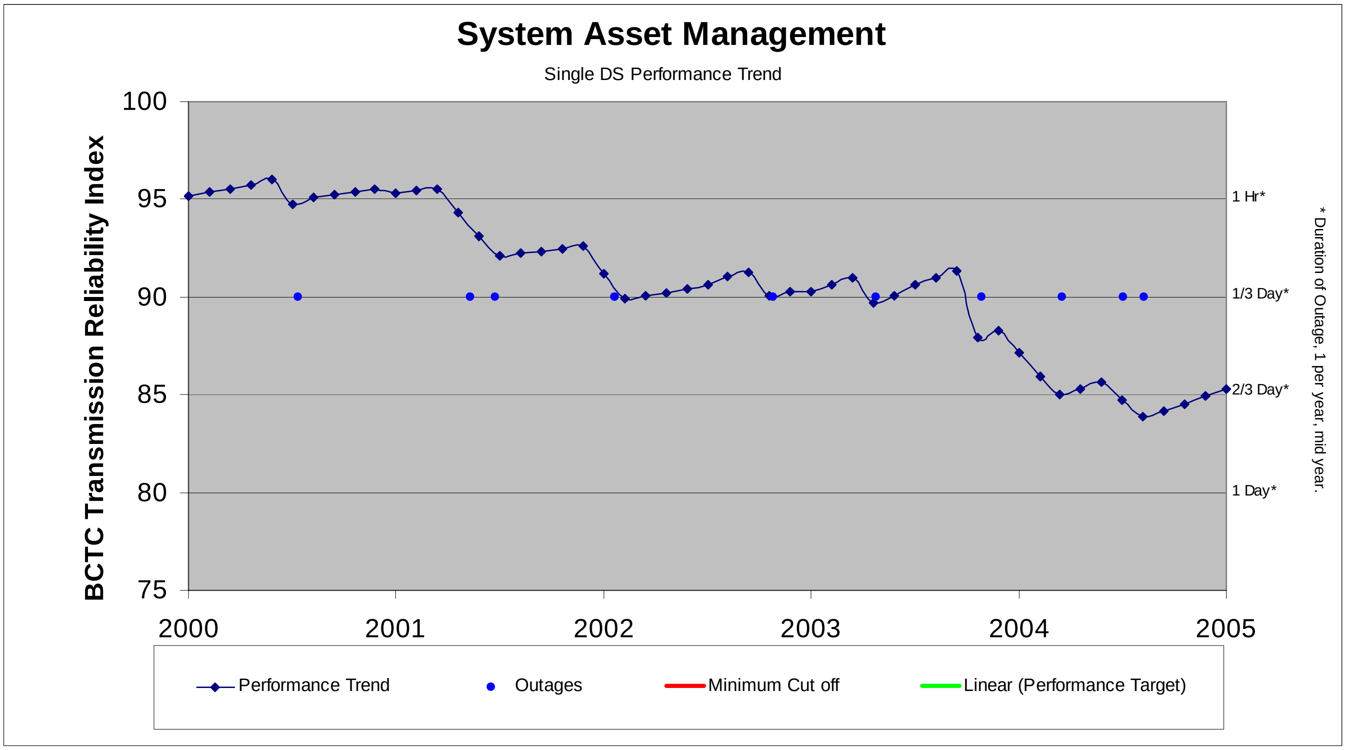
2

3 The above plot shows the state of the system as at January 1, 2005

4 The chart above shows a high level view of the system. This chart represents all
5 outage types for all delivery stations.

6 The general goal is that each station be brought up to the target line, shown in green.

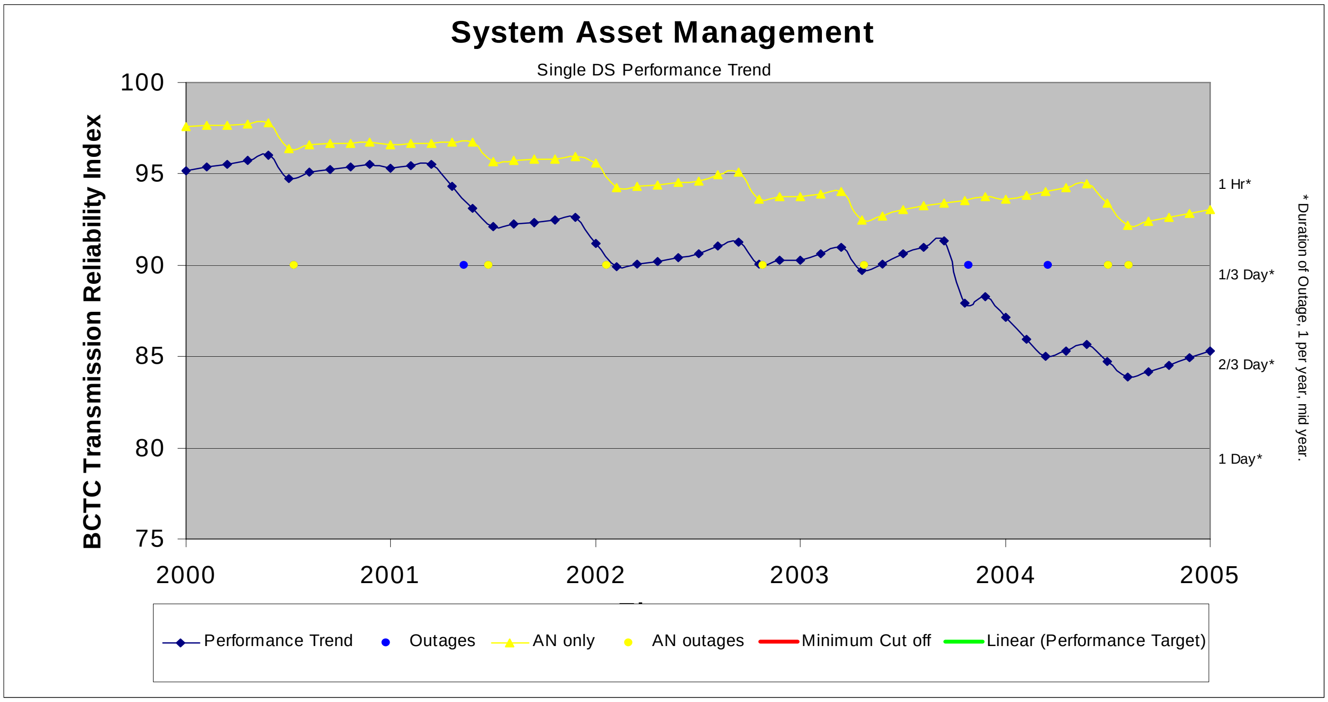
PROGRAM DEVELOPMENT



This graph shows the historical reliability, navy line, for all outage types for Whalley station (WHY) from January 1, 2000 to 2005.

The green line is the target performance for Whalley. The red line is the minimum acceptable performance for any BCTC delivery station.

We can see that there are 11 outages, shown by single blue dots on the 90 TRI line. The outages at Whalley (WHY) have reduced reliability to a level below the target since early 2001.



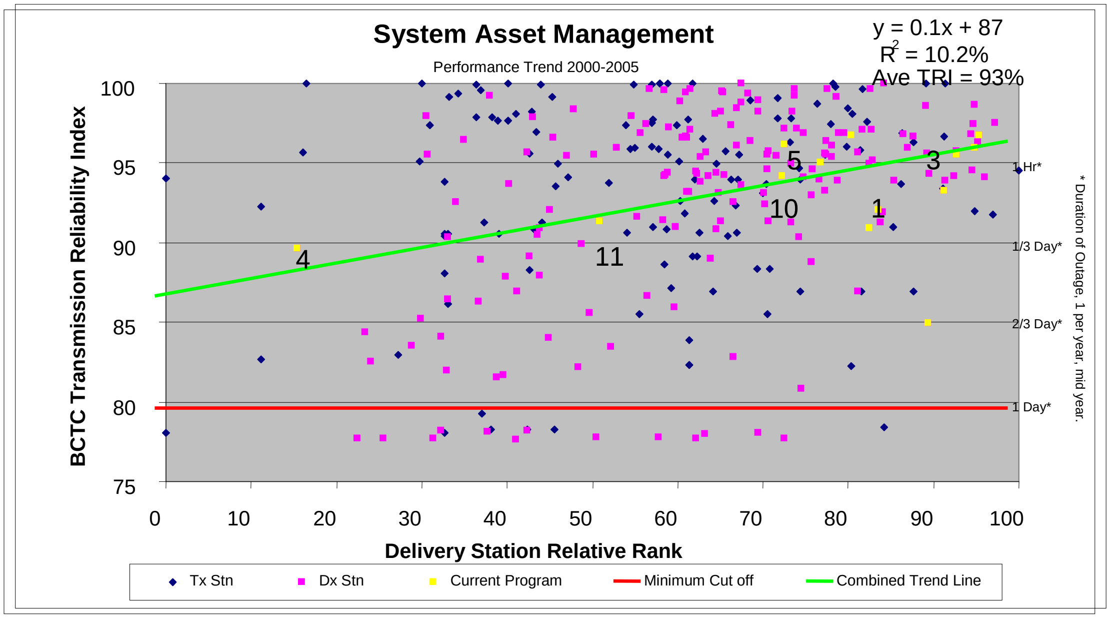
This graph shows the difference between animal contact outages, yellow dots, and all other outage types, blue dots, at Whalley. The affect of the animal contact outages on the station reliability is shown by the yellow trend line. The yellow line makes up a portion of the total impact on station reliability which is the navy line.

We can see that the Animal and Bird outages make up a significant portion of the outages affecting TRI. In fact, the Animal and Bird outages alone are enough to pull the Reliability below the target. One approach to develop a new program is to repeat this level of analysis at other stations and identify common outages causes. Thus, the objective support required to create a program to address them.

This graph shows the difference between animal contact outages, yellow dots, and all other outage types, blue dots, at Whalley. The affect of the animal contact outages on the station reliability is shown by the yellow trend line. The yellow line makes up a portion of the total impact on station reliability which is the navy line.

WO Number	Date	Cost
#122102	26JUN01	$ 984.33
#140686	28JAN02	$ 3,425.16
#167365	29OCT02	$12,213.20
#204762	28APR03	$ 8,076.44
#321112	05JUL04	$ 7,224.16
#321154	05JUL04	$ 596.79
#330403	09AUG04	$ 1,274.91
#339852	10SEP04	$ 739.34
		$34,534.33

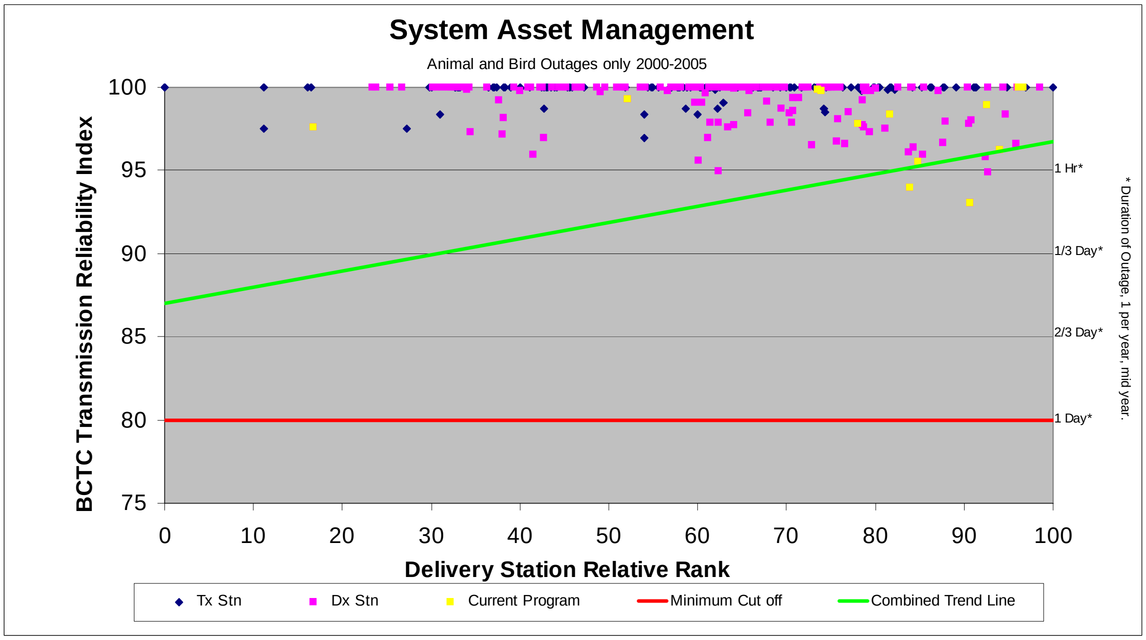
PROGRAM ANALYSIS



This graph represents all outage types for all stations at the system level. The yellow squares are stations that are included in the current Station Animal Outage Reduction Program.

The current program is designed to address only animal outages. As the plot above is based on all outage types, it is difficult to use the plot to determine if the current program is focussed on the best candidate stations. The final step is to focus on the precise stations most affected by animal outages.

We will regenerate the above plot to included animal outages only. This step will produce a display of much interest to asset managers as the SAM tool can be used to identify, and prioritise which stations are affected by the types of outages they are primarily responsible to address.

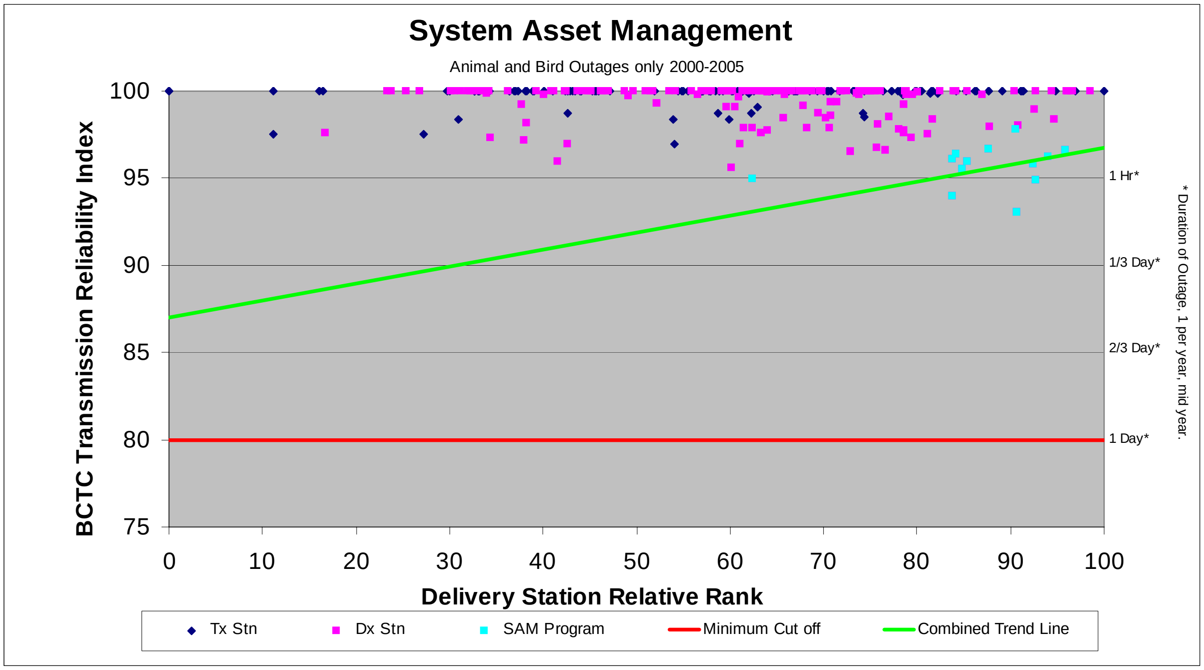


Animal and bird outages are plotted; the yellow squares are stations that are included in the current Animal Contact Reduction Program. All stations are included it the plot.

We can see that there are a couple of stations in the current program that are well above the target line, namely, the stations at Keogh(4) and Port Hardy(11). In addition, there are a few stations that have one or fewer animal outages in the last five years. This is shown with a TRI of near 100.

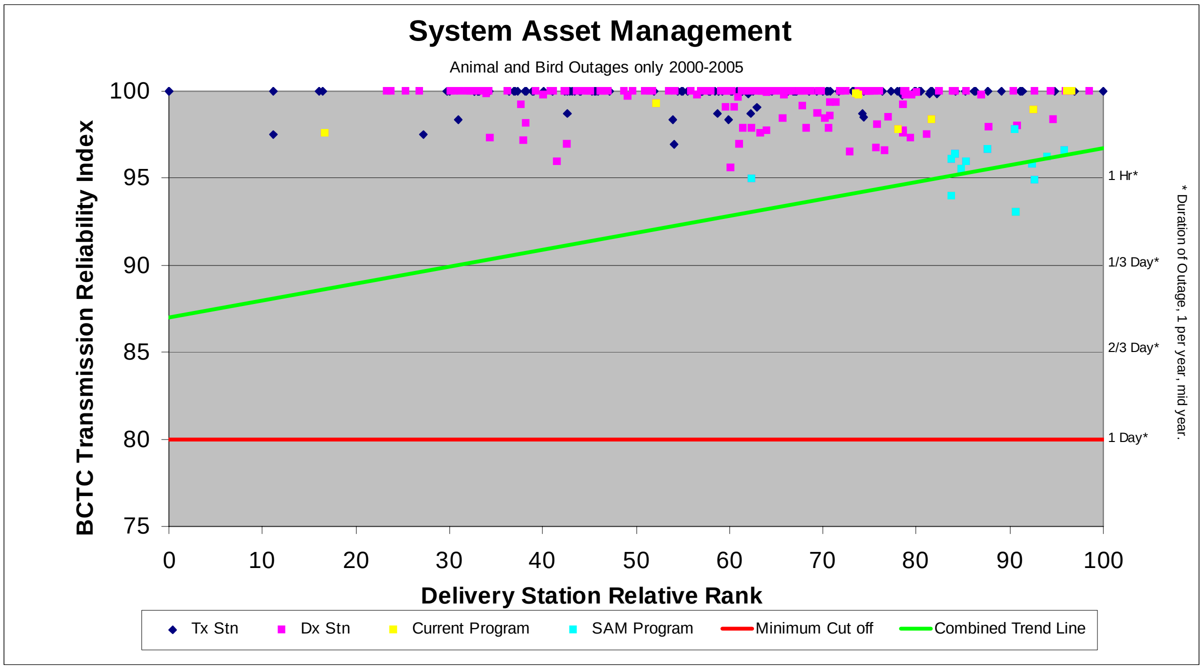
Those stations are Northfield(10), Lantzville(5), McLellan(8), and Mainwaring(6).

	Station		Current Investment
1	CBL	Campbell River	$ 11,899
2	CBN	Clayburn	$ 35,660
3	ESQ	Esquiamalt	$ 17,812
4	KGH	Keogh	$ 11,899
5	LTZ	Lantzville	$ 11,899
6	MAN	Mainwaring	$ 89,170
7	MIS	Mission	$ 17,812
8	MLN	McLellan	$ 41,610
9	MRG	Maple Ridge	$ 24,966
10	NFD	Northfield	$ 11,899
11	PHY	Port Hardy	$ 11,899
12	PKL	Port Kells	$ 24,966
13	WHY	Whalley	$ 35,660



Animal and bird outages are plotted; the turquoise squares are stations that should be included in the Animal Contact Reduction Program as determined by SAM. SAM identified these stations by using GAP-T (Gap to Target line); the number of GAP points between the location of a station on the plot and the green target line. The lower the GAP-T, the higher the priority should be to do work on the station. Thirteen stations were chosen as there are 13 Distribution stations in the current program.

1	CAM	Cambie
2	CBN	Clayburn
3	DUG	Douglas Street
4	FJN	Fort St John
5	KI1	Kidd 1
6	MIS	Mission
7	MRG	Maple Ridge
8	RIM	Richmond
9	SEC	Sechelt
10	SPG	Sperling
11	STV	Steveston
12	WHY	Whalley
13	WLM	Williams Lake



Animal and bird outages only are plotted. The yellow squares are stations identified in the current Animal Contact Reduction Program and the turquoise squares are stations identified by the SAM to be included in the Animal Contact Reduction Program.

We can see that SAM first took a holistic system view and then identified the stations that are below, or only slightly above the target line. That is, those with the lowest (largest negative or smallest positive) Gap to the target line (GAP-T).

Current Program List			**Overlap List**			**SAM Program List**		
#	**STN**	**NAME**	**#**	**STN**	**NAME**	**#**	**STN**	**NAME**
1	CBL	Campbell River	10	CBN	Clayburn	14	CAM	Cambie
2	ESQ	Esquiamalt	11	MIS	Mission	15	DUG	Douglas St
3	KGH	Keogh	12	MRG	Maple Ridge	16	FJN	Fort St John
4	LTZ	Lantzville	13	WHY	Whalley	17	KI1	Kidd 1
5	MAN	Mainwaring				18	RIM	Richmond
6	MLN	McLellan				19	SEC	Sechelt
7	NFD	Northfield				20	SPG	Sperling
8	PHY	Port Hardy				21	STV	Steveston
9	PKL	Port Kells				22	WLM	Williams Lake

Based on the rapid application of the SAM tool, 4 of the 13 stations in the current program have already been identified.

The current program is made of a dynamic station list from fiscal year to year. That is, a set of stations from a master list are worked on within the program every year. Upon investigation of stations worked on in previous years, it was found that 5 of the 9 stations exclusive to the SAM identified list have been worked on in previous years. Those are FJN, RIM, SEC, SPG, and STV.

So, counter measures to animal contact outages may have already been installed and may not need to be addressed again. That being said, 5 of the 13 stations in the current program have also been worked on in previous years but remain in the Fiscal 06 plan. Those are: MLN, PKL, MIS, MRG, WHY.

The additional analysis to investigate if these stations need to be re-addressed is out of the scope of this case study. It will be assumed that all stations identified in the current or SAM program have yet to be addressed.

If we wanted to state that stations worked on in previous years do not need to be re-addressed, the 4 stations exclusive to the SAM program should displace those stations exclusive to the current program. Those are: CAM, DUG, KI1, and WLM.

RESULTS

These charts show both the GAP-T and GAP-R (Gap Reliability). GAP-R is the number of gap points between the location of the station on the plot and 100% reliability. GAP-R is used to quantify the business effectiveness of the investment. The significance of GAP-R is that it is a measure of the difference between the current performances of a delivery station vs. the performance of a delivery station that is with no outages. The smaller the GAP-R, the better the performance. Where as we saw earlier, GAP-T is used to identify and prioritise the stations in the program.

Current Program				**SAM Program**			
Station	**Control Centre**	**GAP-T**	**GAP-R**	**Station**	**Control Centre**	**GAP-T**	**GAP-R**
CBL	VIC	3.19	2.21	WHY	LMC	-2.76	6.94
CBN	LMC	-1.20	6.04	CBN	LMC	-1.20	6.04
ESQ	VIC	3.40	1.64	STV	LMC	-1.13	5.12
KGH	VIC	8.93	2.42	CAM	LMC	-0.17	4.18
LTZ	VIC	5.61	0.20	MRG	LMC	0.10	3.75
MAN	LMC	3.57	0.03	SPG	LMC	0.27	3.41
MIS	LMC	0.27	4.46	MIS	LMC	0.27	4.46
MLN	LMC	3.65	0.00	FJN	NCC	0.62	4.07
MRG	LMC	0.10	3.75	WLM	NCC	0.93	3.91
NFD	VIC	5.66	0.18	DUG	SIC	1.11	3.36
PHY	VIC	7.21	0.70	RIM	LMC	1.19	3.61
WHY	LMC	-2.76	6.94	SEC	LMC	1.89	5.03
PKL	LMC	2.92	1.07	KI1	LMC	2.01	2.18
			Total GAP-R = 29.6				**Total GAP-R = 56**

The total investment in the Current Animal Contact Reduction initiative for the 13 stations is $347K. Assuming that the total Station Animal Outage Reduction costs are the same at the 13 SAM identified stations; we can divide the $347K investment by the GAP-R to calculate the cost per GAP-R point for each program. That is, the investment required per TRI point. Therefore, we can measure and compare the business effectiveness with respect to reliability for each of the programs.

The current program requires a $347k investment for an improvement of 29.6 TRI points. This results in an effectiveness of the Current program of $11.7K/pt.

The total GAP-R for the SAM program is 56 TRI points. Based on this, the effectiveness for the SAM program is $6.2K/pt.

The order of priority of the SAM identified stations is calculated using the GAP-T. The SAM generated priority is shown in the table below.

A lower GAP-T means the higher the priority to do outage prevention work at the station.

	Station	Control Centre	GAP-T	Priority
1	WHY	LMC	-2.76	1
2	CBN	LMC	-1.2	2
3	STV	LMC	-1.13	3
4	CAM	LMC	-0.17	4
5	MRG	LMC	0.1	5
6	SPG	LMC	0.27	6
7	MIS	LMC	0.27	7
8	FJN	NCC	0.62	8
9	WLM	NCC	0.93	9
10	DUG	SIC	1.11	10
11	RIM	LMC	1.19	11
12	SEC	LMC	1.89	12
13	KI1	LMC	2.01	13

CONCLUSION

Based on the effectiveness of the current program of $11.7K/pt and the effectiveness for the SAM program of $6.2K/pt we can make the following statements.

For the current program to target the same 56 TRI point improvement as the SAM program, the current program would need a $654K investment. Alternatively, if the goal is to target only a 29.6 TRI point improvement, this could be achieved with a $184K investment in the SAM program.

From the results of the comparison, SAM has given us the ability to either target a potential improvement to reliability by an additional 89%, or reduce the program cost by 47%. A combination of improved reliability and reduced cost is possible. Thus, SAM's objective to enhance or maintain system reliability while reducing costs is met.

This improvement is achieved in two ways. First, investments made as part of the Station Animal Outage Reduction Program are directed to stations most affected by outages the program is designed to address. Second, investments are directed to stations that are currently performing below their target performance level.

In addition, a prioritization of the stations in the program is generated in the process. Furthermore, the business decisions supported by the SAM program can be repeated using an objective and consistent process.

Appendix I

UMS Group Report on BCTC

UMS Group Report on BCTC
Final Report

UMS Group Report on BCTC
Final Report

Table of Contents

1. Executive Summary

UMS Group was retained to undertake an assessment of BCTC with respect to its Asset Management capabilities and to provide an independent view of its performance, including strengths and gaps as compared to the global transmission industry. The goal was to provide BCTC with the insights necessary to allow it to respond more fully to the BCUC with regard to BCTC's current and proposed spending and its relationship to reliability. Specifically, we focused our assessment on BCTC's levels of spending; its Asset Management processes, capabilities and effectiveness; its ability to understand and predict the relationships between spending and system performance (reliability); and BCTC's suite of decision support tools, all in comparison to other transmission utilities and those known to be superior performers.

The findings of our analysis are that:

- **BCTC's costs for transmission system investments (Growth, Sustain and OMA), including those projected out to 2009, are below the range of what should be expected for a system like BCTC's.**

- **We can expect to see BCTC's costs of replacements grow steadily over the next ten years** as it begins to address an asset replacement wave and balances the timing of the spending for replacements against workforce availability. It may need to advance replacements to ensure a manageable workload.

- **BCTC's system performance is good and is reflective of solid work being done by BCTC in managing the assets and making sound investment decisions.**

- **BCTC is a solid Asset Manager. Its analytical capabilities are logical, credible and can reasonably be relied upon.**

- **BCTC has continuously improved upon its Asset Management capabilities with results clearly evident in the system cost and operations performance, and is actively working on continuous improvement efforts.**

- **BCTC will be facing a number of challenges in the next several years as its asset base ages and the effects of several externalities become clearer.**

- We did identify gaps in performance that are consistent with other Asset Management organizations at BCTC's stage of implementation. **BCTC is aware of the gaps and is committed to working to close them.**

In undertaking this analysis we have relied on a combination of publicly available information, information contained in UMS Group's proprietary databases, and information that we collected from BCTC. We have relied heavily on publicly available data to allow for validation of our findings. We have used UMS Group's proprietary data as either a source for our own validation of our findings, or as the source of information where public sources are not available. The BCTC information was supplied to us based on specific requests that we made of BCTC to review a variety of reports, process documents, analyses and filings.

With regard to BCTC's spending levels relative to its peers, we used a variety of comparisons between BCTC and other Canadian and US transmission companies. Overall, we found BCTC's recent spending levels to be below the range that we would expect for a company with its system characteristics (size, customer density, terrain, location on the interconnected grid, relative level of wheeling, etc.).

We also analyzed BCTC's projected levels of spending against the US companies, based on industry projections. Although its projected rate of spending in comparison to its current levels is rising, we found BCTC's projected position relative to its peers to be below the range we would expect it to be.

Our analysis of BCTC's costs raised one concern. On several of the measures most meaningful for a company with BCTC's characteristics, BCTC's spending in recent years is on the low end of the expected range. Since its inception, BCTC has seen a steady rise in its asset related spending, which suggests that in earlier years, the transmission related asset spending may have been below the normal range for an asset base like BCTC's. If this is indeed the case, we would expect to see BCTC's costs rise at a higher rate than some of its peers who maintained consistent spending levels over the lifecycle of their assets.

In assessing BCTC's system performance, we considered but did not rely upon the traditional customer interruption based reliability measures, SAIDI and SAIFI. Our experience is that reliability targets are typically set as a combination of what is achievable technically, what the customers view as an acceptable level of interruptions, and what the regulators believe is appropriate, given relative differences in cost. Comparing company SAIDI and SAIFI is only useful to a point, as customer expectations vary significantly. As an example, we have seen information for a multistate company in the US where its customer satisfaction levels are highest in the jurisdiction in which it has the lowest reliability level.

Hence, for this assessment we looked to failure data for assets and system components. Asset failure rates and trends tend to be a good indication of underlying asset or system condition and are, therefore, often a better predictor of future required levels of sustaining capital than standard reliability indices. We used failure data in lieu of detailed asset health information because it is more readily compared across companies, as the scope and content of asset health indices vary widely. BCTC had previously conducted a comprehensive Asset Health index, which was made available to us. The failure rates for BCTC, and our conclusions regarding the state of BCTC's system, are consistent with the earlier analysis of asset health.

For BCTC we looked specifically at Power Transformer and Circuit Breaker failure rates. These are two of the most costly groups of assets within the transmission system and are also those for which a level of sophistication and diligence is required in assuring sound lifecycle cost performance. BCTC's failure rates for breakers and transformers are well below industry norms and therefore indicative of a sound maintenance program. We also verified that failure rates for other system components, within BCTC, were comparable to breaker and transformer performance and concluded that BCTC exhibits similar performance across its entire asset base. However, while failure rates for breakers are still below the industry average, the trend over the past several years has been rising at a rate that may suggest that many of the older units are beginning to approach the end of their lives.

This is consistent with other analysis which revealed that BCTC's breaker and transformer fleets have a much higher proportion of their equipment in the 26-35 year range Our analysis of BCTC data, and the experience of other utilities (including better performing companies where most replacements take place in the 35 to 48 year range), suggests that BCTC is facing a bow wave of replacements that will be starting over the next ten years.

In addition to the potential impact of the replacement wave, we also determined that BCTC's projected costs through 2009 do not appear to fully reflect the significant potential impact that several externalities could have on its spending. Among these are:

- Beetle infestation and the associated vegetation management costs
- The full impact of adopting mandatory reliability standards
- Wildfire mitigation requirements for which BCTC is now accountable
- Species at Risk legislation requirements for which BCTC is now accountable
- Changes to risk tolerance levels and associated risk mitigation for seismic events

We concluded that BCTC's solid system and asset performance is due in large measure to sound decisions made by the organization. This speaks highly of the Asset Management organization. For the work that it accomplishes, it is relatively small in size and efficient. Most importantly, in our view, BCTC recognizes that it could be a better Asset Manager and the organization appears to be motivated to work toward that end. The improvements that BCTC has made in its processes and decision making in recent years is significant. BCTC has focused on many of the areas with greatest leverage to impact cost and performance, and has tackled these first.

In addition, our assessment highlighted gaps to be closed:

BCTC's strong focus on improving system performance has resulted in a degree of siloing, in which each group is focused intently on improving their own aspect of the system and as a result, opportunities for cross group collaboration are often missed. Growth, Sustain and

OMA have been managed as separate and distinct areas and cross portfolio opportunities are only examined relatively late in the investment planning process. This is compared to other asset management organizations that identify optimum solutions to system needs independently of the type of spending required. We therefore believe that there are potential economies of scale that could be gained by broadening the problem solving focus earlier in the planning process and creating more of a cross-portfolio perspective.

The relationship between BCTC and BC Hydro has reportedly improved over the past 4 years, but is still not as strong as it needs to be. There are structural and cultural barriers that impede the ability of the two organizations to focus together on delivering the work plan. While they do work together well in several areas, there appears to be an incomplete recognition that neither can be successful in its goals without the other.

Finally, BCTC has developed a number of tools that it uses in making its asset investment decisions. While many of these are industry leading, BCTC has not created an integrated set of tools, nor does it have a technology plan for integrating all of its tools and data sources. BCTC tends to use many of the tools in standalone mode or with some limited interconnection, and therefore does not fully leverage the capabilities of all of its existing tools. There are several cases where BCTC's capability to relate cost and performance are extremely good. These tend to be limited to a certain aspect of the system, such as breaker operations. For example, BCTC has not yet linked the tools that assess breaker operations with tools that predict outages from vegetation, which is one driver of breaker operations. We believe that BCTC could improve upon its plans through greater use and integration of its existing tools.

We believe that BCTC needs to begin working to address the gaps identified above and have laid out specific recommendations, with our view of the relative priorities and time frames for each, in the recommendations section of this report.

2. Introduction

UMS Group was retained to undertake an assessment of BCTC with respect to the focus and sufficiency of its sustain capital spending, as compared to the global transmission industry. The goal was to provide BCTC with the insights necessary to allow it to respond more fully to the BCUC with regard to BCTC's current and proposed spending levels and the relationship between spending and reliability. Specifically, we focused our assessment on BCTC's levels of spending, its Asset Management processes, capabilities and effectiveness; its ability to understand and predict the relationships between spending and system performance (reliability); and BCTC's suite of decision support tools, all in comparison to other transmission utilities and those known to be superior performers.

UMS Group is a Management Consulting firm with a global client base. The company is a well established leader in benchmarking and the identification of best practices for utilities and uses proprietary techniques for normalizing data to allow valid "apples to apples" comparisons between companies operating in different regions with varied market drivers and regulatory requirements. UMS Group has been doing this successfully for the last 18 years. UMS Group has become a leading authority on Asset Management for utilities and has assisted dozens of utilities on five continents in building or improving their Asset Management organizations and capabilities.

In undertaking this current effort, UMS assembled a team with significant Asset Management and utility expertise. The team worked over an 8 week period to collect, review and analyze key information, and to prepare our findings. UMS Group used a combination of quantitative and qualitative approaches in conducting the assessment. These included statistical and numerical comparisons, benchmarking, and analysis of BCTC processes against those in place at known best performing Transmission companies. All of these are discussed in this report. The UMS team worked onsite to collect data and information and conducted interviews with key management personnel to validate the information and data collected. In conducting our analysis we have relied on information collected from BCTC, publically available data as well as data contained in our proprietary databases.

A detailed list of UMS Group's clients and the professional profiles of the key project team members are included in the appendices.

3. Asset Management in the Electricity Industry

Overview and History

Asset Management is a philosophy for how to organize and manage an asset intensive business and a set of processes focused on making the most effective asset investments possible. It was first introduced in the Scandinavian automotive industry close to 20 years ago. It was adopted by Scandinavian and British utilities in the early 1990s in response to the dramatic changes that they faced with privatization and an opening of competition in the once government run monopolies. Along with changes in the market came changes in regulatory structure. These previously unregulated, government owned utilities found themselves privatized, in a competitive market, and facing regulators that pushed the utilities hard for improvements in both cost and service quality.

In seeking to accomplish the improvements required by the regulators and their new shareholders, the utilities realized that there was an inherent conflict in their historical decision making processes. The conflict arose from managers being accountable for both the direction and utilization of the workforce and for maintaining the condition of the assets in their geographic region. The companies found that the amount of work typically done on the assets tended to follow the availability of internal resources to do the work. When the resources were limited (as during normal vacation periods), some necessary work was not done on the assets. Conversely, when there were more resources available than needed for the required work, the work was frequently expanded to keep the resources occupied. This added to the cost of operating and maintaining the system and often led to more intrusive maintenance than was needed. It would also frequently create more in-service failures than would otherwise have been experienced, due to the fact that intrusive maintenance work can often cause new problems while solving others (e.g. introducing contaminants, improper replacement of parts, failure to properly reseal the device, etc).

The utilities that adopted the Asset Management philosophy embraced the separation of accountability for asset performance from accountability for the performance of the workforce. Doing so allowed Asset Managers to focus on defining what work was needed to ensure that the assets met stated performance objectives. This simultaneously freed those accountable for the work force to focus on improving staff training, skills and efficiency, and safety. When functioning well, this created a partnership between those accountable for the assets and those accountable for the workforce and for getting the work done, as separately each could innovate to drive improvement, but neither could be fully successful without the other.

As a result of adopting Asset Management, utilities in the UK were able to drive significant improvements in both quality of service and cost performance. In comparison to the other utilities, those that had adopted Asset Management moved quickly and achieved results that exceeded expectations from only 18 months prior. Many of the utilities in the UK saw 25% reductions in operating costs over a three year period, while reliability and customer satisfaction improved. Some critics suggest that these dramatic reductions in cost were more the result of trimming bloated workforces than from making more effective asset investment decisions. There is no doubt that the workforces were larger than were needed to support the assets however it is clear that those that adopted Asset Management were able to rationalize and resize their workforces more quickly and effectively through fact based decision making. At that point in time, not all of the utilities in the UK or Scandinavia had adopted Asset Management, and those that had not, failed to keep pace with the dramatic changes in performance accomplished by those that had adopted Asset Management. It became clear that Asset Management had been at least the catalyst, if not the main driver, for the dramatic improvements in performance.

As these significant changes in performance became evident, the rest of the industry took notice, and through benchmarking and other comparative studies the link between Asset Management and superior performance was validated. Through such utility collaborative studies, common themes emerged among Asset Management organizations, particularly those that were leading in cost efficiency and service level performance. It became evident that there are four domains within an Asset Management organization that are the keys to its success. These are:

1. **Organization** – The vision, structure, responsibilities, and accountabilities

2. **Processes** – The definition of process (the flow and work content of each step) within Asset Management and their connection with other supporting and related processes, and their linkage to the overall business strategy and objectives

3. **People** – The culture, competencies, and capabilities of the organization and its partner organizations

4. **Technology** – The tools necessary to reasonably support the decision making needs of the Asset Management organization, including access to data and information in the right timeframes

Among the companies that had adopted Asset Management there was, and continues to be, a wide variation in the way they focused on each of the four domains. Over time we have seen an evolution of Asset Management, as various companies worked on improving on their performance, and made adjustments in each of the four domains. The evolution has also been spurred by a growth in the number of companies adopting Asset Management, with many of them building upon the lessons learned by their peers and adopting the improvements as part of their own transformation to Asset Management. Figure 3-1 illustrates the four generations of Asset Management that we see across the industry. As with any population, we can find utilities that are straddling the generational boundaries. We have drawn distinct lines here merely for clarity of the discussion.

First Generation	Second Generation	Third Generation	Fourth Generation
ORGANISATION CENTRIC	*PROCESS FOCUSED*	*ASSET AND INFORMATION CENTRIC*	*ONE COMPANY – ONE ASSET*
Organization • Clear Organizational Separation of "Decision and Action" • Aligned Around Asset Groups • Rigid Hierarchical Reporting • More Accountability than Authority **Process** • Detailed task focused within Asset Groups • Focused on deliverables - reports and plan • Focused on workforce performance **People** • Strong inherited technical capabilities • Historical knowledge base **Technology** • Data overload - Information Poor • Independent Tools applied as needed	**Organization** • Clear Organizational Separation of "Decision and Action" with bridge building • Aligned Around Local Area Asset Groups • Somewhat more flexible reporting • Increased Authority at lower levels **Process** • Better integration of the overall process within AM • Focused on process performance outcomes & regulatory rules **People** • Specialist technical competencies • Network with global peers • Greater process mgt skills **Technology** • Greater availability of Information • Increased integration of tools and information sets • Missing functionality identified	**Organization** • Aligned around 3 Ball Model • AM Org aligned to match Ops Regions (local AM presence) • More integrated matrix structure • Increased Authority at lower levels **Process** • Better integration of the overall process within AM and across the enterprise (CFO and Customer) • Focused on Asset & Human Performance outcomes **People** • Technical staff recognize the importance of economic factors • Risk & business strategy focused • Greater business acumen **Technology** • Greater use of Information • Elimination of duplicate data • Tools and information sets built around key decisions and regulatory requirements	**Organization** • 3 Ball Model - expanded • Regional workforce Empowered by AM strategies and plan • More integrated matrix structure • Increased Authority and shared accountability at lower levels **Process** • Better Integration of the overall process within am and across the Enterprise AM (CFO, Customer, Regulatory, Supply, HR) • Deliver one plan for whole Asset Focused on Asset, Human & AM Decision Performance **People** • Seeking balance and optimization of investments • Focus on business outcomes • Strong sense of partnerships **Technology** • Use information to create insight • Technology treated like any other investment – must have value

Figure 3-1 – Asset Management Evolution

Current State of Asset Management in the Electric Transmission Industry

UMS Group has long term relationships with many of the world's leading transmission companies. In addition to serving as the program manager to a large industry consortium of approximately 30 transmission companies called ITOMS (International Transmission O&M Study) for the past 13 years, our proprietary databases contain detailed practices and performance data on these and dozens of other companies. The focus of much of our work with these clients is to measure and compare cost and effectiveness and to identify *industry good practice* (practices that reflect the current state of the industry with respect to generally accepted and effective methods, processes and tools that produce sustained, superior performance levels among peer companies) and *emerging best practices* (these are new practices that while not yet in widespread use, have been shown to be a contributing factor in raising the effectiveness of individual companies or segments of the industry to new levels). We have relied upon our work with these utilities in undertaking our analysis and in the conclusions that we have drawn.

Whom Do We Consider Industry Better Performers In Transmission Asset Management?
We drew from a range of industry performance information and conducted an analysis of relative performance (looking for companies with reasonably low O&M costs, modest capital spending, and high reliability) and combined that with our insights into the practices and capabilities of transmission companies around the world, to identify a number of companies that represent leading practices and thinking about asset and reliability performance management across the Industry. We highlighted 7 transmission companies as the proxy for Industry Good Practice. Five of these companies are from markets outside of North America. In the mid-nineties, they were among the first to adopt the Asset Management model for managing the asset intensive transmission business. These markets are Australia, Scandinavia and the UK.

We selected these companies based on five factors:

- First, their cost and reliability performance (sustained over several years) has been superior to their peers across the Industry (Figure 3-2, below, highlights the companies of interest, those with higher levels of reliability- as indicated by the top oval, and those whose costs are well below the average with acceptable reliability - as indicated by the oval to the right), and we are able to link their operational performance to their success on each of the other contributing factors;

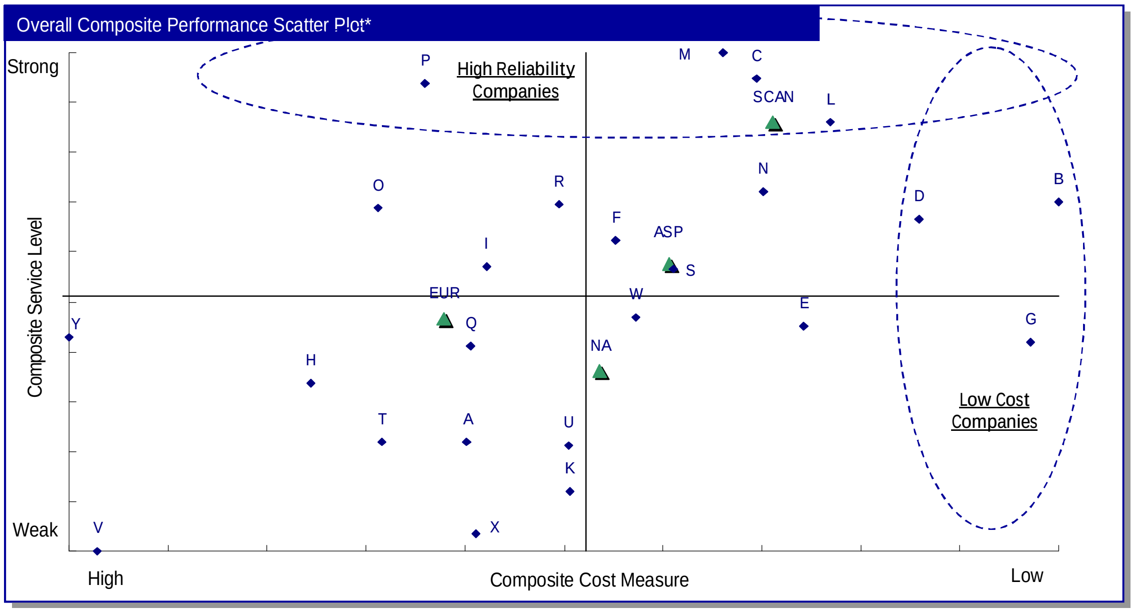


Figure 3-2

- Second, they have in place well defined processes for making decisions and managing risks in the business;
- Third, they have a well defined organization structure with clear definition of asset management responsibilities, authorities and accountabilities, and a strong focus on asset management activities and issues;
- Fourth, they have developed cultures which foster learning and innovation rather than silos and dogmatic adherence to past approaches; and
- Fifth, they make effective use of tools and information. They have made judicious investments in decision support tools and in collecting and validating the data necessary to improve on their decision making capabilities.

The company demographics for the panel are summarized in Figure 3-3.

- Characteristics of the 7 Companies We Interviewed For Industry Best Practices

Company	GWh Delivered	Peak System Load (MW)	Service Area (km2)	Number of Structures	Number of Substations	Include Energy Dispatch and Field Operations in Transmission Business Unit
Transgrid	76,979	13,292	801,349	40,308	82	No
Powerlink Queensland	47,734	8,295	313,132	29,277	98	No
SP AusNet	50,267	8,730	227,420	13,004	44	No
National Grid Company UK	297,300	53,730	151,189	22,038	386	Yes
AEP	134,297	40,275	445,635	134,297	1,272	No
Fingrid	61,600	13,970	336,592	48,159	107	No
APS	26,478	No Data	118,000	41,668	85	No

Figure 3-3

Three of the companies are from Australia. The first is Powerlink Queensland, a government owned transmission business that is a perennial best performer among the ITOMS Peer Group and has a somewhat similar territory to BCTC (a relatively high growth metro area at the southern end of their system, but also a long thin populated area with very long circuits serving remote areas to the north) and a similar resourcing strategy, in that a large portion of their work is carried out by one of the local Distribution Companies. TransGrid, the second, is also government owned. Its system serves Sydney and the rest of the State of New South Wales. TransGrid also has a history strong financial and operational performance. It is similar to BCTC in that it enables market opportunities for wheeling power to others and balances this with the technical and economic issues that arise in optimizing outage management, and network availability. SP AusNet, the third, headquartered in Melbourne and serving the state of Victoria, is privately owned, with somewhat higher ownership pressures on cost, and earnings, and arguably greater focus on the regulator's reliability incentive mechanism.

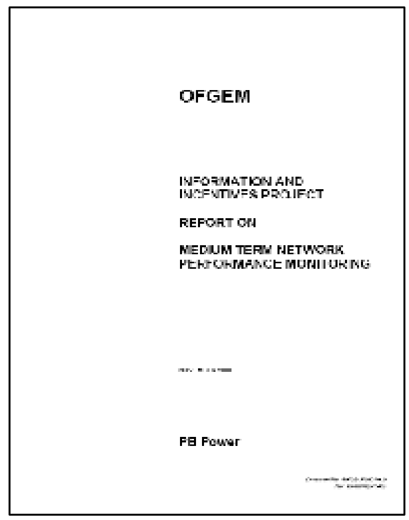
In Scandinavia we chose Fingrid, in Finland, widely acknowledged to be one of the best Asset Managers among its peers for many years. It is also government owned and has a transmission network similar to BCTC's. From the UK we included National Grid Transco (NG). NG is privately owned and has been expanding its business through acquisition into the UK and US. Although its costs are somewhat higher than its peers, its reliability levels are extremely high. We have included NG in this discussion because of its operational performance levels and because it is often cited by regulators and market participants as the example of a well run independent grid company. NG focuses strongly on understanding and meeting the Regulator's requirements and on effective management of risk in the business.

In North America we chose American Electric Power (AEP) and Arizona Public Service (APS). AEP, headquartered in Columbus, Ohio, is a large multi-state utility with the largest transmission network in the US (its system stretches from southern Michigan to the border between Texas and Mexico). AEP operates in 11 States with 15 independent State regulatory jurisdictions, plus FERC. Its transmission system operates within two ISOs and multiple NERC regions. AEP has demonstrated consistent reliability performance and has managed its costs well, within its constraints. AEP has more experience in working with regulators to define successful reliability strategies than any other North American utility company.

APS, headquartered in Phoenix, Arizona, is a company that was an early adopter of Asset Management in the US. It is similar in size and customer density to BCTC. It also has significant seasonal loading on its system and like BCTC is located on the edge of the interconnected grid. Thus, like BCTC its transmission system does not wheel energy to the same extent as other utilities in the heart of the grid. APS has also demonstrated consistent performance in cost and over the last ten years has steadily improved its reliability. Since 1996 APS has improved its system SAIFI by 38% and has improved its system SAIDI by 44%.

In addition to these in-depth interviews with leading asset management practitioners, we conducted searches of industry literature on the subjects and had discussions with a range of thought leaders on the current NERC efforts to define standards for Transmission System Reliability. Stewart Ramsay (one of the principal authors of our report) serves on the Members Representative Committee of NERC as the WECC representative to the Regional Reliability Organization class.

What Did We Learn About Current Industry Practices from These Companies? - In addition to utilizing extensive information from our ongoing industry benchmarking programs, we spent 1 to 2 days in intensive interviews with managers and specialists across a number of disciplines within each of these companies. We agreed to their requests for anonymity on all new comparisons of performance and assessments of capabilities, and to provide a copy of our industry comparative findings in exchange for their time and agreement to share fully their approach and best practices on processes, tools and documents. Our findings are outlined in the paragraphs below.


OFGEM

INFORMATION AND INCENTIVES PROJECT

REPORT ON

MEDIUM TERM NETWORK PERFORMANCE MONITORING

PB Power

Reliability Management and Projections – The relationship between spending and system reliability (or even availability) is extremely complex, involving many independent variables such as system configuration and redundancy, weather, wild fires, load, maintenance practices, etc., in addition to equipment reliability or failure, which is a primary driver of transmission spend. Compounding this complexity, the relationship between these factors is very non-linear, making modeling or predicting how the outcome will vary as a function of inputs extremely difficult.

OFGEM, the UK regulator, has been trying since 2000 (with their IIP project) to define a medium term network performance monitoring regime (MTP) that would allow them to identify cases where deteriorating asset performance threatened to jeopardize overall system reliability. Their results to date have been mixed, with no overall predictive model produced. Their efforts at regulation of this issue seem to have migrated toward the development of overall standards for Asset Management process effectiveness, through the PAS 55 standards development efforts of the IAM (Institute of Asset Management) which has been gathering support over the past year or so in other markets around the world.

<u>OFGEM's IIP Project</u>

Ofgem is concerned that distribution businesses may be able to achieve short-term improvements in performance on output measures at the expense of medium-term performance (MTP). Ofgem is also concerned that, in the future, as cost savings become harder to achieve and companies take different approaches to maintaining their networks, the risk of a decline in MTP increases.

Ofgem's preferred approach is to develop a set of reliability output measures or indicators based on an analysis of faults by asset type and cause and to monitor trends in performance of assets over time. It would also be desirable to develop indicators which have within them a predictive quality, i.e. that are able to indicate the possibility of a decline in future performance.

Figure 3-4

As a result, we found no credible or effective formula or algorithm that can be used across the industry to predict incremental or decremental effects of spending on reliability. Instead, best practice today is to develop various scenarios to stress test the plan, by first identifying known relationships between certain spending types and their reliability impact and then by fixing all the other variables at levels that represent reasonable and congruent points and a practical combination of circumstances that could be experienced on the system. Those companies with best capabilities in accurately forecasting the reliability impacts of their overall spending plan have done so by constructing multiple relationship models for each investment type that has been proven to have a measurable impact on performance. They use the outputs of these models in combination to develop scenarios, with a probabilistic link established between models.

As an example, some companies have developed models that can tie vegetation management spending to tree-related outages. Some have also created models that can link the number of breaker fault operations to breaker condition and by extension to breaker maintenance and replacement costs (BCTC does this well). Linking such models together to predict the change in the number of breaker operations that would result from a change in vegetation spending has been difficult however. To date, where this has been done, it is most often done manually through examination of different scenarios using the respective models and their outputs, as no 'mega-model' exists.

Some Asset Managers have speculated that even if a 'mega-model' to forecast system reliability considering all possible factors could be constructed, it would require more computing horsepower than is reasonably available to reach a solution, and that solution would have such a broad band of uncertainty as to render it of little value for regulatory or asset management decision making. Notwithstanding this view, it has been reported that OFGEM and NGT continue to work collaboratively on the IIP project to try to develop an effective model of system outputs (summarized in Figure 3-4). If that effort is successful, it could quickly be considered an emerging best practice, and we would expect regulators and transmission companies around the world to look closely at its applicability for their systems.

Reliability Measurement: Industry standard practice varies widely across the world in terms of what factors transmission companies measure for reliability (Figure 3-5). Two general schools of thought have existed for a number of years, one focused on the factors that are most readily under the control of the transmission business – maintaining sufficient delivery capacity to meet the need, and maintaining the assets in appropriate condition. These companies typically measure the number of incidents and the duration during which elements of the transmission system are out of service. This measure represents Transmission System Availability, and has been considered a robust indicator of the quality of work done by the transmission company in maintaining the system. The metric most frequently used by this school of thought is Availability (weighted % of the year that transmission circuits are available – typically in the range of 99.200 to 99.998%). This school of thought is favored by generators, and by those regulators that view the transmission system in a transportation context, as the long haul carrier of energy.

Company Name	Primary Transmission Reliability Measures Used	Specific Metrics & Definitions
AEP (11 States - US)	TSAIDI, TSAIFI and TCAIDI	Tx Contribution to Distribution SAIDI, SAIFI and CAIDI
	Outage Frequency	Outages / 100 Ckt Miles, (also per Ckt and per Delivery Point)
	New measures coming from NERC TADS	(> 15 Measures Now Under Study)
APS (Az, US)	TSAIDI, TSAIFI and TCAIDI	Tx Contribution to Distribution SAIDI, SAIFI and CAIDI
	Outage Frequency	Outages / 100 Ckt Miles, (also per Ckt and per Delivery Point)
	New measures coming from NERC TADS	(> 15 Measures Now Under Study)
SP AusNet (Victoria, Australia)	Network Availability	(Lines, Transformers, and Reactive Plant, Peak/non-peak)
	Planned Outage Scheduling	(Total mins of outage during Hi, Med & Low Load Periods)
TransGrid (NSW, Australia)	Network Availability	(Lines, Transformers, and Reactive Plant)
	Reliability	(<5 events > 0.05 syst mins, <1 event > 0.4 syst mins)
	Restoration	(Avg Restoration time > 1,500 mins per event)
	New - Market Impact of Planned Outages	(Mkt Cost Impact and Length of Notice Provided)
PowerLink Queensland (QLD, Australia)	Network Availability	(Critical / non-critical Circuits, Peak / non-peak timie)
	Loss of Supply Events	(>0.20 Minutes, >1.00 minutes)
	Forced Outage Restoration Time	(Average time, capped at 7 days)
	New - Market Impact of Planned Outages	(Mkt Cost Impact and Length of Notice Provided)
National Grid (Nationwide UK)	Network/System Availability	Ckt Outage Hours/Total Ckt Hours
	Overall Reliability of Supply	Unsupplied Eneregy (% of MWHrs)
	Loss of Supply	Number of Incidents
	Quality of Transmission Service	# of voltage and Frequency Excursions
Fingrid (Finland - Nationwide)	# of Interruptions per connection point	(0.1 - 0.4)
	Mins of Interruption per connection point	(1.5 - 5.0)
	Network (Circuit) Availability	(99.995 - 99.999)
	Value of Lost Load	Unserved MWHrs (Weighted By Customer Class)
	Market Impact of Outages	Minutes / Yr When Tx Constraints Drive Price Differences

Figure 3-5

The other school of thought focuses on the impact the transmission network has on the customer - measuring the number of incidents and duration during which customers have been interrupted from service. This metric represents Transmission System Reliability, and is considered to be the most effective measure of the effectiveness of the transmission business in delivering against its mission of providing reliable electricity through the network to users. The metrics most frequently used by this school of thought are:

- TSAIDI (total number of minutes that the average customer had service interrupted over the year as a result of transmission problems – for example, 2 to 20 average minutes per year), or
- TSAIFI or Number of Loss of Supply Events due to transmission problems greater than a certain number of minutes (for example 1 to 3 events per year greater than 0.3 average Customer minutes impact)

Industry "Good Practice" in this area is increasingly being driven by regulatory requirements. Regulators have also tended to follow one or the other of these schools of thought, and well run transmission companies have focused on measuring (and managing) what they are required by their Regulator to measure and report. Regulatory clarity on reliability priorities tends to drive companies to be more rigorous in their efforts to achieve prescribed reliability and availability targets. This is especially so in jurisdictions where regulatory incentives are in place for meeting reliability targets.

Industry Emerging "Best Practices" In This Area Include:

- Thought leaders are setting targets and incenting achievement of System Reliability Goals, but considering Transmission System Availability as well as Equipment Failure and the Frequency of Equipment Defects to be leading indicators of Transmission System Reliability. They are also allocating Maintenance and Replacement priorities to classes of equipment that show the greatest risks from these leading indicators. This has worked well when the Incentive Targets represent areas in which the organization has full accountability and authority for delivery of objectives. However, where constraints are in place, such as mandatory spending, or provisions mandating or banning outsourcing, the targets need to be adjusted to reflect what is controllable by the organization and what factors are beyond its reasonable ability to control.

Reliability Management: System Reliability and Availability are becoming the primary drivers for operating priorities and practices within the transmission business. Most utilities have made these two measures the principal focus for their maintenance and testing strategies. And in many regions, more sophisticated preventive maintenance optimization and asset investment optimization strategies and tools are emerging as a result.

Coincident with this is a growth in the number and severity of constraints on the system (congestion, capacity limitations, etc), making it more difficult to obtain maintenance outages. This has driven significant increases in the rigor of Outage Management (planned and reactive), Asset Information Management, and Risk Management across the asset portfolio. The goal has clearly moved beyond "most effective maintenance" to "minimal downtime maintenance" that leaves every component of the system in service as much as possible.

Industry "Good Practice" in this area includes:

- Forecasting Equipment Failure Rates by asset class based on defect frequency and scale. It is critical to capture all information from inspections, preventive maintenance tasks, and malfunctions discovered and use this information in an

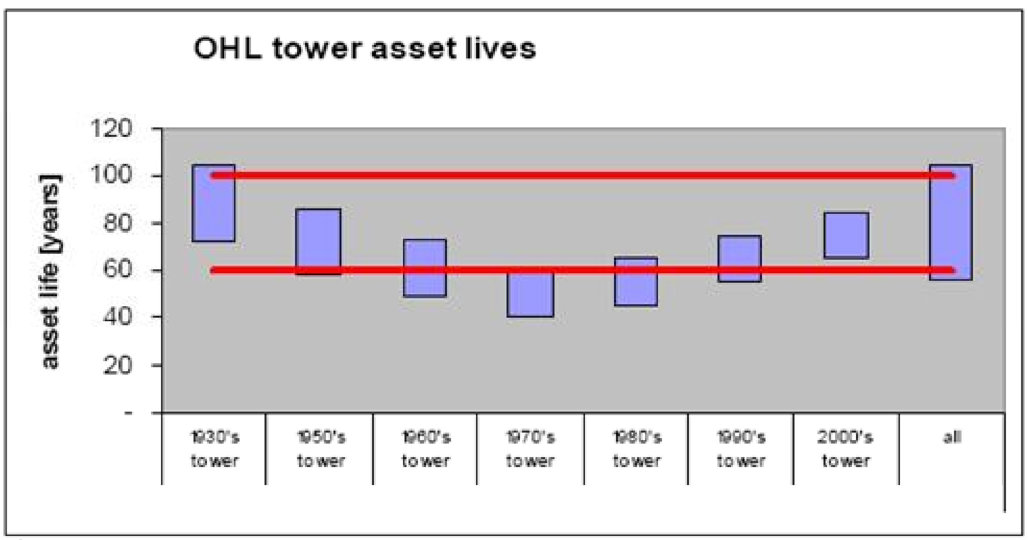


Figure 3-6

integrated fashion to predict when classes are approaching end of life. This example (Figure 3-6, previous page), from Scottish Power in the UK, shows that projected asset lives vary even within a class, based on initial designs, materials used, and manufacturer safety margins.

- A shift toward more Condition Based Maintenance (CBM) in which maintenance decisions are made based on condition information from inspection and test results (Figure 3-7).

Less than 5% Of Work

- No More than 20% Of Maintenance
- Few, If Any Replacements

- 20 to 40% Of Maintenance
- Most Remaining Replacements

Reactive Maintenance ⇨ **Interval Based Maintenance** ⇨ **Condition Based Maintenance**

§Breakdown Maintenance
§Repairs are made as defects and failures are discovered
§Weak Maintenance Planning

§ Elapsed Time Based Maintenance
§ Intervals extended based on failure experience and inspection results
§ Scope of PM Activities driven by OEM Recommendations and failure / defect experience

§Maintenance decisions made based on inspection and test results
§Asset Health Index maintained to support decision making

Figure 3-7

- Assigning all customer delivery points a relative criticality based on size and nature of load served, and for other assets based on impact on operational risk or flexibility.
- Install more real time asset condition monitoring equipment to be able to identify

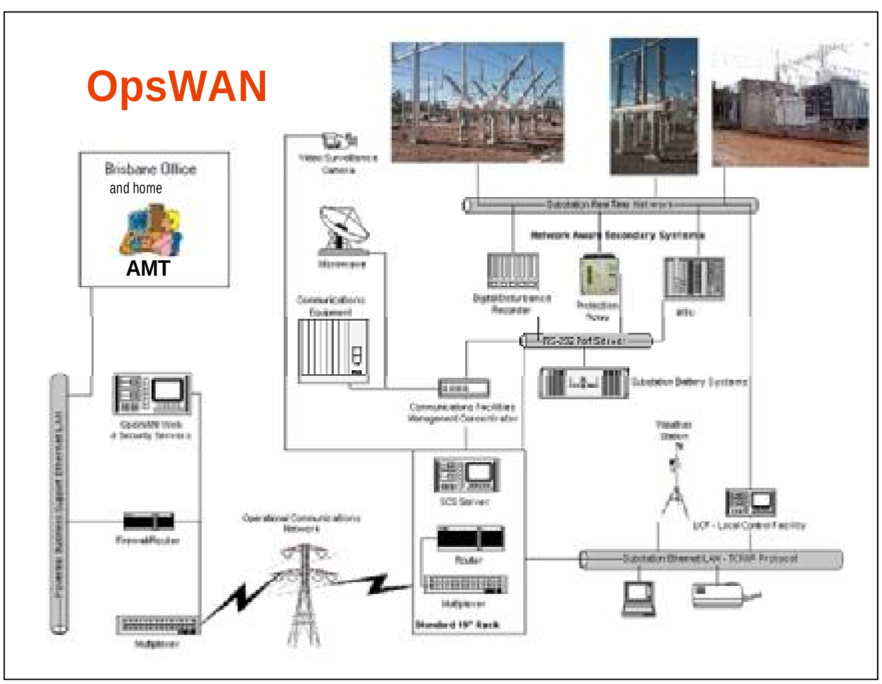


Figure 3-8

emerging problems in between inspections or preventive maintenance activities. Figure 3-8 (previous page) illustrates the innovative approach used by PowerLink Queensland, in Australia.

- Proactive efforts to shift to a reliability oriented culture:
  - o Drive more risk awareness and business acumen,
  - o Emphasize open learning rather than just deep technical knowledge,
  - o Prize innovative thinking and creative solutions, and
  - o Value diversity of input into problems and solutions (field, engineering, planning, business, regulatory).

Industry Emerging "Best Practices" In This Area Include:

- Data mining of maintenance readings and test results over the past 10+ years to analyze equipment performance and aging as inputs to optimizing both scope and frequency of preventive maintenance over the life of each equipment class and type. Figure 3-9 presents innovative analyses conducted recently by Fingrid to drive new insights into condition deterioration mechanisms in various types of equipment.

Pantograph DCNs Non-Pantograph DCNs

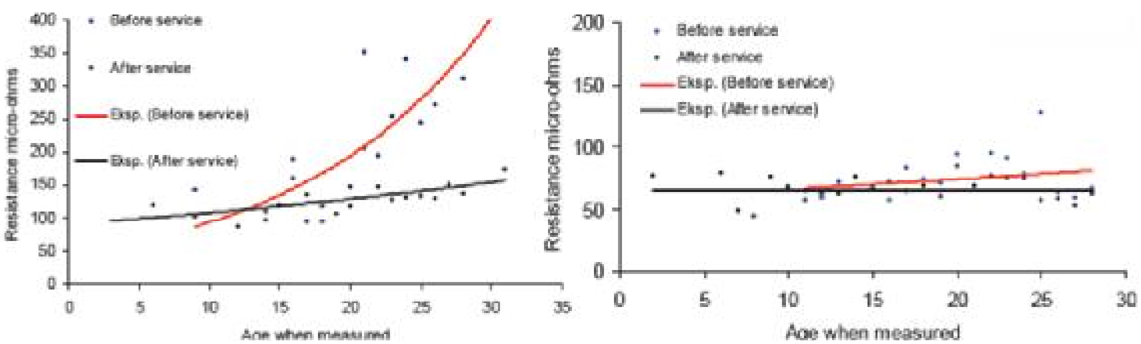


Figure 3-9

- Probabilistic assessments – Modeling probabilities of each potential outcome and presenting results as a distribution of probabilities for future results.
- Preventive Maintenance Optimization - A shift beyond CBM to Risk and Criticality based maintenance decision making, with the scope of PM Activities optimized based on condition assessment, failure analysis and asset criticality within the transmission system (Figure 3-10, following page).

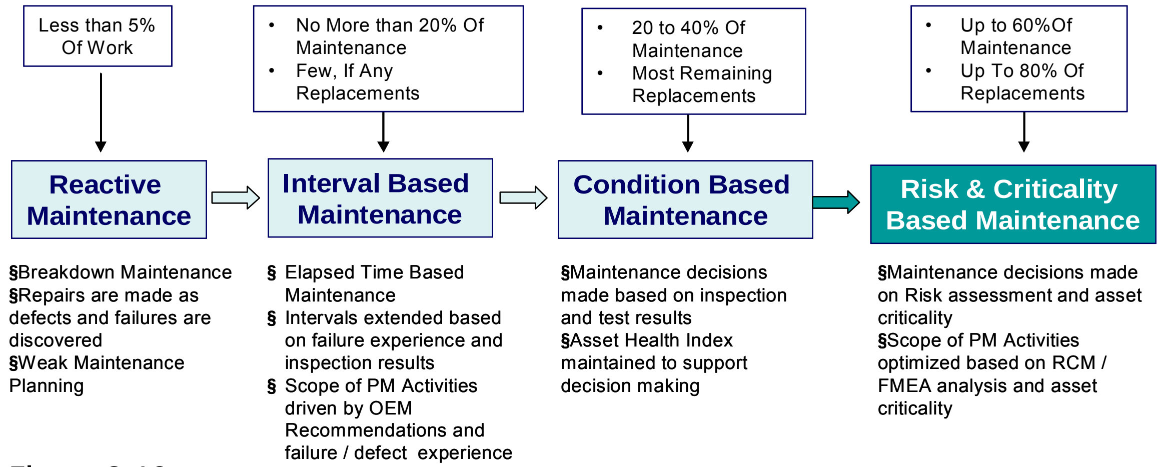


Figure 3-10

- Asset Monitoring Team - Real time condition monitoring of all operating parameters – with an Asset Monitoring Team assigned from Asset Management. This team is responsible for data mining to identify deterioration trends in the asset physical condition or dynamic response. They also make rapid assessments of any fault event, establish response strategies, and provide direction to the System Operations Center as to actions to be taken following such events (e.g., remove from service, restore to service, or additional tests required).
- Continual progress in driving evolution of the culture, as employees become more confident in dealing with risk and uncertainty, and begin to seek balance and optimization among tradeoffs rather than the rule driven comfort and clarity of rigid policies and procedures. Employees also become action oriented, focusing beyond activities to business outcomes.

Replacement Planning - Besides the analytic impracticality of constructing a 'mega model' for exploring tradeoffs between capital spending and reliability projections, leading asset managers believe there is only one "optimal" solution. That is *The Plan* that can effectively:

- Address the greatest risks of equipment failure on the system (adjusted for probability of failure and asset / customer delivery point criticality)
- Accomplish this at minimal cost,
- Produce an acceptable and sustainable level of system performance (reliability, availability, etc.) as defined by the regulatory framework, and
- Be delivered within all known constraints (outage access, resource availability, manufacturer/equipment delivery, etc.).

This last point is crucial to ensuring the plan is optimal. Many replacement projects have a most efficient time, when viewed in isolation (the point of imminent failure, for 'just-in-time" replacement). Because of varying ages and condition levels, replacement of the various components or assets within a unit of plant (e.g., an overhead line, or a substation) would, in the absence of constraints, be targeted to happen at various times over perhaps a 10 year or longer period. In the emerging environment, because of difficulties of securing outage clearances to do this work, industry good practice is to bundle much of the related work into projects that can be done within an envelope of fewer outages. To the extent that this results in retiring a particular asset somewhat before it is ready to fail, it may reduce the '*efficiency*' of that component of the solution, but this is a necessary price of having an '*achievable'* plan, and can result in an overall less costly and more effective total plan.

Similarly, 'just-in-time' replacement planning often results in very uneven or 'lumpy' replacement workload from year to year or a very large peak over a one to two year period. Besides the unlikelihood that such a large volume of replacement projects would be able to secure the access (outages) required with such a congested schedule, this often poses problems in resourcing the work, as the pool of skilled labor required for this kind of work is limited and growing tighter every year.

Industry "Good Practice" in this area includes:

- <u>Capital Budgeting</u> - All projects compete for funding based on their merits. Asset Management and operations groups identify projects based on system and customer needs, with detailed financial analysis for justification. Finance reviews justifications, determines available capital and returns the budget to the Asset Management and operations groups for revision. This process iterates until agreement is reached. Budget items are then ranked in NPV or IRR order and summed until the budget limit is reached. This Sustain Capital budget and portfolio of projects is then proposed to the regulator for consideration and approval (see Figure 3-11). In the US, UK and Australia, it is common practice for these to be presented as a 5 year plan (7 in the UK). In most jurisdictions these plans are internal documents, sometimes filed with

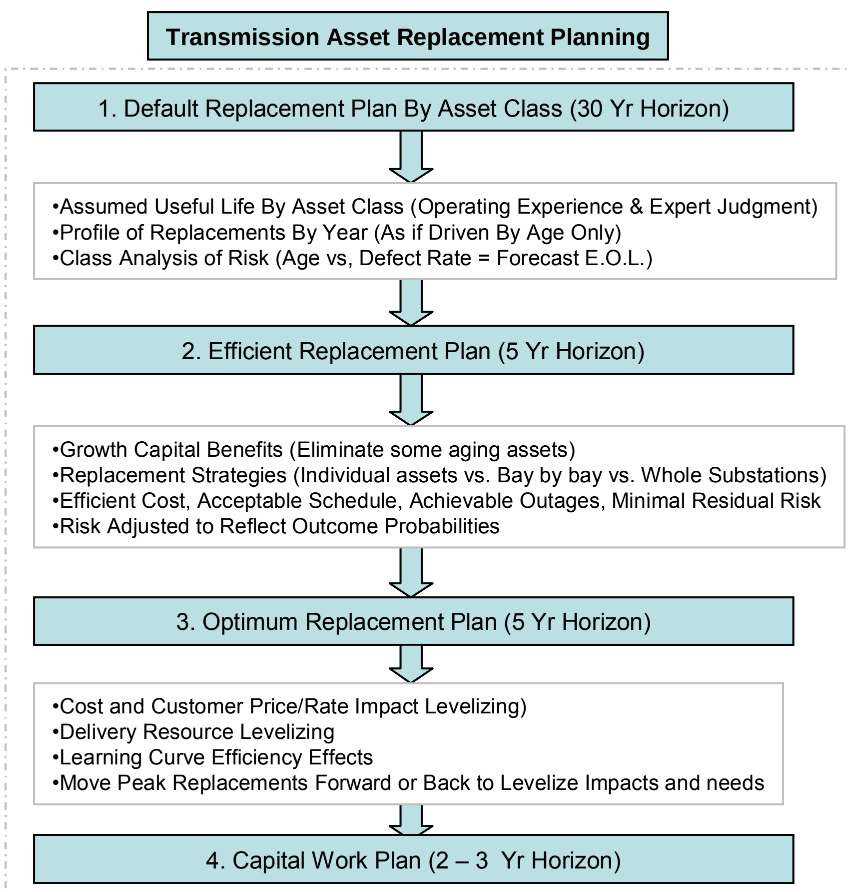


Figure 3-11

the regulators, but more often remaining confidential due to codes of conducts concerns. They are, however, frequently used in discussions with the regulators.

Industry Emerging "Best Practices" In This Area Include:

- Levelizing Plans To Make Them More "*Deliverable*" - Leading companies are 'levelizing' their 5 year plans to take into account issues such as: ability to deliver the work (staffing resources, contractors, etc.), Purchasing issues (vendor manufacturing constraints, economies of scale in volume purchases, etc.), and System Access (ability to get sufficient planned outages to do the work).
- § Stretch Goals – Leading Asset Management teams are building learning curve effects into their plans, assuming that they will make efficiency gains over the course of the plan. So for example, projected installation costs per unit decline in real terms (in some cases by as much as 1 to 3% per year) over the course of the plan.
- § *"Optimization" of Infrastructure Spending:* Creating an optimized portfolio from the extensive list of competing projects is a daunting task for most companies. This is especially so given that the business and regulatory environment is a dynamic one and the "optimum" project mix often changes throughout each year and across the typical 5 year plan horizon. Even defining the term "optimized" is challenging for many firms. In the context of investment portfolio balancing, "optimized" means selecting the group of investment opportunities (projects) that best satisfies specific value criteria (OMA cost, risk mitigation, Project NPV, customer/ environmental value, etc.) within a targeted budget range. While such criteria can be similar for each utility, the importance or ranking, of each varies between organizations, depending on factors such as business environment, regulatory incentives and priorities, company maturity (maintain, grow, retrench), and funding availability. Several of the companies interviewed indicated that they were using the Optimization approach discussed in UMS Group's white paper on this topic (a copy of the White Paper is included in the appendices).

Staying ahead of the "replacement bow wave". In our interviews, several of the Asset Managers expressed concerns about asset replacement bow waves. For some it was dealing with the bow wave at hand. For others it was dealing with the pending bow wave that they knew was coming. In all cases their messages were consistent, "If we fall too far behind the advancing bow wave of required asset replacements, we can find ourselves in the situation where we can't recover by spending any amount of money." This is the Concept of *"Spiral Decline."* As the volume of assets reaching their end of life rise, the percentage of reactive replacement work rises, first as increases in corrective work (break-fix) and then as replacement due to in-service failures. This reactive work typically involves significantly higher costs and manpower (rule of thumb 3 times as much or more) than planned replacements, where the projects are properly staged and set up, with all the required materials, resources, safety and outage work clearances arranged in advance. The disruption to the normal flow of work grows rapidly, as managers and staff dash around fixing assets and canceling planned work. As a result, other assets begin to fault and fail, creating even greater demands on the business. Eventually, insufficient outages or resources to do the growing volume of work become a limiting factor preventing the organization from catching up with the spiraling system condition.

<u>Why is it the "Optimal" Plan?</u> - Any change from the "Optimal" Plan, will produce 'economic regrets' in future periods. Once the chance to accomplish any replacement in its optimal time window passes, other factors (e.g., constraints in budget, resources, or outage access) often make it impossible to do it at a later time without displacing another replacement project, thereby creating further disruptions to the "Optimum" Plans in those future periods. The "Optimal" Plan is the only 'No Regrets' solution.

<u>Regulatory Dialogue:</u>
We explored the scope and nature of dialogue that each of these leading companies was having with their Regulator for proposing and reaching agreement on appropriate levels of sustaining capital investment. Our objective in these discussions was to identify the most successful approaches and practices in reaching mutually beneficial outcomes in this area with the Regulator. We broadly examined the practices each company used for discussion with their regulator on reliability management and maintenance / refurbishment investment, as well as the types of information that their regulators had found to be helpful in identifying and resolving issues and tradeoffs in the process of making their determinations.

Industry "Good Practice" in this area includes:

- Active participation in discussions with the regulator and its staff on reliability, helping educate the regulator on issues and constraints, and suggesting work-arounds that might help meet the regulator's purpose or objectives. Listening carefully to the regulator regarding its views on the practical constraints on the utility's plans.
- Developing financial / economic models to examine financial and operational implications of any regulatory proposals and feeding this back to the regulator before the proposals are implemented.
- Dedicated multi-skilled (technical, operational, financial and legal skills) utility team with complete access to information across the company responsible for interfacing with the regulator and its staff in the period leading up to application filing and during the following regulatory inquiries.

Industry Emerging "Best Practices" In This Area Include:

- In leading markets, in which regulatory reforms have 'matured', transmission companies are often viewed by regulators as partners in establishing an efficient open access Grid, working to eliminate capacity constraints, and policing the market behaviors of generators. Transmission business effectiveness in these 3 areas often takes precedence over efficiency, at least during the period of open market development.
- 'Proactive' disclosure in response to regulatory requests for information, going beyond providing the specific information requested, to offering additional information considered responsive to the 'intent' of the request, emphasizing openness and transparency in communications with regulators.

- Conducting broad scenario analyses to ensure that all dimensions of regulatory guidelines or standards are understood and potential ‘unintended consequences’ (for customers as well as for the utility) are fully explored before they are implemented.

Organization and Culture: Within the companies interviewed we see a strong alignment of the organization to the processes employed. The companies organize to support the process rather than based on spending type. Classic organization structures create a separation of groups that work on capital from those that work on expense (OMA). In better performing organizations, the type of spending factors into the process at the business planning stage but does not drive the organization structure. Figure 3-12 reflects a generic view of the Asset Management organization as it is applied by these companies. Each of them has customized it to meet the specifics of their processes and their market/regulatory needs. Each views it as critical that the organization facilitate rather than constrain the process and the people.

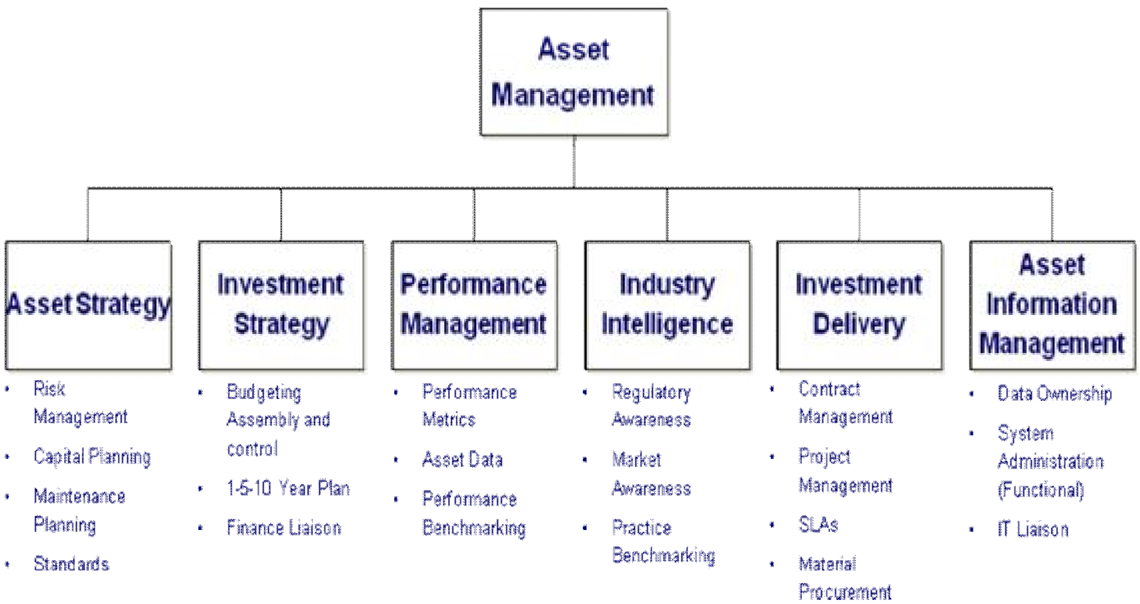


Figure 3-12

Industry “Good Practice” in this area includes:

- Flat Organization structure with clear definitions of roles, responsibilities and accountabilities.
- Focus on asset class performance (e.g., “Experts in breakers, transformers, relays, and communications”) and its impact on network performance.
- Clear understanding of the Owner and its role in determining the vision for the assets
- Strong teamwork and collaboration within the Asset Management Organization and with Finance

Industry Emerging "Best Practices" In This Area Include:

- Flat Organization structure with clear definitions of roles, responsibilities and accountabilities, with an overriding sense of shared accountability for delivery of results
    - I don't win if the team is not successful
    - I have a vested interest in the success of the team
- Focus on geographical network performance (regional system performance rather than the "breaker expert"), with a clear view of performance of the overall system – "The One Asset"
- Clear understanding of the need for a partnership between the Owner, the Asset Manager and the Service Provider
- Strong teamwork and collaboration within the Asset Management Organization and across the enterprise
- Seamless relationship between Asset Management and Finance

Asset Management Decision Support Tools: A growing number of utilities around the world have adopted the asset management philosophy for managing their transmission network and in so doing have made significant strides in improving the effectiveness of their organization structure, processes and skills. Technology support (IT infrastructure, data availability and quality, and decision support tools) have now become the limiting factors for many in progressing their asset and risk management effectiveness. We explored the current state of Decision Support Tools and the underlying Technology at each of these companies. We asked about their views on the right Asset Management decision support architecture (e.g., how tools fit within their process model) and on the priority / relative importance and value of the various decision support tools.

We found both commonalities and differences among these companies. All of them identified the need for a strong linkage between information and tools, ensuring that the data sources are consistent and that all tools rely on the same underlying data to generate information. We also found that many of the differences in tools or applications appeared to be the result of specific market driven needs. As a result, no company has all of the tools represented by this group. In essence each has taken a combination of the foundational tools and added to them the peripheral and, in many cases, more advanced tools necessary to meet their needs.

Industry "Good Practice" in this area includes:

- A functional orientation to thinking about the suite of tools and the underlying infrastructure, depicted in Figure 3-13.
- The use of a single asset register containing the key data regarding the assets and providing a common point of reference for linking asset information across the multiple tools.
- A system architecture that enables integration of the various tools and uses common data.

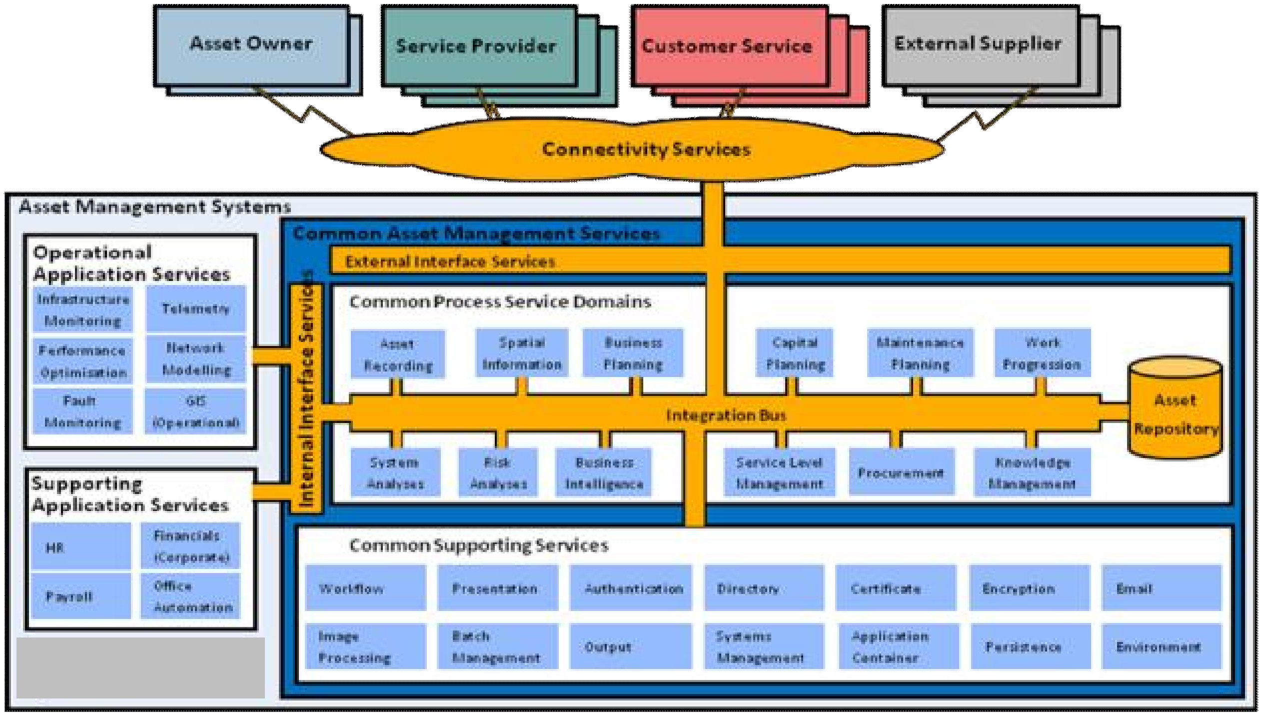


Figure 3-13

Industry Emerging "Best Practices" In This Area Include:

- Alignment of the tools and systems around the key asset management processes.
- Building upon the underlying infrastructure as seen with Good Performers, the Better Performers are leveraging the same tools across multiple aspects of the process to provide stronger, more meaningful information. See Figure 3-14.

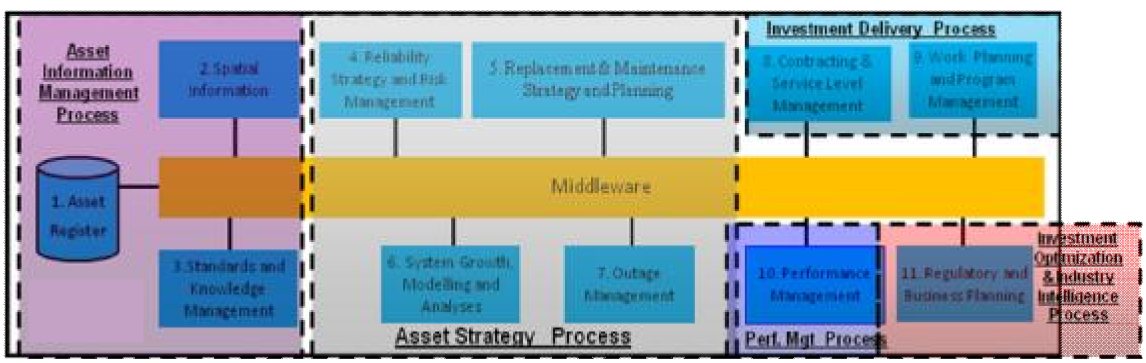
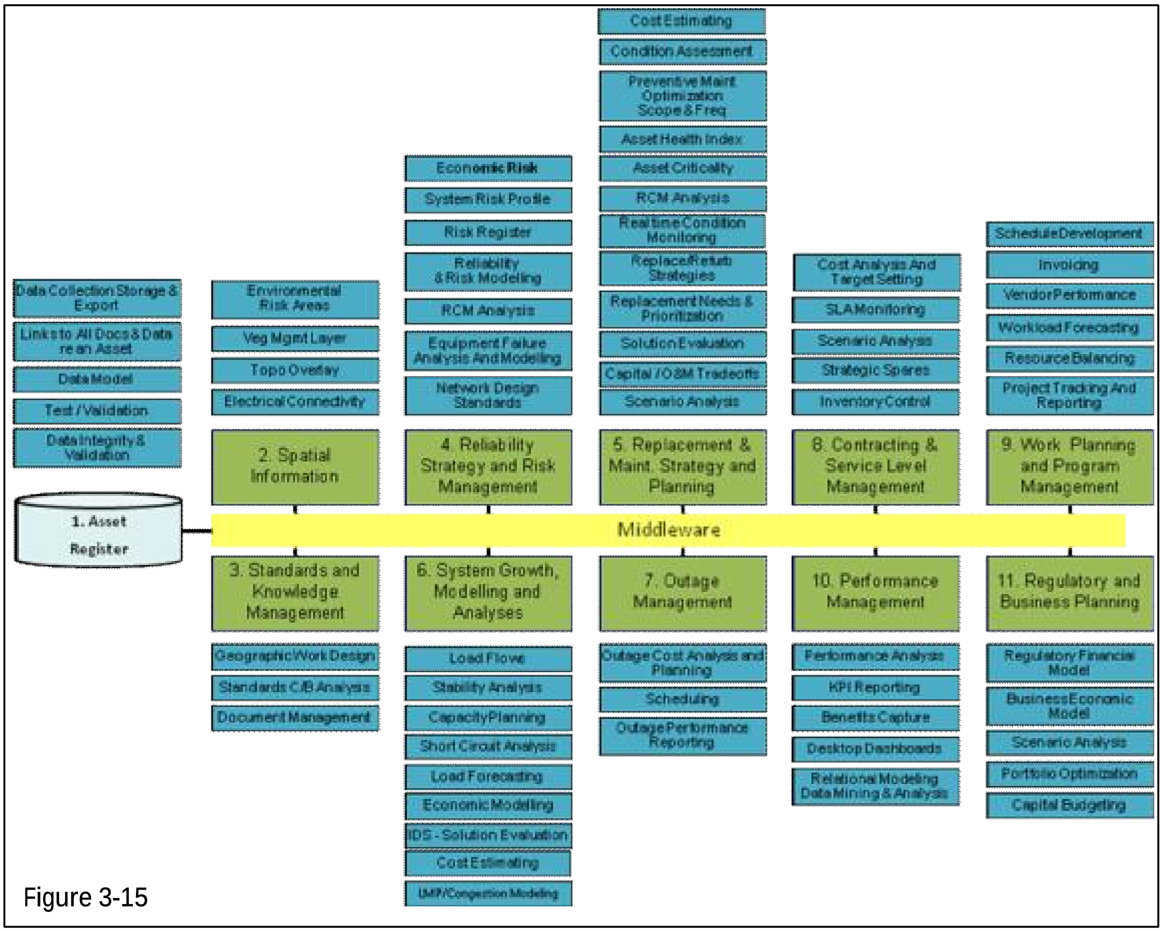


Figure 3-14

- Systematic evaluation of information and technology gaps to making the next level of improved decision making.
- Applying Asset Management rigor to each decision to invest in the next tool (e.g. what is the life-cycle cost of the tool, including data capture and upkeep versus the value that the tool will deliver, and how does that evaluation compare to other asset investments that could be made with the money to be spent for the next tool). Thus each tool in the tool suite, Figure 3-15, has met the business case hurdles applied to all other system investments.



Cost Estimating
Condition Assessment
Preventive Maint Optimization Scope & Freq
Asset Health Index
Asset Criticality
RCM Analysis
Real time Condition Monitoring
Replace/Refurb Strategies
Replacement Needs & Prioritization
Solution Evaluation
Capital / O&M Tradeoffs
Scenario Analysis
Economic Risk
System Risk Profile
Risk Register
Reliability & Risk Modeling
RCM Analysis
Equipment Failure Analysis And Modelling
Network Design Standards
Data Collection Storage & Export
Links to All Docs & Data re an Asset
Data Model
Test / Validation
Data Integrity & Validation
Environmental Risk Areas
Veg Mgmt Layer
Topo Overlay
Electrical Connectivity
Cost Analysis And Target Setting
SLA Monitoring
Scenario Analysis
Strategic Spares
Inventory Control
Schedule Development
Invoicing
Vendor Performance
Workload Forecasting
Resource Balancing
Project Tracking And Reporting
2. Spatial Information
4. Reliability Strategy and Risk Management
5. Replacement & Maint. Strategy and Planning
8. Contracting & Service Level Management
9. Work Planning and Program Management
1. Asset Register
Middleware
3. Standards and Knowledge Management
6. System Growth, Modelling and Analyses
7. Outage Management
10. Performance Management
11. Regulatory and Business Planning
Geographic Work Design
Standards C/B Analysis
Document Management
Load Flows
Stability Analysis
Capacity Planning
Short Circuit Analysis
Load Forecasting
Economic Modelling
IDS - Solution Evaluation
Cost Estimating
LMP/Congestion Modeling
Outage Cost Analysis and Planning
Scheduling
Outage Performance Reporting
Performance Analysis
KPI Reporting
Benefits Capture
Desktop Dashboards
Relational Modeling Data Mining & Analysis
Regulatory Financial Model
Business Economic Model
Scenario Analysis
Portfolio Optimization
Capital Budgeting

Figure 3-15

4. Industry Trends on Reinvestments in the System

Any analysis of historical investments in the utility industry will reveal the cyclic nature of infrastructure spending. The cycle has two primary drivers, economic growth and reinvestment for asset replacements. Economic growth is the driver for much of the green/brown field investment and asset replacement emerges generally 20-50 years after the initial investments, as the age and condition of the assets leaves replacement, rather than continued maintenance, as the prudent decision. The cycle is true for all types of infrastructure, but it is more evident in electric and gas transmission.

By their nature, transmission investments require long lead times to plan, permit, engineer and construct. This is particularly true for EHV (Extremely High Voltage) lines used for bulk power transmission from remote locations or for major area interconnections. Due to the long lead and high impact nature of the lines, they are generally built to carry the load that they will see 10 to 15 years into their life, rather than merely to meet the current day demand. Thus during times of economic growth, these lines are constructed and as the economy grows and consumes the available capacity, reserve margin begins to diminish to the point where new lines are required.

In the most recent cycle, highlighted in Figure 4-1, the effects of the economic growth of the late 1990s can be seen in the rising construction spending. This economic growth coincided with the opening of the electricity market in most of the US and parts of Canada to Independent Power Producers (IPPs) and merchant plants. The rise in spending was magnified in part due to an earlier down turn in transmission spending in the US due to regulatory uncertainty. That uncertainty was driven by the FERC's deliberation on, and ultimate promulgation of, Orders 888 and 889, which solidified open access on the majority

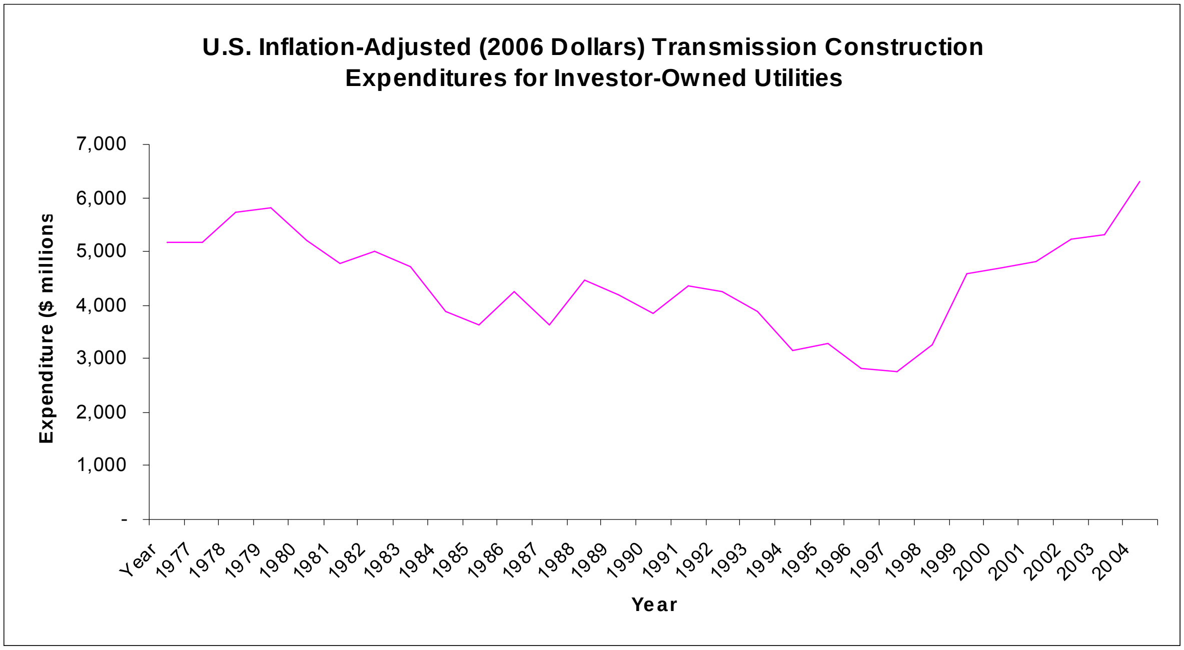


Figure 4-1 Source: Edison Electric Institute

of the US transmission grid. FERC had been contemplating this ruling and discussing it with industry participants for several years prior to its institution in 1996. Uncertain as to the impact of the ultimate rules, many utilities reined back on transmission investments, particularly large, costly projects. Most were reluctant to subject customers and shareholders to the risks of investments with no clear means of cost recovery.

Thus in the late 1990s the industry experienced the combined impact of more open access to the transmission system for IPPs and merchant generators; the growth in the economy; and the need to “catch up” on transmission improvements. The result was a growth surge in the need for new transmission, to connect the new generators and to reinforce the grid to carry the greater energy flowing across the lines.

Less apparent in Figure 4-1 is a secondary driver of spending – asset replacements. The previous growth cycle for most of these utilities occurred in the 1970s. While utilities were experiencing significant growth beginning in the late 90s, many, if not all, were beginning to see the leading edge of the asset replacement wave. The replacement wave has continued for most of the industry and is expected to continue for the next ten years as maintenance programs and life extension strategies give way to the economics of asset replacement.

<u>Reinvestment in the System</u>

The experience in the UK, where many utilities were found to be deliberately investing in costly projects merely to hit reinvestment targets (see Appendix 2), and a small number of other similar occurrences in North America, highlighted the need on the part of regulators and boards to ensure that utility management teams were reinvesting in the system at appropriate rates. While many have suggested that “Rate Base” regulation, which is the predominant structure in the US, incents companies to overinvest, Corporate Boards are sensitive to the risk of having such investments disallowed on prudency grounds. As a result, they are very often as keen as are the regulators to ensure that the investments match the needs of the system without going further than is necessary.

The challenge for Regulators and Boards then is how to gauge the appropriateness of the level of investment being made in the system. For both Boards and Regulators there is a tendency to look into the details of proposed spending plans. In doing so they can see the specific plans that are in place and the improvement goals the utilities are seeking to achieve. While this is a valuable step in understanding how and where the companies are focusing their investments, it does not, in general, answer the question of spending adequacy to keep the system in the desired state of health.

In the US, it is common for Boards and Regulators to seek external comparisons of spending levels. In this way, they can complement their knowledge of the detailed spending plans with a comparison of the rate of spending, to determine if companies are reinvesting sufficiently to maintain the condition of the system. One common comparator that many find useful is the rate of spending versus annual depreciation expense. Looking at a single year of data does not provide much insight. However, examining a multiyear trend can often allow Boards and Regulators to see patterns that may not have been apparent through and examination of the detailed annual investment plan.

Figure 4-2 highlights the trends for approximately 70 US utilities. We have limited this

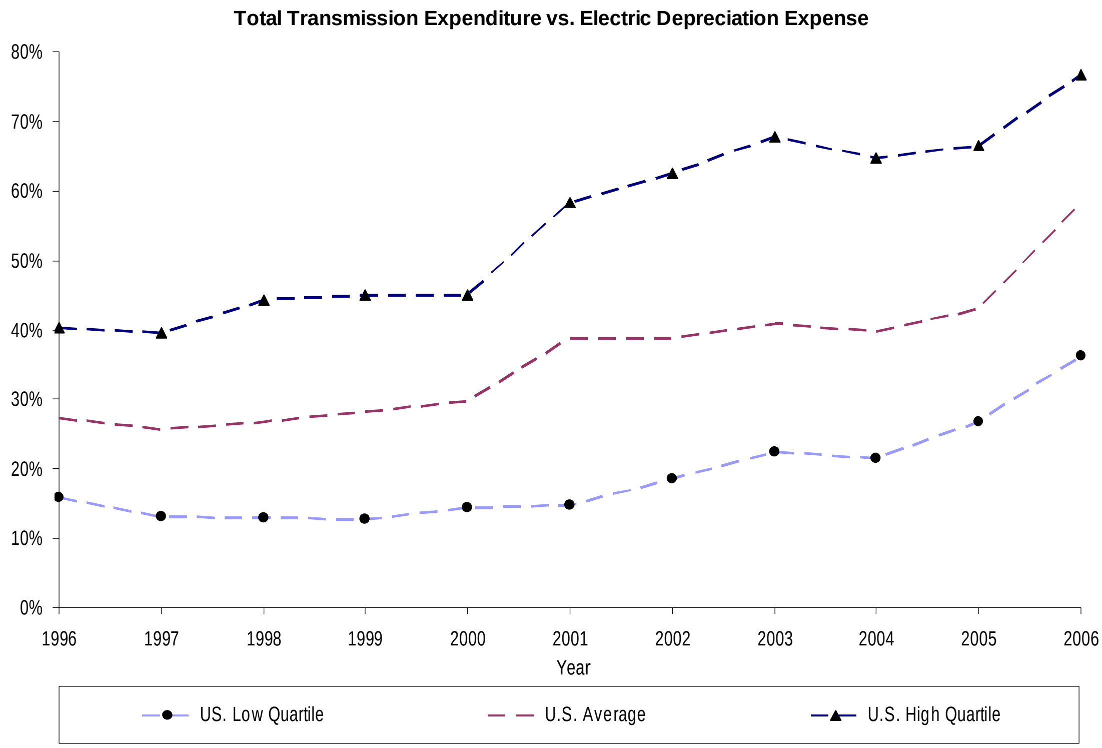


Figure 4-2

analysis to Transmission Capital and O&M (OMA) expense so that it is consistent with the overall spending trends discussed earlier. In order to compare the effects of spending between companies, we have deliberately limited the scope of the analysis to spending on the assets. This includes labor and materials directly associated with the transmission assets as well as planning, engineering and management costs. We have not included costs associated with office buildings, nor have we included distribution or generation costs for companies that are vertically integrated. All costs have been adjusted to 2005 Canadian dollars using regional wage and material adjustments rather than simple currency exchanges rates. We have maintained this approach throughout the report unless otherwise noted on the charts.

We can see, in Figure 4-2, that the range of reinvestments rates is wide, but is increasing for all utilities. At first glance, one would expect to see reinvestment rates equaling or exceeding the rates of depreciation. A combination of factors for US transmission companies drives reinvestment rates to be lower than annual depreciation. These include regulatory allowances for accelerated depreciation on some assets in the system, the cyclic nature of transmission investment discussed earlier (e.g., build large assets and then grow into them), and regulatory expectations for improvements in efficiency on the part of utilities.

Boards and Regulators have cause for concern for companies that are below the average, and specifically those that fall below the average of the lower quartile. There may be valid reasons for their apparently low levels of reinvestment, and Regulators and Boards should be able to align the company's explanation of the variance with their own knowledge to determine the plausibility of the explanation and the alignment of the company's plans going forward to the expected trends in reinvestment.

The level of spending as compared to the depreciation of the asset base is a useful comparator, but by itself it is not conclusive. In gauging the level of investments in the system it is also useful for Regulators and Boards to compare the spending levels against operational parameters. Three such common measures for transmission systems are spending per end use customer; spending per kilometer of line; and spending per MWh of throughput. As with depreciation, none of these measures itself is conclusive. But, taken in combination, and validated with supporting information, they can be very useful in making a high-level assessment of a company's investment patterns.

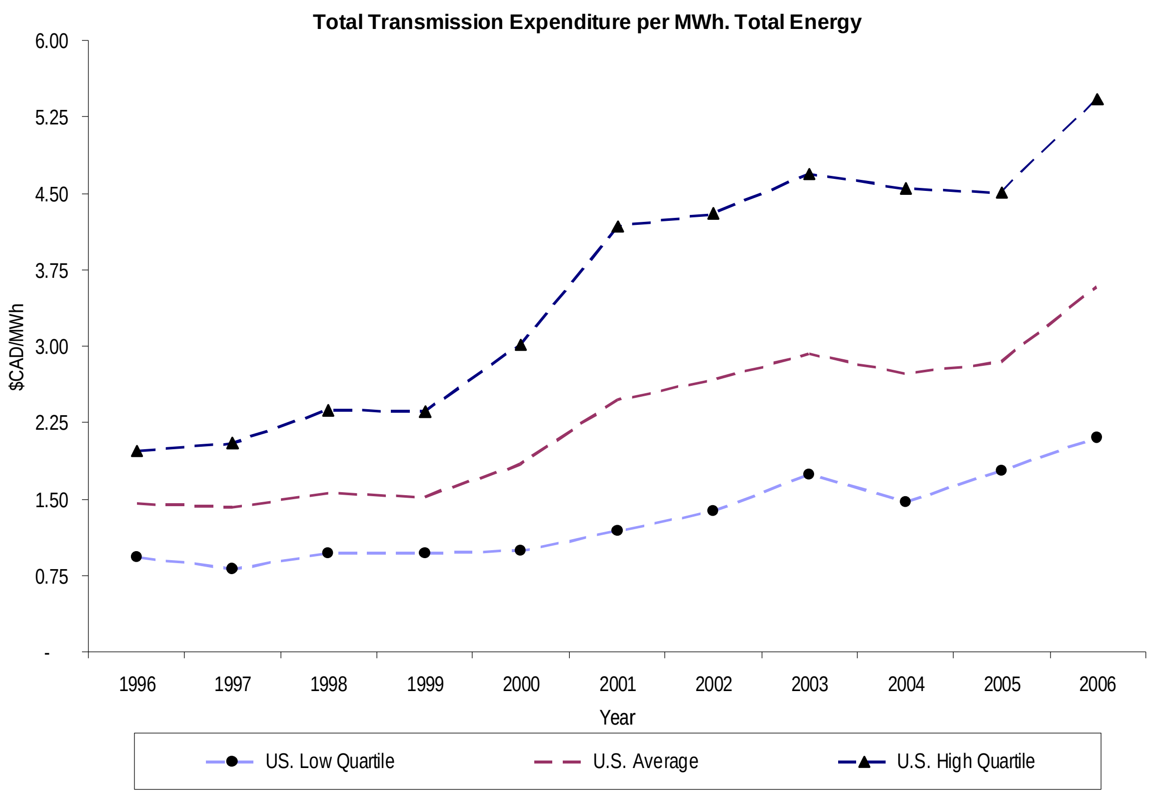


Figure 4-3

Looking at these indicators (Figures 4-3, 4-4, and 4-5) for the same group of US companies, we see that the upward trend is consistent. The investment per customer depicted in this chart does not translate directly to an annual rate impact, as these costs must first flow through regulatory accounting. However, a sustained trend at any given level can be a good indicator of the cost impact that customers will ultimately see in rates.

Spending per MWh is useful in gauging the efficiency of the operating costs of a transmission system. The cost per MWh tends to reflect the cost adder that a transmission system represents on the delivered energy. For most utility customers, transmission costs remain a small fraction of the total cost of delivered energy. Nonetheless, Figure 4-3 (previous page) highlights the wide variation in costs per MWh transmitted. Companies at the lower end of the range tend to be either those that have large transmission systems that wheel significant amounts of energy to other systems, or those that are under spending. Companies at the higher end of the range tend to be those that have significant transmission investments (large geographic service areas) with modest levels of wheeling to other systems, or may be investing too heavily in their systems.

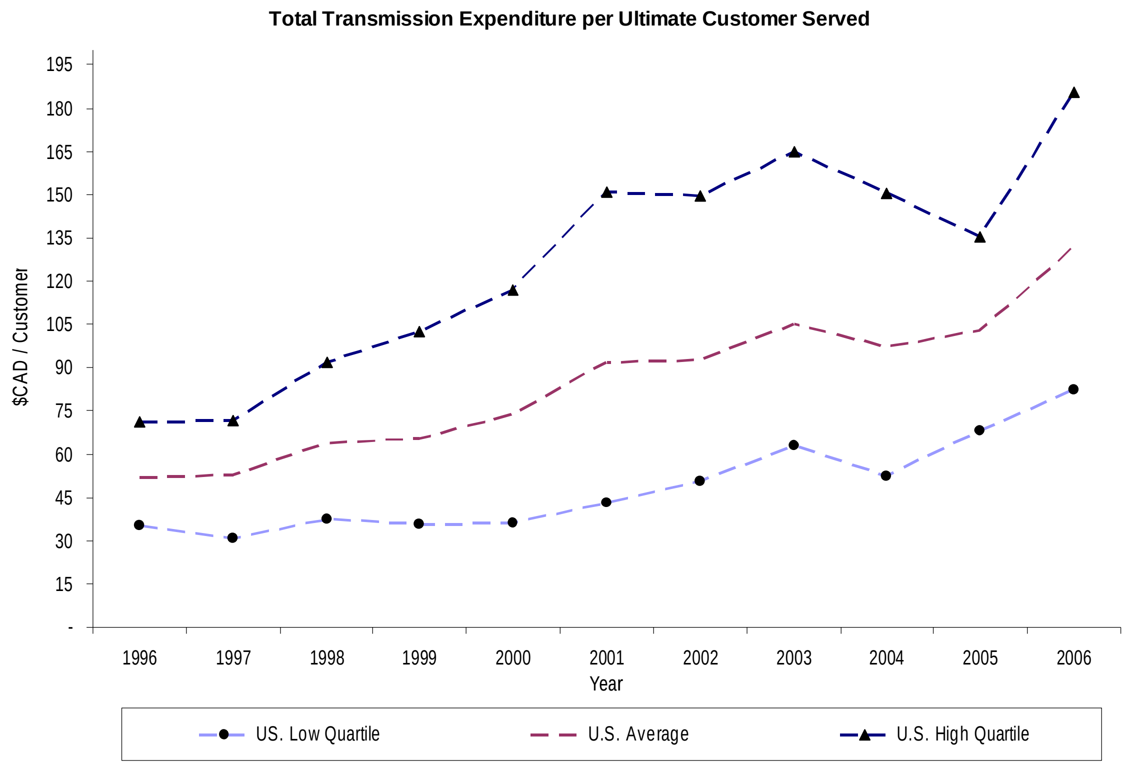


Figure 4-4

The second measure is spending per ultimate customer served (Figure 4-4). For this analysis we only counted the end use customers within the footprint of the transmission utilities in question. For many companies this is a difficult number to obtain. Many transmission utilities serve a far greater population than their own customers. Hydro One and many of the utilities in the US serve their own native customers as well as the customers of transmission dependent utilities. In Hydro One's case this includes the customers of the Toronto and other Ontario Munis. Thus when considering the implications of this analysis we must understand the count of customers included in the analysis. The spending per customer depicted in this chart again suggests that there is a potential that the companies at the lower end of the range are under investing, or benefit from economies of scale from high customer density. Those at the high end of the range are seeing high cost per customer as a result of low customer density or as a result of genuinely higher spending levels.

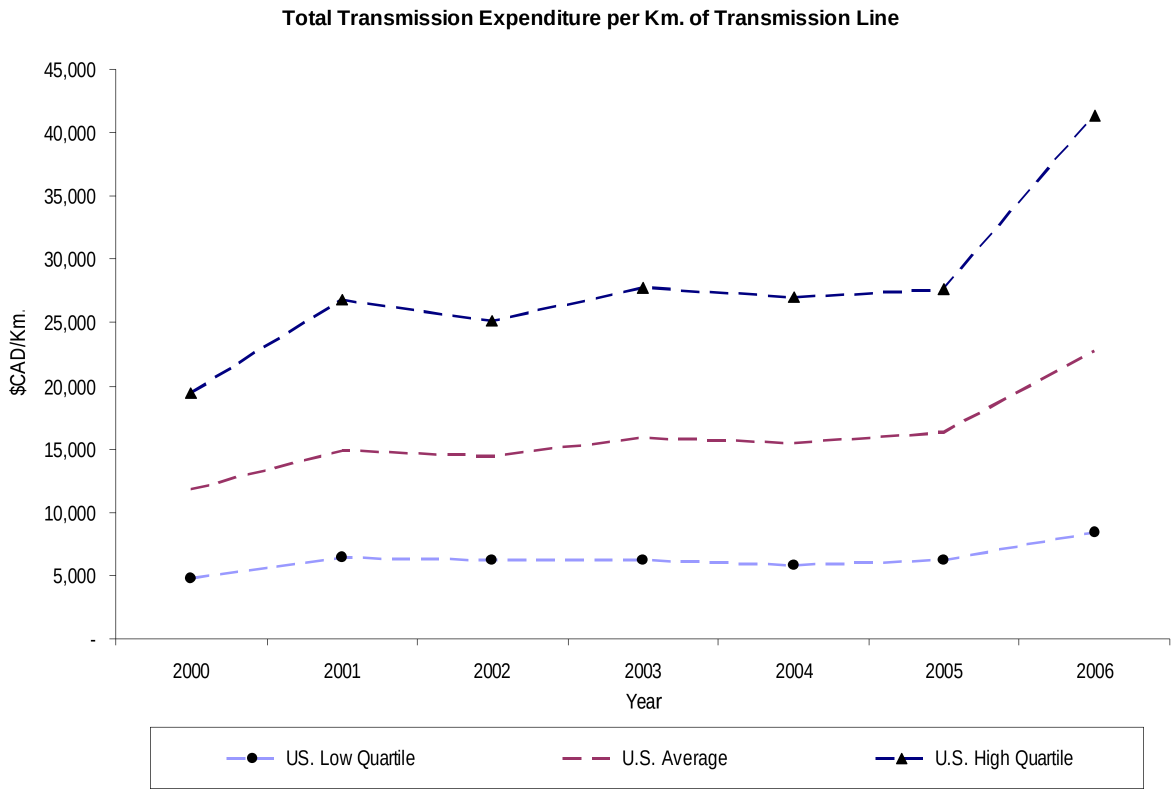


Figure 4-5

Spending per kilometer of line (Figure 4-5) normally tends to be influenced by customer density and asset intensity. It tends to be the more meaningful measure when comparing low customer density systems as they tend to have more expansive systems. Most of these systems appear on the lower half of the spending per Km chart. The companies represented in the upper half of the chart tend to be those with high asset intensity, often driven by high customer density. ConEd in New York is a good example of asset intensity. ConEd has fewer kilometers of line than many of its peers, but a far greater number of customers. The lines it does have then are both large and costly. ConEd provides greater capacity in each mile of line than would be prudent for less dense systems, and it is paying a premium in costs for the heavily urban nature of their system.

Using these measures, we can draw conclusions about a company by comparing its position on each of these charts to what is known about the company and what we would expect, given its system characteristics. In seeking to understand a company's performance, the analysis may give rise to questions of customer density, and asset intensity. These too can be calculated and used as supporting analysis in rounding out the picture of performance. The goal is to determine if there is an explanation, or explanations, that are consistent with both our knowledge of the system and with the position of the company on each of the charts. Where such explanations cannot be found, or are not consistent, then one can draw new conclusions regarding the appropriateness of the spending level.

5. BCTC as Compared to Other Transmission Companies

In undertaking the assessment of BCTC we examined, in detail, the two main indicators of its ability to manage the current and future performance of the system. These are: 1) the processes, methods, data, information and tools BCTC uses in making investment decisions; and 2). relative system costs and performance as indicators of the impact of these investment decisions

We believe that it is appropriate and necessary to look to both of these indicators. Effective processes and methods are critical enablers of sustainable success in managing asset performance. But, of course, looking only to the processes, methods, etc., ignores the outcomes produced, which is what matters most to customers. If the processes and tools are not well used, or focus is placed on the wrong sets of decisions, the outcomes will fall short of the expectations of stakeholders. The analogy of the tool not making the craftsman clearly applies here.

Similarly, superior performance can be a key indicator of effective decision making. But, without knowing how the performance was achieved, we cannot tell if superior performance is the result of effective processes and execution, or simply a legacy from over investment in years past. Nor can we determine if inferior performance is due to shortfalls in current capabilities and decisions, or a result of underinvestment in years past. By looking at both the performance outcomes and the processes currently employed, we can draw conclusions about the ability of the company to deliver sustainable or improved results in the future.

Spending

Building on the analysis discussed in the previous section, we collected the information necessary to overlay BCTC on the charts with North American peer companies. We have graphed the average for the peer companies and the means for the upper and lower quartiles. In this way we can see more clearly where, within the ranges of cost, BCTC compares. We collected information, as available and reliable, to overlay Hydro One and Hydro Québec on the charts, as they represent the other two large transmission companies in Canada. We also sought comparisons with National Grid UK, where data was available and reliable.

In our analysis, we have made direct comparisons of BCTC to American Electric Power and Arizona Public Service. As we discussed in Section 3 of this report, we know that these two companies have demonstrated sound transmission performance (low cost, good reliability) over the last ten years. They also have many of the same drivers of cost as BCTC in terms of customer density, system configuration, and regulatory obligations to ensure reasonable access to transmission in sparsely populated service territories. We can compare BCTC's position relative to the industry average and quartiles with the positions of APS and AEP as known reference points. Using AEP and APS as proxies for the type of performance that we should generally expect for BCTC, we should be able to test the reasonableness of the conclusions that we draw regarding BCTC.

As we discussed in the previous section, the costs reflected in the following charts include all Capital (Growth and Sustain) and Expense (OMA) expended on the assets. The costs are limited to spending on lines, stations and supporting equipment and personnel. As such, the costs include all expenditures for material, labor, planning, engineering and supervision. They do not include costs associated with office buildings, generation, or distribution facilities. All of the costs have been converted to 2005 Canadian dollars using regional wage and material adjustments. We have used the regional material and wage adjustments as our benchmarking work has shown these to be more representative of actual cost differences than relying on foreign currency exchange rates. The data for the US companies is yearend actual filed data up through 2006. For 2007 and beyond we have projected the average and quartile costs based on industry projections from EEI. For 2007 we show a range of +/- 10% around the EEI projection and for the remaining years we show a +/- 20% band around the EEI projection.

In undertaking our preliminary analysis, we noted that there were several companies that exhibited what appeared to be periodic anomalistic spending. In essence their costs jumped dramatically once or twice over a 10-15 year period. Upon investigation we determined that these jumps in spending were most often the result of investments associated with major interconnections, generally inter-regional or inter-utility bulk system interconnections. As we discussed earlier in the report, these types of investments are significant and go well beyond the normal expenditures associated with ensuring that growth and sustainment needs of the system are met. We were concerned that these extraordinary investments could distort the analysis, undermining meaningful comparisons between the utilities with regard to their investment patterns for typical year-on-year system performance.

Upon further examination of the data, we noted that these types of extraordinary investments were indeed infrequent and when looking at the overall population of the utilities, the spikes in spending were averaged out. But this was not the case when looking at any one company. Having identified APS and AEP as meaningful proxies for BCTC we reviewed their detailed spending and discovered that both had made extraordinary investments during the ten year analysis period. In the case of AEP, one investment, the Wyoming-Jacksons Ferry 765 kV line represented close to 50% of the total system investment in the one year in which its costs were reflected. A similar, though less dramatic, case occurred for APS when its investments in a 500kV interconnection resulted in a doubling of the normal annual kilometers of line additions and inflated its costs over the 2+ year project period (see supporting analysis at the end of this section). In both cases we concluded that to ensure comparability between BCTC, the proxies, and the peer group averages, we needed to remove the costs associated with the AEP and APS extraordinary spending. Therefore, the costs for these extraordinary investments for AEP and APS have been removed from the analysis, as noted on the accompanying charts.

We then turned to BCTC to determine if there were similar extraordinary costs in its historic and projected system spending. We found two categories of extraordinary spending in

BCTC's investment information. The first is major interconnections, akin to those that we identified for AEP and APS. BCTC has two projects underway, each analogous to the projects that we removed from the analysis for the proxies. These are: the Vancouver Island Transmission Reinforcement (VITR); and the Interior Lower Mainland (ILM). Each of these is a major interconnection and each in its own right would represent a significant portion of the overall system investment. The VITR, as an example, is projected to cost approximately $287M, with $165M of that being reflected in a single year (F2009). The ILM costs projected for F2009 alone represent close to the total system capital investment (Growth and Sustain) for F2007 ($189M). We concluded that to provide for meaningful comparisons with the other utilities, we needed to remove these extraordinary projects from the analysis. There were several other significant investments in BCTC's forecasts, including the Central Vancouver Island Reinforcement. Our review of these projects indicated that they were analogous to the routine types of investments that were being made by other utilities, and despite their relatively large size, were not extraordinary and therefore should remain in the analysis.

The second area of extraordinary spending that we noted for BCTC was in IPP interconnections. We reviewed BCTC's historic and projected levels of interconnections and were concerned to see 100% growth year-on-year in the number of new connections. This in turn results in much higher overall spending for BCTC. This level of growth in the number of connections, and the resulting expenditures, are far beyond what would be expected among the peer companies. While all of the peers have IPP interconnection costs, they are not currently facing the dramatic growth in volume that BCTC is seeing, and in some cases the costs are borne by the IPP seeking the interconnection and therefore are not reflected in the utilities' reported costs. If we were to leave the BCTC IPP costs unadjusted, we believe this would distort the analysis. BCTC's projected F2009 IPP interconnection costs are $149M. This again is close to the total Growth and Sustain capital investment level in F2007. Similarly, if we were to remove all of the costs we believe that this too could be distorting the analysis. After reviewing publically available information for the other utilities and reviewing the BCTC IPP cost projections we concluded that adjusting the BCTC IPP expenditures downward by 50% for F2008 and F2009 would allow for a more meaningful comparison with the other utilities. This still represents a significant portion of BCTC's total system capital investments, and thus could tend to produce a slightly more conservative (less favorable) analysis of BCTC's cost performance.

<u>Spending Per MWh</u>

The analysis in Figure 5-1 suggests that BCTC's spending relative to throughput is projected to climb steadily. This is consistent with the proxies and with the industry as a whole. We note that in earlier years, BCTC's costs were below the average. Given the nature of BCTC's system, we would expect its costs per MWh to be on the higher end of the range and somewhat higher than the proxies.

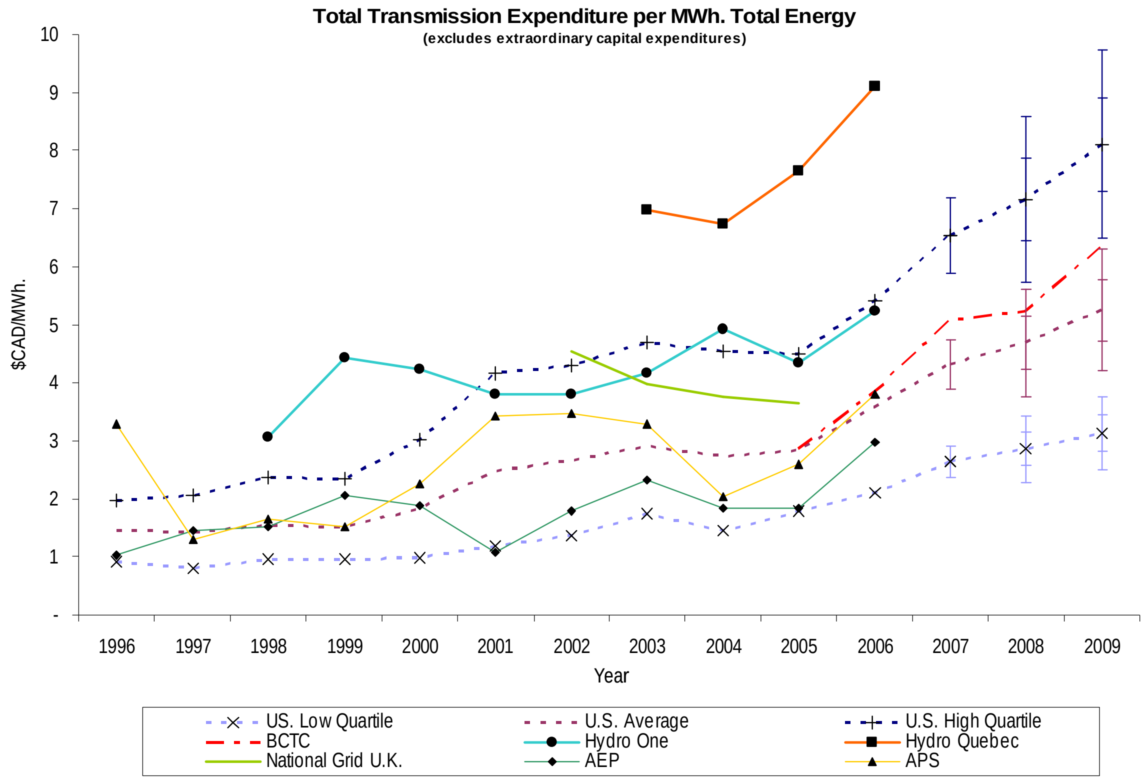


Figure 5-1

When comparing the Canadian utilities with the US companies at first glance it appears that the Canadian companies could be over-investing. In reality some of the higher cost position for the Canadians may be a result of the Canadian systems being at the edge of the integrated network. Most of the US companies are heavily integrated with their neighbors, in all directions, and form a highly integrated physical and economic network. As a result the flows across their transmission systems are significantly greater than that required for their own customers. For many of these companies, the energy transmitted across their networks is twice that needed to serve their own customer load. The other Canadian companies are integrated into the network and engage in bilateral transactions and direct sales to the US. Their physical location on the grid, however, limits the amount of wheeling, outside their foot prints, their systems are called upon to support. In fact, the same situation exists for some US companies that are located at the outer edge of the grid, or exist within peninsulas (see Figure 5-2, following page).

The analysis of historical spending per MWh throughput (Figure 5-1) is somewhat surprising, in the difference between BCTC and the other two large Canadian utilities. The other two Canadian systems have higher throughput levels than BCTC. Hydro One supplies energy to a large number of municipal utilities in Ontario, which accounts for the majority of the difference. Hydro Quebec has a significantly higher per customer consumption rate than BCTC. (See supporting analysis at the end of this section of the report). In addition, both Hydro One and Hydro Québec have invested heavily in their systems over the last 15 years to support sales of energy to the US. As such, their systems are large and integrated in the area close to the border and they have seen the sales volumes with the US grow. All of these factors should have combined to result in lower costs per MWh for the other Canadian companies. That they remain well above average on this metric despite their higher throughput levels suggests that their underlying cost structures are the contributing factor. BCTC, on the other hand, while supporting a slight growth in wheeling (Figure 5-3), has focused heavily on maintaining and expanding the infrastructure within the Province. We expected BCTC to be at the upper end of the range in this analysis and above the two proxies (AEP and APS). However, it's spending per MWh in fact is on par with APS and only slightly above AEP. More significantly, its costs appear within the average range even with the projected increases through F2009, and are below what we expected. We did note that tracking the growth rate back to previous years would suggest that prior to 2005, BCTC's investment level, as indicated by this measure, was below the average.

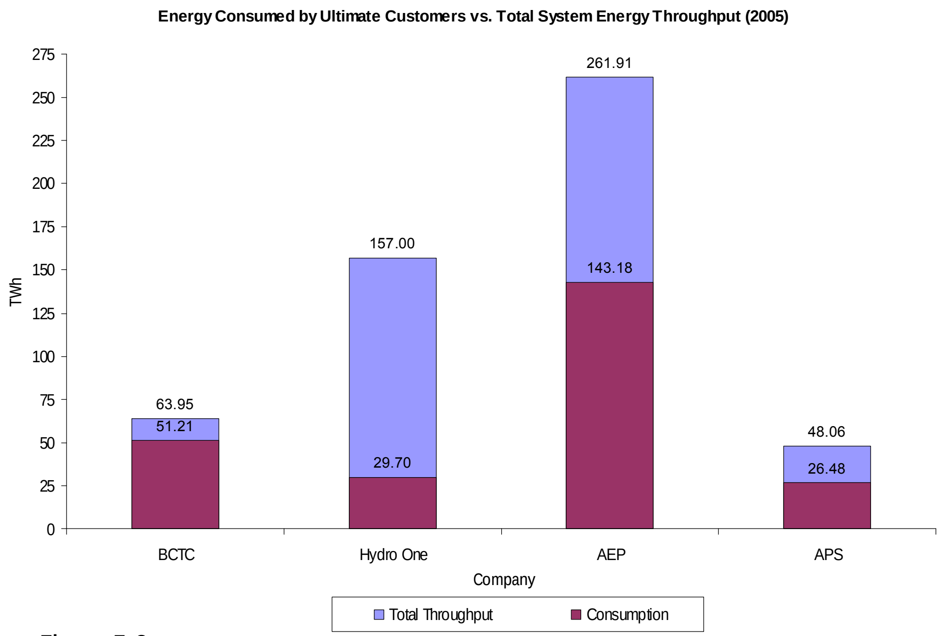


Figure 5-2

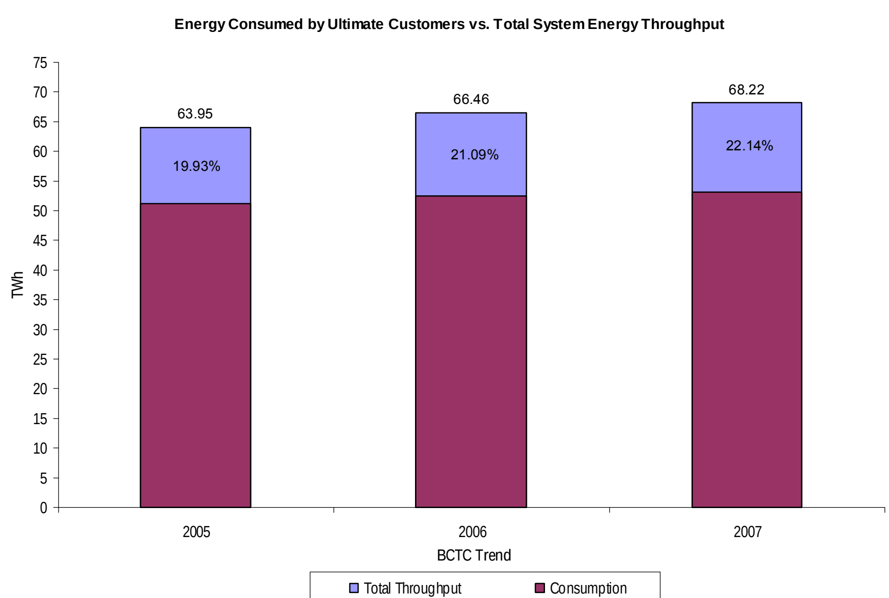


Figure 5-3

The growth and expansion of the BC market and the potential for additional sales into the US could cause BCTC's performance on this metric to improve (decrease) over time. The growth in sales and in the use of the transmission system to support a greater volume of economic transactions could contribute to the need for additional expenditures to ensure that the capacity is sufficient to support the transactions.

Experience in other markets has shown that the cost of investments that support wheeling is generally borne by the market transactions and that the net effect to the end use customers is a benefit. The customers benefit in reduced costs per kWh through greater use of the fixed investment, and from the inherent reliability improvement resulting from the transmission capacity that is added to support the economic transactions. Clearly AEP benefits in lower system costs per MWh and it transports a significant amount of energy for others, resulting in lower overall costs to its own customer base.

Comparing BCTC to the proxies and to the industry quartiles, its cost position, given the nature of its system and its location in the grid, is below what would reasonably be expected.

In looking at AEP's expenditure level, the sharp rise appears to have been as a result of recent NERC standards that call for improvements to be made based on the use of deterministic analysis. AEP, like many other companies, had historically used probabilistic analyses to determine the priorities for its spending, and might defer investments associated with extremely low probability events. That being the case, we would expect that the upturn resulting from this driver would only be present for a year or two as AEP finishes bringing itself into compliance with the new application of these standards. There are several other utilities that face similar circumstances as well as responding to additional external factors.

AEP has announced several other significant transmission investments in Texas and in its eastern service territory. Most of these investments are medium and long haul lines and we would expect to see it continuing to grow its capability to move energy for other utilities.

For some of the companies in the analysis we know that their costs are increasing as a result of several factors that had not previously been considered or required in their planning. These include:

- Pest infestations and disease – pine beetle (Alaska, Southeast US, Pacific Northwest), emerald ash borer (Great Lakes region), sudden oak death syndrome (California), etc. All of these cause premature death in trees along rights of way. In many cases the kill happens much faster than can be seen in historical inspection cycles. They also have the potential to result in uncontrollable need for immediate spending as a result of large scale infestations.
- New or revised environmental regulations – as an example, many companies are now investing at greater levels to add bird diverters to their transmission lines that are in proximity to migratory flyways.

- Changes in the level of risk tolerance as a result of growth of the system or the change in customer demographics. An example of this can be seen in cases where the population has grown closer to existing facilities. Often greater levels of sound wall and fire barriers are added. Other examples include changes in post event restoration tolerance for storm and seismic events due to changes in the concentration and criticality of the load.

These tend to be company specific; however, our conversations with many utilities indicate that most of them are facing a growing number of these new challenges.

We should also note that some of the new transmission investments are being made by independent transmission companies. In some cases these are transmission providers such as National Grid USA, and Hydro Quebec, operating outside their historic foot print. In other cases it is private equity firms such as Babcock and Brown (underwater cable in San Francisco Bay), TransElec (Path 15 California) or merchant transmission companies like Neptune. As a result of the introduction of these participants in the market, the publicly available data will not reflect all of the costs and kilometers of line, though the costs will be seen by the end use customers of the system. We need to bear this in mind when making any direct comparisons.

This is the case with APS. We note that it is planning on participating in the development of new long haul transmission lines. Its plans call for joint investments with National Grid USA. As a result, the full costs of the investment would not appear in APS future costs as some of them will be borne by its partners.

<u>Spending Per Kilometer of Line</u>

Spending per kilometer is a useful measure in looking at systems with large, thinly populated service territories. The nature of the service territory and the need to provide reasonable access to transmission tends to be a greater driver for these systems than overall customer count or throughput. The analysis of 'spending per kilometer of line' (Figure 5-4) indicates that BCTC's spending over the last several years is at the lower end of the range for the industry. Its spending level is comparable to those of AEP and APS. BCTC's spending levels in earlier years is at or below that of the proxies. Its 2005 levels were on par with AEP, whose overall system size and spending provide it far greater economies of scale than BCTC can achieve. This raises the question of the sufficiency of BCTC's spending levels in earlier periods.

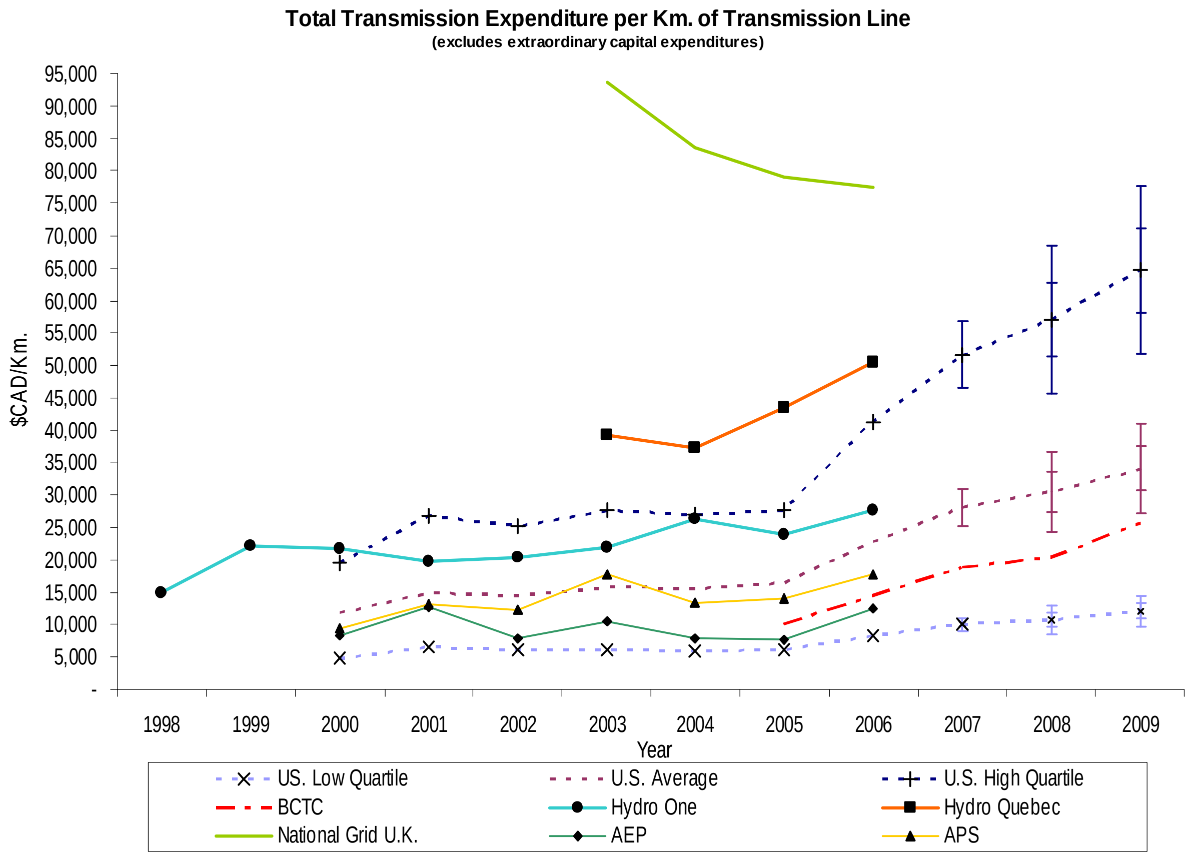


Figure 5-4

There is a temptation to assume that BCTC's position is driven only by the nature of its transmission service territory and seemingly lower customer density. However, we compared the customer density for BCTC to the other companies (Figure 5-5) and found that it alone does not explain the low cost position occupied by BCTC. As Figure 5-5 highlights, BCTC does have a lower than average customer density, but it is not the lowest. In fact BCTC's customer density is higher than the average of the lower quartile of the US companies and is comparable to AEP and APS. We also note that

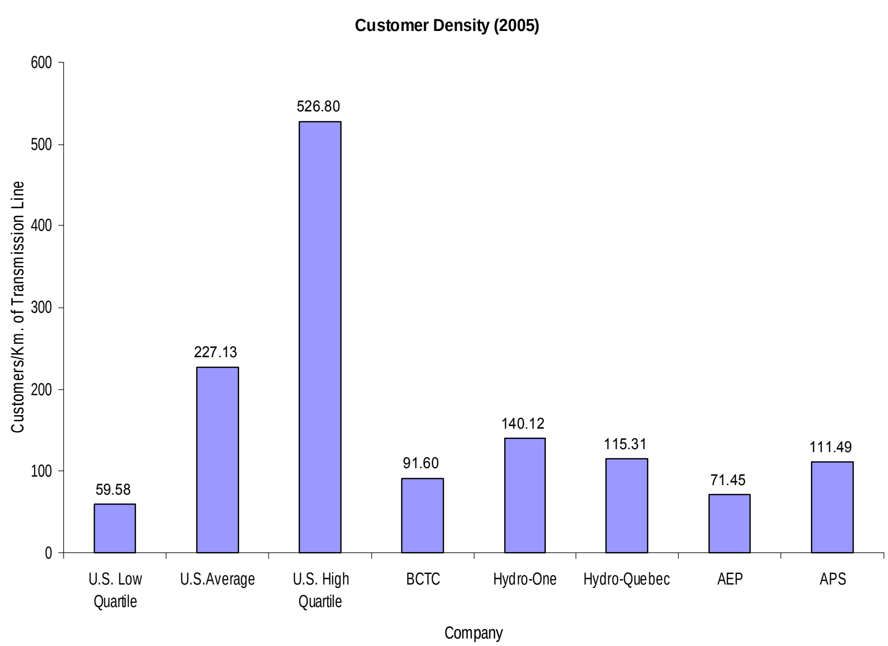


Figure 5-5

the customer density for BCTC is closer to that of Hydro One and Hydro Quebec than to the US average. (Note that we have adjusted the customer count for Hydro One to include all customers served by the Municipal Utilities served by Hydro One. This was done to ensure comparability to BCTC on this metric.) It stands out then, when we see that BCTC's cost position is well below the other Canadian companies on this measure. This suggests that BCTC is spending less per kilometer than would be expected. This could be the result of greater efficiency on the part of BCTC, greater asset intensity on the part of the Canadian companies, or an indication that BCTC has not been spending at levels consistent with the ongoing needs of the system.

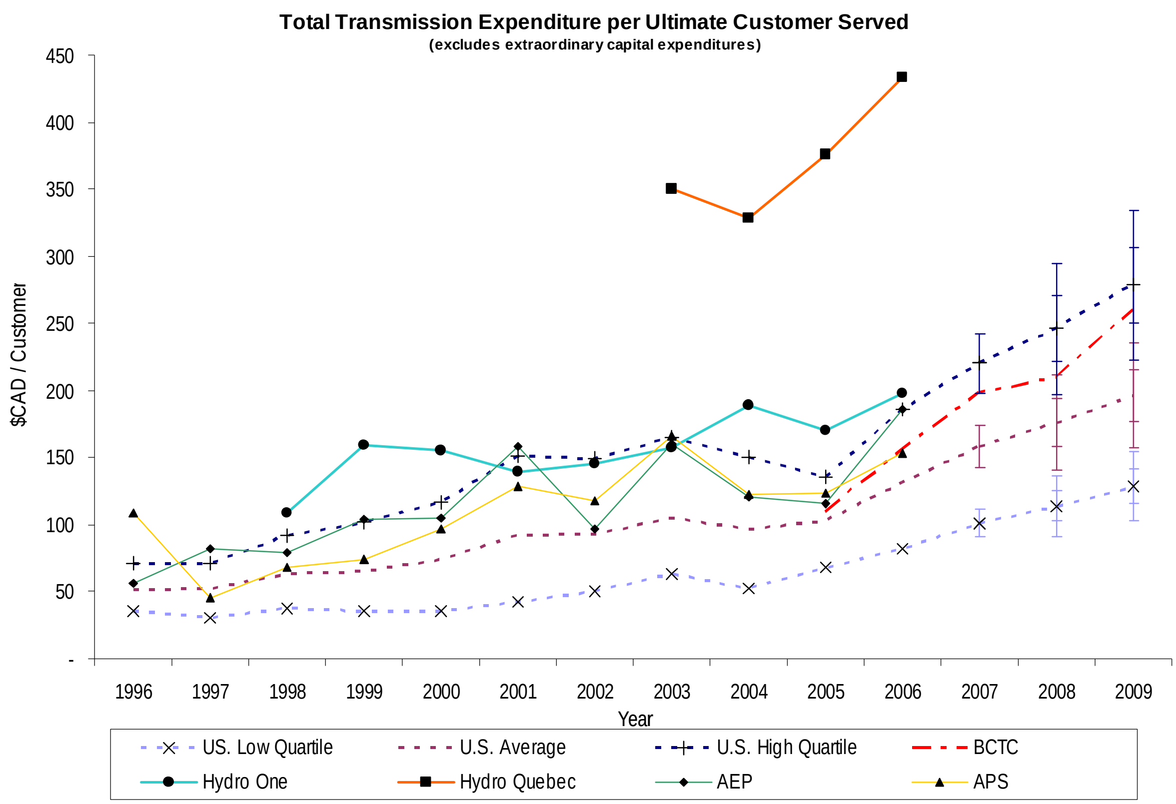


Figure 5-6

Spending Per Customer

Analysis of 'spending vs. total customers served' (Figure 5-6) suggests that BCTC's expenditures have grown, at a rate comparable to the industry. Its current spending level, as viewed from this measure, remains below AEP and the other major Canadian companies, and is on par with APS. Some of this can be understood from the previous discussion on customer density. (Note that we have adjusted the customer count for Hydro One as described above.) Systems with lower customer densities require more asset base per customer, which leads to a higher per customer investment level (this relationship is borne out in the analysis in Figure 5-7 below of asset base per customer). While BCTC's costs per customer increase over the analysis period, its current and projected levels are consistent with what we would expect to see among lower density systems making large system investments. Its per customer spending level is consistent with those of the proxies, reinforcing that the projected spending level per customer is reasonable.

The analysis in the charts above has revealed two common threads that warrant exploration. These are:

1. The relatively high cost position of the other two Canadian transmission companies
2. BCTC's and the industry's upward cost trend

In seeking to understand the higher cost position of the other Canadian companies, we noted that all of the charts above suggest that they are investing at higher rates than the other utilities. To explore this further we examined the relative investment level of asset intensity (the amount of asset per customer, or per km, they are building), Figure 5-7 and 5-8. In this analysis we used the total plant in service, this figure represents the total cost basis of the system, reflecting additions and deletions (retirements/removals). It is different from net book value as it does not reflect depreciation expense. We used this approach because of the significant difference in accounting practices between US and Canadian companies with regard to depreciation. Differences in depreciation lives, and standards for accelerated depreciation result in an inability to use net book value as a meaningful comparator between Canadian and US companies. Total plant in service also appears to have some variability between Canadian and US companies, but in general appears to be a more consistent method of assessing the total amount currently invested in the assets.

In Figures 5-7a and 5-7b we see BCTC's performance is consistent with the other lower

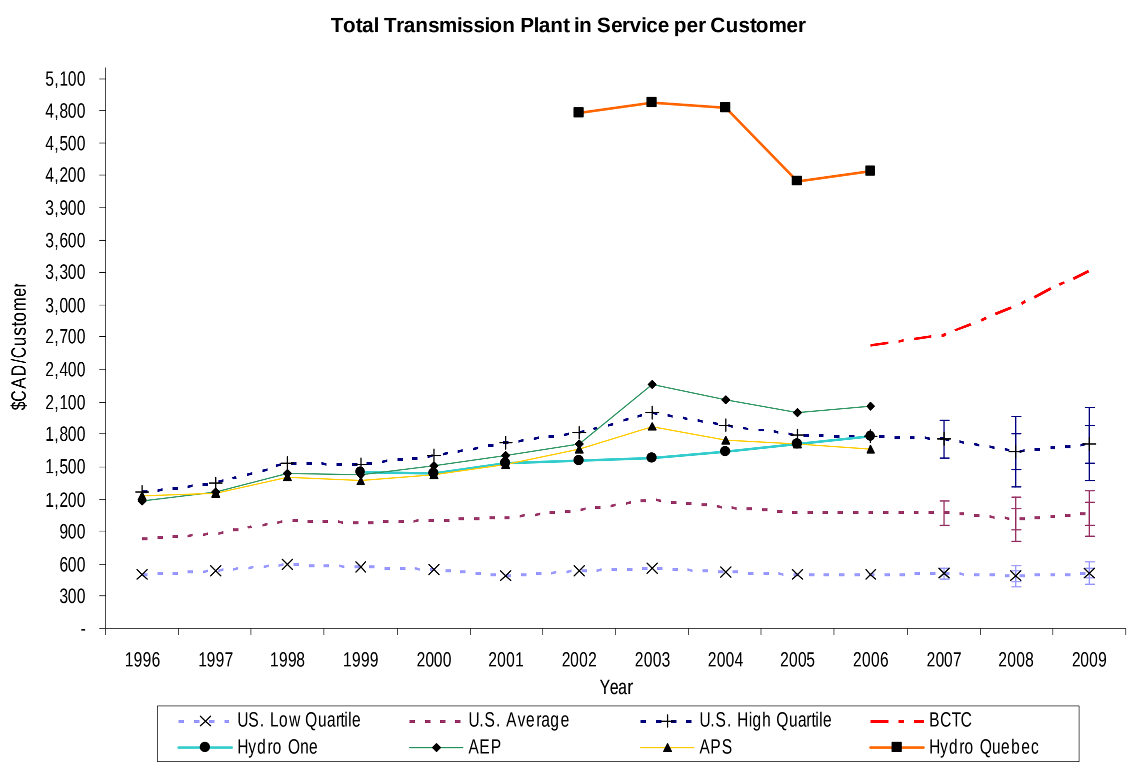


Figure 5-7a

density systems. On a per customer basis (Figure 5-7a) BCTC falls where we would expect, at the upper end of the range and above the proxies. Figure 5-7b highlights the level of investment per Km of transmission line. BCTC's position is as expected, slightly above the average and the proxies. Its position on both metrics is reflective of the customer density on

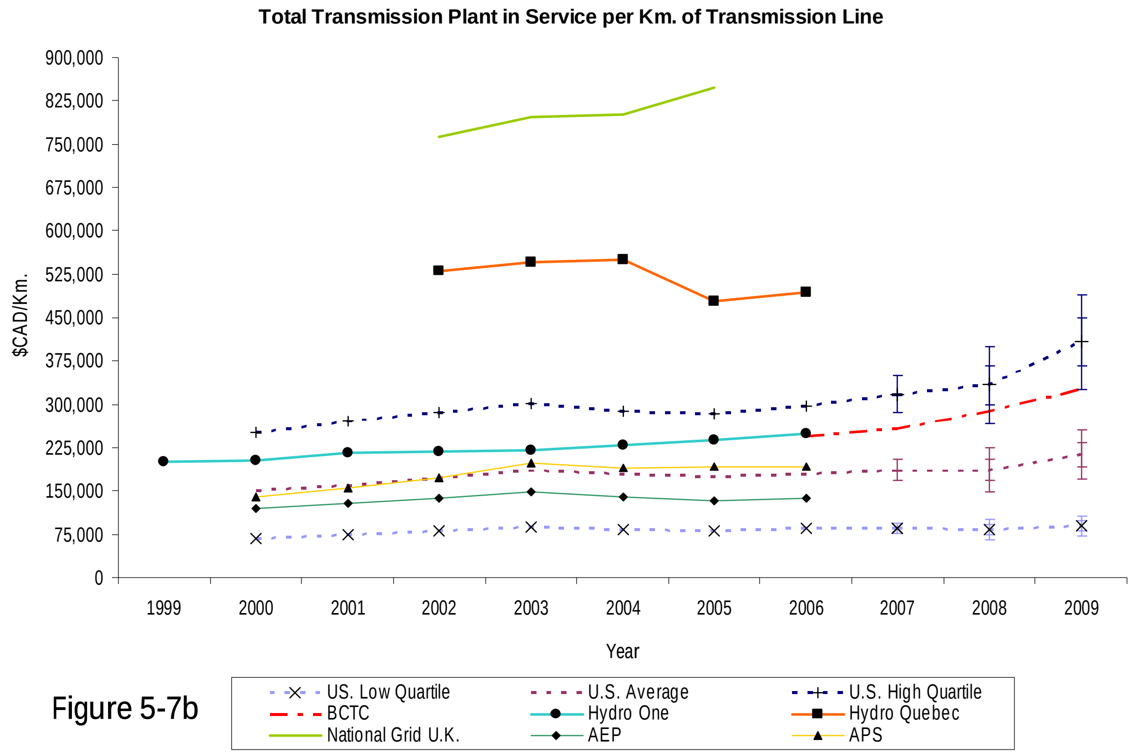


Figure 5-7b

its system and the higher dependence on radial components in transmission system (Transmission lines to more remote areas where there is not practical capability to network the system).

When comparing its investment level to the underlying asset base (Figure 5-8), BCTC falls below the mean of the lower quartile, which is well below expectations. This is significant as this is a measure of the level of reinvestment in the system.

Given the nature of AEP's system, its position in each of these three charts makes sense. Its transmission system serves far more than its native load. AEP serves hundreds of Municipal Utilities and Electric Cooperatives through its transmission system and the end use customers of these utilities do not feature in AEP's customer count. AEP also wheels a great deal of energy through its system for other utilities. Thus on a per customer basis we would expect AEP to be higher than average. On a per dollar of plant investment, we see that AEP appears to be benefiting from economies of scale in that its costs are lower than average.

BCTC's position on Figure 5-8 suggests that its reinvestment levels are below what is needed to sustain the underlying asset base.

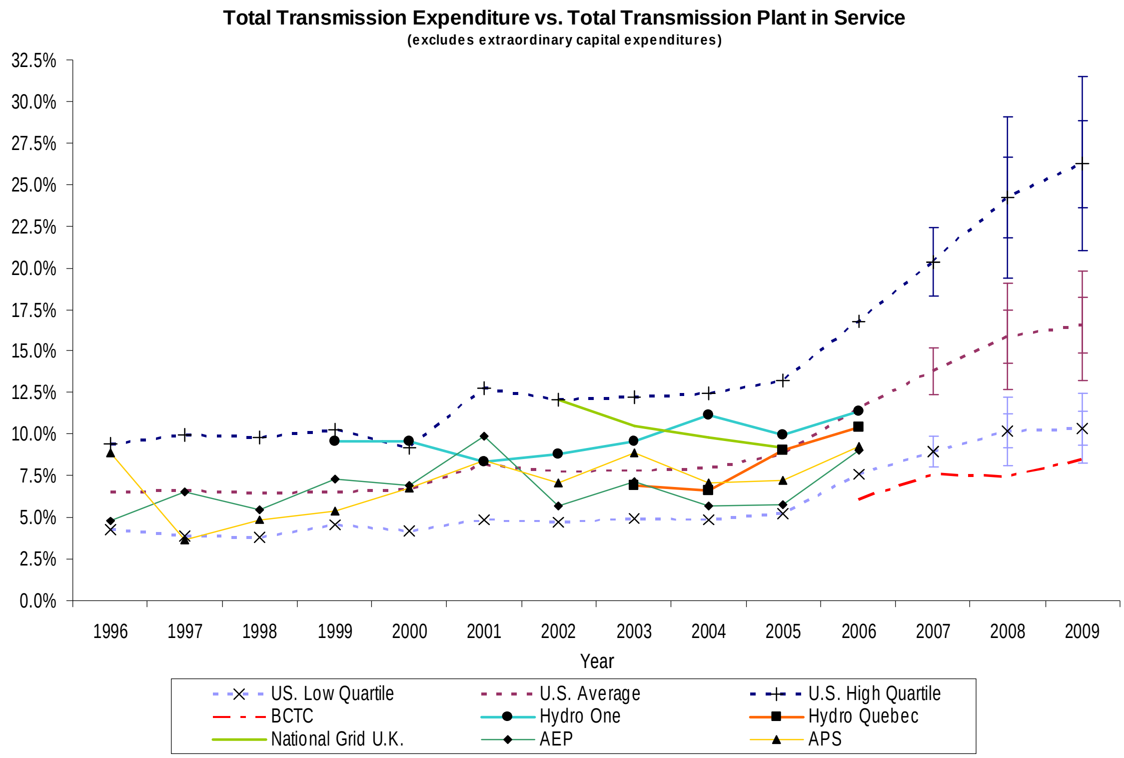


Figure 5-8

Hydro Quebec falls outside expectations in both asset base per customer and per Km. We would expect it to be higher on an asset base per customer, but not higher than AEP, or as far above the top quartile average as it appears. Hydro Quebec falls within expectation on a reinvestment per asset base. In the case of Hydro Quebec we have sought to ensure that all costs associated with investments outside Quebec have been removed from the analysis. It is possible that there has been a blending of the inside and outside Quebec investments in the financial reporting that we have used, which is not apparent. We identified and removed from the calculations investments outside Quebec representing hundreds of millions of dollars and do not believe that blending of investments alone could account for the position of HQ on these charts. This leads us to the conclusion that Hydro Quebec is investing in greater levels of plant than BCTC and other comparable utilities.

Normally this would be attributed to greater levels of redundancy and capacity in the system. However this hypothesis does not provide the full explanation. BCTC itself has a conservative planning and operating criteria for loading of its stations. It plans its stations (using a strict interpretation of the N-1 planning criteria) so that they are only loaded to 50% during the peak. This approach has been commonplace in the industry in the past and provides greater reliability and availability. Most US companies, however, have succumbed to the pressure to rely on their integrated networks and interties to other utilities for reliability and tend to load their stations to much higher levels, relying on emergency ratings and an interconnected network (BCTC has fewer such connections and must be more self reliant). That being the case, we would expect that since BCTC had retained the conservative methodology, it would show up as having greater asset investment per customer than its peers. It does not. Its costs are comparable to similar US systems, though its US counter parts have not held as strongly to the conservative loading criteria. Therefore, if redundancy and capacity are the primary cause for the higher cost position of the other Canadian companies, it can only be that they are adding significantly greater levels of redundancy than is BCTC, or that BCTC has been under investing. In the case of higher investment levels for the other Canadian companies, some of this may be in support of redundancy requirements for nuclear plants but that alone would not account for the difference.

As we discussed above, greater redundancy, while adding reliability and capacity benefits, adds to the cost of the system. It is important to note that it is not only the first cost where the impact is felt. Systems with very high levels of redundancy see the impact in increased maintenance and replacement costs for the additional assets. By their nature, systems with greater redundancy have more assets, and often have more complex system configurations, both of which add to the cost to sustain the system.

This leads us to our second area for exploration. In most of the cases above, BCTC falls in the quartile we would expect. Knowing that BCTC's standards result in a greater level of capacity and redundancy than many of its peers, we expected it to fall in a cost position above companies like APS and AEP. Our concern is that its position, in several cases, is lower within that quartile than we would have expected relative to its US peers and to the proxies (it is well below expectation on the level of reinvestment figure 5-8).

All of this is most evident in the earlier years of the analysis. While it is difficult to separate accounting data from earlier periods in order to make a straight comparison, we note that BCTC has been seeking higher levels of investment in recent periods than was its previous norm. Given that the current spending levels represent a reasonably sharp rise, then the earlier levels appear to have been too low.

With a level of spending in earlier periods below the level necessary to sustain the asset base, we would expect to see an increase in the rate of growth in corrective maintenance and asset replacements. While these both would grow anyway as a function of the age/condition of the asset base, they would also grow at a faster rate as a result of lower spending in earlier periods.

System Performance

Having made comparisons to the industry on a cost basis, we also need to look to comparisons of reliability. When making reliability comparisons for transmission systems, there are two different types of measures. The first is reliability, as seen by key stakeholders. For end use customers this is outage events and durations. For generators this is system capacity and availability. For Provincial and Regional Reliability Organizations it is system adequacy and system security, in which both outages and availability are significant factors.

The second type of measure is often more illuminating. It is the underlying failure rate of major equipment. As was highlighted in the discussion of better performing companies, equipment failure rates can be very telling as leading indicators of all the other reliability measures. Equipment failure rates also tend to have a closer relationship to system condition than many of the standard reliability measures, such as TSAIDI and TSAIFI, which are useful as measures of customer experience, but are much less direct indicators of system condition.

Using TSAIDI as an illustration, we recognize that TSAIDI is driven first by the number and the magnitude of the outages e.g. how many outages and how many customers are affected by each outage. It is also driven by the time it takes to restore power to the affected customers, whether done through remote switching or through dispatching of crews to an outage location. To make a performance assessment of a company with a low TSAIDI, one has to know if the superior performance comes through elimination of outage events; as a result of investments in a large integrated network (transmission or distribution) that support automatic switching to restore power; or if it comes as the result of more responsive restoration efforts on the part of field crews. In the end, such an assessment often cannot provide an adequate indication of the underlying condition of the full system.

Equipment failure rate trends on the other hand bring us a much closer indicator of the underlying asset condition. There are very few transmission assets for which in-service failure is the preferred replacement strategy. As mentioned previously, the industry rule of thumb is that reactive replacement of assets is at least three times more costly than proactive replacement. It is true that for a few assets that are non-critical, in-service failures may be acceptable and may not result in a premium cost, but for critical assets the ratio can be much higher than three times.

In examining equipment failure rates, we looked first to power transformers. Power transformers are the single most expensive and critical component in the transmission grid. They are also more susceptible to failure than many of the other components on the system and so provide a good indication of the effectiveness of both maintenance investment and maintenance practices.

In looking at the performance history of the industry, we used a combination of publicly available sources and a proprietary database of international transmission companies.

Figure 5-9 tracks failure rates for North American companies and projects a growth in failure rates (shown in red) in the coming years as more of the transformer populations reach the end of their design life. The growing failure rate is a combination of the significant investments made in the 1970s, discussed previously, and greater stress placed on the transformer assets in today's more highly integrated transmission grid.

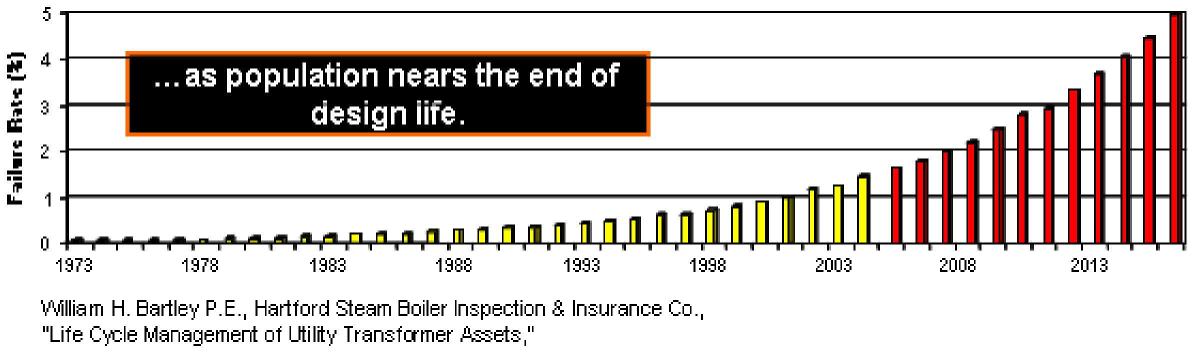


Figure 5-9

Figure 5-10 depicts the transformer failure rates for a group of transmission companies from five continents and 18 countries (left hand chart). BCTC appears to be well below average against the international group of companies and at level far below what we would expect from Figure 5-9 above, looking only at the North American companies.

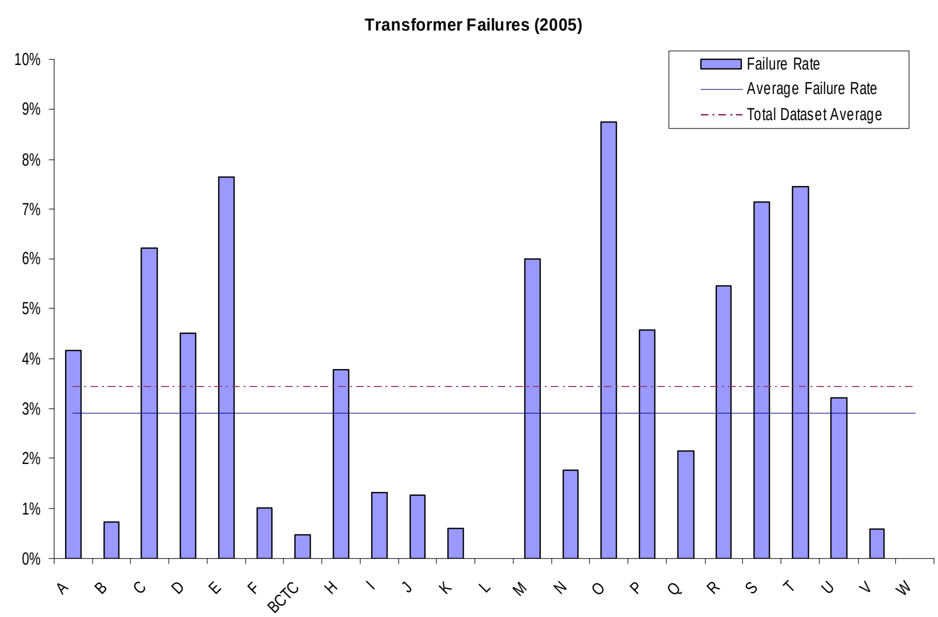


Figure 5-10

Figure 5-11 shows the BCTC transformer failure rate over time. It is clear that BCTC has been experiencing significantly lower failure rates than many of its peers in the industry for several years. This appears to indicate to us either a highly effective maintenance strategy/program and a well targeted replacement program, or a much younger system than in the comparison companies

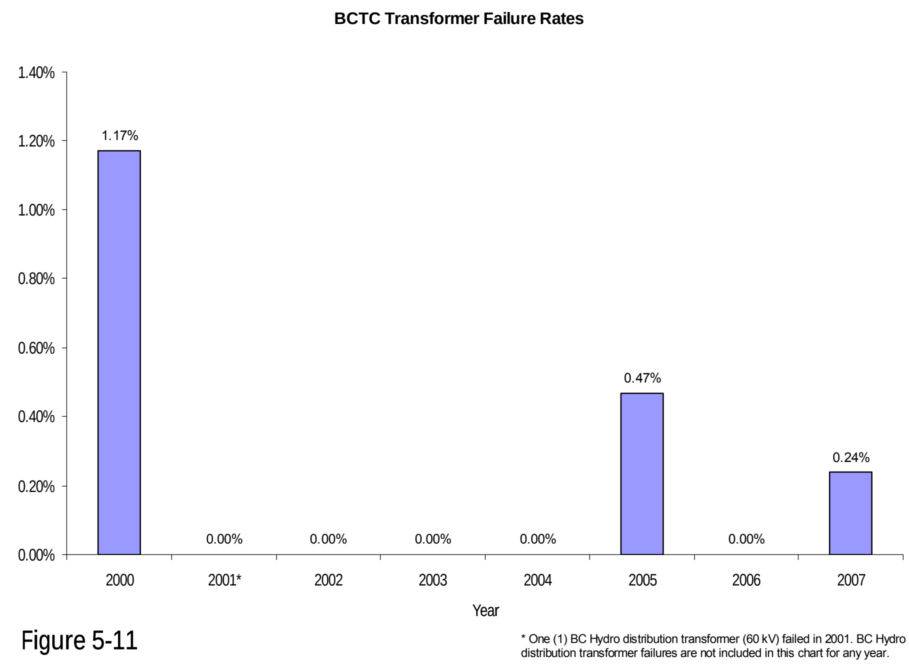


Figure 5-11

Figure 5-12 examines failure rates of circuit breakers, among the same group of transmission companies. Again we see that BCTC's failure rate is well below the average of its peers. In the case of circuit breakers, however, BCTC's trend is rising (Figure 5-13). Though BCTC's rate of breaker failures has more than tripled in the last five years, its current overall rate is still only half that of the average of its peers. While we are not alarmed by the rising failure rates, we do recognize it as a common sign of assets that are nearing their end of life.

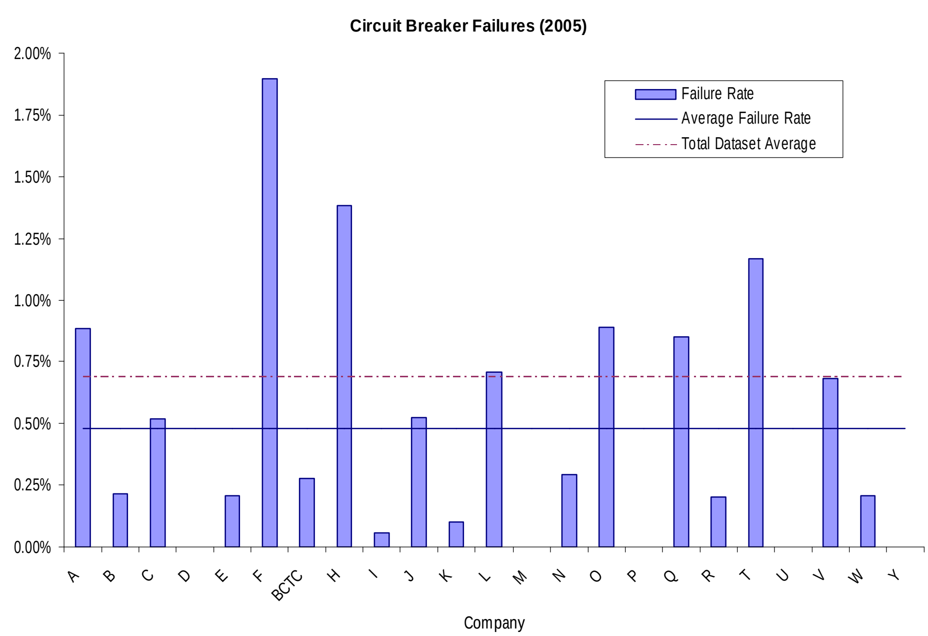


Figure 5-12

Given the rising failure rates for breakers, we examined the age demographics of BCTC's power transformers and circuit breakers and compared them to those of its peers (Figures 5-14 and 5-15).

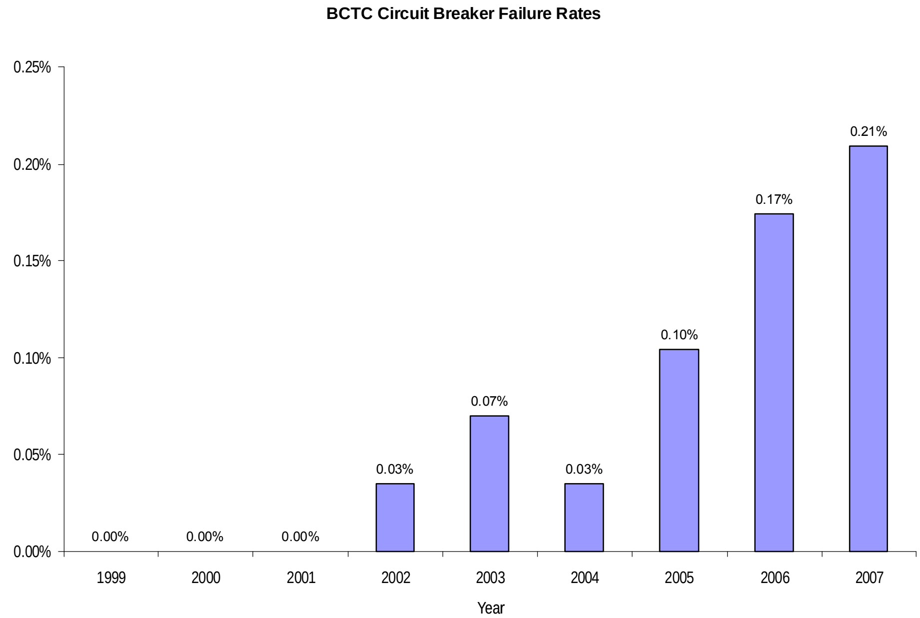


Figure 5-13

This analysis is telling in several respects. The first is that BCTC's transformer and breaker fleets have fewer very old assets than do its peers. This could contribute to BCTC's lower failure rates. It is likely due to the combination of the build out of the BCTC system and BCTC's replacement standards for breakers and transformers. BCTC replaces assets at the

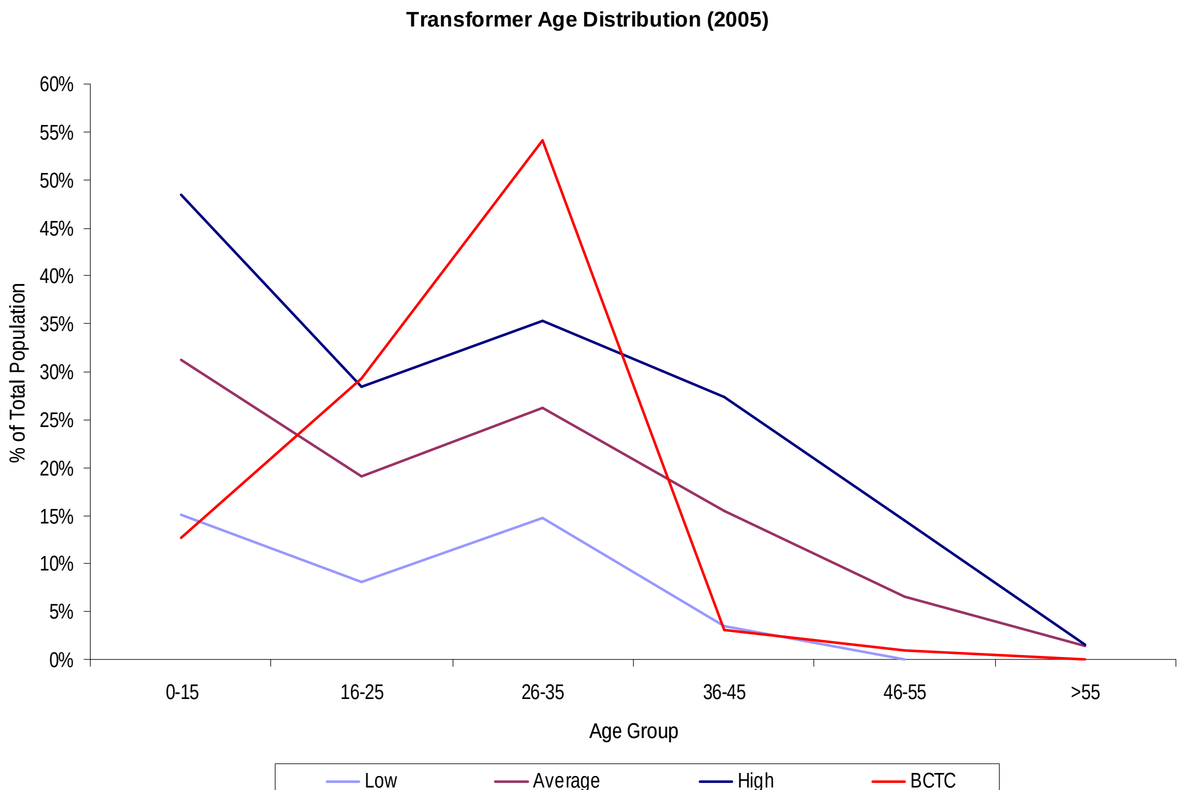


Figure 5-14

point where the continued cost of maintenance outweighs the cost of replacement, or when the criticality of the asset is too high to risk an in-service failure due to condition. That BCTC is making sound decisions in this regard is evident to us. Given what we have seen in the analysis of cost performance and the lower failure rates, it appears that BCTC has been making prudent decisions on timing of replacements.

More striking is the spike in the demographic profile. Over 50% of BCTC's transformers and breakers are over 25 years old, with the vast majority being in the 25-36 year range. Circuit

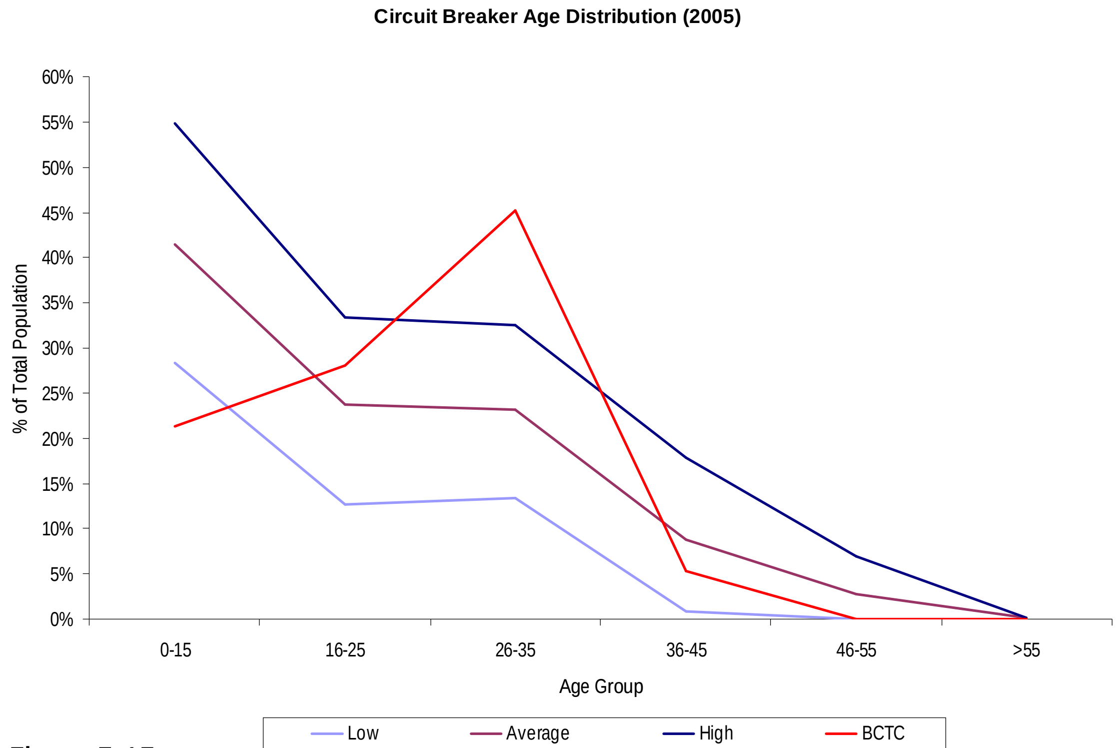


Figure 5-15

Breakers have an expected life of approximately 40 years. Given that some reach end of life early and others late, the age range expectation is 35-45 years. There are a large number of 500kV breakers in the front edge of this age group. This represents a significant replacement wave that BCTC will be facing in the next ten years in both cost and complexity. While many of these assets will continue to operate for at least that ten year period and maybe beyond, we believe that BCTC is starting to see the front edge of the replacement wave. Transformers and breakers are not the only assets involved in this replacement wave. Most of the ancillary equipment (disconnect switches, insulators, PTs, CTs, relays, etc) is of the same vintage as the transformers and breakers, having been installed as part of the initial installation. Many of these components have different mean lives (some shorter and some a little longer) than the breaker or transformer with which they are associated. However it is standard practice to replace most, if not all, of these components when the major equipment is being replaced, as many are physically tied to the major equipment items.

Figure 5-16 is taken from analysis done by BCTC to identify the source of the growth in the level of corrective maintenance spending. This analysis, when combined with the age demographics for BCTC and its peers, and the failure rates experienced by BCTC's peers who are ahead of BCTC on the age curve, all serve to reinforce the concern that BCTC will need to begin replacing almost half of its breaker and transformer fleet over the next decade. This is a significant undertaking and will need to be done while simultaneously responding to growth needs and maintaining stable system performance level. This is especially significant when considering that a number of the replacements will be on the 500kV system.

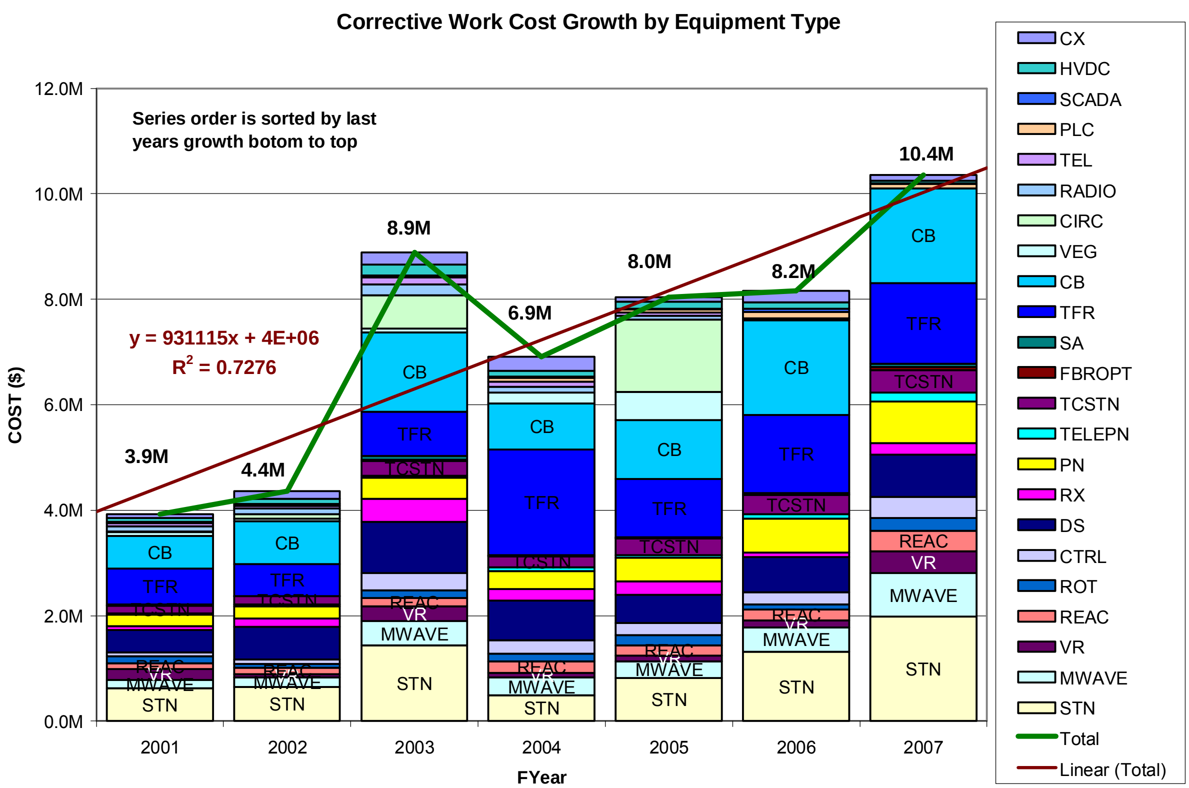


Figure 5-16

The final note from our age demographics analysis is that many of BCTC's peers appear to have begun shaving their replacement peaks. As discussed earlier, many companies have sought to find the optimal point in the cost and practicality of asset replacement programs. Overall the age profiles of its peers are flatter than BCTC's (although most of them have seen a significant spike in the growth of their systems as evidenced by the large percentage of new assets in the system). For most this is the result of deliberate steps taken to avoid either rate shock or an unachievable workload level. In either case, this is something that BCTC should be considering as it develops its long-term asset strategy and its long range spending plan.

Current State and Projections

Based both on the information that we have reviewed for BCTC and our knowledge of the industry, we believe that BCTC's system condition is comparable to many of the other utilities in North America. The age demographics of the assets are consistent with a great many of its US counterparts, though BCTC appears to have a higher concentration of assets over 25 years of age. BCTC is currently experiencing failure rates for major equipment below those of most of its peers but its corrective maintenance workload is rising steadily. Based on our analysis, we would expect to see an increase, over the next several years, in the number of BCTC's major and ancillary assets that need to be replaced due to end of life.

Gaps

Based on relative age and failure analysis and BCTC's spending levels in comparison to its peers, we see several indications that BCTC's current spending levels may not be sufficient to allow it to maintain the current level of system performance. The current spending levels appear to be below many of its peers. While BCTC appears to have done well at extending the useful life of many of its assets, the age demographics of the system, and the experience of other utilities, strongly suggest that BCTC could see a sharp climb in the number of assets requiring replacement over the next ten years. We do not believe that current spending levels will support the increase in the end of life replacements that will be required over the next 10 years.

In addition to the potential wave of replacements required, we do not believe that the current or projected spending levels fully reflect some externalities now being imposed on the system and BCTC. Examples of these include:

- WECC mandatory standards will result in more strict and stringent interpretation of the previous standards. The new standards are also accompanied by significant financial penalties for failure to meet the standards. Prior to this the standards were used as guidelines, leaving companies to use business judgment on applying the standards to any given investment decision. Under the new application of the standards, they are deterministic and are to be applied regardless of the probability of occurrence of an event. To the extent the BCUC adopts the new standards; BCTC will need to ensure that its plans are adjusted as the full implications of the standards become clearer through time and implementation.

- BCTC is facing a pine beetle infestation across its service territory. Similar infestations exist in many other areas of North America. The experience of many other utilities suggests that BCTC will see a significant increase in its cost for either:
    - Proactive removal of infested trees along/adjacent to its rights of way (ROW); or
    - Reactive removal of dead trees that have fallen, or are in danger of falling, into the ROW; or
    - Fines or penalties associated with failure to ensure the integrity of the ROW

- Legislation under which BC Hydro had historically been exempted and now which specifically applies to all utilities, including:
    - Species at Risk
    - Wild Fire Mitigation

- Changes in the level of Risk that is considered acceptable for:
    - Seismic Risk and recovery times post event
        - Some of the system components would be rendered inoperable in the event of a significant seismic event (over 50% of BCTC's 500kV breakers are live tank design which is not capable of withstanding significant seismic events)
    - Severe weather outside current and historic system design criteria
        - Flooding
        - Ice and Snow loading

BCTC will need to ensure that its obligations resulting from these and other such external events and changes in the acceptable levels of risk, are adequately reflected in its funding plans. Failing to do so will result in either emergency funding requests, or a diversion of funding from maintaining system performance.

Asset Management Processes and Capabilities

In undertaking our assessment of BCTC's processes and capabilities, we conducted interviews of Asset Management personnel ranging from the Executive, to engineers and analysts working within the group. We also collected and reviewed numerous studies, reports and analyses that had been previously prepared by the Asset Management team. We conducted a review of the tools currently in use, as well as an examination of the underlying data sources. Based on this information, we were able to compare BCTC to other Asset Management organizations, and specifically to make the comparison to transmission utilities that have demonstrated superior performance over sustained periods of time.

Overall we concluded that the BCTC Asset Management organization is an Industry "Good" Performer. Like all organizations it has areas in which it excels, and areas in which it should seek to improve. These are discussed in more detail in the following paragraphs.

Organization

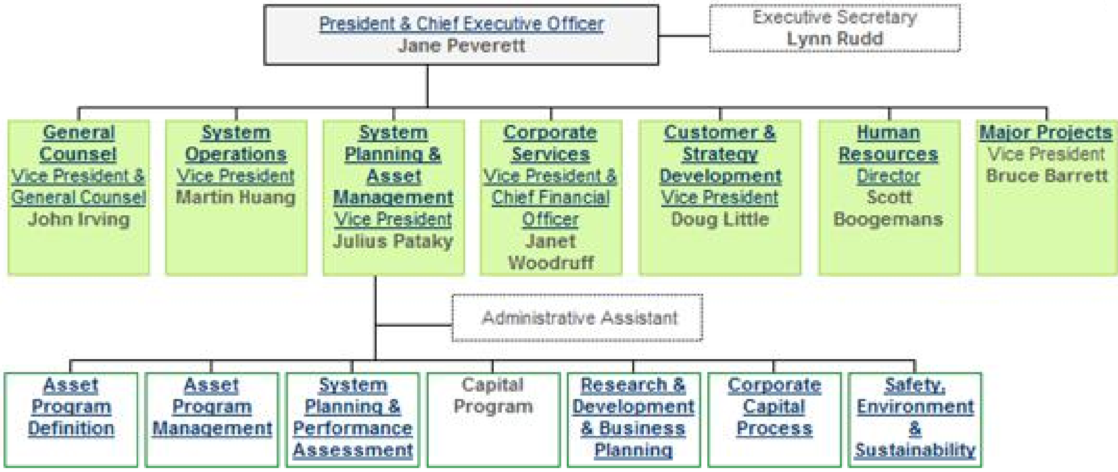


Figure 5-17

BCTC's Asset Management organization structure (Figure 5-17) aligns with the historical BCH/BCTC view of spending, rather than the process or asset view most often found in Asset Management organizations.

The main groups within the BCTC Asset Management organization are: System Planning and Performance Assessment, which focuses on system planning and growth spending; Asset Program Definition, which focuses on the definition and development of the system standards and the investments that comprise the Sustain Capital and OMA spending; and Asset Program Management which oversees the execution of all of the work that is generated by either group. There are also other groups that serve to enable and support the Asset Management organization. These include: Corporate Capital Process; Capital Program; Research & Development and Business Planning; and Safety, Environment & Sustainability.

All design engineering and all of the actual work on the assets is done under contract by BC Hydro or other third party contractors. BCTC does not conduct any field work, other than inspections of the assets or inspections of work being done on the system. This structure is not unique. While it is not commonplace in the US and Canada, it is well established in several countries in Europe, Australia and New Zealand. This situation creates an interesting dynamic for BCTC, as BCH is both the main "customer" for its work and also its largest service provider. This will present continuing challenges for BCTC as it works to develop a set of relationships in which parts of its organization are buyers of services from BCH and others are service providers to BCH. Our experience suggests that getting both these relationships right will be important, but cannot work unless both BCTC and BCH recognize that they are *Service Partners* in delivering superior results for the customer and that neither can succeed without the other.

Though the organization functions reasonably well, it is organized around spending categories rather than to support the underlying processes. Often such a functional alignment can create silos and siloed thinking. Sound Asset Management principles eschew functional alignment and silos in favor of a process orientation and recognition that the system is the asset being managed. Analysis of better performing organizations has revealed that process orientation, and a ”One System – One Asset” view tends to engender greater innovation and collaboration, resulting in more effective decisions.

With regard to Vision, Goals, Accountabilities and Philosophy, our assessment of BCTC is mixed. There is currently a clear vision and an understanding of the goals. These, however are more narrowly focused than we have seen in other comparable transmission organizations. The vision and goals for the system, as seen by Asset Management personnel, tend to focus on delivering consistent reliability (maintain current levels) at level costs. Given the long lead nature of transmission system development and transmission's role as the enabler of economic development and sufficient generation supply network, we would expect to see a clear articulation of the future of the system in terms of growth, technology and expected role. We believe that BCTC should be more explicit in creating and articulating the vision of the system 10 to 20 years into the future so that it ensures that its investments in the next five years are supporting the future role of the system.

Within the Asset Management organization, the accountabilities for each group are clear and well understood, even at the individual performer level. However, the accountabilities appear to be more narrowly focused and aligned with spending categories rather than with process outcomes or achieving an overall system result. The accountabilities need to evolve toward greater collaboration and a greater focus on the overall business objectives rather than individual or functional group objectives.

Process

BCTC's *Asset Management processes* are well laid out and well documented. They are clearly understood within each of the groups within the Asset Management organization. The processes incorporate many of the same characteristics of the processes at work in other AM organizations, particularly Best Performing organizations. The BCTC processes rely both on information and knowledge of the practitioners to produce the results, and BCTC has used the combination to good effect. It has married the knowledge and insight of its Asset Management personnel with improving data and information, as well as decision support tools.

It is clear that BCTC's processes are efficient and effective. The staff compliment in the BCTC organization is modest in comparison to other Asset Management organizations for large transmission companies. BCTC's replacement spending breakdown (percent corrective, interval based, condition based and criticality based are generally in keeping with the better performing asset management companies. BCTC has been making effective decisions on repair/replace and has been delivering a relatively stable reliability level in spite of its aging asset base and an increase in corrective type work. In our experience this is only produced through effective execution of sound processes by skilled personnel. BCTC has a good performance measurement framework in place. It has a clear understanding of the performance of the assets in terms of cost and reliability. It uses the performance management tools and process as an effective guide for course corrections and in laying out the architecture for the overall system plan. BCTC continues to work to improve the effectiveness of its processes and decision making.

However, we believe that there is room for additional improvement. BCTC's processes appear to have been developed to produce results aligned with the historical view of Growth and Sustain spending. The processes as currently followed, do not call for collaboration or reconciliation of cross category spending until relatively late in the investment development stage. Other Asset Management organizations, especially better performing organizations, tend to ignore the Growth and Sustain distinction in the early stages of development. Instead they tend to look at the overall system needs in terms of performance, capacity and customer expectations. The process then is used to identify the range of alternatives that could be employed to meet all of the objectives, without limitations of spending categories. From these the most effective combinations are selected and rationalized within spending limitations.

By using this approach in their process, better performing AM organizations have found that the solutions produced tend to be better, in terms of overall cost and in system performance results. In effect they have released the Asset Management personnel from the artificial constraints of organizational boundaries and freed them to find the most effective solutions. Most have found that to be an effective transmission provider they need to have a collaborative relationship with the transmission dependent entities (generators and distributors). They have also greatly improved the efficiency of the spending plan by collapsing Growth and Sustain needs into more comprehensive long term plans. These comprehensive plans tend to require lower overall cost to the customer and can also represent more levelized costs, ensuring that customers are insulated as much as possible from periodic spikes in rates.

BCTC's *Performance Management process* is relatively efficient but is used for monitoring project work with mixed results. BCTC understands the performance of the assets and the performance of its contract resources. It uses the information in discussions with its service providers to improve the level of field performance, using the information from its process and systems as its fact base. These fact based discussions with contract resources appear to have produced improvements in several aspects of field performance. However, BCTC's performance management process tends to be somewhat more limited than that of other Asset Management organizations, especially in terms of the level of performance information it has access to and can use with its contract resources. For example, BCTC does not have detailed information regarding the responsiveness of crews responding to forced outages (e.g. Dispatch, Journey, and Repair times for each event). Many other Asset Management organizations would be analyzing the details of the response times to determine if there were improvements that could be made in the response and restoration process that would result in greater improvements in SAIDI than those represented in the asset spending plan. In many cases, improvements in the effectiveness of the field processes can produce the most cost effective improvements in system performance as seen by the customers. In addition, such analysis often reveals improvements in the asset design that can facilitate improvements in restoration efforts. In this case, we do not believe that BCTC is in a position to take full advantage of the range of improvements that may be available.

Looking at the evolution of BCTC's process and at its current decision making approach, it is clear that BCTC is moving in the direction of greater integration of the process and a stronger application of the "One Asset" philosophy. We believe that BCTC sees the gaps, including those significant gaps mentioned above, and has a genuine intention to close them.

People

BCTC's Asset Management organization is on par with many of its peers. The team, though relatively small in number, is well educated, experienced and knowledgeable. The knowledge and education level of the organization has allowed it to develop sophisticated approaches to identifying and solving many problems that face Asset Managers. An example of this is BCTC's current approach to maintenance of circuit breakers and power transformers.

BCTC currently uses Indus Passport as the tool for managing and scheduling maintenance on breakers and transformers. Within the industry, many asset managers consider this tool to be a fairly unsophisticated maintenance management system. This is because Passport generally employs time based triggers (rather than asset condition) to determine when maintenance is required on any given system component, and then generates a work order to initiate the work. Using the knowledge and insight within the organization, BCTC has been able to transform this simple tool into a condition based maintenance/preventive maintenance optimization tool.

Through rigorous analysis, BCTC has been able to establish that, for its system, the major driver of failures for both breakers and power transformers is the number of operations. For circuit breakers, BCTC has been able to isolate this to fault operations and for power transformers it has isolated it to load tap changer operations. While the algorithm used is appropriately unique to the BCTC system, the underlying approach is consistent with better performing Asset Management companies. Combining this analysis with age information, BCTC has been able to establish condition based maintenance triggers for each circuit breaker and power transformer in the system. By tying Passport to the operational information, BCTC can track the actual number of operations and adjust the individual maintenance plans to reflect actual changes in condition. BCTC can also conduct scenario analysis looking at changes in overall system performance and predict increases and decreases in maintenance cost and changes in failure rates. This information then is used to help determine the optimal replacement regime for different breaker types and for power transformers. In essence BCTC can estimate when it will cross the tipping point where the stream of preventive maintenance costs outweighs the cost of replacement, or where the risk of failure of a critically important asset outweighs the savings from deferring replacement.

BCTC does not have this level of insight for its entire asset base, nor, we should point out, do most Asset Management organizations, even the better performers. BCTC's approach is logical and consistent with best performers, in that it has focused on the most costly and most critical components in its system first. The company is in the process of applying this technique to other assets for which operations, rather than time, is a major driver of condition.

A second example of asset management innovation is the way in which BCTC analyzes the criticality of the delivery points on its system. BCTC examines the reliability impact of

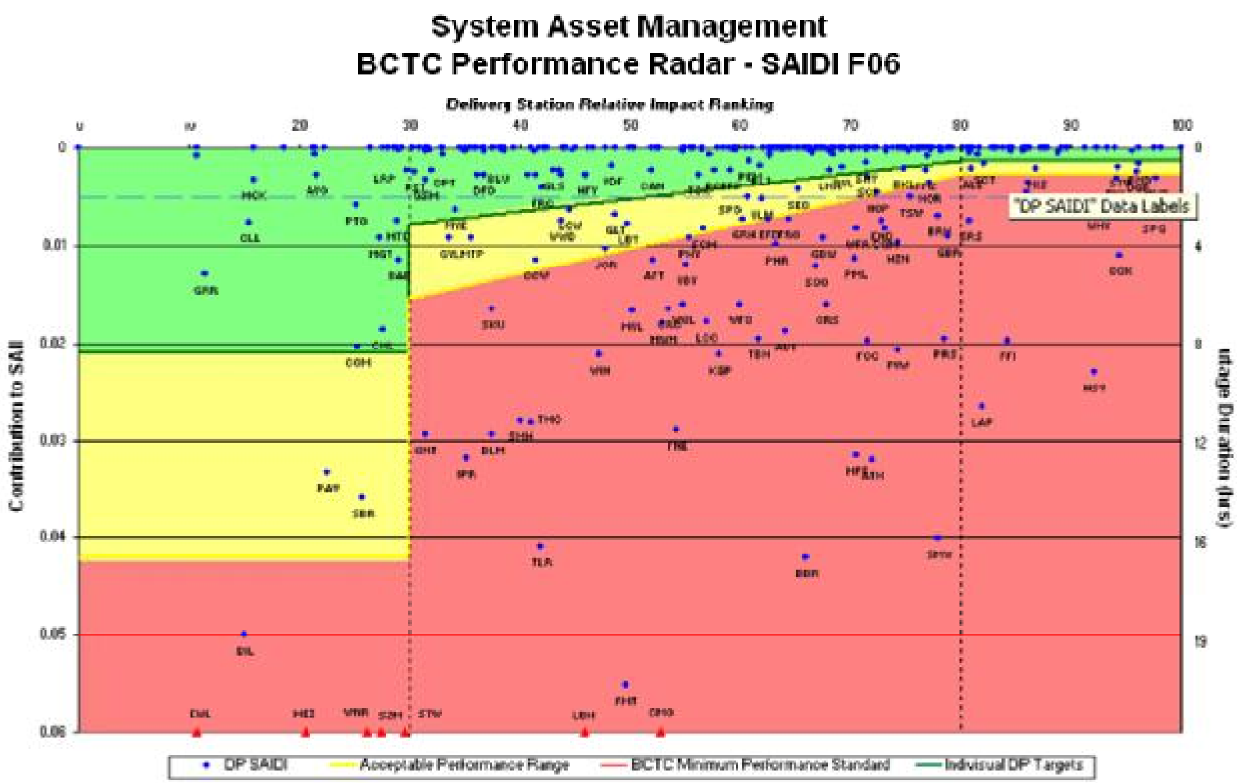


Figure 5-18

outages on every delivery point and matches these with the criticality of load served by that delivery point (e.g. hospitals, police, fire, etc), illustrated in Figure 5-18. BCTC uses this analysis to compare the actual reliability level of any delivery point to its specific target (based on criticality and reliability impact to customers). BCTC combines this analysis with other factors in establishing its spending priorities.

The methodology that BCTC uses is logical, sophisticated and consistent with those employed by leading Asset Management organizations. It is appropriately sophisticated (to be able to deal with complex customer tradeoffs) and a very useful construct. It demonstrates an understanding of the BCH customer reliability concerns, as well as transmission system integrity. Its development, necessarily, involved a broad group of stakeholders and input from many different groups within BCTC and BCH.

We believe that these examples highlight BCTC's ability to create a team orientation to problem solving and to balance business and technical results.

While we are impressed with BCTC's capabilities and approach to asset management, we did note several improvement opportunities. First, when we reviewed the analysis that BCTC undertakes, including the examples above, we noticed a pattern of very heavy analytical rigor and the desire for precision or accuracy. There appears to be an unspoken drive to ensure that every decision be "correct". This drive toward accuracy and rigor is prudent and appropriate to a point, but in excess it can begin to inhibit decision making and impede action in the organization. There is also a sense that the need for precision is high, in part because the BCUC expects BCTC to be able to provide definitive projections of cost and performance.

As part of its evolution and growth in its Asset Management capabilities, BCTC will need to gain a better level of acceptance for making decisions based on the best information and insight available. High performing Asset Management organizations recognize in hindsight, that most of their decisions could have been better. This hindsight comes generally as a result of better information, or better methodologies being developed than were available at the time the original decision was made. The very best performing organizations use such hindsight to their advantage. Rather than criticizing the earlier decisions, they use them to illuminate the blind spots that existed when the decisions were made. With such blind spots fully in view and understood, Asset Managers are in a position to see where those blind spots could have also influenced decisions over which there is still the opportunity to improve. They also use them to help identify and remove other existing, yet unseen blind spots.

A culture of perfection and a culture of continuous learning are generally not compatible. In other organizations, we have seen a culture of perfection stifle the ability of the organization to learn and improve. While we do not think that is currently the case within BCTC, we do believe that the ingredients for a perfection culture are present and that BCTC needs to work to reinforce a culture oriented to learning from past decisions and improving upon them.

A second significant opportunity lies in the indications of self limiting behaviors that we saw in our discussion with the Asset Management organization personnel. Common among many organizations, self limiting behavior exists when personnel believe that there is only room for the basic plan and therefore they do not put forward ideas that may go beyond the traditional plan, regardless of their ultimate benefit level. The perceived limit can be either budgetary in nature (not enough funding for anything but the basics) or cultural (no tolerance for innovative ideas). It also occurs when there is a strong orientation to traditional approaches or rigid views on how problems must be solved. As an example, we often find companies where there is a view that certain problems are “capital” problems and others are “OMA”. For leading asset managers, a problem is a problem and they seek to find the best solution. It is the solution, then, that defines the amount of capital or OMA, not the problem itself. We believe that perceptions exist within BCTC that the company must adhere to a fairly rigid view of spend categories as the source for solutions and that at the senior level there is little support for anything out of the traditional approach.

A third opportunity involves diversity of input, a common characteristic of Best Performing Asset Management organizations. Better performers tend to reach out to field, engineering and operations personnel for input into problem solving and in critique of their plans. In essence better performing Asset Management organizations seek to gain as many different perspectives as practical, in effect surrounding the problem. With diversity of input they see the situation more fully and can respond with a more effective solution. The structure and existing culture within BCTC do not foster this approach. Within the Asset Management organization the structure, processes and accountabilities tend to focus people internally within their work groups rather than outwardly for external input. This is compounded by the interface that exists between BCTC and BCH. The nature of the relationship creates a perspective of BCH as the Customer or as the Contractor, rather than as a partner in delivering on the plan. As such there appears to be a hesitancy to involve BCH personnel in much more than root cause analysis of failures and post project critiques. We believe that these artificial barriers between internal groups and between BCTC and BCH could be depriving the Asset Management organization of valuable input and insight from the people carrying out work on the assets. As was described in earlier chapters, this is a common phenomenon in newly formed asset management groups. Better performing organizations have found ways to create a partnership without undermining the contractual nature of the relationship with the owner and service providers.

In summary, BCTC appears to be following the trend of other companies as it evolves in its Asset Management capabilities. Most companies have found the cultural/people transitions to be the most challenging. Clearly BCTC has avoided many of the pitfalls and needs to continue its work in this area to ensure that the organization continues its track record of producing sound, reliable and credible results.

Technology

In terms of the development and use of tools, BCTC is similar to most Good Practice utilities. It has tools in each of the domains identified in Figure 5-19, below. In some areas BCTC is ahead of many utilities in the industry. Examples of this have been discussed earlier in the report and involve the tools and frameworks used to assess the criticality of equipment and delivery points; and the tools used in determining the timing of maintenance for breakers and transformers. BCTC has also done very good work on creating selective links between data sources and the tools, eliminating the need for manual data entry. BCTC is also on par with, or ahead of, most utilities in terms of its system planning and growth modeling tools.

In recent years BCTC has developed a large number of tools in-house to support its needs.

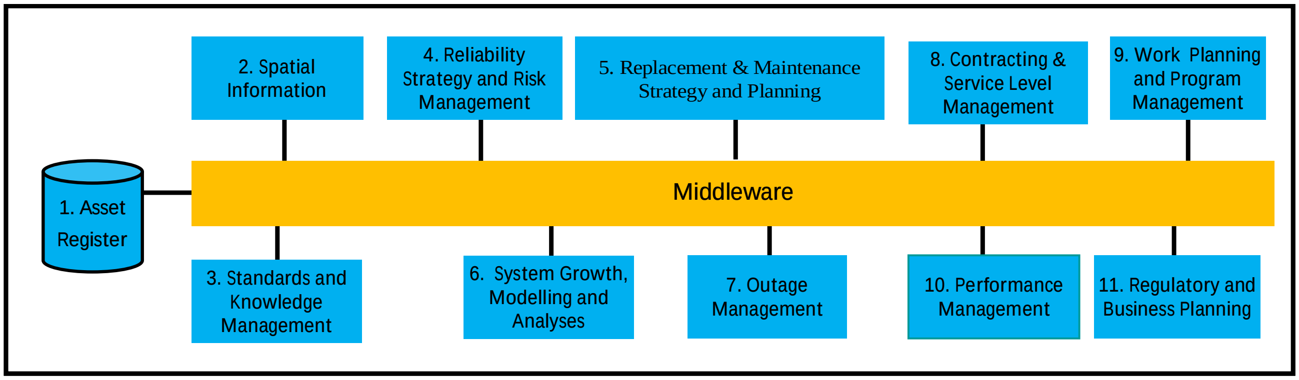


Figure 5-19

These range from spreadsheet based analyses to more complex software development. Many of these tools are very sophisticated and produce sound results. However, in many cases these tools are not interconnected with each other and with the underlying data sources. And in some cases the use of the tools is limited to the part of the organization in which they were developed.

BCTC's Asset Management organization appears to be missing a well developed system architecture and a tool development strategy. As a result, many of the existing tools go underleveraged, and the prioritization of the development and implementation of the tools is not clear. BCTC should examine the full suite of current capabilities to determine which tools should be used more widely and those that should be retired in favor of other tools in use within the organization.

Given its goals to improve its investment decision making capabilities, we expect that there are several capabilities that BCTC will be investigating over the next several years. These should all be approached with clear system architecture in place and through a standard prioritization process.

BCTC should be applying the same asset management rigor to tool development decisions that it applies to all other asset investment decisions. BCTC had a clear understanding of the needs for additional decision support capability and should be using that knowledge to assemble its technology plan, much as it does with other asset planning.

6. Conclusions

Summary

Based upon the interviews conducted and the analysis we carried out, we believe that:

- **BCTC's costs for transmission system investments (Growth, Sustain and OMA), including those projected out to 2009, are below the range of what should be expected for a system like BCTC's.**

- **We can expect to see BCTC's costs of replacements grow steadily over the next ten years** as it begins to address an asset replacement wave and balances the timing of replacement spending against workforce availability. It may need to advance replacements to ensure a manageable workload.

- **BCTC's system performance is good and is reflective of solid work being done by BCTC in managing the assets and making sound investment decisions.**

- **BCTC is a solid Asset Manager. Its analytical capabilities are logical, credible and can reasonably be relied upon.**

- **BCTC has continuously improved upon its Asset Management capabilities with results clearly evident in the system cost and operations performance, and is actively working on continuous improvement efforts.**

- **BCTC will be facing a number of challenges in the next several years as its asset base ages and the effects of various externalities become clearer.**

- We did identify some gaps in performance that are consistent with other Asset Management organizations at BCTC's stage of maturity. **BCTC is aware of the gaps and is committed to working to close them.**

Spending and Reliability

Overall we found BCTC's recent spending levels to be within the range that we would expect for a company with its system characteristics (customer density, terrain, location on the interconnected grid, relative level of wheeling, etc.), though in some cases it is lower than expected.

Since its inception, BCTC has seen a steady rise in its asset related spending, but on several of the cost measures that are most meaningful for a company with BCTC's characteristics, BCTC's position in recent years is on the low end of the expected range. This suggests that in earlier years, BCTC's transmission related asset spending may have been below the expected normal range. If this is indeed the case, we would expect to see BCTC's costs rise at a higher rate than some of its peers who maintained consistent spending levels over the lifecycle of their assets.

Based on our analysis, we believe that BCTC's costs, including those projected out to 2009, are reasonable and within the range of what should be expected given BCTC's system characteristics.

As we discussed earlier in the report, we relied on asset failure rates as the main indication of the underlying system condition and expected reliability levels. For BCTC, we looked specifically at Power Transformer and Circuit Breaker failure rates. We also examined failure rates for other components to ensure that breaker and transformer performance was representative of the overall system. We found that BCTC's breaker and transformer failure rates were well below the industry average and indicative of a very good maintenance program. We found that BCTC exhibits similar sound performance across the balance of the asset base.

Our analysis did reveal that BCTC's breaker and transformer fleets have a much higher percentage of equipment in excess of 25 years old than its peers. Based on our review of BCTC data, and based on the experience of other utilities, including better performing companies, this suggests that BCTC is facing a bow wave of replacements that will be starting over the next ten years. We would expect to see BCTC's costs for replacements begin to ramp up accordingly. Given the steepness of the potential wave, BCTC may need to advance some of the replacements to ensure that it is managing both the cost impact and the practicality of executing the expected level of workload in a tightening resource market.

We also identified that BCTC's projected costs through 2009 do not appear to fully reflect the potential impact of several externalities that could have a significant impact on its spending. Among these are:

- Beetle infestation and the associated vegetation management costs
- The full impact of adopting mandatory reliability standards
- Wildfire mitigation requirements for which BCTC is now accountable
- Species at Risk legislation requirements for which BCTC is now accountable
- Changes to risk tolerance levels and associated risk mitigation for seismic events

BCTC's system performance is good and is reflective of solid work being done by BCTC in managing the assets and making sound investment decisions. BCTC will be facing a number of challenges in the next several years as its asset base ages and the effects of the externalities become clearer. BCTC will need to continue its improvement efforts relative to its skills and decision making capabilities to deal with these challenges while maintaining the level of system performance that it currently enjoys.

Organization, Processes and Technology

Based on our analysis, interviews and review of BCTC's current processes and capabilities, we concluded that BCTC's solid system and asset performance is due in large measure to the talent and resourcefulness of the organization. We see the effect of its decision making in the system performance. This speaks highly of the Asset Management organization, which is talented, often innovative, and works to ensure that the system meets the performance expectations. For the work that it accomplishes, it is relatively small in size and efficient. Most importantly, in our view, is that BCTC recognizes that it could be a better Asset Manager and the organization appears to be motivated to work toward that end. The improvements that BCTC has made in its processes and decision making in recent years is significant. BCTC has focused on many of the areas with greatest leverage to impact cost and performance, and has tackled these first.

Our assessment highlighted some gaps to be closed, and BCTC was aware of most, if not all, of these:

BCTC's focus on improving system performance has resulted in a degree of 'siloing'. BCTC tends to focus on Growth, Sustain and OMA as separate and distinct areas and only examines cross portfolio opportunities relatively late in the process. Other effective asset management organizations focus on system needs and solutions, which then identify the type of spending required. Therefore, we believe that there are some potential economies of scale for BCTC that could be gained by broadening focus earlier in the planning process and creating a more cross-portfolio perspective.

The relationship between BCTC and BC Hydro is not as strong as it needs to be. There are structural and cultural barriers that impede the ability of the two organizations to focus on delivering the plan together. While they do work together well in several areas, there remains a tension between them and there seems to be a lack of recognition that neither can be successful in its goals without the other.

Finally, BCTC has developed a number of tools that it uses in making its asset investment decisions. While some of these are industry leading, BCTC has not created an integrated set of tools, nor does it have a technology plan for integrating all of its tools and data sources. BCTC tends to use many of the tools in standalone mode or with some limited interconnection. It does not fully leverage the capabilities of all of its existing tools. There are several cases where BCTC's capability to relate cost and performance are extremely good. But these tend to be limited to a certain aspect of the system, such as breaker operations. As an example: BCTC has not yet linked the tools that assess breaker operations with tools that predict outages from vegetation, which is one driver of breaker operations. Therefore, BCTC could improve upon its plans through greater use and integration of its existing tools.

7. Recommendations

Context for Recommendations

In making our recommendations we are mindful that our assessment of BCTC has been generally limited to the Asset Management organization and processes. Our assessments have only involved other parts of the organization to the extent that there is overlap or coordination with the Asset Management accountabilities. As such, there may be factors we are not aware of that may impact BCTC's ability to act upon one or more of the recommendations.

We are also clear that in adopting any of these recommendations, BCTC will need to ensure that it can take on the additional work each represents. Given the growing workload that we believe will be emerging, BCTC will need to be thoughtful about how and when it implements any of the recommendations to avoid becoming over-committed. This is a particular concern for us, as the Asset Management organization appears to be fairly lean in its current state.

In all cases, we would expect BCTC to apply Asset Management principles in its evaluation of the recommendations and in any decision to proceed. BCTC should understand the cost and value of implementing the recommendations as it compares each to all other investment opportunities, and should only move forward with any recommendation when it is seen to produce greater overall value than the other investment requirements that it would displace.

With these factors in mind, we have organized our recommendations into three categories:

1. Short-term Implementation – these should be started soon, with an expectation that the full benefits will begin to materialize within 12-24 months.
2. Medium Term – these should be targeted for completion over the 3-5 year time frame, with benefits following completion.
3. Long Term or Opportunistic – these should be planned for beyond the five year time frame, or if the opportunity arises earlier to embed them in another initiative with no/low incremental cost/effort, or if their value to the organization warrants earlier implementation.

Short-term (12 – 24 Months)

1. BCTC needs to develop an Asset Management IT strategy and system architecture. This should:
    a. Provide the basis for standards regarding tool development and deployment.
    b. Allow for interconnection of existing tools.
    c. Allow for rationalizing and removing tools that are no longer of value.
    d. Align with the overall BCTC IT strategy and architecture.
    e. Be focused on integration of the tools and data sets currently used throughout BCTC.

   f. Allow BCTC to make effective tool development deployment decisions based on the ability of the tool to work in the integrated environment. This specifically excludes the development of new tools and systems.
2. BCTC's Asset Management organization needs to continue its evolution toward a "One Asset" view. In the short-term, this would consist of finding cross-group working strategies that ensure better cross-portfolio collaboration.
3. BCTC should ensure that there is a clear, uniform, and well understood vision of the transmission system 20 years out. This should form the basis for the overall asset strategy and deployment plans.
4. BCTC should review the externalities identified in this report and develop its own complete set. It should evaluate which of these needs should be addressed in the near term, and which are more appropriately left for the medium term.
5. BCTC needs to work with BC Hydro to continue to improve the relationship, and to ensure that:
   a. Both organizations are partnering to deliver on the plan.
   b. BCTC is leveraging the knowledge and insight from BCH field resources as input to its analysis of asset condition, etc.
   c. BCTC can evaluate where improvements in system performance can more effectively be derived through changes in field performance.

<u>Medium Term (3-5 Years)</u>

6. BCTC needs to develop a strategy to address the replacement wave that appears to be on the horizon. This should include:
   a. Scenarios associated with:
      i. Faster and slower approach of the wave
      ii. Cost constraints
      iii. Resource constraints
      iv. Material constraints
      v. System access/planned outage constraints
      vi. Bundling of work to allow for risk reduction work to be carried out as part of the replacement program
   b. Plans to manage the replacement workload within the projected constraints of:
      i. Cost – the replacement wave could represent a step increase over current replacement expenditures
      ii. Access to the system – planned outages
      iii. Availability of resources to do the work – both engineering and construction
      iv. BCTC's other normal ongoing work
      v. The impact of externalities
7. BCTC's Asset Management organization needs to continue its evolution toward a one asset view. In the 3-5 year time frame, this would include reworking processes and accountabilities to ensure that better cross-portfolio thinking is embedded from the start of solution evaluation.

8. Improve its Performance Management systems and reporting to:
    a. Go beyond asset performance to include:
        i. Component performance
        ii. Contractor performance
        iii. Performance of the decisions made by the asset management organization
    b. Provide management personnel with desktop dash boards
    c. Ensure that all performance assessments are made using complete and consistent data
9. Revisit the level of Risk Tolerance of BCTC and its stakeholders. This should be done periodically to ensure that decisions made in the past regarding large scale events such as seismic, pandemics, etc remain valid in the current environment.

<u>Long Term (beyond 5 years) or Opportunistic</u>

10. BCTC needs to continue to develop and enhance its decision support tools. Accordingly, BCTC should use the architecture and tool strategy to determine what tools are needed in terms of form and functionality so that it is in a position to implement these on an opportunistic basis and so that it can participate with tool suppliers in the development of industry standards and methodologies.

8. Additional Observations

During the course of our work, we identified two areas, not generally within our mandate, that we believe are worthy of mention. These are Cost Estimating and Project Management. We know that BCTC has other support in reviewing these areas; however we believe that it is important to include our observations and recommendations here for the sake of completeness of our report.

Cost Estimating

BCTC's ability to generate consistent and reliable cost estimates at each stage of the investment lifecycle lags the industry significantly. BCTC's estimates are done largely on a project specific basis and are not tied directly to material and labor contracts, nor do they tie to standard accepted material and labor escalations. This gap has the potential to undermine BCTC's credibility as an Asset Manager and significantly diminish the value of its other decision making capabilities, several of which are industry leading.

BCTC's process for cost estimating does not provide it with consistent and credible cost estimates. Its process starts estimates at the concept stage which are continually refined throughout the development and commissioning of the project. At a high level the process is the same as we would find in other good and better performing companies. However, at the detailed level, the process deviates from normal practice in several respects, all of which serve to undermine the usefulness of the estimates.

At the concept stage, BCTC uses a +/- 50% estimate. This level is regarded by most Asset Management organizations to be too broad a range to be useful. Most of these organizations start with estimates in the +/- 25% range for concept and planning. The wide range is further compounded by the fact that BCTC has no cost estimating tools. It is reliant on BCH or other external providers to prepare cost estimates. The current process for estimating relies on an individual estimate, done by an estimator or engineer in BCH or at another contractor firm. Further, the estimates are not tied electronically to standardized cost information. And despite BCTC's and BCH's heavy use of standards, there appear to be no standardized costs for station and line construction. Rather, each estimate is done on what appears to be a semi-independent basis.

Given the level of sophistication of both BCTC and BCH we would expect to see cost estimates based on detailed planning and construction standards and that those standards would in turn be tied to supply chain and contract information regarding market based materials and labor pricing. While eventually each project needs to have a customized estimate, better performing companies are able to do the customization later in the project development and as a result find that the variation from the planning level is nominal. BCTC has seen significant swings in its cost projections for several projects, even those that are under construction. The inability to produce consistent, credible, fact based cost estimates quickly and routinely, undermines BCTC's ability as an Asset Manager to accurately convert its physical asset needs into meaningful costs.

As Asset Manager, BCTC must be accountable for producing credible projections of cost and changes in system performance. We see that there is not as strong an integration of the Asset Management processes and the field processes as exist in other high performing organizations. We believe that BCTC, BCH and the other third party contractors would benefit from greater process and performance management integration, and from improvements in the cost estimating process.

Project Management

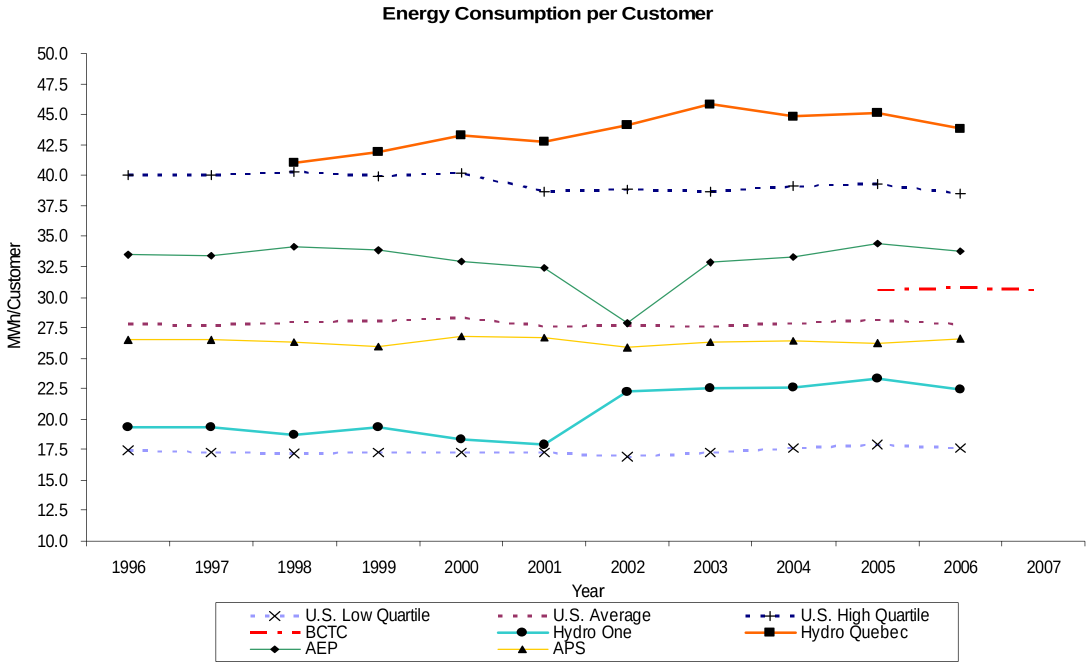
BCTC's project management capabilities are not on par with many of its other superior skills. It needs to improve its ability to manage all of its projects on a consistent basis. It appears that overall the capability is present, as evidenced by the fact that many of the projects are delivered on time and within budget. However, there are several projects for which BCTC has experienced significant delays and overruns whose impacts were not well known until near project completion. BCTC also has experience of missing yearend spending projections made at mid- year, by significant amounts.

Recommendations

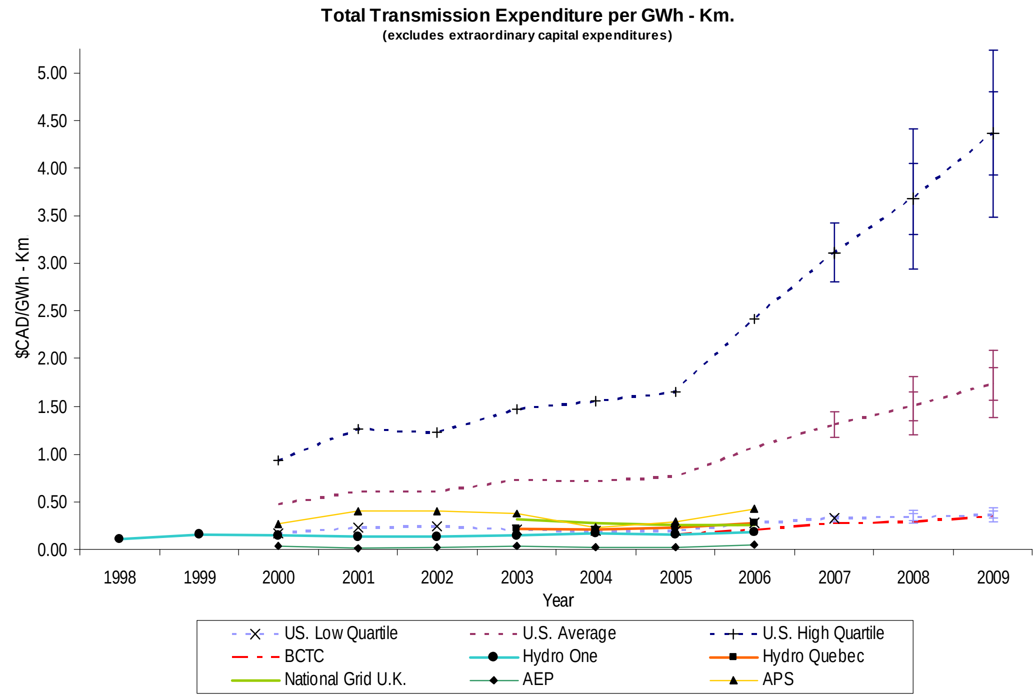
1. Fundamentally rework the cost estimating process, procedures and tools to enable BCTC to produce consistent credible estimates that:
    a. Are based on BCTC's system planning and design standards
    b. Are tied to long-term equipment procurement agreements that establish known, verifiable pricing for materials and major equipment
    c. Are tied to labor agreements and reflect known and projected increases in contract costs and which use inflation figures that are uniform and consistent with all of BCTC's financial projections
    d. Are made using a consistent set of tools so that they are not subject to wide variation as a result of the personal preference of the estimator
    e. We would expect that BCTC, or its service providers will need to make investments in the supporting technology to enable successful completion of this item.
2. BCTC needs to improve its project and program management capabilities and tools to ensure that:
    a. BCTC can manage its projects and programs within schedule and budgets on a consistent basis
    b. At any given point in time BCTC can understand the full cash and resource impact of all of its ongoing projects, and any interrelationships between them, and can make appropriate and timely decisions regarding project continuation, acceleration or even suspension, as changes in the external environment may dictate throughout the year.
    c. BCTC can project its year end capital and OMA expenditures accurately at each quarter and be confident that the projections are based on remaining work matched to available resources and known constraints.

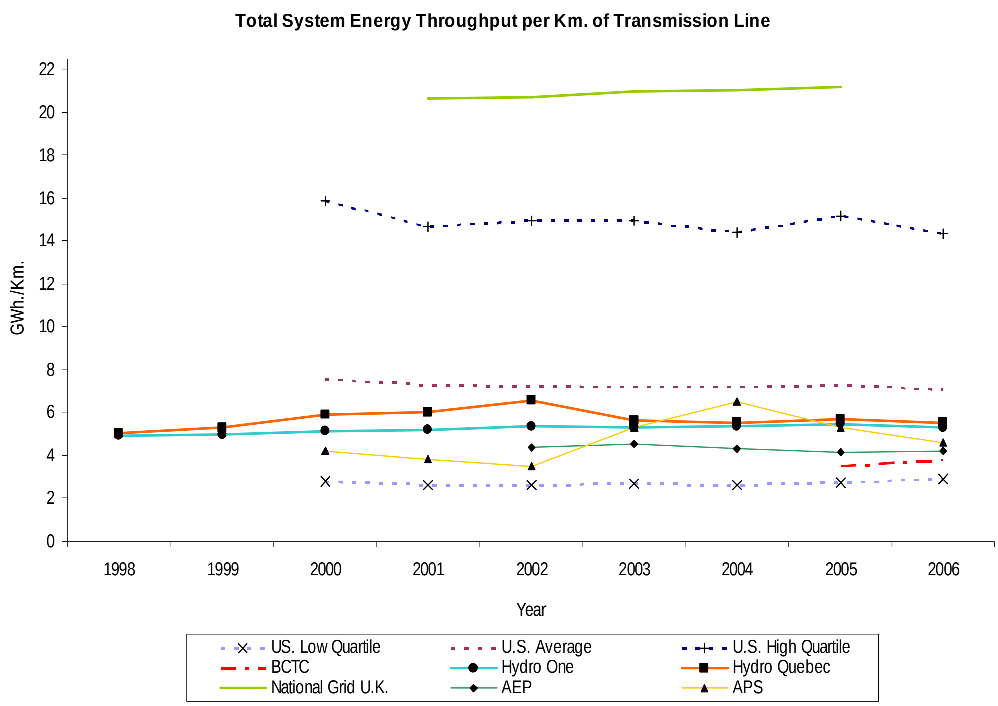
Appendix 1 - Supporting Analysis

The chart below shows clearly that the energy consumption for customers served by BCTC's system is average and consistent with the proxies.

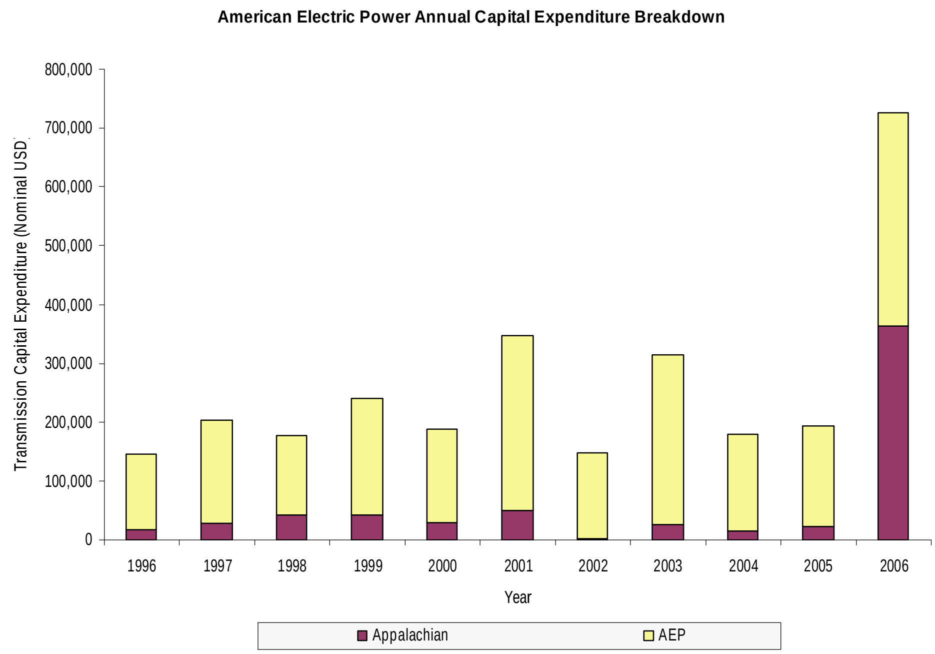


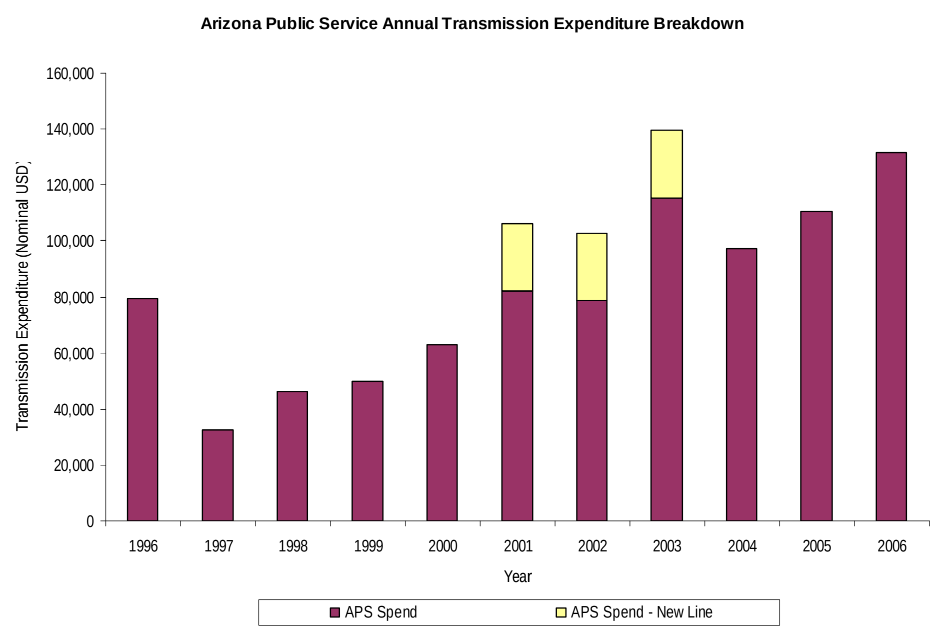
The charts below highlight the fact that BCTC is an efficient electricity transport company despite its low customer density. Its total throughput per Km of line is lower than average and lower than the proxies. Its costs per GWh-Km are at the low end of the range and consistent with the proxies.





The charts below highlight the impacts of extraordinary spending. In the case of APS a 500kV interconnection inflated its overall costs during the project period. In the case of AEP we see the impact of a 765kV interconnection, all of the costs of which appear in the Appalachian Power subsidiary's costs. Both of these cases highlight the need to remove extraordinary expenditures when making a company specific comparison.





Appendix 2 – Case Discussion of UK System Reinvestment – Gaming Regulation

The relationship between system investment and reliability is at once straightforward and complicated. It is clear, as seen both through logic and observing actual practice, that chronic underinvestment in the system leads to a degradation of the system condition, which ultimately leads to degradation in reliability. However, the converse is not always true. An increase in investments in the system does not necessarily lead to improvements in the system condition or reliability. The quality, timing and focus of the investments are critical factors in effecting a change in the system condition and its performance. This phenomenon played out in the United Kingdom when the regulator sought to ensure that the newly formed companies were reinvesting in the system. As was common in other regulated environments, the regulator gauged reinvestment rates by analyzing the capital and operating expenditures against the depreciation expense. This provided the regulator with a means of determining if the new market structure was creating profit incentives that discouraged appropriate investment in the system.

The UK had adopted a regulatory framework that established a price cap for a five year period and incentivized the companies to find ways to live within the cap, by allowing them to keep efficiency gains as profit. The caps were set as aggressive improvement targets, and were met by most companies through quick application of new processes and a relentless drive for efficiency. Along with the price caps, the regulator established reinvestment targets for each company to ensure that they were not merely eliminating reinvestment as a means to produce "efficiency gains". As the end of the first five year price review drew near, several companies realized that they were significantly under their reinvestment targets. Some acknowledged their shortcoming to the regulator, which resulted in further reductions in their price cap, during the next re-set period, as a means of returning some of the excess profit. Other companies, not wanting to subject themselves to refunding, set out to hit their reinvestment targets in the last twelve months of the five year window. Some of these companies sought to find the quickest way to invest large amounts of capital to bring their accounts in balance. With this as their driver, they began replacing the largest and most costly items to ensure that the money could be spent in the limited timeframe remaining. As a result, there were many items of equipment replaced that still had significant remaining life. Many of the more critical investments, that were lower in cost but higher in potential reliability impact, fell out of the priority list.

Unfortunately it was not until close to the end of the second five year price review that the differences in the strategies applied by the companies became apparent. Those that had engaged in capital "dumping" found themselves battling a system that was deteriorating faster than they could keep up with. The results were degradation in customer service, which quickly became apparent to the regulator, and rapid growth in emergency repair costs, which quickly came to the attention of the shareholders. The companies that had been candid with the regulator had paid the price in profit terms during the price setting, but had then embarked on a more structured and balanced investment program. As these companies neared the end of the second five year price review, the performance of their systems was stable, as was their customer satisfaction. In relative terms their financial performance was far superior to those that had “gamed” the system.

Through many discussions with the utilities, and through its own analysis, the regulator recognized the need to broaden the number of indicators that it used to gauge reinvestment rates. It recognized that looking at one financial data point, in one time period, was not a sufficient indicator. Instead, to accurately gauge the question, it needed to look at trends in investments in capital and operating expense, as well as leading indicators of system deterioration, such as reliability and equipment failure rates. In the next price setting, the regulator established several service level guarantees that each of the utilities had to meet. Many of these were focused on reliability; others were focused on customer service and customer responsiveness, which had also suffered from “gamed” underinvestment.

After significant discussion and tension, both the regulator and the utilities had far greater clarity on how they would gauge performance of the system, and how to determine that the utilities were investing appropriately. This clarity was timely because at about the point that the Regulator and the utilities reached a mutual understanding of how to gauge reinvestment in the system, the reinvestment needs began to rise. Most of the utilities were beginning to see the front edge of a significant replacement wave. This was the result of heavy investments in the infrastructure that were made during growth periods in the late 1960s and 1970s. As many of the assets closed in on their 30 and 40 year design lives, the maintenance expenditures were being supplanted by replacement costs. Through the lessons learned by the regulator and the utilities, they were able to work together to determine if the growing rate of replacements was the result of inattention on the part of the utilities, or was part of a natural phenomenon. In the few cases where the regulator concluded that it was the former, the utilities were held to account. In most cases, the regulator concluded that the utilities were making prudent decisions to replace the assets proactively, to avoid in-service failures. The utilities and the regulators were able to work together to ensure that future price reviews took into consideration both the replacement need and the need to avoid price shocks to the customers.

Appendix 3 – UMS White Paper on Optimization

***White Paper* – "A New Look At Spending Optimization"**

By UMS Group

<u>Background</u>

Electric utility decisions on where to spend capital and/or maintenance cash have historically been driven by system needs viewed through an engineering perspective. Load growth and system performance (capacity and reliability) have therefore been the primary drivers of investment decisions. Planning activities have been centered around maintaining adequate voltage, power factor, and system flexibility for outage restoration. "N-1" failure contingency planning was common. "Gold-plating" was acceptable, at times even desirable, based on customer needs and business drivers. In the U.S., utility rates were governed by return on investment and adequate funding was generally available. US Regulators utilized the less stringent standard of "used and useful" rather than "ODV" (Optimal Deprival Value) or "necessity" to determine whether capital was invested appropriately.

However, changes in the business and regulatory environment are forcing a new emphasis on reducing capital expenditures. Demands for more rigorous financial integrity, the impact of the collapse of the merchant market on investor confidence, and competing demands for scarce financial resources are driving a new focus on efficiency and spending optimization. In addition, regulatory agendas are shifting to include greater focus on customer and financial issues. Customer demands for lower rates mean that utilities have less to spend, but there is also growing pressure for improved reliability. At the same time, shareholders are looking for more stability and higher rates of return. As a result, most utilities are no longer being driven primarily by engineering views, but by the need to optimize asset performance and financial returns.

<u>Utility Manager Concerns:</u> Asset managers throughout the industry are wrestling with complex challenges and difficult questions every day

> *How can we **optimize** our investments to achieve multiple and often competing target business outcomes?*
>
> *What **impact** will incremental investments have on the business' strategic objectives? How do we then scenario test various alternative investment decisions?*
>
> *How can we then **defend** our investment decisions - to the Asset Owner, External Owners and the Regulator? How do we ensure they remain defensible even after the environment has changed?*
>
> *What impact will **additional budget dollars** have on our achievement of goals and performance? How would a budget reduction impact them?*

*How do we ensure that our investment decisions, when made by **different people** in the business, consistently achieve the **same results**?*

To complicate matters, the budget planning process itself is often complex, inefficient and cumbersome. On average, utilities spend over 70 days in the annual budgeting process, creating at least five different versions using a multiplicity of modeling techniques (zero based, activity based, cash flow, historical, etc.) at a cost often approaching 0.5% of annual revenues. The Operations and Planning groups that identify work, and the Financial Group which controls the dollars usually do not have a common decision making process and frequently utilize different information in arriving at their conclusions. Average year-end budget variances are often in excess of 10% and most utilities lack the corporate integration, decision-making, and modeling capabilities to generate optimized investment portfolios.

Decision Making

This new environment requires far greater rigor by utilities in the decision-making processes that govern cash investments. Decision criteria should generally include:

- A desire to "sweat the assets" or obtain maximum utilization of plant before replacement, while not adversely impacting reliability and avoiding losses on premature asset retirement,
- Maintaining customer (and regulator) satisfaction with asset performance,
- The need to retain adequate capability for shareholders to invest in current or new growth businesses.
- Stability of revenues or regulated returns to shareholders (ROE/ROI).
- Subjective requirements such as political needs or CEO prerogative.

Coupled with the question of how much to spend is the decision on where to spend. Most utilities structure their investment decisions along seven general categories:

- 1) Revenue Generation – investing in infrastructure necessary accommodate new load growth,
- 2) Capacity / Efficiency – expanding the load carrying capability of the network to accommodate growth,
- 3) Reliability – investments to ensure that the network responds adequately to natural, electrical, and mechanical forces which impact its ability to provide service continuity. This includes decisions on asset refurbishment, repair, and early replacement (ie, before the end of their economical and/or technical life),
- 4) Operating Flexibility – projects that enhance the ability of the system to respond to abnormal conditions (switching, automatic transfer schemes, effective use of SCADA, etc.),
- 5) Customer Needs – work driven by specific customer needs (relocations, upgrades, etc.)

- Ø 6) Regulatory or Politically Mandated – projects driven by governmental entities such as road projects, and overhead to underground conversions
- Ø 7) Investment Return – where and how (capital or O & M) to invest in a way that enhances financial performance

The challenge is to develop a sophisticated set of processes and tools that link financial requirements to operational needs in a way that can optimize spending levels and the focus of investments. This challenge is comprised of three dimensions:

> First, *more sophisticated opportunity identification and screening* processes are *needed* to validate potential investment options. The methodology traditionally used to define, select and screen potential project investments relies on system modeling and field engineering solutions for constraint abatement, added to the assumed mandatory work of new customer connections and government-required projects. While such components are still part of today's process, the creation of new asset owner and asset manager roles has expanded the scope of questions being asked. For example, "What will be the impact of this solution on each of our service quality indices?, Have we fully explored the supply, demand and ownership options for dealing with this issue?, and Does dis-investment and/or divestiture of assets have a potential role in the optimum solution?" ROE, ROI, and other financial measures of asset performance are now routinely included in the decision matrix.
>
> Second, a major concern in today's decision-making environment is determining *which criteria to include in the evaluation of investment options*. Traditional evaluation methodologies have focused on basic cost benefit analysis (NPV, IRR, simple payback, etc.), some qualitative assessments of political needs, and little else. Today's decisions are also influenced by detailed consideration of factors such as customer impact (SAIDI, CAIDI, SAIFI, MAIFI), strategic/business implications (new technology, best practices), and more importantly, risk. This often overlooked factor is now playing an increasing role in utility investment decisions, as asset managers shift from deterministic to probabilistic methods for evaluating potential outcomes.
>
> And lastly, *creating an optimized portfolio from the extensive list of competing projects* that the typical utility chooses from annually is a daunting task for most companies. This is especially so given that the business and regulatory environment is a dynamic one and the "optimum" project mix will change throughout the year. Even defining the term "optimized" is challenging for many firms. In the context of investment portfolio balancing, we believe that "optimized" means selecting the group of investment opportunities that best satisfy specific value criteria (O&M cost, risk mitigation, NPV, customer value, etc.) within a targeted budget range. While these criteria can be similar for every utility, the importance, or ranking, of each will vary between organizations depending on factors such as regulatory environment and priorities, current business mode (status quo, growth, retrenchment), and funding availability.

The effectiveness of optimization is also influenced by who makes decisions about which optimizing criteria should be used and how they should be applied. In most mature asset management organizations, the asset owner makes all such decisions on ranking criteria. These decisions must align with corporate goals and objectives and should be constantly re-evaluated to ensure conformity with the current and expected operating environment. In organizations in which the asset manager makes these decisions, system technical or operational factors tend to dominate and “simpler” solutions involving political or regulatory constraint relief are often overlooked. And in companies where the service providers (the field division organizations) are still heavily involved in setting spending or investment priorities, other factors such as workforce productivity and resource availability tend to have a significant impact on the projects that get selected. In both these latter situations, the resulting “optimum” portfolio usually falls well short of the potential impact/value that the investment levels could have produced.

One inevitable question that arises in the discussion of optimizing investments is what is the value of such precision, given the regulatory or political uncertainties we all face? Discretionary spending for most utilities is limited, so can optimizing 20-30% of the annual budget really produce value in excess of the effort involved? The answer is a resounding “yes” and here’s why. Optimizing:

- Ensures alignment between the asset management and financial (CFO) functions or processes of the business.
- Provides an auditable trail that can be used with business counterparts and regulatory agencies.
- Can be used to asses the true net benefit of “mandatory” projects.
- Means that the optimal portfolio can be one that does not use the entire budget.
- Ensures that the highest value investments are the ones selected. (value being determined by the Asset Owner’s optimization criteria, otherwise known as the strategic objectives)

Current State

Our research indicates that utilities generally fall into one of three categories based on the sophistication of their internal investment decision-making and modeling capabilities:

Novice (Most companies)	Learner (Some companies)	Expert (Few companies)
The ‘Technical’ View	**The ‘Economic’ View**	**The ‘Strategic’ View**
Process: Building and maintaining poles, wires, transformers, etc. to ensure high reliability and quality of supply - mature practice, common in most utilities.	Process: Effective capital rationing through robust financial assessment of options (hurdle rates, NPVs etc) – adolescent practice, being truly integrated in some utilities at present	Process: A holistic view of the asset’s lifecycle to plan the optimal operational and maintenance strategies required to achieve business outcomes, commercial goals, and customer satisfaction, supported by integrated processes and systems – infant practice, being developed in a few utilities at present
Tools: Typical budget analysis and reporting	Tools: Financial modeling (NPV, IRR) and cash flow	Tools: Financial modeling, cash flow, optimization

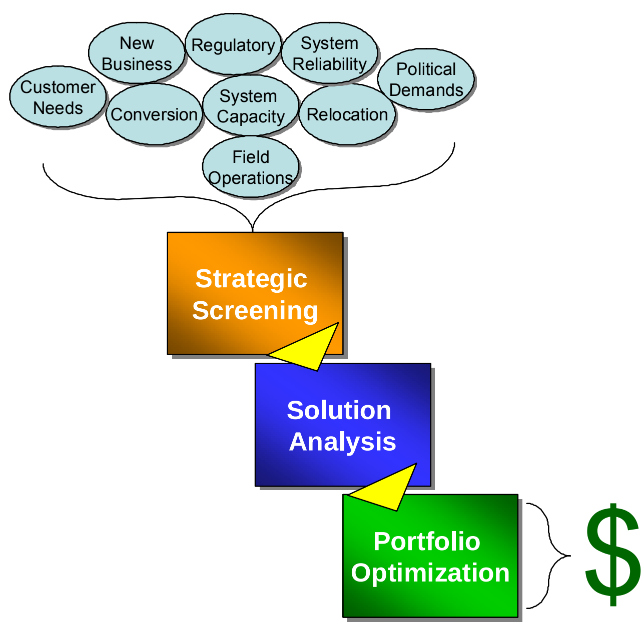
Novice companies use traditional planning and budgeting methods. Engineering and operations groups identify projects based on system and customer needs, generally without detailed justification. Finance groups crunch the numbers and determine that the selected group of projects is too expensive. The budget returns to the engineering and operations groups for revision. This process is circular until some form of agreement is reached.

Learner companies start with the same approach but add detailed financial analysis to justify projects. Budget items are then ranked in NPV or IRR order and summed until the expected budget limit is reached.

Expert companies integrate financial, operational, customer, business drivers, and risk analysis into the project selection process so that identified projects are screened and analyzed simultaneously through portfolio optimization. This provides the financial and operating link necessary for a robust decision-making process. For these companies, the cost of projects that pass the screening criteria often falls short of available funding.

Spending Optimization

One solution to the development of optimized investment portfolios is to build an integrated and efficient process complemented with sophisticated modeling tools. The diagram below illustrates this kind of basic spending optimization process.



An **Inputs** Process collects project investment needs to ensure that all appropriate input sources have been given due consideration.

A **Strategic Screening** process serves as a funnel to integrate and manage the variety of project input options to deal with duplication, practicality, feasibility, and probability of implementation.

A **Solution Analysis** process then evaluates potential projects in terms of their ability to satisfy key goals such as financial cost benefit, customer impact, business and strategic implications, and risk mitigation (the strategic objectives).

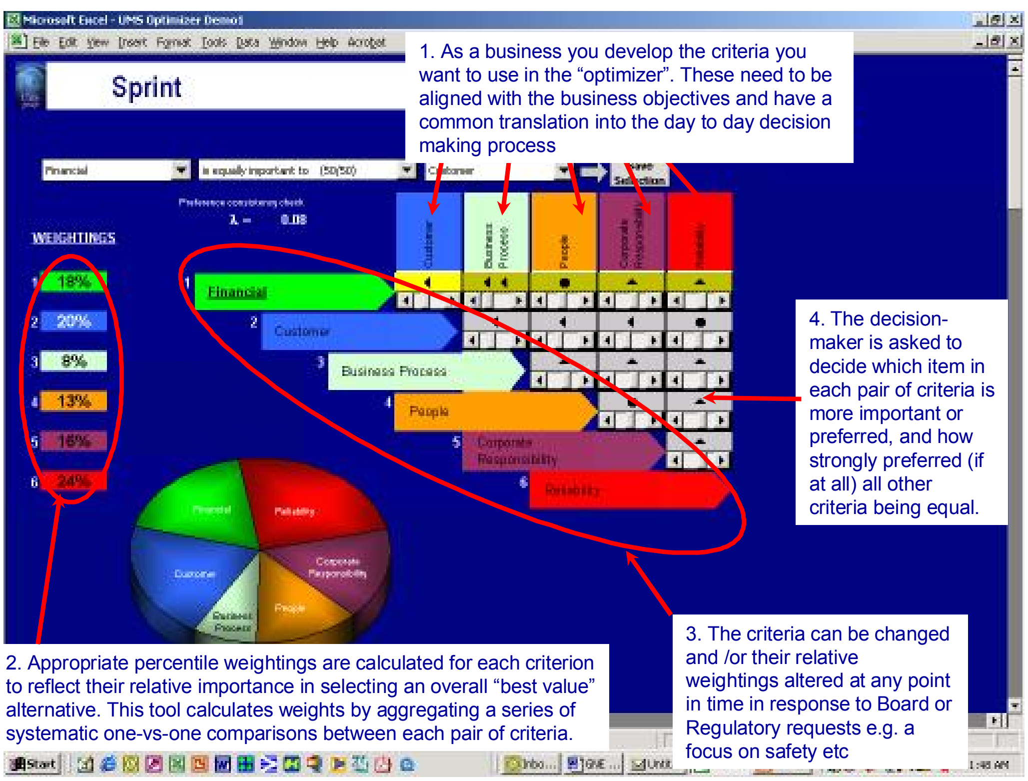
Finally, a **Portfolio Optimization** process takes outputs from the Decision Analysis process and develops an optimal balance of investment opportunities. Such a process must be iterative since refinements made in the Decision Analysis process will affect final optimization, and portfolio optimization can point to flaws in the Decision Analysis process.

The SAM Solution: while this optimization process seems relatively straightforward, the ability to incorporate all of the various sub-processes, decision criteria, strategic objectives and business and operational modeling is not. The SAM (*Strategic Asset Management*) process solution developed by UMS Group is supported by an analytical toolset that takes full advantage of the mathematical decision and modeling capabilities of current desktop tools. Three types of financial analyses are incorporated, based on client preferences, in a spending optimization model to support a broad array of decision-making scenarios. Financial dimensions of alternative projects are measured in terms of Net Present Value, Internal Rate of Return, and Project Payback Term (or other methods acceptable to the finance organization). The figure below shows a sample Cost / Benefit analysis.

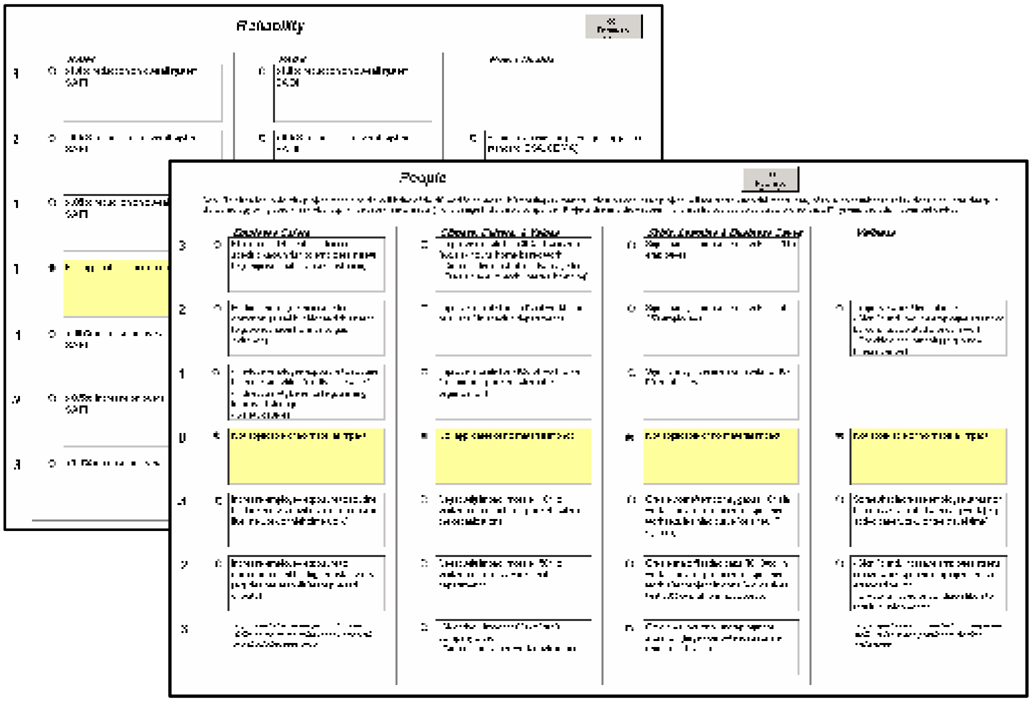
Annual escalation rate:	0.50%	Payback (years):	5
Discount Rate (for NPV):	8.00%	Net Present Value:	$1,307,151
NPV payback (years):	20	IRR:	22.77%

Year		Costs					Benefits					Net
#	Actual	Capital	Operating	Maint.	Admin.	Other	Operating	Maint.	Admin.	Revenue	Other	Cash Flow
1	2002	$1,000,000	$15,000	$25,000	$12,500	$5,200	$55,000	$150,000	$32,500	$12,000	$35,000	($773,200)
2	2003		$15,075	$25,125	$12,563	$5,226	$55,275	$150,750	$32,663	$12,060	$35,175	($545,266)
3	2004		$15,150	$25,251	$12,625	$5,252	$55,551	$151,504	$32,826	$12,120	$35,351	($316,192)
4	2005		$15,226	$25,377	$12,688	$5,278	$55,829	$152,261	$32,990	$12,181	$35,528	($85,973)
5	2006		$15,302	$25,504	$12,752	$5,305	$56,108	$153,023	$33,155	$12,242	$35,705	$145,397
6	2007		$15,379	$25,631	$12,816	$5,331	$56,389	$153,788	$33,321	$12,303	$35,884	$377,924

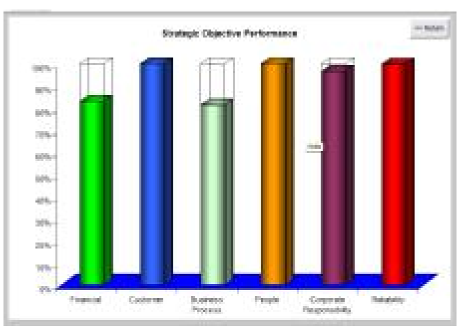
Factors beyond financial considerations, such as customer impact, risk, strategic impact, etc., are incorporated through Analytical Hierarchy Preferencing (AHP or forced pairs ranking) combined with a driver satisfaction matrix. AHP (see below) is used to determine the relative importance of each criterion (% weight) and a ranking scale is used to add objectivity to how well an investment option satisfies specific criteria (for example, if a proposed project decreases system SAIFI by >1% it might receive a reliability ranking of 3. If it reduces SAIFI by >.05%, it might receive a reliability ranking of 1).

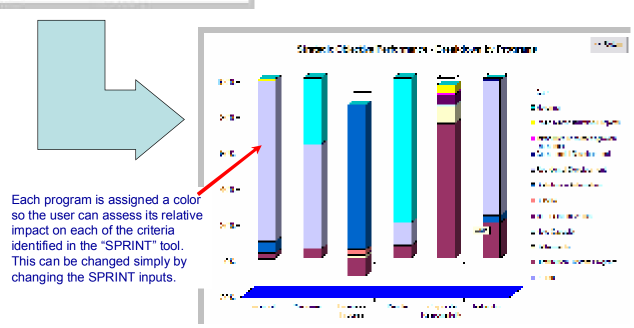


It is critical in any such system to achieve consistency of evaluations across all individuals who may provide scores for projects. UMS Group's approach utilizes a definitive set of descriptors to characterize the range of potential impact on each component measure within each investment criterion. Empirical results demonstrate a high degree of consistency achieved with this approach.

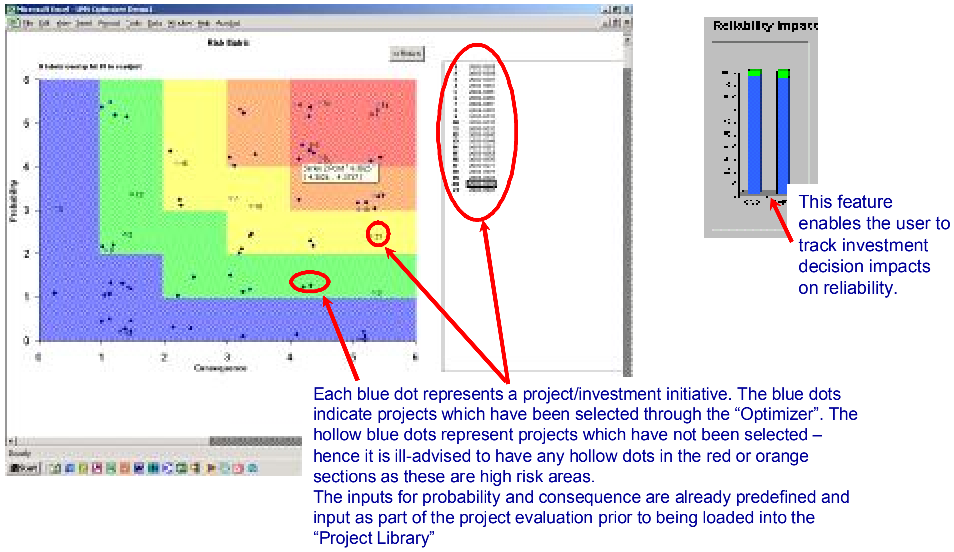


The Strategic Screening and Decision Analysis processes form the initial stages of the Spending Optimization process flow, but a final step is required to optimize the spending plan. UMS Group's optimizer routine first evaluates all possible investment scenarios to arrive at the portfolio that best satisfies the defined investment criteria.



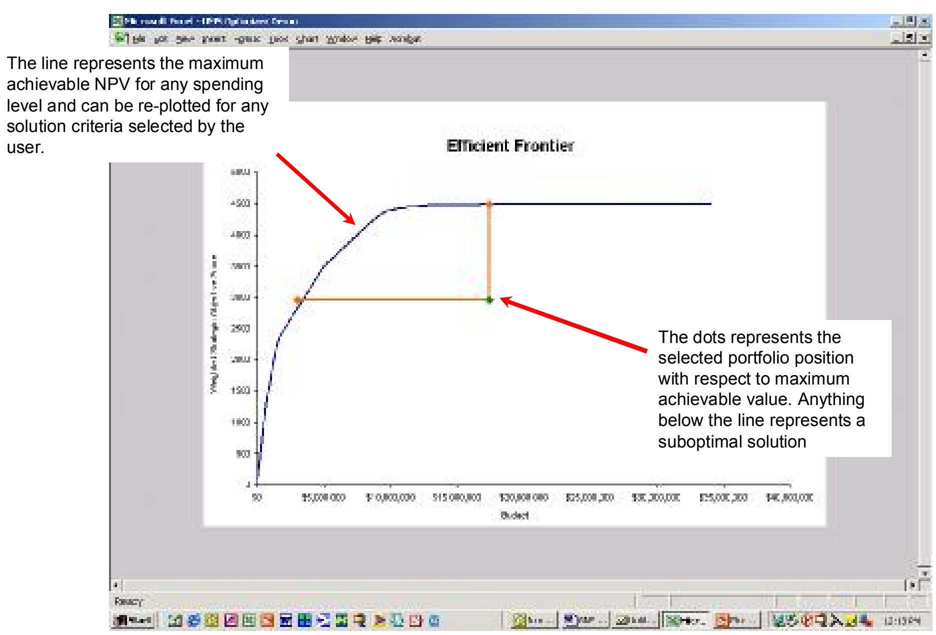


A second key component of the optimization process is the ability to generate a risk profile based on the projects selected during optimization. In so doing, Planners can easily identify high risk projects or investments and then determine whether they should continue to be included in the optimized portfolio.



The third key component of the process is the ability to demonstrate graphically the impact to reliability (CAIDI, SAIDI and SAIFI) based on the projects selected during optimization. This allows easy comparison with other optimal scenarios to evaluate the reliability impact of each.

A fourth feature of the process provides the Planner with an efficient frontier based on the optimizing criteria selected. The frontier will tell the Planner the maximum possible value (NPV, strategic objective score, etc.) for any given budget level. Comparing the selected portfolio against the frontier identifies how far below optimal the selected set of investments falls. This capability is critical in evaluating the impact of mandated projects in the optimization process.



Lastly, one of the key advantages to this process is its ability to treat political/regulatory influences and management concerns more objectively in spending optimization decisions. All financial and strategic objective criteria are quantified through a rigorous analytical approach in the Strategic Screening and Decisions Analysis processes. In addition, budget planners (and the CFO) can easily see the impact of adding (or removing) "pet" projects from a financial, strategic objective, risk mitigation, or reliability standpoint, through multiple scenario modeling. They can also readily determine the risk profile of various scenarios, in terms of consequence and probability.

Summary: As utilities struggle to adapt and stay ahead of ever tightening performance and financial constraints, the pressure for optimizing expenditures will likely continue to increase. New decision making models and support tools must be developed in order to make better decisions on how best to allocate limited capital. The Spending Optimization process described in this white paper, coupled with an appropriate optimizing tool set provides a powerful potential solution, which is being adopted by a growing number of utilities around the world.

Not surprisingly, these companies are also discovering added advantages from upgrading their processes and capabilities in this area. The greater clarity around project evaluation criteria and enhanced ability to trace strategic objectives to the actual projects that are designed to support their achievement produces significant accountability benefits as well. Project design staff quickly realize that to get their projects approved they must reassess all options from a 'optimized value' perspective and as a result, the quality and value of proposed projects climbs. And at the same time, the direct linkage of Project deliverables and impacts to Business Unit goal achievement allows project managers to be held accountable for their role in the timing and accomplishment of larger goals.

Significant enhancements to management's ability to communicate about Capital Spending with various stakeholder groups also emerge from these process improvements.

The Board - The new rigor of the process strengthens management credibility with the Board, and greater decision making speed and adaptability provided by these tools is often viewed as a substantial upgrade to the corporation's ability to manage risk, a growing concern to most boards today.

Regulators - The greater access to information on Capital requirements and tradeoffs – both those between O & M and Capital, and those between spending and reliability – also strengthens management's credibility with Regulators. This important external stakeholder typically sees the more direct linkage between spending and customer benefits or the accomplishment of regulatory goals as an important step in improving regulatory effectiveness. Understanding such linkages is also critical to management's ability to navigate the growing chorus of demands for Customer Service Guarantees, and to effectively manage the real risks and opportunities of PBR Programs.

Unions - Finally, these enhanced insights provide senior management with better support for tough discussions with Union leadership about spending reductions and staff impacts. The ability to clearly see all the tradeoffs and look at various scenarios serves as a strong fact-based counter to emotional claims about likely deterioration in reliability and public / employee safety.

Appendix 4 – CVs of UMS Project Personnel

John M. Shearman

Summary and Background

Mr. Shearman is the Chief Executive of UMS Group. He has more than 30 years of consulting and management experience serving global electric and gas utility markets. His special focus is on Regulation, Performance Improvement, and the Management of Change. He is an experienced expert witness and also has extensive expertise in strategic planning, organizational effectiveness and performance analysis. He is a frequent speaker at industry conferences and is well known for his perspectives on industry strategic directions.

Prior to founding UMS, Mr. Shearman was a senior member of Booz, Allen & Hamilton's utility practice. He also served for 11 years in various leadership capacities at two major U.S. east coast utilities. Mr. Shearman holds a professional engineer's license and an M.B.A. in finance from New York University.

Highlights of Experience:

- For a number of major electric and multi-utility companies around the globe, Mr. Shearman has led large-scale asset management organization transformation projects. These efforts have typically followed significant shifts in strategy and been designed to implement rapid simultaneous change in organizational structure, culture and capabilities to align with the new strategy. Such transformation projects have usually involved redefinition and redesign of core processes, adoption of new business models, redirection and new priorities for I/T, and establishment of new leadership practices and a more commercial and competitive organizational culture.
- Mr. Shearman has conducted numerous organizational restructuring projects at utilities over the past 20 years. He leads UMS Group's Organization Restructuring practice and is responsible for much of the firm's work in client business and competitive strategy development. His recent work in this area has included strategic analysis and organization design to implement horizontal unbundling and business streaming of utility companies. Most of these projects have included in-depth assessment of profitability, competitiveness and growth potential of individual business streams and key business processes.
- Mr. Shearman has led many engagements around the world which were responsible for fundamental redirection of clients' business strategy. He has worked with many CEOs and Boards to help frame a more robust understanding of industry drivers and directions, and clarify how shareholders view value in the business. These assignments have been structured around a more deliberate and informed approach to Strategic Choice and have often produced dramatic shifts in the strategic options considered.
- He recently worked with senior management of a major US east coast combination utility to help them restructure their delivery business into an Asset Management architecture. The project involved their full senior team (about 30 senior managers) in an intensive 1 week series of all-day working sessions. The project team facilitated their discussions and deliberations of organizational options, pros and cons, informed their thinking with benchmarking and best practice information, and helped document their decision making

process as they built out the organization from the top down through three levels of management and decided on staffing and skills requirements for all key AM functions and processes. As a result of this intervention, the client saved a net of more than $6 million annually, achieved an unprecedented level of clarity and alignment around the new roles and structure, and put in place a completely new organization in a small fraction of the time required for other approaches.

- Mr. Shearman has prepared and filed expert witness testimony for many utility clients in the US and abroad on the subjects of industry direction, regulatory incentives, affiliate cost justification and appropriate use by regulators of performance benchmarking information. These assignments have varied widely based on the specific issues of the client proceeding but most have included some element of client performance assessment and establishment of appropriate standards for regulators to apply in determining appropriateness of utility cost and services levels. Some highlights include:
  - For Entergy in a Texas affiliate cost case, Mr. Shearman led a team that conducted a broad based industry benchmarking effort to secure and supply performance assessment information to internal teams and Company expert witnesses charged with supporting specific affiliate classes of costs. He then developed and filed an overall piece of testimony that integrated the Company's approach to benchmarking and proposed appropriate standards for regulators to use in applying benchmarking in making rate determinations.
  - For Central Maine, Mr. Shearman was asked to develop rebuttal testimony in a Performance Based Rate Making proceeding in which Commission staff had retained an Economic / Modeling expert to develop a multiple regression factor model to predict what the utility's cost should be over the succeeding 5 year period. Our team evaluated and discredited the model, demonstrating several "fatal flaws" in the underlying statistical rigor, and provided vital behind-the-scenes support to client counsel in cross examination of the model's developer. As a result, the model was effectively withdrawn by opposing counsel. Our rebuttal testimony also went further, demonstrating CMP's relatively high performance compared to other utilities and advocating a longer rate stability period. The client's rate case objectives were fully achieved, with a substantially lower "X" factor than feared and a 7 year cycle rather than the 3 year period advocated by commission staff.
  - For Puget Sound Energy, Mr. Shearman was retained to provide testimony on PSE's relative efficiency to support three objectives: 1) to demonstrate their superior reliability and safety performance and reasonableness of costs, 2) to support the targets proposed for the company's new performance incentive program, and 3) to provide an independent assessment of the Company's performance against synergy savings commitments made at the time of a merger with a local gas distribution company 5 years earlier. Mr. Shearman led a joint team providing analytic support to outside counsel, integrating findings and conclusions across various Company witnesses, and framing arguments and supporting analysis required to underpin the three objectives.
  - For Entergy, in another Texas affiliate cost case in which more than $60M of affiliate costs had been disallowed due to inadequate evidence of reasonableness provided in the original case, Mr. Shearman was asked to help provide substantive proof of efficiency and effectiveness across the range of affiliate costs. Some benchmarking information had been submitted in the original case but had been disallowed when confidentiality restrictions were ruled to render the comparisons as not credible, because intervener witnesses were unable to validate it. At the time we were retained, insufficient

time remained to approach the industry for new information without confidentiality restrictions. UMS Group pioneered a novel “double blind” approach in which we secured “average” and “top quartile” data extracts from several well respected benchmarking service providers and then applied those standards in comparisons which we conducted across the affiliate classes of costs.

- For FP&L, Mr. Shearman led a combination internal / external team charged with analyzing FPL’s cost and reliability performance over the 10 year period since their last rate case. The goal of the team was to demonstrate that the substantial performance improvement FPL achieved during that period was significantly better that overall industry trends and that their performance at the time was approaching industry best practice.

- UMS Group, under Mr. Shearman’s leadership has also provided expert witness testimony and analytic support in a wide range of regulatory and governmental proceedings across many overseas jurisdictions. These assignments typically have included testimony focused on utility industry evolution, competition and performance improvement, reasonableness of affiliate costs, regulatory incentives, best practices and effective use of cost and reliability information to conduct performance benchmarking. Countries / jurisdictions involved in this work include the United Kingdom, New Zealand, Australia, South Africa, and Ireland, among others.

- Over the last 10 years, he has served as the engagement manager for a number client performance and best practices collaboratives. These projects have been conducted for industry trade groups, such as EEI (Edison Electric Institute), NEI (Nuclear Energy Institute), IWO (Institute of Water Officers in the UK), and ESAA (Electricity Supply Association of Australia), and for independent consortia assembled by one or more utilities for the purpose of industry benchmarking. Some of these, like ITOMS (International Transmission Operations and Maintenance Study), have become long running multi-year programs in which the participants have significant ownership and commitment to, and which have evolved and grown well beyond the original intent.

- For a number of electric and several combination utilities around the world, Mr. Shearman has led consulting projects to capture merger synergies from consolidation. These projects have often resulted in staff reductions on the order of 30% and cost reductions of up to 40%. Many of these projects have faced unusually difficult circumstances, with severe political issues and resistance by labor unions and/or municipal government stakeholders associated with one or the other company

- Mr. Shearman has conducted a number of very successful efficiency rationalization projects for Government owners of electric and other utilities. In one case, for a Middle East government, Mr. Shearman led the project to rationalize 60 smaller distribution companies into two large government owned entities prior to privatization. The project was a large success, with over $60 million in annual savings achieved and staff reductions greater than 50% realized. Many unique regulatory, asset ownership and technical integration issues were also addressed in this project.

- A particular area of focus in Mr. Shearman’s engagement portfolio has been performance management. He has worked for many companies in the US, UK and Australia in designing and developing performance management and reporting systems. In one case, for a leading U.S. electric utility he designed and helped implement a comprehensive top management performance measurement and reporting system. For the utility's chief executive, he led executive workshops to define key objectives and measures of success and then spearheaded an analytic effort to determine relative importance and value, and appropriate time frame for each measure. These measures were then rolled down through three levels of the organization and linked into the management incentive compensation program.

- In the formative years of UMS Group, Mr. Shearman led the design and delivery of several landmark utility industry benchmarking studies. These studies were unique at the time, introducing several breakthrough methods for normalizing performance across companies operating in widely varying environments and credibly computing controllable improvement gaps. Each project explored the tradeoffs between productivity, cost and service levels and identified innovative ideas and leading edge practices for use in closing performance gaps. Examples of these programs include:

  1. A&G - A major 15 man-year study of 12 of the largest and best electric utility companies in the United States focused on the Administrative and General functions (i.e. accounting and finance, human resources, information systems, procurement and materials management, property management, transportation, communications, legal, internal audit and risk management). The study produced improvements yielding $59 MM in annual savings at one of the sponsoring companies.

  2. Operations – The core operating functions and processes of electric utilities were examined in detail over two years in a collaborative effort with dozens of US companies. The project, called PACE OPS (<u>P</u>erformance <u>A</u>nd <u>C</u>ompetitive <u>E</u>xcellence), produced a sustainable core of annual benchmarking programs that have been run around the world in each year since 1992. In all, more than 200 utilities, including numerous Gas and Water companies have now participated in these programs.

Stewart M. Ramsay

Summary and Background

Mr. Ramsay is an outcome oriented executive with strong leadership skills and broad experience in the global Utility Industry. His breadth of experience ranges from strategy, governance and transformation, to engineering, construction, operations, and performance improvement for gas and electric transmission, distribution and customer service as well as generation. Mr. Ramsay's experience includes expert witness testimony and regulatory strategy development in FERC and State regulatory matters including transmission access, and territorial boundaries. He is an internationally recognized expert in Asset Management for Utilities. Mr. Ramsay's proven leadership skills include the ability to create aligned organizations that leverage the combined talents of the team to create innovative solutions to complex challenges.

Highlights of Experience

Vice President – Asset Management and Electric Transmission for West Coast Gas & Electric Company

In the Electric Transmission role, Mr. Ramsay was accountable for the development and execution of the growth strategy for the Electric Transmission business, including overall P&L. This included preparation of a clear strategy and plan presented to the Board. Execution of the plan entailed development of FERC rate case strategy, investment plans for growth, building transmission required to meet renewables targets and regional expansion planning. Mr. Ramsay improved effectiveness of the transmission system and produced a minimum 12% ROE each year. He provided leadership in pioneered new operational techniques using helicopters for live line work up through 500kV.

In the Asset Management role, Mr. Ramsay was accountable for the development of Capital and O&M plans for all electric and gas transmission and distribution investments. The annual plan comprises over $2 billion in spending for 9 million customer system (5.2 M electric and 3.8 M gas). Mr. Ramsay was accountable for the development of reliability and sustainability plans for both gas and electric systems. He was successful in improving both the effectiveness of the system and improving efficiency of the spending.

- Improved overall system reliability each year for both gas and electric.
- Drove the rationalization of operational practices, reducing planned outages by over 100,000 customers per year.
- Developed long range reliability strategy, including the deployment of distribution automation and distributed energy storage.
- Brought insight to operational processes, resulting in significant improvements in average restoration times.
- Exceeded all forestry program goals, completing program at budget ($100 M annually).

Provided Leadership on several internal transformational initiatives

- Member of the Utility Operating Committee and Utility Executive Committee.
- Executive sponsor for the development and deployment of a new Geographic Information System.
- Executive sponsor for internal Leadership Academy, strengthening leadership skills for over 2200 managers and supervisors throughout the company.
- Executive lead on several Enterprise Risk Management initiatives requested by the Risk and Audit Committee of the Board.

Vice President – Distribution Asset Management for Midwest Electric Power Company

Mr. Ramsay was accountable for the development of Capital and O&M investment plans for the distribution and customer operations business, which encompassed over $1 billion in annual expenditures for seven operating companies, in eleven States and fifteen regulatory jurisdictions. He was accountable for the development of reliability improvement, and asset sustainability plans and the creation of the regulatory/funding strategy to ensure that appropriate recovery of investments is achieved. He was directly accountable for the execution of all large system capital projects and all Transmission and Distribution Forestry work. In this role, Mr. Ramsay provided the leadership and drive required to foster innovation and a shift in the culture, allowing for significant improvements in system and financial performance:

- Improved reliability on worst performing circuits by 30% in one year.
- Improved CEMI performance significantly in one year.
- Achieved all major forestry program goals completing the program under budget.
- Drove the rationalization of accounting policies, resulting in a $27 million annual benefit to the business.
- Developed long range reliability strategy approved by the Board resulting in increased investment between 2006 and 2009, producing significant reductions in long term O&M.

Senior Vice President for a Management Consulting Firm

Mr. Ramsay was the global business unit lead for the firm's two largest business segments and a Member of the Board of Directors and of the global leadership team. He was responsible for global business development and client relationship management. Mr. Ramsay was consistently one of the firm's top consultants, obtaining the highest client satisfaction ratings.

Mr. Ramsay was responsible for all performance management, process improvement and Asset Management products and services for transmission, distribution and customer service, as well as the supporting infrastructure processes. In this role he:

- Led global business development and service delivery team working with utilities worldwide.
- Was the Manager or Officer in Charge for several large utility organizational transformations, for clients on three continents.
- Provided executive coaching for utility executives.

- Led the development of innovative services and regulatory strategy offers to support clients in newly deregulated markets, and for newly separated transmission business units.
- Provided post merger performance improvement support for clients on three continents.
- Developed analytical approaches and services specifically geared toward understanding and improving upon Asset Management capabilities.

Mr. Ramsay led the development of several innovative and powerful analytical and decision support tools:

- Spending Optimization Model
- Acquisition Targeting and Screening
- Outsource Candidate Evaluation Profile

In 2001, Mr. Ramsay accepted the role of the Managing Director of UK operations, after the separation of the previous MD from the business. He lived and worked in the UK for nine months on this temporary assignment, and was responsible for:

- Rebuilding client relationships.
- Rebuilding the revenue stream.
- Re-staffing the organization to fit the business strategy.
- Restoring the UK/European business segment to profitability.
- Recruiting and hiring a permanent Managing Director.

Prior to joining the management consulting firm, Mr. Ramsay worked for an internationally recognized Consulting Engineering firm. He was responsible for all planning and engineering, for utilities in Southeast US, Caribbean, Southeast Asia. He was a member of the global leadership team responsible for business strategy and business development across North America, the Caribbean and Southeast Asia. Mr. Ramsay provided support as an expert witness and regulatory strategy lead for several clients in FERC and State regulatory matters. He was responsible for the development of long-range business strategies for several clients across North America, and provided technical support and expert review in support of financing of projects in excess of 1 billion dollars.

Jason C. Kinslow

Summary and Background

Mr. Kinslow is a Principal with UMS Group in the North American Energy Delivery Consulting Practice. His experience covers more than ten years of management consulting experience, six years in the electric utility industry. His experience includes Asset Management Business model development, competitive strategy development and organization transformation. Mr. Kinslow has a diverse background in transmission, distribution, and generation engagements.

He holds a Bachelor of Science degree in Industrial and Management Engineering from Rensselaer Polytechnic Institute, as well as minors in management and industrial psychology.

Highlights of Experience:

- Mr. Kinslow has served as Project Manager or Assistant Project Manager for organizational transformation efforts for many of the Firm's Transmission and Distribution and Generation utility clients. These have included process reengineering, culture change, corporate transformation, market focuses, strategic planning, and planning for deregulation.
- Mr. Kinslow is one of the firms key experts in the Asset Management Model and its processes, functions, and details. He has amassed considerable experience in the design, planning, and installation of all aspects of the Asset Management Model in both the T&D and Generation businesses.
- Mr. Kinslow has led the design and adoption of the Asset Management Model at several major utilities in the USA and Canada.
- Mr. Kinslow was project manager for the development and implementation of an asset management business for a major southern utility. He led the design, refinement and installation of the asset management process, tools, and methodologies.
- Mr. Kinslow facilitated the design of the Asset Strategy Process for a major eastern utility. This was an integral process in the development of the asset management model. In addition Mr. Kinslow led the integration effort to combine the designs of the various Asset Management processes to provide a seamless workflow for the utility.
- Mr. Kinslow has also had experience with the installation of asset management processes, tools and methodologies in commercial and governmental industries.
- Prior to joining UMS Group, Mr. Kinslow worked at the Port Authority of NY & NJ as an Associate Management Engineer were he lead project teams in reengineering, supply chain improvement, facility design, and system integration projects.
- While with the Port Authority, Mr. Kinslow led a team in the development and implementation of a paperless purchasing system. By implementing a procurement card program, expanding the blanket orders initiative, and reengineering the contract administration process, major savings were achieved and integration of the system was expedited.

- Mr. Kinslow led a team in the moving and redesign of the JFK Airport facility warehouse. The project involved scheduling the logistics of the move, selection of inventory picking technology, and the design of the warehouse layout. In addition, he quantified and determined the most efficient and effective workload allocation and individual staff responsibilities to maximize staff utilization of the Material Control function, as well as identified opportunities to streamline workflow, methods, and procedures to improve the operation.

Marc Jan Hartsema

Summary and Background

Mr. Hartsema is a Director with UMS Group Europe. He has 16 years of management and consulting experience in energy and utilities and he has extensive knowledge in strategic planning, investment, maintenance, risk and contract management, and the management of change. His focus area is in asset management in the energy and utilities markets.

Highlights of Experience

- Prior to joining UMS, his experience included 5 years working at Capgemini where he participated successfully as a lead consultant/content expert in several international projects to develop and implement an asset management framework, and the design and implementation of asset management business processes, and 10 years working within Energy Company Nuon in the Netherlands.
- 3 years as a manager Contracting Department, member of the MT Asset Management, responsible for sales and purchases with regard to the product and service portfolio of Asset Management in the area of investment, maintenance and management of E, G and Water infrastructure.
- 2 years as a Senior Project Manager, member of MT, responsible for the acquisition and contracting complex and multi-disciplinary projects on new development and redevelop locations (houses and industrial) in the area of energy and water infrastructure. Lead of project teams from acquisition to the realisation phase.
- 2 years as a Grid Controller, member of MT Continuon Netbeheer, responsible for developing and managing the implementation of strategic, technical and financial policy with regard to the development of the electricity infrastructure. Also responsible for the investment and maintenance planning

He holds a B.Sc. in Technical information technology, a B.Sc. in Mechanical Engineering (in Energy Technology), and a Higher-degree equation in Gas Technology.

Joseph R. Lake

Summary and Background

Mr. Lake is a Business Analyst at UMS Group. He has served in this capacity for five months, having joined UMS Group in July of 2007.

Prior to joining UMS, Mr. Lake studied business at the Rensselaer Polytechnic Institute in Troy, NY. While attending school, he worked as a Web Developer and Senior Production Assistant for the Production and Video Services department at Rensselaer, where he led several teams in the video production of Distance Education classes. He holds a Bachelor's degree in Management, while having also minored in Economics.

Highlights of Experience:

- Mr. Lake has contributed to several data collection and analysis projects in his months with the company. In only his first few weeks as an analyst, he was part of a team that built and analyzed a database of publicly available electric distribution company financials. This information would become the major tool utilized in a discussion with a distribution company seeking the advice of UMS Group prior to an important rate case hearing.
- With his experience as a Web Developer and Database Administrator, Mr. Lake has contributed greatly to UMS Group internally. He has been working as part of a team charged with the task of bringing online and further developing the benchmarking processes which UMS Group has designed.
- In addition to data collection and analysis, Mr. Lake has specifically made contributions to projects in the form of documentation, report building, presentation creation, and process architecture design.

Appendix 5 – UMS Group Partial Client List and Map

Americas Utilities and Associations

Alabama Power
Alliant Energy
Ameren
American Electric Power
Aquila
Arizona Public Service
ATCO Electric (AB)
Austin Energy
Avista Utilities
Baltimore Gas & Electric
Barrie Hydro (ON)
Basin Electric
BC Hydro
BC Transmission Corp
Bonneville Power Admin.
Central Louisiana Electric Co.
Central Maine Power
Chugach Electric
City of Hamilton (ON)
City of Portland (OR)
Consolidated Edison
CMS Energy
CPS Energy (San Antonio)
Delmarva Power
Dominion
DPL Energy
DTE Energy
Duke Energy
Duquesne Light
ENMAX (AB)
E.ON US
Electric Power Research Institute (EPRI)
Empire District Electric Co.
Energy Northwest
Entergy
Erie Thames Power
Essex Power
Exelon
First Energy
Florida Power & Light
Georgia Power
GPU
Homer Electric
Hydro One
Hydro Ottawa
Idaho Power
IID Energy
Intermountain Power
International Transmission Company
Kansas City Power & Light
Lansing Board of Water & Light
Long Island Power Authority
Los Angeles DWP
Lower Colorado River Authority
Mississippi Power
NSTAR
National Grid US
New York Power Authority
NiSource
Northeast Utilities
Nova Scotia Power
Nuclear Energy Institute (NEI)
National Rural Electric Coop Association (NRECA)
Oklahoma Gas & Electric
Omaha Public Power District
Pacific Gas & Electric
PEPCO Holdings
PNM (NM)
Portland General Electric
PPL Corporation
Progress Energy
Public Service Electric & Gas
Salt River Project
San Diego Gas & Electric
San Francisco PUC
SaskPower
Seattle Public Utilities
Sierra Pacific Power
Southern California Edison
Southern Company
SMUD
TECO Energy
Tennessee Valley Authority
TransAlta (AB)
TXU Energy
UGI Utilities
United Illuminating
WE Energies
WPS Resources
Xcel Energy

Non-Utility Energy Related Companies

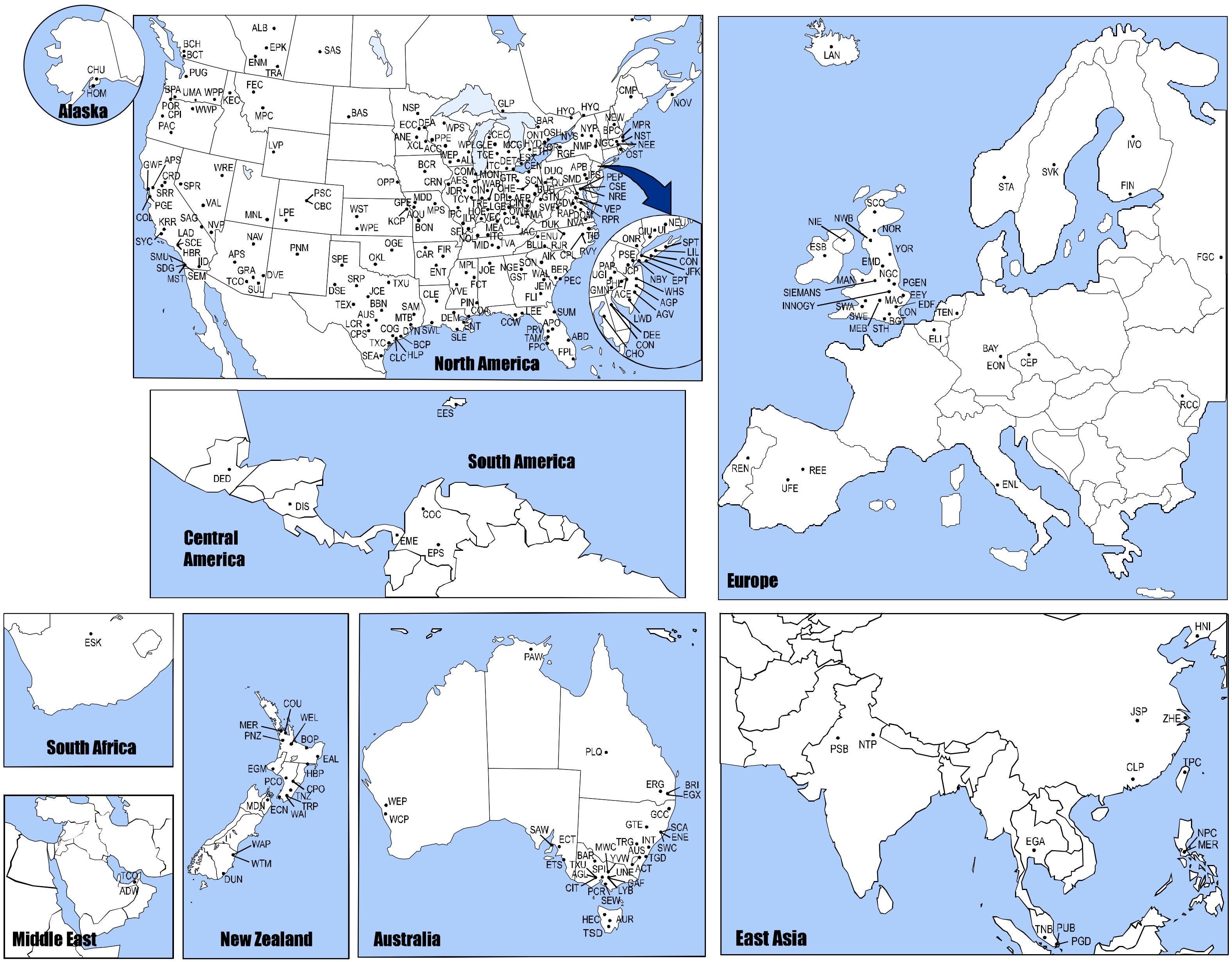
Air Products & Chemicals, Inc. (Cambria)
Asplundh Tree Expert Co.
Airservices Australia (Aus)
Bayou Cogeneration Plant
Black & Veatch
Caterpillar
Central Power & Lime
Chevron
Chickasaw Nation
CRA International
Doswell Limited Partnership
GE Answer Center
Macquarie Bank
Mission Energy
Newark Bay Cogeneration
Oakleigh Industries (Aus)
Pacific National (Aus)
RJ Reynolds
Shell (China)
A. E. Staley
Westinghouse

Asia Pacific Utilities and Associations

Actew-AGL (Aus)
AGL (Aus)
Aurora Energy (Aus)
Barwon Water (Aus)
Brisbane Water (Aus)
City West Water (Aus)
Central Power (NZ)
China Light & Power (Hong Kong)
Christchurch City Council (NZ)
Country Energy (Aus)
ElectraNet (Aus)
Energex (Aus)
Energy Australia (Aus)
Ergon (Aus)
ETSA Utilities (Aus)
Gold Coast Water (Aus)
Gosford City Council (Aus)
GPU (Aus)
HIPD Corp. (China)
Hobart Water (Aus)
Hunter Water Corporation (Aus)
Integral Energy (Aus)
JiangSu Prov. Elect. Bd. (China)
Logan Water (Aus)
Maroochy Water (Aus)
Melbourne Water (Aus)
Mercury Energy (NZ)
Metrowater (NZ)
Mission Energy (Aus)
National Power Corporation (Philippines)
National Thermal Power Corporation (India)
Orion Energy (Aus)
PowerCo (NZ)
Powercor-CitiPower (Aus)
Powerlink (Aus)
PowerNet (NZ)
Power & Water Authority (Aus)
PowerLink (Aus)
Punjab State Elect. Board (India)
SA Water (Aus)
Singapore Power (Singapore)
Singapore PUB (Singapore)
South East Water (Aus)
SP AusNet (Aus)
State Grid (China)
Sydney Water (Aus)
Taiwan Power Corporation (Taiwan)
Tenaga Nasional Berhad (Malaysia)
Transend (Aus)
TransGrid (Aus)
TransPower (NZ)
TRUenergy (Aus)
Unison (NZ)
United Energy (Aus)
Vector Networks (NZ)
WAPDA (Pakistan)
Water Corporation (Aus)
WEL Networks (NZ)
Western Power (Aus)
WSAA (Aus)
Yarra Valley Water (Aus)

Europe, Mideast and Africa Utilities

Abu Dhabi Water & Electric (UAE)
Eastern Electricity (UK)
EDF Group (France, UK)
Elia (Belgium)
Enel (Italy)
E.ON (Germany)
ESB (Ireland)
Eskom (South Africa)
Federal Grid Corp. (Russia)
Fingrid (Finland)
Ivo Voimansiirto Oy (Finland)
Landsnet (Iceland)
Manweb (UK)
National Grid (UK)
Northern Electricity (UK)
Red Eléctrica De España (Spain)
Rede Eléctrica Nacional (Portugal)
Scottish Power (Scotland)
Southwestern Electricity Board (UK)
Statnett SF (Norway)
Svenska Kraftnät (Sweden)
Tennet (Netherlands)
Thames Water (UK)
Transco (Abu Dhabi)
Transelectrica (Romania)
United Utilities (UK)


Alaska
North America
South America
Central America
Europe
South Africa
Middle East
New Zealand
Australia
East Asia

Appendix 6 – Abbreviations and Acronyms

Acronym	Phrase
AHP	Analytical Hierarchy Preferencing
AM	Asset Management
BCH	British Columbia Hydro
BCTC	British Columbia Transmission Company
BCUC	British Columbia Utility Commission
CBM	Condition Based Maintenance
Ckt	Circuit
EEI	Edison Electric Institute
EHV	Extremely High Voltage
EOL	End of Life
FERC	Federal Energy Regulatory Commission (USA)
FMEA	Failure Mode and Effects Analysis
GWh	Gigawatt hour
GWh-Km	Gigawatt hour-Kilometer
IAM	Institute of Asset Management
IIP	Indices of Industrial Production
ILM	Interior Lower Mainland
IPP	Independent Power Producers
IRR	Internal Rate of Return
ISO	Independent System Operator
IT	Information Technology
ITOMS	International Transmission Operations & Maintenance Study
Km	Kilometer
kV	Kilovolt

MAIFI	Monetary Average Interruption Frequency Index
MTP	Medium-Term Performance
MW	Megawatt
MWh	Megawatt hour
MWhrs	Megawatt hours
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
O&M	Operations & Maintenance
OEM	Original Equipment Manufacturer
OFGEM	Office of Gas and Electricity Markets (UK)
OHL	Overhead Lines
OMA	Operations, Maintenance, and Administration
OpsWAN	Operations Wide Area Network
PAS 55	Publicly Available Specification 55
PM	Preventative Maintenance
RCM	Risk & Criticality based Maintenance
ROE	Return on Equity
ROI	Return on Investment
SAM	Strategic Asset Management
SCADA	Supervisory Control and Data Acquisition
TADS	Transmission Availability Data System
TCAIDI	Total Customer Average Interruption Duration Index
TSAIDI	Total System Average Interruption Duration Index
TSAIFI	Total System Average Interruption Frequency Index
VITR	Vancouver Island Transmission Reinforcement
WECC	Western Electricity Coordinating Council (USA)

Appendix J

Prioritization Model User Manual

Table of Contents

1.0 INTRODUCTION

A significant development in 2006 was the implementation of a formal prioritization methodology for all capital portfolios. Previous capital investment rating systems consisted only of rating investments as “mandatory” or “discretionary”, which was inadequate for ranking investments and assembling portfolios. A capital investment ranking system, to better discriminate between capital investments, was needed.

BCTC engaged UMS Group Inc. (UMS), a consultant experienced in creating similar ranking systems within other utilities, to assist in the development of a formal prioritization methodology.

The prioritization methodology is used to assist BCTC’s senior management in portfolio planning. All proposed investments are evaluated using this methodology. The results are reviewed and discussed and become an input into the portfolio decision-making process. The methodology does not relieve BCTC of its decision-making responsibility, but it does aid management in identifying the critical and valuable investments that should be undertaken to ensure the success of BCTC, as well as those investments which may be candidates for complete or partial deferral in a resource constrained environment. BCTC’s prioritization methodology has become an integral part of its capital planning process.

This document will help the readers understand what the prioritization methodology is, and provides guidance for its use. First, an overview of the methodology is provided in Section 2 of this document. Section 3 provides a description of how the categories and criteria used to score each investment, together with their weightings, are determined. Section 4 provides details of the different computations required to calculate the scores for each investment. Finally, the approach to assembling the portfolios using the prioritization scores is described in Section 5. The Appendices to this document provide reference information. Appendices A to D provide the figures, data and look-up tables relevant to the prioritization of the F2009 Capital Plan, while Appendices E to G provide three examples of score computations.

2.0 OVERVIEW OF THE METHODOLOGY

2.1 Assessment Approach

BCTC uses the prioritization methodology to evaluate proposed investments in each of its three capital portfolios:

i. Sustaining;
ii. Growth; and
iii. BCTC Assets.

The prioritization methodology considers two attributes of each investment:

a. Value: the value achieved by implementing the investment; and

b. Deferral Risk: the risk associated with deferring the investment for one year.

For each attribute, a score is calculated by assessing each investment against nineteen criteria in six categories. The six categories are:

(a) Financial

(b) Reliability

(c) Market Efficiency

(d) Asset Condition

(e) Relationships

(f) Environment and Safety

Once value and deferral risk scores are calculated for all proposed investments, a review is undertaken to ensure scoring is consistent within each portfolio. The scores are then used to rank the investments and identify lower deferral risk and lower value investments, which become candidates for deferral if required by resource constraints.

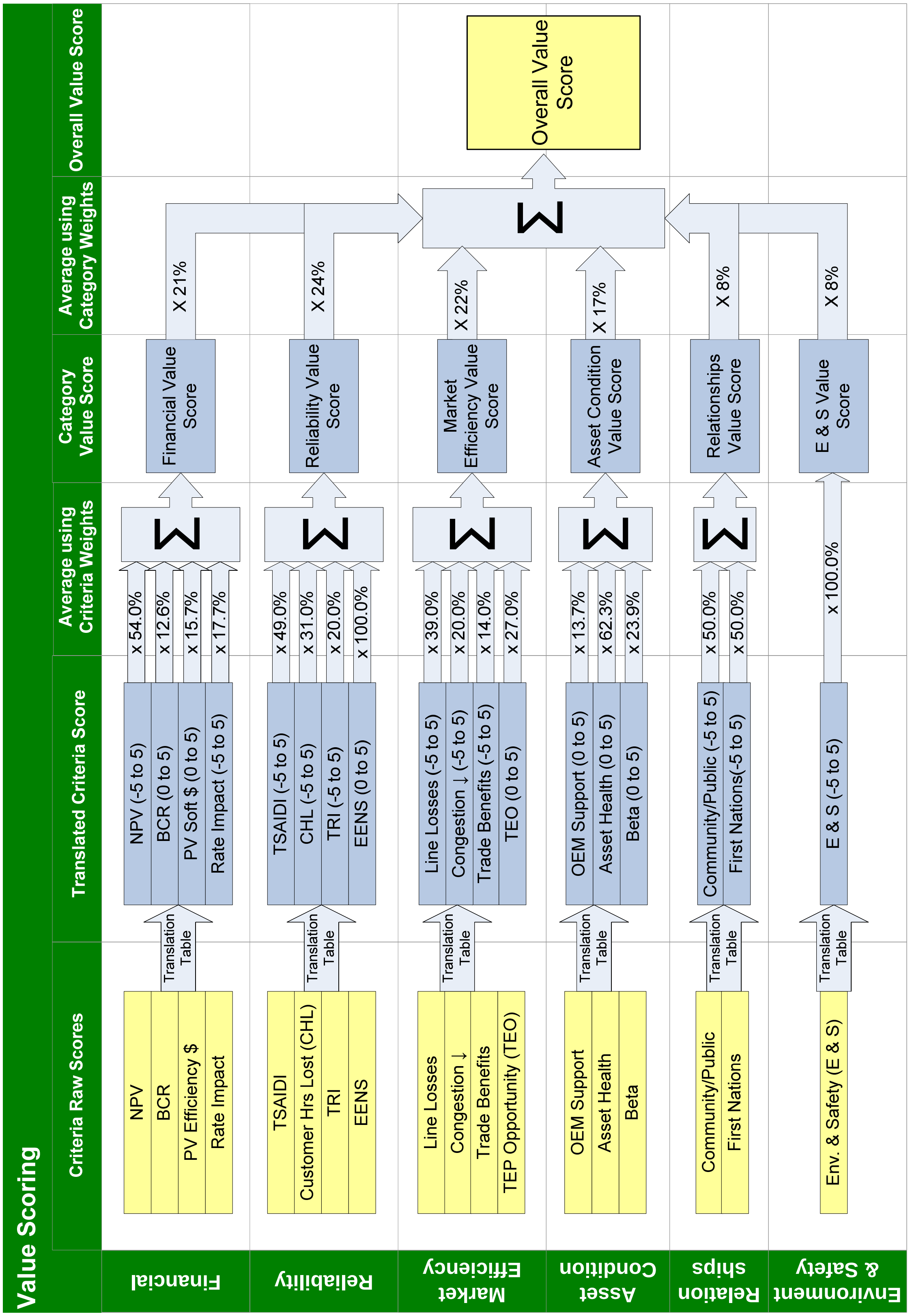
The following sections define the value and deferral risk attributes, as well as the nineteen criteria.

2.2 Value Attribute

The value of an investment is measured by evaluating the costs and benefits associated with the investment for each of the 19 criteria. A score is determined between -5 and 5 using the value matrix in Appendix B. Then, within each of the six categories, the individual criteria scores are weighted to arrive at a score for that category. The overall value score is then computed as a weighted average of the category scores. The determination of the weights is done using a methodology called Analytical Hierarchy Process (AHP). AHP uses a series of pair wise comparisons to develop group consensus on relative weighting across various elements. Using this process, managers and subject matter experts establish the criteria weights and senior managers establish the category weights. The methodology is further discussed in Section 3 – Determination of Categories and Weightings. The weightings are provided in Appendix A.

Figure 1 illustrates how the Value Score is computed.

Figure 1. Value Scoring



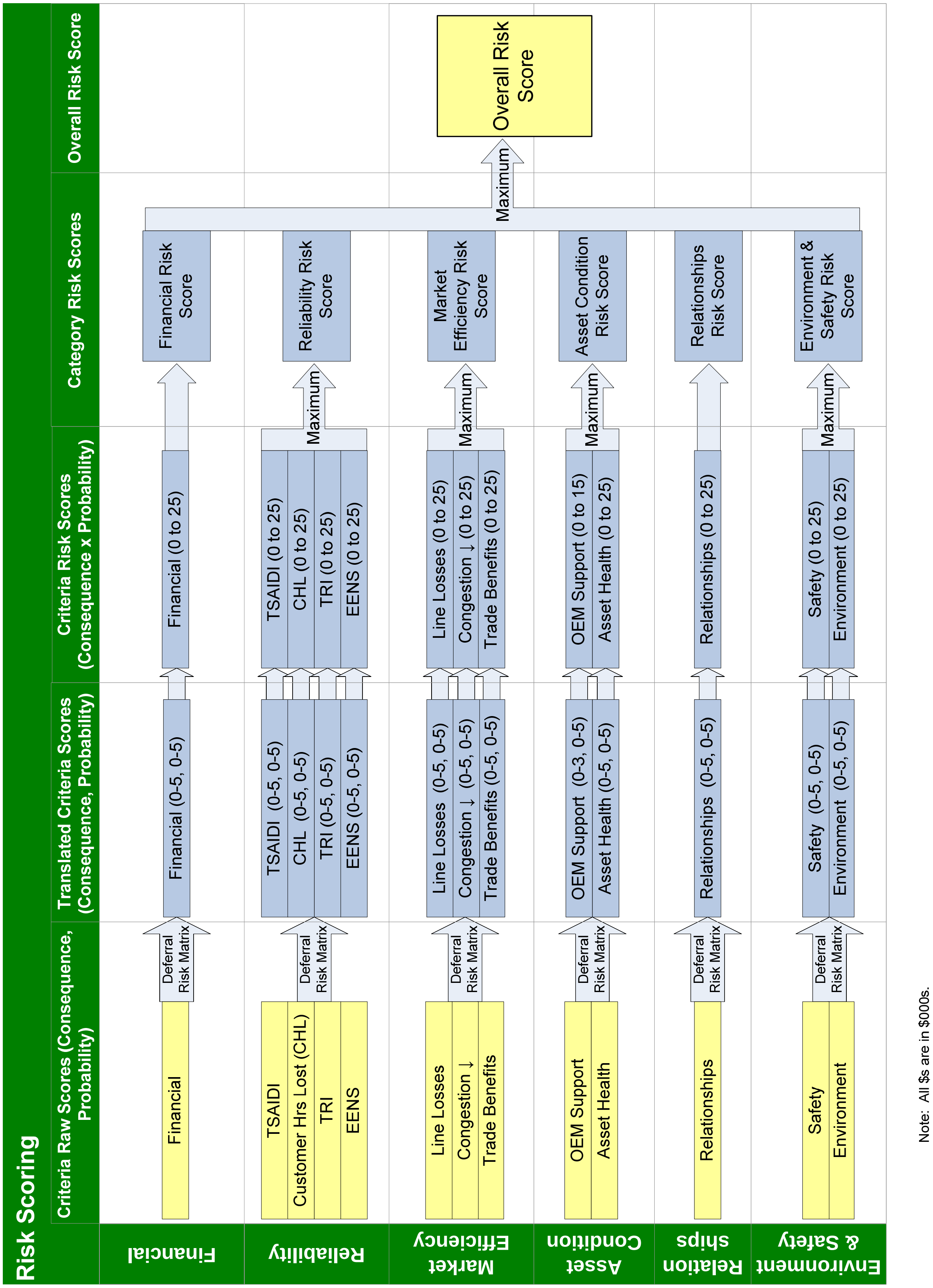
Note: All $s are in $000s.

2.3 Deferral Risk Attribute

The deferral risk is the risk associated with the investment being deferred one year. The consequence and probability components of the most likely risk scenario (the consequence with the highest probability) are each determined on a scale of 0 to 5 using the Deferral Risk Matrix, shown in Appendix C. In many cases, the deferral risk consequence is derived from the value attribute data. Once the two components have been determined, the risk score for each criterion is calculated by multiplying the consequence and the probability. This results in a deferral risk score between 0 and 25. This deferral risk is calculated for each criterion. The deferral risk of each category is then the highest risk score of the criteria within that category. Similarly, the highest risk score of the six categories becomes the deferral risk of the investment.

Figure 2 illustrates how the deferral risk score of an investment is derived.

Figure 2. Risk Scoring



2.4 Category Criteria

2.4.1 Financial Criteria

(a) Net present value: discounted cash flow;

(b) Benefit to cost ratio: net present value of OMA cost savings and revenue compared to net present value of all costs;

(c) Rate impact of each investment; and

(d) Efficiency savings related to time savings, efficiency, or effectiveness that do not impact the bottom line.

2.4.2 Reliability Criteria

(a) Transmission System Average Interruption Duration Index ("TSAIDI"): the average outage duration across all delivery points over a one-year period;

(b) Distribution Customer Hours: the number of end-use customers experiencing an outage combined with the duration of that outage;

(c) Transmission Reliability Index (TRI): a function of the weighted duration and number of failures over a five-year period, the mean time between failures over a five-year period, and the duration since the last failure; and

(d) EENS (Expected Energy Not Served): the amount of expected energy not served based on the frequency of planned and unplanned outages, the duration of these outages, and the load curtailment.

2.4.3 Market Efficiency Criteria

(a) Real Line Losses Reduction: the estimated reduction in transmission line energy losses due to the investment;

(b) Congestion Reduction: the estimated reduction in annual congestion due to the investment;

(c) Trade Benefits: measures the investment's expected impact on trade; and

(d) Transmission Expansion Opportunity: indicates the benefits of the investment related to BCTC's Transmission Expansion Policy.

2.4.4 Asset Condition Criteria

(a) Equipment Spares Support: assesses the level of support provided by the Original Equipment Manufacturer ("OEM") and the availability of spares before and after the proposed investment;

(b) Asset Health: based on the pre- and post-investment assessment of the assets that will be impacted by the proposed investment. Asset Health scoring comprises the following areas: Remaining Life, Failure Rates, Asset Condition and Criticality (assessed by scoring Load, Role, Redundancy and Voltage for Stations, Circuit Criticality for Lines, and System Criticality for BCTC Assets); and

(c) Failure Rate (Beta): the change in the Time Between Failures rate.

2.4.5 Relationship Category Criteria

(a) The Community/Public relations criterion measures the impact of the investment on relationships with the Community and the general public, focusing on BCTC's relationships with the following stakeholders: Industrial, Commercial and Residential Customers; IPPs and Wholesale Transmission Customers; Municipal Governments; Provincial Governments; and the general public.

(b) Similar to the Community/Public relations criterion, the First Nations criterion measures the impact of the investment on relationships with First Nations.

2.4.6 Environment and Safety Category Criteria

(a) The Environment criterion assesses the construction, operation and decommissioning impacts of the investment on Greenhouse Gas Emissions, Air Quality, Waste, Land, Water, Species at Risk and Environmental Management Systems. Investments which are initiated to meet Federal, Provincial, or Municipal environmental requirements are considered to be mandatory, but are still scored.

(b) The Safety criterion assesses the construction, operation and decommissioning impacts of the investment on Employee, Workforce and Public Safety. Investments which are initiated to meet Federal, Provincial, or Municipal safety requirements are considered to be mandatory, but are still scored.

3.0 DETERMINATION OF CATEGORY AND CRITERIA WEIGHTINGS

The categories and criteria BCTC uses in its prioritization methodology were originally defined in 2006 by reviewing the mission statement, key performance indicators, values, and annual reports to identify the business objectives. These were then discussed with senior decision makers and distilled into six categories and 18 criteria, representing the competing and complementing variables that are required to make sound capital spending decisions at BCTC. In 2007, a criterion for Transmission Expansion Opportunities was added to the Market Efficiency category, increasing the total number of criteria to 19.

BCTC has used the Analytical Hierarchy Process (AHP) or "forced pairs methodology" to set the weightings for the categories and criteria used in value scoring. The Analytical Hierarchy Process Model was designed by TL Saaty[1] as a powerful and flexible decision making aid to help set priorities and make the best decision when both qualitative and quantitative aspects of a decision need to be considered. By reducing these complex decisions (such as developing weightings for the categories) to a series of one-on-one comparisons, then synthesizing the results, AHP not only helps decision makers arrive at the best decision, but also provides a clear rationale that it is the best.

Specifically, the process involves building a hierarchy of decision elements and then making comparisons between each possible pair of the elements based on a relative level of importance. This gives a weighting for each element within a cluster (or level of the hierarchy).

Traditionally, AHP uses a 9-point scale to determine relative importance of the pair wise comparisons (1—equally important, 3—moderately more important, 5—strongly more important, 7—very strongly more important, 9—extremely more important). For simplicity, BCTC used a 4-point scale (1—equally important, 2—slightly more important, 3—more important, 4—much more important) in the pair wise comparison model.

[1] T. L. Saaty, The Analytic Hierarchy Process: Planning, Priority Setting, Resource Allocation, McGraw-Hill, New York, 1980. Dr T.L. Saaty, PhD, Mathematics, Yale University, 1953, developed AHP in the 1970's while he was a professor at the Wharton School of Business of the University of Pennsylvania. He is currently University Professor at the Katz Graduate School of Business of the University of Pittsburgh.

The following steps outline the mathematics behind the Analytical Hierarchy Process used at BCTC:

1. Determine the objectives to be compared. For BCTC, these are Reliability; Financial; Asset Condition; Market Efficiency; Relationships; and Environment & Safety.

2. Set up a hierarchy model and determine the relative importance of each pair of objectives using BCTC's 4-point scale. Table 3.1 shows the first step of the AHP using the development of BCTC's category weightings as an example. In Table 3.1, the number in the ith row and jth column gives the relative importance of Category i as compared with Category j. For example, the entry in the Reliability row and Market Efficiency column indicates that Reliability is considered slightly more important than Market Efficiency, scoring a '2'. The inverse, ½, is shown in the Market Efficiency row under the Reliability column.

Table 3.1 – Step 1 of the AHP

	Financial	Reliability	Asset Condition	Market Efficiency	Relation-ships	Environment & Safety
Financial	1	1	1	1	3	3
Reliability	1	1	1	2	3	3
Asset Condition	1	1	1	1/2	2	2
Market Efficiency	1	1/2	2	1	3	3
Relationships	1/3	1/3	1/2	1/3	1	1
Environment & Safety	1/3	1/3	1/2	1/3	1	1
Total	4 2/3	4 1/6	6	5 1/6	13	13

3. Divide each entry by the sum of the column it appears in, as shown in Table 3.2. For instance the (Reliability, Reliability) entry would be calculated as 1/(1+1+1+1/2+1/3+1/3) = 0.24 . The other entries become:

Table 3.2 – Step 2 of the AHP

	Financial	Reliability	Asset Condition	Market Efficiency	Relation-ships	Environment & Safety
Financial	0.2143	0.2400	0.1667	0.1935	0.2308	0.2308
Reliability	0.2143	0.2400	0.1667	0.3871	0.2308	0.2308
Asset Condition	0.2143	0.2400	0.1667	0.0968	0.1538	0.1538
Market Efficiency	0.2143	0.1200	0.3333	0.1935	0.2308	0.2308
Relationships	0.0714	0.0800	0.0833	0.0645	0.0769	0.0769
Environment & Safety	0.0714	0.0800	0.0833	0.0645	0.0769	0.0769

4. Next, average the entries in each row to determine the relative weighting of each objective, as shown in Table 3.3.

Table 3.3 – Step 3 of the AHP

	Financial	Reliability	Asset Condition	Market Efficiency	Relation-ships	Environment & Safety	Average
Financial	0.2143	0.2400	0.1667	0.1935	0.2308	0.2308	21.3%
Reliability	0.2143	0.2400	0.1667	0.3871	0.2308	0.2308	24.5%
Asset Condition	0.2143	0.2400	0.1667	0.0968	0.1538	0.1538	17.1%
Market Efficiency	0.2143	0.1200	0.3333	0.1935	0.2308	0.2308	22.0%
Relationships	0.0714	0.0800	0.0833	0.0645	0.0769	0.0769	7.6%
Environment & Safety	0.0714	0.0800	0.0833	0.0645	0.0769	0.0769	7.6%

5. The final weightings become: Financial - 21%; Reliability – 24%; Asset Condition – 17%; Market Efficiency – 22%; Relationships - 8%; and Environment & Safety – 8%. These are the category weightings used for the F2009 Capital Plan.

The same methodology was used to determine criteria weightings within each category. Criteria weightings can be found in Appendix A.

Changes in BCTC's business environment can impact the criteria and categories that are used to calculate each investment's value score. Consequently, BCTC reviews the category and criteria annually to assess their ongoing relevance to investment evaluation and identifies any new categories or criteria that need to be added. The review also includes an analysis of the category and criteria weightings. It is the responsibility of the Manager, Corporate Capital Planning Process to ensure the categories, criteria and weightings are reviewed annually.

4.0 COMPUTATION OF CRITERIA AND CATEGORY SCORES

The section below describes the computation required to score the investments. The assessment and scoring of each investment is to be done preferably by the planner responsible for the investment, or alternatively, by individuals fully knowledgeable about the investments.

As a general guideline, all new investments coming for approval in the next year (or two in the case of the Sustaining Portfolio), together with any approved projects that could be reasonably considered for deferral, should be scored.

4.1 Financial Category

4.1.1 Value Scoring

The Value Score for the Financial Category is calculated by adding the weighted scores of each criterion as follows:

$$\sum \begin{array}{l} \text{Weighting A1 * NPV} \\ \text{Weighting A2 * Benefit to Cost Ratio} \\ \text{Weighting A3 * PV of Efficiency Dollar Savings} \\ \text{Weighting A4 * Rate Impact} \end{array}$$

The financial analysis cost, savings, and benefits components used in the Financial category criteria are described in the following section. This is followed by a description of the methodologies for calculation of the four financial criteria value and deferral risk scores. The current weightings are provided in Appendix A.

4.1.1.1 Financial Analysis Cost, Savings, and Benefits Components

All cost, savings and benefits components used in the calculation for the four financial criteria should be unescalated.

Cost Components

i Capital Investment Costs – any costs incurred to buy or construct an asset. This would include internal labour, contractor labour, materials/equipment, services/other, BC Hydro owned new land purchases, ROW costs, and contingency costs.

ii % Allocation of Capital Investment Costs by Asset Class, Circuit Lengths – used for depreciation and tax calculations.

iii Overhead Costs – overhead costs are calculated as a percentage of Capital Investment Costs. Refer to Appendix A for the current overhead rates.

iv Contribution in Aid of Construction (CIAC) – CIAC dollars are any contributions received from third parties to fund the construction of an asset. These contributions provide an off-set to the finance charges, including IDC and depreciation associated with the Capital Investments Costs. For the purpose of prioritization, it is assumed that CIAC is received in equal instalments over the construction period of the investment; ie a four year cash flow for a capital investment that has a CIAC component would use the annual CIAC as (CIAC$/4).

v Residual Equipment Book Value – residual book value of equipment removed from service. This is used for rate impact calculations.

vi Average Number of Depreciable Years Remaining – remaining depreciable years of equipment removed from service. This is used for rate impact calculations.

vii Interest During Construction (IDC and AFUDC) Costs – IDC costs are calculated for Growth and Sustaining Portfolio investments. AFUDC costs are calculated for BCTC Portfolio investments. Both IDC and AFUDC are calculated as a percentage of Capital Investment Costs and Capital Overheads. For the purpose of the prioritization, capital expenditures in the current year will be applied using the half year rule. IDC and AFUDC are compounded yearly. Refer to Appendix A for the current IDC and AFUDC annual rates.

viii Project OMA Costs – any costs required by the project that do not meet the rules of capitalization. These costs are incurred prior to or during the in-service year and would include items such as data conversion, incremental insurance required during construction, work process development and staff training (not including training materials which can be capitalized). The estimate of project OMA costs should include all internal labour, contractor labour, materials/equipment, services/other expenses.

ix OMA Ongoing Costs – any on-going operations and maintenance costs (internal labour, contractor labour, materials/equipment, services/other). Generally these costs begin during the in-service year and may continue throughout the life of the asset. These costs would include maintenance, hardware and software costs including licences and fees.

x Dismantling and Removal Costs (Net of Salvage Value) – any remediation, asset dismantling/retirement, or clean-up costs, net of salvage value. These costs are expensed in the year they occur and included as total OMA costs.

xi Grants and Taxes – These taxes are applied to new transmission lines, existing line extensions and station investments (Growth Investments) but not to Sustaining or BCTC capital investments. Grants and Taxes are calculated based on cost and asset information and rates provided in Appendix A. Grants and taxes calculations begin in the in-service year (applying the half year rule during the in-service year) and span the life of the asset.

Growth Grants and Taxes:

i. Computers and communications assets have no tax impact.

ii. Switchyard Equipment, Buildings, ROW (land rights) and BC Hydro Owned Land can be combined for calculating Grants and Taxes. Total taxable dollars include capital costs, overhead and IDC, but are not net of CIAC.

iii. Lines are taxed based on line or cable length (km) built and the voltage and type of construction (underground, overhead, steel, wood pole, submarine cable). Lines are grouped into tax assessment classes. For Lines with no assessment class, the tax is based on the total investment cost (capital expenditures, overhead costs, and IDC) and a tax allowance rate based on cost. The tax allowance rate is provided in Appendix A.

BCTC Grants and Taxes:

i. Grants and taxes pertaining to BCTC investments are not applicable unless a specific capital investment where land or other taxable assets (such as new building construction or additions) are to be purchased or constructed. If the investment being evaluated has such a component contact Finance for an estimate of the ongoing grants and taxes.

Savings and Benefit Components

i. OMA Savings –OMA savings are those that result in a reduction to OMA. OMA savings include reductions to maintenance, FTEs, chargeable overtime, contractor costs, hardware maintenance, and software licences. If a reduction to OMA is not to be made then the savings are considered to be efficiency savings, i.e. avoided costs (such as increased herbicide use to reduce future vegetation maintenance, replacement PCB filled equipment to reduce the risk of accidents requiring cleanup (i.e. oil spills) or environmental accidents, site reconstruction reducing the risk of a site fire), productivity improvement, redirected labour and efficiency gains unless the business case specifically identifies the date when the savings would occur and OMA is reduced at this date.

ii. Incremental Revenue (for Growth Investments) – a revenue stream is calculated to recognize new revenue from additional load, based on the following information:

a. Incremental load growth in MW each year within the investment's scope area (Starting in the in-service year)
b. MW of the above growth that can be served by existing capacity (pre-investment)
c. MW of new capacity that the investment will add
d. Load Factor of the expected growth
e. MWhr rate for load growth revenue

The annual incremental revenue is calculated from the load growth served by the project, calculated as follows:

Annual Incremental Revenue =
Load Growth Served by the Project (MW) x Hours in a Year x Load Factor
x MWhr rate

iii. Firm PTP Sales – forecast sales of firm PTP facilitated by the investment, not included in the load growth forecast, expressed in dollars.

It is to be noted that Losses Reduction, Congestion Reduction savings, or any other savings accruing to third party, should not be included in this criteria, as they are captured in the Market Efficiency Strategic Objective.

Efficiency Dollar Savings Components:

These dollars savings are those related to time savings, efficiency, or effectiveness improvements that do not impact the bottom line.

i. Labour Savings (Labour Efficiency Gains, Redirected Labour)

ii. Avoided Costs (Materials/Equipment Costs avoided)

iii. Other Dollar Savings that do not impact the bottom line.

4.1.1.2 Net Present Value

<u>Description</u>

Net Present Value (NPV) measures the present value of the benefits due to the investment, the forecast revenue and estimated savings, less the present value of the estimated costs. The calculation of NPV will not consider any efficiency savings.

<u>Calculation Methodology</u>

The NPV formula is as follows:

$$\text{NPV} = \sum_{i=1}^{n} \frac{values_i}{(1 + rate)^i}$$

Year 1 is the year in which costs of the investment begin and year “n” is 19 years after the in-service year of the project or the life of the asset; which ever is shorter. The period was selected as representative of a reasonable time frame to assess investment considering that the ability to forecast cost flows diminishes significantly past twenty years.

The calculation will use the Real Discount Rate provided in Appendix A.

The values will include all the applicable unescalated Cost, Savings and Benefit Components identified in Section 4.1.1.1. over the period. Efficiency Dollar Components will not be incorporated in the NPV analysis. These are addressed in the PV of Efficiency Dollar Savings in Section 4.1.1.4.

NPV calculated results are translated to a -5 to 5 scale, according to the Value Score Translation Table shown in Appendix D, where a 5 represents a high positive NPV of an investment.

4.1.1.3 Benefit to Cost Ratio

Description

The Benefit to Cost Ratio (BCR) of an investment measures the ratio of the present value of the OMA cost savings and revenue (the benefit) to the present value of all costs.

Calculation Methodology

$$\text{BCR} = \frac{\text{PV Savings and Benefit components}}{\text{PV Cost Components}}$$

Where the Present Values are calculated as follows:

$$PV = \sum_{i=1}^{n} \frac{values_i}{(1 + rate)^i}$$

Year 1 is the year in which costs of the investment begin and year “n” is 19 years after the in-service year of the project or the life of the asset; which ever is shorter.

The calculation will use the Real Discount Rate provided in Appendix A.

The values will include all the applicable unescalated Cost, Savings and Benefit Components identified in Section 4.1.1.1. over the period. Efficiency Saving Components will not be incorporated in the BCR analysis.

A “break-even” BCR is equal to 1.0. An investment with a BCR greater than 1.0 is profitable and an investment with a BCR less than 1.0 is not profitable.

BCR calculated results are translated to a 0 to 5 scale, according to the Value Score Translation Table shown in Appendix D, where a 5 represents a high positive BCR of an investment.

4.1.1.4 PV of Efficiency Dollar Savings

Description

Measures the present value of the Efficiency Dollar Savings impact of the investment.

Calculation Methodology

Present value of efficiency dollar savings are calculated as follows:

$$PV = \sum_{i=1}^{n} \frac{values_i}{(1 + rate)^i}$$

Year 1 is the year in which costs of the investment begin and year “n” is 19 years after the in-service year of the project or the life of the asset; which ever is shorter.

The calculation will use the Real Discount Rate provided in Appendix A.

The values will include all the applicable unescalated Efficiency Dollar Components identified in Section 4.1.1.1. over the period.

PV of Efficiency Dollar Savings is translated to a 0 to 5 scale, according to the Value Score Translation Table shown in Appendix D, where a 5 represents a high positive savings due to an investment.

4.1.1.5 Rate Impact %

Description

This measure assesses the impact of the investment on BCTC and BC Hydro rates over a 20 year horizon after the asset is placed in service. The rate impact calculation takes into account that there will be additional costs in the rate base and additional load served.

Calculation Methodology

Rate Impact =

$$\frac{\text{PV Incremental Cost of Service - PV Incremental Transmission Revenue}}{\text{PV BCH Transmission Revenue Requirement}}$$

Where the Present Values are calculated as follows:

$$PV = \sum_{i=1}^{n} \frac{values_i}{(1 + rate)^i}$$

Year 1 is the year in which costs of the investment begin and year "n" is 19 years after the in-service year of the project or the life of the asset; which ever is shorter.

The calculation will use the Real Discount Rate provided in Appendix A.

The Incremental Cost of Service values are calculated as follows:

Annual Equity Cost x ROE%

+

Annual Interest Cost = Debt Component x Interest %

Where Debt component = Rate Base (less Capital Asset accumulated depreciation and CIAC accumulated depreciation) x Interest %

+

Depreciation Expense

Annual depreciation for Capital Depreciable Assets and CIAC (the CIAC depreciation if an off-set to the Capital Asset depreciation)

+

Net Book Value of Assets Retired (Added in Year T=0 Only)

+

Grants and Taxes

+

Incremental OMA (OMA Costs less OMA Savings)*

(Net Annual OMA (Includes OMA Costs, Removal Costs, and any offsetting OMA Benefits)

Non-cash components are treated as follows:

a) Residual Equipment Book Value (Net Book Value of Assets Retired) – Added into Revenue Requirement Annual Amount in the In-service Year.
b) Depreciation Expense for Capital Costs – An accumulated depreciation expense is netted out of the capital costs (excluding BC Hydro owned land) in each year beginning in the in-service year (1/2 depreciation used in T=0) and ending when the asset is fully depreciated. (Capital costs are allocated by a percentage breakdown of asset types included in investment and are depreciated as per the applicable asset type depreciation schedules).
c) Depreciation Expense for CIAC – An accumulated depreciation expense is netted out of the CIAC in each year beginning in the in-service year (1/2 depreciation used in T=0) and ending when the CIAC is fully depreciated. CIAC, like capital costs, is allocated by a percentage breakdown of asset types included in investment and is depreciated as per the applicable asset type depreciation schedules).

The Incremental Revenue Requirement values are calculated as described in Section 4.1.1.1. The BC Hydro Transmission Revenue Requirement values are located in Appendix A.

A negative Rate Impact indicates that the investment will contribute to a reduction in Transmission rates while a positive Rate Impact will result in an increase in Transmission rates.

Rate Impact is translated to a -5 to 5 scale, according to the Value Score Translation Table shown in Appendix D, where a 5 indicates a high percentage rate decrease of an investment and a -5 indicates a high percentage rate increase.

4.1.2 Risk of Deferral Scoring

Financial Risk is evaluated on the consequence and probability of the most likely risk scenario if the investment is deferred by one year. The predicted financial impact of deferring the investment by one year is determined for the following categories:

i. Project Cost Increases – Land / ROW, Labour (Internal/Contractor), Materials and Equipment;
ii. Loss of Revenue – Transmission (Current) Revenue; and

iii. Other Cost Implications – Penalties/Fines, Increased Outage Expenses, Increased Ongoing OMA Expenses.

These impacts are summed and translated into a consequence score of 0 to 5. The probability of the most likely scenario is also translated into a probability score of 0 to 5. The translations are based on the Project Deferral Risk Matrix, shown in Appendix C.

The Financial Category Risk Score is the product of the consequence score and the probability score, and will have a value between 0 and 25.

4.2 Reliability

Reliability criteria assess the values and risks related to BCTC's investments that are associated with supply to end user customers (e.g. BC Hydro's residential, commercial, industrial customers).

Reliability measures are typically not associated with congestion impacts on generation, as this is addressed in the Market Efficiency category. For example, for prioritization purposes, generation re-dispatch is considered to be an economics issue rather than a reliability issue up to the point that no generation re-dispatch remains. However, where applicable, generator reliability is considered in the reliability assessment.

4.2.1 Value Scoring

The Reliability Value Score is calculated using:

$$\sum \begin{array}{l} \text{Weighting B1 * TSAIDI} \\ \text{Weighting B2 * Distribution Customer Hours Lost} \\ \text{Weighting B3 * Transmission Reliability Index} \\ \text{Weighting B4 * Expected Energy Not Served} \end{array}$$

Further detail on each criterion is included in the following sections; the weightings are shown in Appendix A. Sustaining investments will normally be measured against the first three reliability criteria, while Growth investments will be measured against the EENS criterion. As a result, weightings B1, B2, and B3 sum to 100% and B4 alone is 100%. Investments in the BCTC

Portfolio will be measured against the first three criteria or alternatively against the EENS criterion depending on the nature of the investment.

4.2.1.1 Transmission System Average Interruption Duration Index (TSAIDI) (Sustaining Portfolio)

Description

This criterion measures the expected impact of the investment on the Transmission System Average Interruption Duration Index (TSAIDI), assuming the investment is made. TSAIDI is defined as the average outage duration in hours per delivery point and is calculated by dividing the sum of all outage durations in one year by the total number of delivery points in the system. Specifically, this criterion measures the investment's improvement on (reduction in) total outage duration time or the less likely degradation on (increase in) total outage duration time. As the number of delivery points is a constant across all investments, this evaluation is based on Total Outage Duration Hours only.

Calculation Methodology

$$\text{TSAIDI Impact} = \begin{array}{c}\text{Total Pre-Investment}\\ \text{Outage Duration Hours}\\ \text{(for impacted failure types,}\\ \text{one year total)}\end{array} \times \begin{array}{c}\text{Percentage of Pre-Investment}\\ \text{Outage Duration Hours}\\ \text{Eliminated/ Added by}\\ \text{Investment}\end{array}$$

The Total Pre-Investment Outage Duration Hours is the actual total number of outage duration hours contributed by the assets impacted by the investment in the previous year.

The % eliminated represents the portion of the outage duration hours contribution of the assets impacted by the investment that would have been avoided had the investment been made prior to the previous year. The % added represents an estimate of the additional outage duration hours that would have been incurred had the investment been made prior to the previous year.

TSAIDI scores are translated to a -5 to 5 scale, according to the Value Score Translation Table shown in Appendix D, where a positive score represents the greatest positive impact of an investment and a negative score indicates an adverse impact of an investment.

4.2.1.2 Distribution Customer Hours Lost (Sustaining Portfolio)

Description

This criterion measures the investment's expected impact on Distribution Customer Hours Lost, assuming the investment is made. Distribution Customer Hours Lost is defined as the number of end-use customers experiencing an outage and the duration of that outage downstream from the delivery point. Scoring for this measure will be calculated as the increase/decrease in Distribution Customer Hours.

Calculation Methodology

Distribution Customer Hours Lost Impact = Total Pre-Investment Distribution Customer Hours Lost X Percentage of Pre-Investment Distribution Customer Hours Eliminated/ Added by Investment

The Total Pre-Investment Distribution Customer Hours Lost is the actual number of Distribution Customer Hours Lost contributed by the assets impacted by the investment in the previous year.

The % eliminated represents the portion of the Distribution Customer Hours contribution of the assets impacted by the investment that would have been avoided had the investment been made prior to the previous year. The % added represents an estimate of the additional Distribution Customer Hours that would have been incurred had the investment been made prior to the previous year.

Distribution Customer Hours Lost impact scores are translated to a +5 to -5 scale, according to the Value Score Translation Table shown in Appendix D, based on where a positive score indicates an improvement and a negative score indicates degradation of Distribution Customer Hours Lost.

4.2.1.3 Transmission Reliability Index (TRI) (Sustaining Portfolio)

<u>Description</u>

This criterion assesses the predicted capacity of the investment to impact the Transmission Reliability Index (TRI) of the specific asset. TRI is a function of the frequency of failures over a five-year period.

<u>Calculation Methodology</u>

$$\text{Calculated Impact on TRI} = \begin{array}{c}\text{TRI for the targeted}\\ \text{assets prior to the}\\ \text{investment}\end{array} \times \begin{array}{c}\text{\% Improvement/}\\ \text{Degradation in TRI post-}\\ \text{investment}\end{array}$$

The TRI for the targeted assets prior to the investment is established by averaging the number of actual failures over the previous five years.

The % improvement represents the number of actual failures that could have been avoided had the investment been made five years earlier, divided by the total number of failures. The % degradation represents an estimate of the number of additional failures that would have been incurred had the investment been made five years earlier.

Results are translated to a scale from -5 to 5, according to the Value Score Translation Table shown in Appendix D, where a positive score represents a positive impact of an investment and a negative score indicates an adverse impact.

4.2.1.4 Expected Energy Not Served (EENS) (Growth Portfolio)

<u>Description</u>

This criterion assesses the reduction in expected energy not served due to the investment. EENS reflects the probabilistic amount of energy not served based on the frequency of planned and unplanned outages, the duration of these outages, and the amount of load curtailment. Scoring for this measure is calculated as the decrease in EENS attributable to the investment.

<u>Calculation Methodology</u>

EENS Reduction = EENS in the year prior to the investment

- EENS after the investment

EENS is measured in MWh/yr. No investment is expected to completely eliminate EENS.

EENS scores are translated to a 0 to 5 scale, according to the Value Score Translation Table shown in Appendix D where a positive score represents a positive impact of an investment.

4.2.2 Risk of Deferral Scoring

Reliability Risk is assessed across the same sub-criteria as those used in computing the Reliability Value score. The risk is evaluated on the consequence and probability of the most likely risk scenario if the investment is deferred by one year.

For Sustaining investments, TSAIDI, Distribution Customer Hours Lost, and TRI are used and evaluated on the consequence and probability of deferring the investment for the most likely scenario. The consequence is translated into a consequence score of 0 to 5. The probability of the most likely scenario is also translated into a probability score of 0 to 5. The translations are based on the Project Deferral Risk Matrix, shown in Appendix C. For each criterion, a risk score is calculated as the product of the consequence score and the probability score, and will have a value between 0 and 25. The Reliability Category Risk Score will be the highest risk score out of the three criteria.

For Growth investments, EENS is used to evaluate reliability risk. The consequence is translated into a consequence score of 0 to 5. The translation is based on the Project Deferral Risk Matrix, shown in Appendix C.The calculation for EENS already accounts for probability, so a probability of 5 (100% certain) is automatically applied to this criterion for calculating its risk score. The EENS risk score is the consequence score times the probability score of 5, and will have a value between 0 and 25. The Reliability Category Risk Score will be the same as the EENS criterion score, as it is the only criterion.

For BCTC investments, reliability risk will be evaluated where applicable using the Sustaining or the Growth approach described above depending on which best applies to the specific investment.

4.3 Market Efficiency

Market Efficiency criteria assess the values and risks related to BCTC's investments that are associated with market participants (e.g. generation owners). It is to be noted that the approach described below to evaluating Market Efficiency is very rudimentary and is expected to change significantly over time as the Energy Plan and the Transmission Expansion Policy implementation evolve.

4.3.1 Value Scoring

The Market Efficiency Value Score is calculated using:

$$\sum \begin{array}{l} \text{Weighting C1 * Line Losses Reduction} \\ \text{Weighting C2 * Congestion Reduction} \\ \text{Weighting C3 * Trade Benefits} \\ \text{Weighting C4 * Transmission Expansion Opportunities} \end{array}$$

Further detail on each criterion is included in the following sections; the weightings are shown in Appendix A.

4.3.1.1 Line Losses Reduction

<u>Description</u>

Line Losses Reduction is assessed in terms of the estimated reduction in transmission line energy losses due to the investment over a 20 year period.

Calculation Methodology

Line Losses Reduction = PV (energy losses reduction x value of energy losses)

Where the Present Value is calculated as follows:

$$PV = \sum_{i=1}^{n} \frac{values_i}{(1 + rate)^i}$$

Estimated reductions in annual line losses are converted to dollars at an energy value applicable for the region that the losses savings will occur. These energy values are shown in Appendix A (Section AA.3.3). The yearly dollar figures are then discounted by a real discount rate, also shown in Appendix A (Section AA.3.1), to the in-service year of the project.

Results are translated to a scale from 0 to 5, according to the Value Score Translation Table shown in Appendix D, where a 5 represents the greatest positive impact of an investment.

4.3.1.2 Congestion Reduction

Description

Investments are assessed in terms of their capacity to reduce congestion. This criterion provides an estimate of the avoided cost of re-dispatch of existing generation.

Calculation Methodology

Congestion Reduction =

(Generation Re-dispatch Excluding Storage x Rate Excluding Storage)

\+ (Generation Re-dispatch Using Storage x Rate Using Storage)

Congestion Reduction is calculated for the first year following completion of the project. Generation Re-dispatch is estimated in GWhrs for two categories: reduction in generation that does not use BCH storage; and reduction in generation that uses BCH storage. These GWhrs are then converted to dollar values using their respective re-dispatch rates shown in Appendix A (Section AA.3.3). Congestion Reduction is the sum of these two values.

Results are translated to a scale from 0 to 5, according to the Value Score Translation Table shown in Appendix D, where a 5 represents the greatest positive impact of an investment. .

4.3.1.3 Trade Benefits

Description

This criterion evaluates the investment's expected impact on trade, which is measured as the additional new energy sales made possible by the investment. Therefore, this criterion provides an estimate of the trade benefit of the investment, accruing to generator owners, due to additional generation dispatch made possible by the investment. This criterion does not take into account additional BCTC revenues as they are included in the Financial Category described in Section 4.1.

Calculation Methodology

Trade Benefits = Additional New Energy Sales x Rate for Value of Trade Benefits

Trade Benefits are calculated in GWhrs for the first year following completion of the project. The additional GWhrs of new sales may require consultations with the generator owner to quantify, and should be a probability-adjusted figure. The Trade Benefits Rate is provided in Appendix A (Section AA.3.3).

Results are translated to a scale from 0 to 5, according to the Value Score Translation Table shown in Appendix D, where a 5 represents the greatest positive impact of an investment.

4.3.1.4 Transmission Expansion Opportunities

Description

This criterion indicates the benefits of the investment related to BCTC's Transmission Expansion Policy (TEP). Transmission Expansion Opportunities (TEO) are proposed investments that are built in advance of need (i.e. Special Direction 9). This criterion was added to the prioritization methodology to recognize the value of proposed TEP projects

<u>Calculation Methodology</u>

Until the TEP is fully developed and implemented, the value of TEO is assessed using the same calculation as for the NPV criteria, which is described in Section 4.1.1.2.

Results are translated to a scale from 0 to 5, according to the Value Score Translation Table shown in Appendix D, where a 5 represents the greatest positive impact of an investment.

4.3.2 Risk of Deferral Scoring

Market Efficiency Risk of Deferral is assessed for Line Losses Reduction, Congestion Reduction, and Trade Benefits. Deferral risk is not assessed for Transmission Expansion Opportunities. Each of the three criteria is evaluated on the consequence of deferring the investment for one year. The consequence is based on the loss of value due to a one year deferral.

Market Efficiency Risk of Deferral consequence levels are calculated using the same calculation methods as used for the value scores but considering only the first year.

The consequence level is the sum to the one-year values for Line Losses Reduction, Congestion Reduction and Trade Benefits. The consequence level is translated to a score according to the Project Deferral Risk Matrix shown in Appendix C.

Market Efficiency Risk of Deferral probability scores are assumed to be 5 (100% probability) as the consequence of the one year deferral is either 100% certain as in the case of Line Losses Reductions, or the calculated value is already probability adjusted as in the case of Congestion Reduction and Trade Benefits.

The Market Efficiency Risk Score is the consequence score times the probability score of 5, and will have a value between 0 and 25.

4.4 Asset Condition

Asset condition is considered a leading indicator of equipment performance. This category evaluates the value and deferral risk of investments that impact the condition of the assets.

4.4.1 Value Scoring

The Asset Condition Value Score is calculated using:

$$\sum \begin{array}{l} \text{Weighting D1 * OEM Support/Availability of Spares} \\ \text{Weighting D2 * Asset Health} \\ \text{Weighting D3 * Beta} \end{array}$$

Further detail on each criterion is included in the following sections; the weightings are shown in Appendix A.

4.4.1.1 Original Equipment Manufacturer (OEM) Support & Availability of Spares

Description

The OEM Support and Availability of Spares criterion assesses the level of support available on the market and the availability of spares before and after the proposed investment. This measure is calculated as the change in support and availability of spares for the impacted investment area as a result of the investment.

Calculation Methodology

OEM Support/ Availability of Spares Impact =

$$= f(\text{Support, Availability of Spares}) \text{ Before Investment}$$
$$- f(\text{Support, Availability of Spares}) \text{ After Investment}$$

Where both the ‘Before’ and ‘After’ scores are assessed per Table 4.1 .

Table 4.1 – OEM Support & Availability of Spares Value Scoring.

	Spares	No Spares/Not Applicable
No OEM Support (obsolete)	4	5
OEM Support will be discontinued within 1 year	3	4
OEM Support will be discontinued within 5 years	2	3
OEM Support will be continued for > 5 years	0	0

‘No OEM support’ indicates that there are no other viable or economic options to maintain the equipment. No Spares / Not Applicable means either that spares are no longer available or that spares are not required to maintain the equipment.

Subtracting the ‘After’ investment score from the ‘Before’ investment score results in a value score between 0 and 5.

4.4.1.2 Asset Health

<u>Description</u>

The Asset Health criterion is based on a pre- and post-investment assessment of the assets that will be impacted by the proposed investment. Asset Health scoring considers the following areas:

a) Remaining Life;
b) Failure Rates;
c) Asset Condition; and
d) Asset Criticality.

Scoring for this measure is calculated as the weighted average of the Remaining Life, Failure Rates, Asset Condition, and Criticality scores.

<u>Calculation Methodology</u>

Asset Health Impact =

$$\sum \begin{array}{l} \text{Weighting D2.1} * f(\text{Remaining Life Score, prior to investment, after investment}) \\ \text{Weighting D2.2} * f(\text{Failure Rates Score, prior to investment, after investment}) \\ \text{Weighting D2.3} * f(\text{Asset Condition Score, prior to investment, after investment}) \\ \text{Weighting D2.4}* f(\text{Criticality Assessment Score, after investment}) \end{array}$$

Each component of the Asset Health impact score is weighted to reflect its relative importance. These weights are shown in Appendix A.

The Remaining Life Score is determined by assessing the remaining life of the impacted assets pre- and post- investment using Table 4.2:

Table 4.2 – Remaining Life Value Scoring

Remaining Life (%) After Investment	Remaining Life (%) Before Investment					
		< 10%	25%	50%	75%	> 90%
	< 10%	0				
	25%	2	0			
	50%	3	1	0		
	75%	4	3	1	0	
	> 90%	5	4	3	1	0

The Failure Rates Score is determined by evaluating the current failure rates before the investment and predicting the failure rates after the investment using Table 4.3.

Table 4.3 – Failure Rates Value Scoring

Failure Rates After Investment \ Current Failure Rates Before Investment	Multiple Failures Per Year	One Failure Per Year	Expected Failure Within 1 Budget Year	Expected Failure Within Planning Horizon	No Failures (in Foreseeable Future)
Multiple Failures Per Year	0				
One Failure Per Year	1	0			
Expected Failure Within 1 Budget Year	3	1	0		
Expected Failure Within Planning Horizon	4	3	2	0	
No Failures (in Foreseeable Future)	5	4	3	2	0

Within the Asset Health category, Asset Condition is determined by evaluating the impacted assets pre- and post-investment according to the definitions in Table 4.4 and scoring using Table 4.5:

Table 4.4 - Asset Condition Description

A	Means the component is in “as new” condition
B	Means the component has some minor problems or evidence of aging
C	Means the component has many minor problems or a major problem that requires attention
D	Means the component has many problems and the potential for major failure
E	Means the component has completely failed or is degraded beyond repair

Table 4.5 - Asset Condition Scoring Matrix

Asset Condition After Investment	Asset Condition Before Investment				
	A	B	C	D	E
A	0	2	3	4	5
B		0	1	3	4
C			0	1	3
D				0	2
E					0

The Criticality Score is assessed differently for Stations investments than for Lines and BCTC Owned Assets investments. The Criticality score for Stations investments is calculated as a weighted average of the sub-criteria shown in Table 4.6; the weightings are shown in Appendix A.

Table 4.6 - Criticality Scoring Matrix for Stations

Criticality - Stations		**5**	**4**	**3**	**2**	**1**
Weighting D2.4.1 x	Load	>1000 MW	>700 MW – 1000 MW	>350 MW – 700 MW	50 MW - 350 MW	<50 MW
Weighting D2.4.2 x	Role	Power delivery assets		Assets that directly support power delivery assets		Other assets such as fences, structures, etc.
Weighting D2.4.3 x	Redun-dancy	N - 0		N - 1		N - 2
Weighting D2.4.4 x	Voltage	500-300 kV		230 kV		<=138 kV

For Lines and BCTC Owned Assets, Criticality is assessed using the definitions and scoring shown in Table 4.7:

Table 4.7 – Criticality Definitions and Scoring for Lines and BCTC Owned Assets

Rating	Description	Score
A	High Criticality. High consequence to the system in the event of a failure. High probability of a prolonged customer or business outage in the event of a failure. High cost of repair or disruption to the business in the event of a failure.	5
B	Medium Criticality. Moderate consequence to the system in the event of a failure. Moderate probability of a prolonged customer or business outage in the event of a failure. Moderate cost of repair or disruption to the business in the event of a failure.	3
C	Low Criticality. No or Low consequence to the system in the event of a failure. Low probability of a prolonged customer or business outage in the event of a failure. Low cost of repair or disruption to the business in the event of a failure.	1

Asset Health impact score is translated to a 0 to 5 scale according to the Value Score Translation Table shown in Appendix D.

4.4.1.3 Beta

Description

This criterion assesses the Beta value of a group of like assets that includes the assets to be addressed by the investment. Beta is the mathematical expression for the slope of the curve that represents change in the time between failures over time. The Beta value indicates if the time between failures is increasing, decreasing or remaining stable over time. Scoring for this measure is calculated as the acceleration of failure over time for the impacted investment area.

Calculation Methodology

$$\text{Beta} = \left(\frac{\text{Change in time between failures during Analysis Period}}{\text{Analysis Period}} \right)$$

The Analysis Period represent the period over which data is available.

Beta value scores are translated to a 0 to 5 scale, according to the Value Score Translation Table shown in Appendix D

4.4.2 Risk of Deferral Scoring

Asset Condition deferral risk is assessed across two of the three criteria used to determine the Value Score: OEM Support/Availability of Spares and Asset Health. The risk score (consequence * probability) for Beta is not included at this point in time[2]. Each criterion is evaluated on the consequence and probability of not funding the investment. The actual deferral risk score for Asset Condition is then the highest risk score (consequence * probability) out of the two criteria.

If these two criteria are not addressed, there is a 100% certainty that the current state of OEM Support/Availability of Spares and Asset Health will continue. Consequently, a probability score of 5, representing this 100% certainty, is automatically assigned to each Asset Condition risk criterion.

4.4.2.1 OEM Support / Availability of Spares

If the investment is not funded, the expected consequence is equal to the current (pre-investment) level assessment. Table 4.8 shows the scoring matrix used to determine the pre-investment OEM Support/Availability of Spares score:

[2] Considerations will be given to include Beta in the determination of the Asset Condition deferral risk in the future.

Table 4.8 – OEM Support/Availability of Spares Risk Scoring

	Spares	**No Spares/Not Applicable**
No OEM Support (obsolete)	2	3
OEM Support will be discontinued within one year	2	2
OEM Support will be discontinued within 5 years	1	2
OEM Support will be continued for greater than 5 years	0	0

'No OEM support' indicates that there are no other viable or economic options to maintain the equipment. Not Applicable means that spares are not required to maintain the equipment.

4.4.2.2 Asset Health

Description

The expected consequence of Asset Health (the impact to Asset Health of not funding the investment) is the pre-investment assessment of Remaining Life, Failures, Asset Condition, and Criticality. Specifically, the consequence score is derived from the weighted average of the Remaining Life, Failure Rates, Asset Condition and Criticality scores.

Calculation Methodology

Asset Health Consequence Score =

$$\sum \begin{array}{l} \text{Weighting D2.1} * f(\text{Remaining Life Score, prior to investment}) \\ \text{Weighting D2.2} * f(\text{Failure Rates Score, prior to investment}) \\ \text{Weighting D2.3} * f(\text{Asset Condition Score, prior to investment}) \\ \text{Weighting D2.4} * f(\text{Criticality Assessment Score}) \end{array}$$

Each component of the Asset Health Consequence Score is weighted to reflect its relative importance. These weights are shown in Appendix A.

The Remaining Life, Failure Rates and Asset Condition Scores are determined by assessing the current state of the assets (i.e. equivalent to the pre-investment state determined in the Asset Health value scoring) using Table 4.9:

Table 4.9 – Remaining Life, Failure Rates and Asset Condition Deferral Risk Scoring

	5	4	3	2	1
Remaining Life	< 10%	25%	50%	75%	> 90%
Current Failure Rates	Multiple Failures Per Year	One Failure Per Year	Expected Failure Within 1 Budget Year	Expected Failure Within Planning Horizon	No Failures (in Foreseeable Future)
Asset Condition	E	D	C	B	A

The same asset condition descriptions are used in the deferral risk calculation as in the value scoring. These descriptions are found in Table 4.4 in Section 4.4.1.2.

Additionally, the Criticality scores for Stations, Lines and BCTC assets are calculated using the same method and weightings as described in Section 4.4.1.2, Tables 4.6 and 4.7 and Appendix A.

Asset Health Consequence Scores are translated to a +5 to 0 scale, according to the Project Deferral Risk Matrix shown in Appendix C.

4.5 Relationships

The Relationships category assesses the value and deferral risk of an investment on customer and First Nations satisfaction, and on BCTC's relationships with stakeholders and First Nations.

4.5.1 Value Scoring

The Relationships Value Score is calculated using:

$$\sum \begin{array}{l} \text{Weighting E1 * Community/Public} \\ \text{Weighting E2 * First Nations} \end{array}$$

Further detail on each criterion is included in the following sections; the weightings are shown in Appendix A.

4.5.1.1 Community/Public

Description

The Community / Public criterion measures the anticipated impact of the investment on customer satisfaction and stakeholder relationships. Scoring is calculated as a weighted average of the investment's impact (significantly negative, marginally negative, neutral, marginally positive, or significantly positive) on specific attributes of customer satisfaction and BCTC's relationships with stakeholders. This combined score is then multiplied by an additional weighting relative to the population density of the investment's scope area.

Calculation Methodology

Community/Public Value Score =

$$\left(\sum \begin{array}{l} \text{Weighting E1.1 * Customer Satisfaction Attributes} \\ \text{Weighting E1.2 * Stakeholder Relationships} \end{array} \right) \times \begin{array}{c} \text{Weighting E1.3 (Population Density} \\ \text{Weighting)} \end{array}$$

The Customer Satisfaction Attributes, Stakeholder Relationships and Population Density Weightings are shown in Appendix A.

The Customer Satisfaction Attributes are calculated as a weighted average of six attributes. Table 4.10 shows the customer satisfaction attributes that are assessed together with their weighting reference. Weightings are included in Appendix A.

Table 4.10 – Customer Satisfaction Attributes

Weighting Reference	Description
E1.1.1	Economic Impact
E1.1.2	Health & Safety Impact
E1.1.3	Corporate Image & Reputation Impact
E1.1.4	Aesthetics Impact
E1.1.5	Property Value Impact
E1.1.6	Quality of Transmission Service Impact

Similarly, a weighted average is calculated to determine the Stakeholder Relationship score. Table 4.11 shows the stakeholder relationships that are assessed together with their weighting reference. Weightings are included in Appendix A.

Table 4.11 – Stakeholder Relationships

Weighting Reference	Stakeholder
E1.2.1	Industrial customers
E1.2.2	Commercial customers
E1.2.3	IPPS & Wholesale Transmission Customers
E1.2.4	Municipal Governments
E1.2.5	Provincial Governments
E1.2.6	General Public

The impact of the investment on each Customer Satisfaction Attribute and Stakeholder Relationship is assessed using the scoring matrix shown in Table 4.12:

Table 4.12 – Scoring for Customer Satisfaction Attributes and Stakeholder Relationships

Significantly Negative Effect	Marginally Negative Effect	No or Neutral Effect	Marginally Positive Effect	Significantly Positive Effect
-5	-2	0	2	5

4.5.1.2 First Nations

<u>Description</u>

The First Nations criterion measures the impact of the investment on relationships with First Nations. Scoring is calculated as a weighted average of the investment's impact (significantly negative, marginally negative, neutral, marginally positive, or significantly positive) on specific impacts for First Nations economic opportunities, Reserve lands, and Territorial Lands, and on the relationship with First Nations. This combined score is then multiplied by an additional weighting, shown in Appendix A, relative to the number of First Nation Bands impacted by the investment

Calculation Methodology

$$\sum \left(\begin{array}{l} \text{Weighting E2.1 * First Nations Attributes} \\ \text{Weighting E2.2 * First Nations Relationships} \end{array} \right) \times \text{Weighting E2.3 (Impacted Bands Weighting)}$$

The First Nations Attributes, First Nations Relationships and Impacted Bands Weightings are shown in Appendix A.

The First Nations Attributes is calculated as the weighted average of three attributes. Table 4.13 shows the First Nations Attributes that are assessed. Weightings are included in Appendix A.

Table 4.13 – First Nations Attributes

Weighting Reference	Description
E2.1.1	First Nations Economic Opportunities Impact
E2.1.2	Reserve Land and Resource Impact
E2.1.3	Traditional Territory and Resource Impact

The impact of the investment on First Nations Attributes is assessed using the scoring matrix shown in Table 4.14:

Table 4.14 – Scoring for First Nations Impacts Attributes and First Nations Relationships

Significantly Negative Effect	Marginally Negative Effect	No or Neutral Effect	Marginally Positive Effect	Significantly Positive Effect
-5	-2	0	2	5

The impact of the investment on First Nations Relationships is also assessed using Table 4.14.

4.5.2 Risk of Deferral Scoring

Relationship risk of deferral is evaluated on the consequence and probability of not funding the investment for the most likely scenario. The consequence and probability of not funding the investment is evaluated for each of Community/Public and First Nations. The actual deferral risk score for Asset Condition is then the highest risk score (consequence * probability) out of the two criteria.

The Relationships consequence levels (0-5) and probability levels (0-5) for each of the criteria are shown in the Project Deferral Risk Matrix, which is included in Appendix C.

4.6 Environment and Safety

This category assesses the value and risk of deferral of an investment associated with environment and safety aspects.

4.6.1 Value Scoring

<u>Description</u>

This parameter assesses the construction, decommissioning and operational impacts of the investment on the environment and safety. This category is scored as a function of a current state assessment of the environment according to seven environmental and two safety attributes, and the degree of impact of the investment (significantly negative, marginally negative, neutral, marginally positive, or significantly positive) on each attribute. A weighting, shown in Appendix A, is applied to these calculated scores based on whether the scope of the impacts are dispersed or localized. Investments which are initiated to meet Federal, Provincial, or Municipal environmental requirements are considered mandatory, but are still scored.

<u>Calculation Methodology</u>

The Environment and Safety Value Score = Weighting F1 * Environment & Safety

where

Environment and Safety =

$$\left(\left(\text{Average (3 Most Positive Scores)}\right) + \left(\text{Average (3 Most Negative Scores)}\right)\right) \times \text{Weighting F1.1 (Scope of Impacted Environment/ Safety Issues Weighting)}$$

The net impact on the environment or safety aspects can be positive, neutral or negative. The

Each of the nine attributes is scored based on the impact of the investment on the attribute relative to an assessment of the current state of the attribute. The current state assessment and investment impact are evaluated according to Table 4.15. Each of the attribute score will range from -5 to +5. The Environment & Safety score will also range from -5 to +5.

Table 4.15 – Environment & Safety Value Scoring

	Degree of Impact of Investment on Environment or Safety				
Current State Assessment (Pre-Investment)	Significantly Negative	Marginally Negative	Neutral	Marginally Positive	Significantly Positive
Existing Environmental or Safety Issues/Hazards	-5	-4	-2	4	5
Imminent Threat of Environment or Safety Issue/Hazard	-3	-2	-1	2	3
No Existing Environmental or Safety Issues/Hazards	-2	-1	0	1	2

The Environmental and Safety attributes are:

a) GHG (Build for Future Use. This attribute is currently included under Air Quality) - Examples include avoidance, increase or reduce of thermal energy purchases (e.g. green energy), internal BC Hydro emissions (e.g. SF6, vehicle fleet, buildings, diesel generation, own-use electricity, etc.), or external emissions (offsets).

b) Air Quality - This includes CFC emissions that reduce the ozone layer, local air quality, odors, etc. Examples include additional or reduced existing emissions (SF6, diesel, etc.) into the environment. .

c) Waste – This includes solid or liquid waste generation through spills, releases, disposal, etc. Examples include introduction or reduction of additional waste products (solid waste, special/hazardous waste, PCBs, oil, fuel, pesticides, etc.) into the environment.

d) Land – This includes land, resources, or land-dwelling vegetation or animal species. Examples include contaminated soils remediation, heritage resource disturbance, vegetation removal, landscaping, bird or mammal conflicts, etc.

e) Water – This includes water quality or water-dwelling plants or animals. The impacts may affect fish bearing water courses, wetlands, stream bank vegetation, habitat, etc.

f) Species at Risk – This includes endangered plants or animals - e.g. birds, fish, mammals, reptiles, insects. The impacts may be to individuals (e.g. loss, injury, or restocking) or habitat (reduction or restoration). .

g) Management Systems – This includes environmental management systems (EMS) and inclusion of environmental factors in all decisions. Example investments include environmental reporting, footprint measure development, integration of EMS with other management systems, EMS procedures, environmental audits, training, assessment tools, etc. .

h) Employee / Workplace Safety – This includes injury to or the death of a worker; a major structural failure or collapse of a building, bridge, tower, crane, hoist, temporary construction support system or excavation; major release of a hazardous substance; or an incident required by regulation to be reported.

i) Public Safety - This includes involving a member of the public, resulting from interface with BCTC's facilities.

4.6.2 Risk of Deferral Scoring

Environment & Safety risk of deferral is evaluated on the consequence and probability of deferring the investment for one year for the most likely case scenario. The actual risk score used will be the highest risk score (consequence * probability) out of the two criteria.

The Environment & Safety consequence levels (0-5) and probability levels (0-5) for each of the criteria are listed in the Project Deferral Risk Matrix, which is included in Appendix C.

5.0 DETERMINATION OF PORTFOLIO

It is the responsibility of the Managers involved with each of the three portfolios to determine the prioritized list. The Managers will consider the computed scores in establishing the prioritized list, but the scores are not a substitute for their management decision-making. The final prioritized list may not necessarily follow the computed scores.

The following sections describe the main steps to establishing the prioritized list for each of the three portfolios.

5.1 Step 1

Once the scoring of each investment is complete, a review of the result is required to ensure consistency in the scoring among the investments. Adjustments to the scoring may be required to correct inconsistencies.

5.2 Step 2

The scores are reviewed to identify any investment where the current scoring system may not adequately capture the value or the risk of deferral. The final list may need to be adjusted accordingly. Investment deemed mandatory will fall under this category.

Investments deemed mandatory are defined as investments that are required to meet contractual, legislative or regulatory requirements are deemed Mandatory. In addition, investments required to ensure an adequate level of due diligence in the area of safety and environment will be deemed mandatory.

5.3 Step 3

The next step is to establish how the prioritized list is established for each portfolio. The approach varies according to the portfolios.

5.3.1 Growth

For Growth investments, ranking is based primarily on value, but the deferral risk is also considered. The list is first established by value (and risk) scores. Any adjustments identified in Step 2 are then implemented. Investments deemed mandatory are included in the highest priority group. Remaining investments with similar value and deferral risk are grouped. Each group is then ranked according to an ordinal ranking with 1 being the highest priority. Investments in the lowest groups, i.e. those projects with the lowest value and lowest risk of deferral, are reviewed for possible deferral whether there are resource constraints or not before the list is finalized.

5.3.2 Sustaining

The prioritization of the investments for the Sustaining Portfolio does not result in a prioritized list like the Growth and BCTC Portfolios. The approach is dictated by the fact that Sustaining Capital investments are primarily program expenditures, so that the prioritization is as much about determining the size of programs as well as the priority of programs. Prioritization of Growth capital investments is about prioritizing specific projects, which may be constructed or not, but cannot be varied in size. The Sustaining approach can be termed 'optimization'.

In order to optimize the Sustaining Portfolio, incremental levels of program activities need to be assessed. This is done by disaggregating programs into component projects and then combining the component projects into groups with similar levels of estimated value and deferral risk. Each group of component projects is scored for value and risk of deferral at the group level. Discrete projects are scored individually. Each of the projects is placed into one of four quadrants based on their value and deferral risk. The quadrants are determined such that twenty-five percent of projects with the lowest risk of deferral and value scores are in the fourth quadrant. Thus projects in the fourth quarter represented both low risk and low value relative to the other projects. The projects in the fourth quadrant are reviewed for potential deferral. Projects deemed mandatory, or whose value or risk is not captured adequately per Step 2 above, are not deferred. Selected projects are then recombined into programs, resulting in program sizes that optimize value and risk tradeoffs. Total portfolio costs are also considered for acceptability before finalizing the portfolio.

In order to achieve further deferrals, if necessary, projects in quadrants II and III will be reviewed.

5.3.3 BCTC

In the BCTC portfolio, investments deemed mandatory are ranked first. Investments are then ranked according to their risk of deferral. Those projects with a similar level of deferral risk are ranked according to their value scores and project costs. Any adjustments identified in Step 2 are implemented. The investments are then given an ordinal ranking from 1st to last. The investments with the lowest value and lowest risk of deferral are reviewed for possible deferral whether there are resource constraints or not.

Appendix A - Current Rates and Weightings

AA.1 Strategic Objective & Criteria Weightings for Value Scoring:

A	**Financial**		**21%**
	A1	Net Present Value (NPV)	54.0%
	A2	Benefit Cost Ratio (BCR)	12.6%
	A3	Rate Impact	15.7%
	A4	Present Value of Efficiency Dollar Savings	17.7%
B	**Reliability**		**24%**
	B1	TSAIDI	49.0%
	B2	Distribution Customer Hours Lost (CHL)	31.0%
	B3	Transmission Reliability Index (TRI)	20.0%
	B4	Expected Energy Not Served (EENS)	100.0%
C	**Market Efficiency**		**22%**
	C1	Line Losses Reduction	39.0%
	C2	Congestion Reduction	20.0%
	C3	Trade Benefits	14.0%
	C4	Transmission Expansion Opportunities	27.0%
D	**Asset Condition**		**17%**
	D1	OEM Support/Availability of Spares	13.7%
	D2	Asset Health	62.3%
	D3	Beta	23.9%
E	**Relationships**		**8%**
	E1	Community/Public	50.0%
	E2	First Nations	50.0%
F	**Environment & Safety**		**8%**
	F1	Environment & Safety	100%

In the Reliability category, investment scoring can apply either the first three criteria, for which the criteria weightings sum to 100%, or the fourth criteria, for which the criteria weighting is 100%, but cannot apply the fourth criteria combined with any other Reliability category criteria.

It should be noted that the Risk assessment does not use these weightings. Therefore, although a low weighting was determined for Relationships and Environment and Safety in the

Value Scoring, a significant issue in these categories will be identified in the Risk Scoring. BCTC's rigorous environmental and safety standards ensure that safety and environmentally driven investments score highly in terms of deferral risk.

AA.2 Sub Criteria Weigthings

AA.2.1 Asset Health (Section 4.4.1.2)

Asset Health

Weighting Reference	Factor	Weighting
D2.1	Remaining Life	14%
D2.2	Failure Rates	26%
D2.3	Asset Condition	14%
D2.4	Criticality	46%

Stations Criticality

Weighting Reference	Factor	Weighting
D2.4.1	Load	25%
D2.4.2	Role	25%
D2.4.3	Redundancy	25%
D2.4.4	Voltage	25%

AA.2.2 Community/Public Relationships (Section 4.5.1.1)

Importance Weights for Community/Public:

Weighting Reference	Description	Weighting
E1.1	Customer Satisfaction Attributes Weighting	40%
E1.2	Stakeholder Relationships Weighting	60%

Population Density Weighting:

Area Density	Weighting E1.3
High Density Area (population >50 per square mile)	1.0
Medium Density Area (population >1 and <50 per square mile)	0.9
Low Density Area (population <1 per square mile)	0.8

Customer Satisfaction Attributes Importance Weights:

Weighting Reference	Factor	Weighting
E1.1.1	Economic	16.67%
E1.1.2	Health & Safety	16.67%
E1.1.3	Corporate Image & Reputation	16.67%
E1.1.4	Aesthetics	16.67%
E1.1.5	Property Value	16.67%
E1.1.6	Quality of Transmission Service	16.67%

Stakeholder Relationships Importance Weights:

Weighting Reference	Customer	Weighting
E1.2.1	Industrials	16.67%
E1.2.2	Commercial	16.67%
E1.2.3	IPPs & Wholesale Transmission	16.67%
E1.2.4	Municipal Governments	16.67%
E1.2.5	Provincial Governments	16.67%
E1.2.6	General Public	16.67%

AA.2.3 First Nations Relationships (Section 4.5.1.2)

Scoring Components Importance Weights for First Nations:

Weighting Reference	Description	Weighting
E2.1	First Nations Customer Satisfaction Attributes Weighting	40%
E2.2	First Nations Relationships Weighting	60%

First Nations Attributes Importance Weights:

Weighting Reference	Attribute	Weighting
E2.1.1	First Nations Economic Opportunities Impact Score	25%
E2.1.2	Reserve Land & Resource Impact Score	50%
E2.1.3	Traditional Territory & Resource Impact Score	25%

Impacted Bands Weighting:

Number of First Nation Bands Impacted	Weighting E2.3
Approximately 10 or more bands impacted	1
Approximately 5-9 bands impacted	0.9
Approximately 1-4 bands impacted	0.8

AA2.4 Environment & Safety (Section 4.6.1)

Scope of Impacted Environmental/Safety Issues:

	Weighting F1.1
Dispersed	1.0
Localized	0.8

AA.3 Financial Data

AA.3.1 Financial Category - Transmission Assets (Section 4.1.1.1)

The following tables contain the rates used in the calculations in the Financial Category for Transmission Growth and Sustaining Capital Portfolios :

Line	Transmission Growth & Sustaining Portfolios	F2008	F2009	F2010	F2011	F2012 and Onward
		(a)	(b)	(c)	(d)	(e)
1	IDC Rate	6.88%	6.88%	6.88%	6.88%	6.88%
2	Overhead Rate	3.42%	2.44%	3.32%	3.39%	3.39%
3	Real Discount Rate	2.50%	2.50%	2.50%	2.50%	2.50%
4	Inflation	2.10%	2.10%	2.10%	2.10%	2.10%
5	Interest Rate	4.62%	5.05%	5.58%	6.06%	6.18%
6	ROE %	12.05%	12.05%	12.05%	12.05%	12.05%
7	Debt Ratio	100.0%	100.0%	100.0%	100.0%	100.0%
8	Equity Ratio	0.0%	0.0%	0.0%	0.0%	0.0%
	Grants & Taxes					
9	Allowance for Non-Assessed Lines	35%	35%	35%	35%	35%
10	Allowance for Non-Assessed Stations	30%	30%	30%	30%	30%
11	Tax Rate (School Taxes, etc.)	1.47%	1.47%	1.47%	1.47%	1.47%
12	BCH Owned Land (not Crown Land) - General Grant Tax	4.00%	4.00%	4.00%	4.00%	4.00%
	Taxable Raw Value					
13	Class 1 - 69kV Tx Lines/Underground Cable	$40,200	$40,200	$40,200	$40,200	$40,200
14	Class 2 - 138kV Tx Lines/Underground Cable	$51,100	$51,100	$51,100	$51,100	$51,100
15	Class 3 - 230kV Heavy Duty Double Circuit Steel Pole	$539,900	$539,900	$539,900	$539,900	$539,900
16	Class 4 - 230kV Double Circuit Steel Pole	$408,600	$408,600	$408,600	$408,600	$408,600
17	Class 5 - 230kV Heavy Duty Double Circuit Steel Tower	$502,600	$502,600	$502,600	$502,600	$502,600
18	Class 6 - 230kV Double Circuit Steel Tower	$308,100	$308,100	$308,100	$308,100	$308,100
19	Class 7 - 230kV Wood or Concrete Pole	$80,800	$80,800	$80,800	$80,800	$80,800
20	Class 8 - 287kV to 360kV Single Circuit Wood or Concrete Pole	$89,200	$89,200	$89,200	$89,200	$89,200
21	Class 9 - 230 kV to 360 kV Single Circuit Steel Tower or UG	$219,600	$219,600	$219,600	$219,600	$219,600
22	Class 10 - 500kV Steel Tower	$275,900	$275,900	$275,900	$275,900	$275,900
23	Class 11 - 500kV AC Submarine Cable	$4,549,700	$4,549,700	$4,549,700	$4,549,700	$4,549,700
24	Class 12 - 230kV AC Submarine Cable	$28,400	$28,400	$28,400	$28,400	$28,400
25	Class 13 - 138kV AC Submarine Cable	$78,100	$78,100	$78,100	$78,100	$78,100
	Depreciation					
26	Transmission Lines / Cables	1.86%	1.86%	1.86%	1.86%	1.86%
27	Switchyard Equipment	3.25%	3.25%	3.25%	3.25%	3.25%
28	Buildings / Structures	2.31%	2.31%	2.31%	2.31%	2.31%
29	Computers	10.68%	10.68%	10.68%	10.68%	10.68%
30	Communications	5.40%	5.40%	5.40%	5.40%	5.40%
31	ROW	0.00%	0.00%	0.00%	0.00%	0.00%
	Rate Impact Variables					
32	BC Hydro Average Embedded Cost ($/MWh)	$52.67	$52.67	$52.67	$52.67	$52.67
33	BC Hydro Total Forecast Energy (MWh)	53,850,211	53,850,211	53,850,211	53,850,211	53,850,211
34	BC Hydro Total Revenue Requirement ($ millions)	$2,836	$2,836	$2,836	$2,836	$2,836
35	BC Hydro Transmission Average Embedded Cost ($/MW.h)	$ 8.82	$ 8.82	$ 8.82	$ 8.82	$ 8.82
36	BC Hydro Distribution Average Embedded Cost ($/MW.h)	$ 11.63	$ 11.63	$ 11.63	$ 11.63	$ 11.63
37	BC Hydro Rate for Load Growth ($/MW.h) - at the plant gate	$ 74.00	$ 74.00	$ 74.00	$ 74.00	$ 74.00
38	BC Hydro Rate for Load Growth ($/MW.h) - levelized (delivered to the Lower Mainland)	$ 88.00	$ 88.00	$ 88.00	$ 88.00	$ 88.00
39	BC Hydro Transmission Revenue Requirement ($ millions)	$ 475.0	$ 475.0	$ 475.0	$ 475.0	$ 475.0
40	BCTC Net Transmission Revenue Requirement ($ millions)	$510.1	$510.1	$510.1	$510.1	$510.1
41	Maximum Capacity (MW)	11,100	11,100	11,100	11,100	11,100
42	Long Term Point to Point Rate ($/MW/Month)	$ 3,829	$ 3,829	$ 3,829	$ 3,829	$ 3,829
43	NITS Revenue Requirement ($ millions)	$439.2	$439.2	$439.2	$439.2	$439.2

AA.3.2 Financial Category - BCTC Assets (Section 4.1.1.1)

The following tables contain the rates used in the calculations in the Financial Category for the BCTC Capital Portfolio:

Line	BCTC Portfolio	F2008	F2009	F2010	F2011	F2012 and Onward
		(a)	(b)	(c)	(d)	(e)
1	AFUDC Rate	6.58%	6.48%	5.77%	5.77%	5.77%
2	Overhead Rate	4.10%	2.82%	3.26%	3.32%	3.32%
3	Real Discount Rate	5.52%	5.52%	5.52%	5.52%	5.52%
4	Inflation	2.10%	2.10%	2.10%	2.10%	2.10%
5	Interest Rate	4.58%	4.63%	4.84%	4.87%	4.87%
6	ROE %	12.05%	12.05%	12.05%	12.05%	12.05%
7	Debt Ratio	59.3%	59.3%	59.3%	59.3%	59.3%
8	Equity Ratio	40.7%	40.7%	40.7%	40.7%	40.7%
	Grants & Taxes					
9	Property Tax (Contact Grace Lee 77448)	NA	NA	NA	NA	NA
10	Property Grant (Contact Grace Lee 77448)	NA	NA	NA	NA	NA
	Depreciation					
11	Leasehold Improvement	10.0%	10.0%	10.0%	10.0%	10.0%
12	Building	2.9%	2.9%	2.9%	2.9%	2.9%
13	Land	0.0%	0.0%	0.0%	0.0%	0.0%
14	Computer Software	15.6%	15.6%	15.6%	15.6%	15.6%
15	Computer Hardware	20.5%	20.5%	20.5%	20.5%	20.5%
16	Furniture and Equipment	6.7%	6.7%	6.7%	6.7%	6.7%
17	Communication	8.3%	8.3%	8.3%	8.3%	8.3%
	Rate Impact Variables					
18	BCTC Net Transmission Revenue Requirement ($ millions)	$510.1	$510.1	$510.1	$510.1	$510.1
19	Maximum Capacity (MW)	11,100	11,100	11,100	11,100	11,100
20	Long Term Point to Point Rate ($/MW/Month)	$ 3,829	$ 3,829	$ 3,829	$ 3,829	$ 3,829
21	NITS Revenue Requirement ($ millions)	$439.2	$439.2	$439.2	$439.2	$439.2
22	BC Hydro Average Embedded Cost ($/MWh)	$52.67	$52.67	$52.67	$52.67	$52.67
23	BC Hydro Total Forecast Energy (MWh)	53,850,211	53,850,211	53,850,211	53,850,211	53,850,211
24	BC Hydro Total Revenue Requirement ($ millions)	$2,836	$2,836	$2,836	$2,836	$2,836
25	BC Hydro Transmission Average Embedded Cost ($/MW.h)	$ 8.82	$ 8.82	$ 8.82	$ 8.82	$ 8.82

AA.3.3 Market Efficiency Category (Section 4.3)

The following rates are used in the Market Efficiency category:

a. Line Losses Reduction
    i. Value of Energy Losses, Lower Mainland and Vancouver Island Regions = $88/MWhr
    ii. Value of Energy Losses, all other regions = $74/MWhr
    iii. Discount Rate for PV = 2.5%
b. Congestion Reduction

   i. Re-dispatch rate not using storage = $5/MWhr
   ii. Re-dispatch rate using storage = $15/MWhr

c. Trade Benefits
   i. Trade benefits rate = $5/MWhr

d. Transmission Expansion Opportunities
   i. Same rates as used for the NPV criterion..

Appendix B: Value Matrix

BCTC Project Value Translation Matrix

	Translated Value Score (Note: where calculated score is negative, the translated score is also negative; see Value Score Translation Table)					
Value Category	**0.00 – 0.95**	**1.00 – 1.95**	**2.00 – 2.95**	**3.00 – 3.95**	**4.00 – 4.95**	**5.00**
Financial	• NPV: $0 to <$50K • Rate Impact: 0% to >-0.01% • PV of Efficiency $: $0 to <$50K • Benefit Cost Ratio: 0 to <0.05	• NPV: $50K to <$500K • Rate Impact = -0.01% to >-0.10% • PV of Efficiency $: $50K to <$500K • Benefit Cost Ratio: 0.05 to <0.5	• NPV: $500K to <$1 Million • Rate Impact: -0.10% to >-0.20% • PV of Efficiency $: $500K to <$1M • Benefit Cost Ratio: 0.5 to <1	• NPV: $1M to <$5M • Rate Impact: -0.20% to >-0.98% • PV of Efficiency $: $1M to <$5M • Benefit Cost Ratio: 1 to <5	• NPV: $5M to <$10M • Rate Impact = -0.98% to >-1.96% • PV of Efficiency $: $5M to <$10M • Benefit Cost Ratio: 5 to <10	• NPV: >= $10M • Rate Impact:<=-1.96% • PV of Efficiency $: >= $10M • Benefit Cost Ratio: >= 10
Reliability	• TSAIDI incremental Outage Duration hrs: 0 to <15 • Distribution Customer Hrs Incremental: 0 to <14,167 • TRI % decrease:0 to <1.75% • EENS (MWh): 0 to <10	• TSAIDI incremental Outage Duration hrs: 15 to <30 • Distribution Customer Hrs Incremental: 14,167 to <28,333 • TRI % decrease:1.75 to <3.70% • EENS (MWh): 10 to <100	• TSAIDI incremental Outage Duration hrs: 30 to <45 • Distribution Customer Hrs Incremental: 28,333 to <42,500 • TRI % decrease:3.70 to 5.65% • EENS (MWh): 100 to <200	• TSAIDI incremental Outage Duration hrs: 45 to <60 • Distribution Customer Hrs Incremental: 42,500 to <56,667 • TRI % decrease:5.65 to <7.6% • EENS (MWh): 200 to <1000	• TSAIDI incremental Outage Duration hrs: 60 to <75 • Distribution Customer Hrs Incremental: 56,667 to <70,833 • TRI % decrease:7.60 to <9.55% • EENS (MWh): 1000 to <2000	• TSAIDI incremental Outage Duration hrs: >= 75 • Distribution Customer Hrs Incremental: >= 70,833 • TRI % decrease: >= 9.55% • EENS (MWh): >= 2000
Market Efficiency	• Losses reduction: $0 to <$50K • Congestion Reduction: $0 to <$50 • Trade benefits: $0 to <$50K • Transmission Expansion: $0 to <$50K	• Losses reduction: $50K to <$500K • Congestion Reduction:$50K to <$500K • Trade benefits: $50K to <$500K • Transmission Expansion: $50K to <$500K	• Losses reduction:$500K to <$1M • Congestion Reduction: $500K to <$1M • Trade benefits: $500K to <$1M • Transmission Expansion: $500K to <$1M	• Losses reduction: $1M to <$5M • Congestion Reduction: $1M to <$5M • Trade benefits: $1M to <$5M • Transmission Expansion: $1M to <$5M	• Losses reduction: $5 to <$10M • Congestion Reduction:$5M to <$10M • Trade benefits: $5M to <$10M • Transmission Expansion:$5M to <$10M	• Losses reduction: >= $10M • Congestion Reduction: >=$10M • Trade benefits: >= $10 M • Transmission Expansion: >= $10 M
Asset Condition	• OEM Support/Availability of Spares: 0 to <1 • Asset health score 0.00 to <1.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.0 to <1.1	• OEM Support/Availability of Spares: 1 to <2 • Asset health score 1.00 to <2.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.1 to <1.2	• OEM Support/Availability of Spares: 2 to <3 • Asset health score 2.00 to <3.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.2 to <1.3	• OEM Support/Availability of Spares: 3 to <4 • Asset health score 3.00 to <3.67 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.3 to <1.4	• OEM Support/Availability of Spares: 4 to <5 • Asset health score 3.67 to <4.34 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.4 to <1.5	• OEM Support/Availability of Spares: >=5 • Asset health score >=4.34 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: >=1.5
Relationships	• Community/Public score 0.00 to <1.00 as a function of: o Customer Satisfaction Attributes o Stakeholder Relationships o Population Density of Scope Area • First Nations score 0.00 - <1.00 as a function of: o First Nations Customer Satisfaction Attributes o Relationships with First Nations Bands o # of Bands Impacted	• Community/Public score 1.00 to <2.00 as a function of: o Customer Satisfaction Attributes o Stakeholder Relationships o Population Density of Scope Area • First Nations score 1.00 - <2.00 as a function of: o First Nations Customer Satisfaction Attributes o Relationships with First Nations Bands o # of Bands Impacted	• Community/Public score 2.00 to <3.00 as a function of: o Customer Satisfaction Attributes o Stakeholder Relationships o Population Density of Scope Area • First Nations score 2.00 - <3.00 as a function of: o First Nations Customer Satisfaction Attributes o Relationships with First Nations Bands o # of Bands Impacted	• Community/Public score 3.00 to <4.00 as a function of: o Customer Satisfaction Attributes o Stakeholder Relationships o Population Density of Scope Area • First Nations score 3.00 - <4.00 as a function of: o First Nations Customer Satisfaction Attributes o Relationships with First Nations Bands o # of Bands Impacted	• Community/Public score 4.00 to <5.00 as a function of: o Customer Satisfaction Attributes o Stakeholder Relationships o Population Density of Scope Area • First Nations score 4.00 - <5.00 as a function of: o First Nations Customer Satisfaction Attributes o Relationships with First Nations Bands o # of Bands Impacted	• Community/Public score = 5.00 as a function of: o Customer Satisfaction Attributes o Stakeholder Relationships o Population Density of Scope Area • First Nations score = 5.00 as a function of: o First Nations Customer Satisfaction Attributes o Relationships with First Nations Bands o # of Bands Impacted
Environment & Safety	• Environment and Safety score 0.00 to <1.00 as a function of 7 environmental strategies, 2 safety strategies and local or dispersed scope: o GHG (Green House Gas) o Air Quality o Waste o Water o Land o Species at Risk o Environment Management System o Employee / Workforce Safety o Public Safety	• Environment and Safety score 1.00 to <2.00 as a function of 7 environmental strategies, 2 safety strategies and local or dispersed scope: o GHG (Green House Gas) o Air Quality o Waste o Water o Land o Species at Risk o Environment Management System o Employee / Workforce Safety o Public Safety	• Environment and Safety score 2.00 to <3.00 as a function of 7 environmental strategies, 2 safety strategies and local or dispersed scope: o GHG (Green House Gas) o Air Quality o Waste o Water o Land o Species at Risk o Environment Management System o Employee / Workforce Safety o Public Safety	• Environment and Safety score 3.00 to <4.00 as a function of 7 environmental strategies, 2 safety strategies and local or dispersed scope: o GHG (Green House Gas) o Air Quality o Waste o Water o Land o Species at Risk o Environment Management System o Employee / Workforce Safety o Public Safety	• Environment and Safety score 4.00 to <5.00 as a function of 7 environmental strategies, 2 safety strategies and local or dispersed scope: o GHG (Green House Gas) o Air Quality o Waste o Water o Land o Species at Risk o Environment Management System o Employee / Workforce Safety o Public Safety	• Environment and Safety score >=5.00 as a function of 7 environmental strategies, 2 safety strategies and local or dispersed scope: o GHG (Green House Gas) o Air Quality o Waste o Water o Land o Species at Risk o Environment Management System o Employee/Workforce Safety o Public Safety

Appendix C: Deferral Risk Matrix

BCTC Project Deferral Risk Matrix

Consequence						
CATEGORY	**0**	**1**	**2**	**3**	**4**	**5**
Financial	Combined financial impact totaling $0 to <$50K	Combined financial impact totaling $50K to <$500K	Combined financial impact totaling $500K to <$1 Million	Combined financial impact totaling $1 to <$5 Million	Combined financial impact totaling $5 Million to <$10 Million	Combined financial impact totaling >= $10 Million
Reliability	• TSAIDI – incremental Outage Duration hrs: 0-<15 • Distribution Customer Hrs – Incremental: 0-<14,167 • TRI- % decrease in TRI:0-<1.75% • EENS – MWh: 0-<10	• TSAIDI – incremental Outage Duration hrs: 15-<30 • Distribution Customer Hrs – Incremental: 14,167 -<28,333 • TRI- % decrease in TRI:1.75-<3.70% • EENS – MWh: 10-<100	• TSAIDI – incremental Outage Duration hrs: 30-<45 • Distribution Customer Hrs – Incremental: 28,333 -<42,500 • TRI- % decrease in TRI:3.70-5.65% • EENS – MWh: 100-<200	• TSAIDI – incremental Outage Duration hrs: 45-<60 • Distribution Customer Hrs – Incremental: 42,500-<56,667 • TRI- % decrease in TRI:5.65-<7.6% • EENS – MWh: 200-<1000	• TSAIDI – incremental Outage Duration hrs: 60-<75 • Distribution Customer Hrs – Incremental: 56,667-<70,833 • TRI- % decrease in TRI:7.60-<9.55% • EENS – MWh: 1000-<2000	• TSAIDI – incremental Outage Duration hrs: >= 75 • Distribution Customer Hrs – Incremental: >= 70,833 • TRI- % decrease in TRI: >= 9.55% • EENS – MWh: >= 2000
Market Efficiency	Combined Market Efficiency impact totaling = $0-<$50K resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $50K to <$500K resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $500K to <$1 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $1 to <$5 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling $5 to <$10 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits	Combined Market Efficiency impact totaling >= $10 Million resulting from: o Losses reduction o Congestion Reduction o Trade benefits
Asset Condition	• OEM Support/Availability of Spares: 0 to <1 • Asset health score 0.00 to <1.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.0 to <1.1	• OEM Support/Availability of Spares: 1 to <2 • Asset health score 1.00 to <2.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.1 to <1.2	• OEM Support/Availability of Spares: 2 to <3 • Asset health score 2.00 to <3.00 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.2 to <1.3	• OEM Support/Availability of Spares: 3 to <4 • Asset health score 3.00 to <3.67 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.3 to <1.4	• OEM Support/Availability of Spares: 4 to <5 • Asset health score 3.67 to <4.34 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: 1.4 to <1.5	• OEM Support/Availability of Spares: >=5 • Asset health score >=4.34 as a function of: o Remaining life o Current failure rates o Asset condition o Criticality • Beta: >=1.5
Relationships	Impact is negligible	External opposition resulting in limited increase in complaints and/or external lobbying	External opposition resulting in significant increase in complaints and/or external lobbying	External opposition resulting in increased regulatory and shareholder oversight/scrutiny	External opposition resulting in increased regulatory/ legislative/court action or government intervention resulting in a loss of responsibilities impacting BCTC's corporate mandate	External opposition resulting in loss of license to operate and/or imposed corporate restructuring
Environment & Safety	Impact is negligible	• First aid injury/illness • Non-reportable environmental incident	• Medical aid injury/illness • Non-reportable environmental incident – mitigation required	• Lost time injury/temporary disability • Reportable environmental incident – mitigation not required	• Permanent disability • Reportable environmental incident – mitigation required and possible	• Fatality (ies) • Reportable environmental incident – mitigation required but uncertain
Probability						
Likelihood of Occurrence	< 0.1 % (<1 in 1000) likelihood that event will occur within next year.	0.1% (1 in 1000) likelihood that event will occur within next year.	1% (1 in 100) to <10% (1 in 100) likelihood that event will occur within next year.	10% (1 in 10) to <50% (1 in 2) likelihood that event will occur within next year.	50% (1 in 2) to <90% (9 in 10) likelihood that event will occur within next year.	90% (9 in 10) or greater likelihood that event will occur within next year.

Appendix D: Value Score Translation Table

VALUE SCORE TRANSLATION TABLE

Score	TSAIDI	EENS	TRI	Dist. Customer Hours Lost	OEM Support	Asset Health	Beta	Community/ Public	First Nations	Environmental & Safety Impact	Line Losses Reduction	Congestion Reduction	Trade Benefits	TEO	NPV	BCR	Efficiency Savings	Rate Impact %
5.00	75.00	2,000.00	9.550	70,833	5.00	4.34	1.500	5.00	5.00	5.00	$10,000	$10,000	$10,000	5.00	$10,000	10.000	$10,000	-1.9604%
4.95	74.25	1,931.88	9.453	70,125		4.31	1.495	4.95	4.95	4.95	$9,659	$9,659	$9,659	4.95	$9,659	9.659	$9,659	-1.8936%
4.90	73.50	1,866.08	9.355	69,416		4.27	1.490	4.90	4.90	4.90	$9,330	$9,330	$9,330	4.90	$9,330	9.330	$9,330	-1.8291%
4.85	72.75	1,802.52	9.258	68,708		4.24	1.485	4.85	4.85	4.85	$9,013	$9,013	$9,013	4.85	$9,013	9.013	$9,013	-1.7668%
4.80	72.00	1,741.13	9.160	68,000		4.21	1.480	4.80	4.80	4.80	$8,706	$8,706	$8,706	4.80	$8,706	8.706	$8,706	-1.7067%
4.75	71.25	1,681.83	9.063	67,291		4.17	1.475	4.75	4.75	4.75	$8,409	$8,409	$8,409	4.75	$8,409	8.409	$8,409	-1.6485%
4.70	70.50	1,624.54	8.965	66,583		4.14	1.470	4.70	4.70	4.70	$8,123	$8,123	$8,123	4.70	$8,123	8.123	$8,123	-1.5924%
4.65	69.75	1,569.21	8.868	65,875		4.11	1.465	4.65	4.65	4.65	$7,846	$7,846	$7,846	4.65	$7,846	7.846	$7,846	-1.5381%
4.60	69.00	1,515.76	8.770	65,166		4.07	1.460	4.60	4.60	4.60	$7,579	$7,579	$7,579	4.60	$7,579	7.579	$7,579	-1.4858%
4.55	68.25	1,464.14	8.673	64,458		4.04	1.455	4.55	4.55	4.55	$7,321	$7,321	$7,321	4.55	$7,321	7.321	$7,321	-1.4351%
4.50	67.50	1,414.27	8.575	63,750		4.01	1.450	4.50	4.50	4.50	$7,071	$7,071	$7,071	4.50	$7,071	7.071	$7,071	-1.3863%
4.45	66.75	1,366.10	8.478	63,041		3.97	1.445	4.45	4.45	4.45	$6,830	$6,830	$6,830	4.45	$6,830	6.830	$6,830	-1.3390%
4.40	66.00	1,319.57	8.380	62,333		3.94	1.440	4.40	4.40	4.40	$6,598	$6,598	$6,598	4.40	$6,598	6.598	$6,598	-1.2934%
4.35	65.25	1,274.62	8.283	61,625		3.91	1.435	4.35	4.35	4.35	$6,373	$6,373	$6,373	4.35	$6,373	6.373	$6,373	-1.2494%
4.30	64.50	1,231.21	8.185	60,916		3.87	1.430	4.30	4.30	4.30	$6,156	$6,156	$6,156	4.30	$6,156	6.156	$6,156	-1.2068%
4.25	63.75	1,189.28	8.088	60,208		3.84	1.425	4.25	4.25	4.25	$5,946	$5,946	$5,946	4.25	$5,946	5.946	$5,946	-1.1657%
4.20	63.00	1,148.77	7.990	59,500		3.81	1.420	4.20	4.20	4.20	$5,744	$5,744	$5,744	4.20	$5,744	5.744	$5,744	-1.1260%
4.15	62.25	1,109.64	7.893	58,791		3.77	1.415	4.15	4.15	4.15	$5,548	$5,548	$5,548	4.15	$5,548	5.548	$5,548	-1.0877%
4.10	61.50	1,071.85	7.795	58,083		3.74	1.410	4.10	4.10	4.10	$5,359	$5,359	$5,359	4.10	$5,359	5.359	$5,359	-1.0506%
4.05	60.75	1,035.34	7.698	57,375		3.71	1.405	4.05	4.05	4.05	$5,177	$5,177	$5,177	4.05	$5,177	5.177	$5,177	-1.0148%
4.00	60.00	1,000.00	7.600	56,667	4.00	3.67	1.400	4.00	4.00	4.00	$5,000	$5,000	$5,000	4.00	$5,000	5.000	$5,000	-0.9802%
3.95	59.25	922.73	7.503	55,959		3.64	1.395	3.95	3.95	3.95	$4,614	$4,614	$4,614	3.95	$4,614	4.614	$4,614	-0.9045%
3.90	58.50	851.37	7.405	55,250		3.60	1.390	3.90	3.90	3.90	$4,257	$4,257	$4,257	3.90	$4,257	4.257	$4,257	-0.8345%
3.85	57.75	785.52	7.308	54,542		3.57	1.385	3.85	3.85	3.85	$3,928	$3,928	$3,928	3.85	$3,928	3.928	$3,928	-0.7700%
3.80	57.00	724.77	7.210	53,834		3.54	1.380	3.80	3.80	3.80	$3,624	$3,624	$3,624	3.80	$3,624	3.624	$3,624	-0.7104%
3.75	56.25	668.72	7.113	53,125		3.50	1.375	3.75	3.75	3.75	$3,344	$3,344	$3,344	3.75	$3,344	3.344	$3,344	-0.6555%
3.70	55.50	617.00	7.015	52,417		3.47	1.370	3.70	3.70	3.70	$3,085	$3,085	$3,085	3.70	$3,085	3.085	$3,085	-0.6048%
3.65	54.75	569.28	6.918	51,709		3.44	1.365	3.65	3.65	3.65	$2,846	$2,846	$2,846	3.65	$2,846	2.846	$2,846	-0.5580%
3.60	54.00	525.25	6.820	51,000		3.40	1.360	3.60	3.60	3.60	$2,626	$2,626	$2,626	3.60	$2,626	2.626	$2,626	-0.5149%
3.55	53.25	484.63	6.723	50,292		3.37	1.355	3.55	3.55	3.55	$2,423	$2,423	$2,423	3.55	$2,423	2.423	$2,423	-0.4750%
3.50	52.50	447.15	6.625	49,584		3.34	1.350	3.50	3.50	3.50	$2,236	$2,236	$2,236	3.50	$2,236	2.236	$2,236	-0.4383%
3.45	51.75	412.57	6.528	48,875		3.30	1.345	3.45	3.45	3.45	$2,063	$2,063	$2,063	3.45	$2,063	2.063	$2,063	-0.4044%
3.40	51.00	380.66	6.430	48,167		3.27	1.340	3.40	3.40	3.40	$1,903	$1,903	$1,903	3.40	$1,903	1.903	$1,903	-0.3731%
3.35	50.25	351.22	6.333	47,459		3.24	1.335	3.35	3.35	3.35	$1,756	$1,756	$1,756	3.35	$1,756	1.756	$1,756	-0.3443%
3.30	49.50	324.06	6.235	46,750		3.20	1.330	3.30	3.30	3.30	$1,620	$1,620	$1,620	3.30	$1,620	1.620	$1,620	-0.3176%
3.25	48.75	298.99	6.138	46,042		3.17	1.325	3.25	3.25	3.25	$1,495	$1,495	$1,495	3.25	$1,495	1.495	$1,495	-0.2931%
3.20	48.00	275.87	6.040	45,334		3.14	1.320	3.20	3.20	3.20	$1,379	$1,379	$1,379	3.20	$1,379	1.379	$1,379	-0.2704%
3.15	47.25	254.53	5.943	44,625		3.10	1.315	3.15	3.15	3.15	$1,273	$1,273	$1,273	3.15	$1,273	1.273	$1,273	-0.2495%
3.10	46.50	234.85	5.845	43,917		3.07	1.310	3.10	3.10	3.10	$1,174	$1,174	$1,174	3.10	$1,174	1.174	$1,174	-0.2302%
3.05	45.75	216.69	5.748	43,209		3.04	1.305	3.05	3.05	3.05	$1,083	$1,083	$1,083	3.05	$1,083	1.083	$1,083	-0.2124%
3.00	45.00	200.00	5.650	42,500	3.00	3.00	1.300	3.00	3.00	3.00	$1,000	$1,000	$1,000	3.00	$1,000	1.000	$1,000	-0.1960%
2.95	44.25	193.12	5.553	41,792		2.95	1.295	2.95	2.95	2.95	$966	$966	$966	2.95	$966	0.966	$966	-0.1893%
2.90	43.50	186.54	5.455	41,083		2.90	1.290	2.90	2.90	2.90	$933	$933	$933	2.90	$933	0.933	$933	-0.1828%
2.85	42.75	180.19	5.358	40,375		2.85	1.285	2.85	2.85	2.85	$901	$901	$901	2.85	$901	0.901	$901	-0.1766%
2.80	42.00	174.05	5.260	39,667		2.80	1.280	2.80	2.80	2.80	$870	$870	$870	2.80	$870	0.870	$870	-0.1706%
2.75	41.25	168.12	5.163	38,958		2.75	1.275	2.75	2.75	2.75	$841	$841	$841	2.75	$841	0.841	$841	-0.1648%
2.70	40.50	162.40	5.065	38,250		2.70	1.270	2.70	2.70	2.70	$812	$812	$812	2.70	$812	0.812	$812	-0.1592%
2.65	39.75	156.86	4.968	37,542		2.65	1.265	2.65	2.65	2.65	$784	$784	$784	2.65	$784	0.784	$784	-0.1538%
2.60	39.00	151.52	4.870	36,833		2.60	1.260	2.60	2.60	2.60	$758	$758	$758	2.60	$758	0.758	$758	-0.1485%
2.55	38.25	146.36	4.773	36,125		2.55	1.255	2.55	2.55	2.55	$732	$732	$732	2.55	$732	0.732	$732	-0.1435%
2.50	37.50	141.38	4.675	35,417		2.50	1.250	2.50	2.50	2.50	$707	$707	$707	2.50	$707	0.707	$707	-0.1386%
2.45	36.75	136.56	4.578	34,708		2.45	1.245	2.45	2.45	2.45	$683	$683	$683	2.45	$683	0.683	$683	-0.1339%
2.40	36.00	131.91	4.480	34,000		2.40	1.240	2.40	2.40	2.40	$660	$660	$660	2.40	$660	0.660	$660	-0.1293%
2.35	35.25	127.42	4.383	33,292		2.35	1.235	2.35	2.35	2.35	$637	$637	$637	2.35	$637	0.637	$637	-0.1249%
2.30	34.50	123.08	4.285	32,583		2.30	1.230	2.30	2.30	2.30	$615	$615	$615	2.30	$615	0.615	$615	-0.1206%
2.25	33.75	118.88	4.188	31,875		2.25	1.225	2.25	2.25	2.25	$594	$594	$594	2.25	$594	0.594	$594	-0.1165%
2.20	33.00	114.84	4.090	31,167		2.20	1.220	2.20	2.20	2.20	$574	$574	$574	2.20	$574	0.574	$574	-0.1126%
2.15	32.25	110.92	3.993	30,458		2.15	1.215	2.15	2.15	2.15	$555	$555	$555	2.15	$555	0.555	$555	-0.1087%
2.10	31.50	107.15	3.895	29,750		2.10	1.210	2.10	2.10	2.10	$536	$536	$536	2.10	$536	0.536	$536	-0.1050%
2.05	30.75	103.50	3.798	29,042		2.05	1.205	2.05	2.05	2.05	$517	$517	$517	2.05	$517	0.517	$517	-0.1014%
2.00	30.00	100.00	3.700	28,333	2.00	2.00	1.20	2.00	2.00	2.00	$500	$500	$500	2.00	$500	0.500	$500	-0.0980%
1.95	29.25	89.10	3.603	27,625		1.95	1.195	1.95	1.95	1.95	$446	$446	$446	1.95	$446	0.446	$446	-0.0873%
1.90	28.50	79.42	3.505	26,916		1.90	1.190	1.90	1.90	1.90	$397	$397	$397	1.90	$397	0.397	$397	-0.0778%
1.85	27.75	70.79	3.408	26,208		1.85	1.185	1.85	1.85	1.85	$354	$354	$354	1.85	$354	0.354	$354	-0.0694%
1.80	27.00	63.09	3.310	25,500		1.80	1.180	1.80	1.80	1.80	$315	$315	$315	1.80	$315	0.315	$315	-0.0618%
1.75	26.25	56.23	3.213	24,791		1.75	1.175	1.75	1.75	1.75	$281	$281	$281	1.75	$281	0.281	$281	-0.0551%
1.70	25.50	50.12	3.115	24,083		1.70	1.170	1.70	1.70	1.70	$251	$251	$251	1.70	$251	0.251	$251	-0.0491%
1.65	24.75	44.67	3.018	23,375		1.65	1.165	1.65	1.65	1.65	$223	$223	$223	1.65	$223	0.223	$223	-0.0438%
1.60	24.00	39.82	2.920	22,666		1.60	1.160	1.60	1.60	1.60	$199	$199	$199	1.60	$199	0.199	$199	-0.0390%
1.55	23.25	35.49	2.823	21,958		1.55	1.155	1.55	1.55	1.55	$177	$177	$177	1.55	$177	0.177	$177	-0.0348%
1.50	22.50	31.63	2.725	21,250		1.50	1.150	1.50	1.50	1.50	$158	$158	$158	1.50	$158	0.158	$158	-0.0310%
1.45	21.75	28.19	2.628	20,541		1.45	1.145	1.45	1.45	1.45	$141	$141	$141	1.45	$141	0.141	$141	-0.0276%
1.40	21.00	25.13	2.530	19,833		1.40	1.140	1.40	1.40	1.40	$126	$126	$126	1.40	$126	0.126	$126	-0.0246%
1.35	20.25	22.40	2.433	19,125		1.35	1.135	1.35	1.35	1.35	$112	$112	$112	1.35	$112	0.112	$112	-0.0220%
1.30	19.50	19.96	2.335	18,416		1.30	1.130	1.30	1.30	1.30	$100	$100	$100	1.30	$100	0.100	$100	-0.0196%
1.25	18.75	17.79	2.238	17,708		1.25	1.125	1.25	1.25	1.25	$89	$89	$89	1.25	$89	0.089	$89	-0.0174%
1.20	18.00	15.86	2.140	17,000		1.20	1.120	1.20	1.20	1.20	$79	$79	$79	1.20	$79	0.079	$79	-0.0155%
1.15	17.25	14.14	2.043	16,291		1.15	1.115	1.15	1.15	1.15	$71	$71	$71	1.15	$71	0.071	$71	-0.0139%
1.10	16.50	12.60	1.945	15,583		1.10	1.110	1.10	1.10	1.10	$63	$63	$63	1.10	$63	0.063	$63	-0.0123%
1.05	15.75	11.23	1.848	14,875		1.05	1.105	1.05	1.05	1.05	$56	$56	$56	1.05	$56	0.056	$56	-0.0110%
1.00	15.00	10.00	1.750	14,167	1.00	1.00	1.10	1.00	1.00	1.00	$50	$50	$50	1.00	$50	0.050	$50	-0.0098%
0.95	14.25	8.01	1.663	13,459		0.95	1.095	0.95	0.95	0.95	$40	$40	$40	0.95	$40	0.040	$40	-0.0078%
0.90	13.50	6.41	1.575	12,750		0.90	1.090	0.90	0.90	0.90	$32	$32	$32	0.90	$32	0.032	$32	-0.0063%
0.85	12.75	5.12	1.488	12,042		0.85	1.085	0.85	0.85	0.85	$26	$26	$26	0.85	$26	0.026	$26	-0.0050%
0.80	12.00	4.10	1.400	11,334		0.80	1.080	0.80	0.80	0.80	$20	$20	$20	0.80	$20	0.020	$20	-0.0040%
0.75	11.25	3.28	1.313	10,625		0.75	1.075	0.75	0.75	0.75	$16	$16	$16	0.75	$16	0.016	$16	-0.0032%
0.70	10.50	2.62	1.225	9,917		0.70	1.070	0.70	0.70	0.70	$13	$13	$13	0.70	$13	0.013	$13	-0.0026%
0.65	9.75	2.10	1.138	9,209		0.65	1.065	0.65	0.65	0.65	$10	$10	$10	0.65	$10	0.010	$10	-0.0021%
0.60	9.00	1.68	1.050	8,500		0.60	1.060	0.60	0.60	0.60	$8	$8	$8	0.60	$8	0.008	$8	-0.0016%
0.55	8.25	1.34	0.963	7,792		0.55	1.055	0.55	0.55	0.55	$7	$7	$7	0.55	$7	0.007	$7	-0.0013%
0.50	7.50	1.07	0.875	7,084		0.50	1.050	0.50	0.50	0.50	$5	$5	$5	0.50	$5	0.005	$5	-0.0011%
0.45	6.75	0.86	0.788	6,375		0.45	1.045	0.45	0.45	0.45	$4	$4	$4	0.45	$4	0.004	$4	-0.0008%
0.40	6.00	0.69	0.700	5,667		0.40	1.040	0.40	0.40	0.40	$3	$3	$3	0.40	$3	0.003	$3	-0.0007%
0.35	5.25	0.55	0.613	4,959		0.35	1.035	0.35	0.35	0.35	$3	$3	$3	0.35	$3	0.003	$3	-0.0005%
0.30	4.50	0.44	0.525	4,250		0.30	1.030	0.30	0.30	0.30	$2	$2	$2	0.30	$2	0.002	$2	-0.0004%
0.25	3.75	0.35	0.438	3,542		0.25	1.025	0.25	0.25	0.25	$2	$2	$2	0.25	$2	0.002	$2	-0.0003%
0.20	3.00	0.28	0.350	2,834		0.20	1.020	0.20	0.20	0.20	$1	$1	$1	0.20	$1	0.001	$1	-0.0003%
0.15	2.25	0.23	0.263	2,125		0.15	1.015	0.15	0.15	0.15	$1	$1	$1	0.15	$1	0.001	$1	-0.0002%
0.10	1.50	0.18	0.175	1,417		0.10	1.010	0.10	0.10	0.10	$1	$1	$1	0.10	$1	0.001	$1	-0.0002%
0.05	0.75	0.14	0.088	709		0.05	1.005	0.05	0.05	0.05	$1	$1	$1	0.05	$1	0.001	$1	-0.0001%
0.00	0.00	0.00	0.00	0	0.00	0.00	1.00	0.00	0.00	0.00	$0	$0	$0	0.00	$0	0.000	$0	0.0000%

VALUE SCORE TRANSLATION TABLE																		
Score	TSAIDI	EENS	TRI	Dist. Customer Hours Lost	OEM Support	Asset Health	Beta	Community/ Public	First Nations	Environmental & Safety Impact	Line Losses Reduction	Congestion Reduction	Trade Benefits	TEO	NPV	BCR	Efficiency Savings	Rate Impact %
-0.05	-0.75		-0.088	-708				-0.05	-0.05	-0.05					-$1			0.0001%
-0.10	-1.50		-0.175	-1,417				-0.10	-0.10	-0.10					-$1			0.0002%
-0.15	-2.25		-0.263	-2,125				-0.15	-0.15	-0.15					-$1			0.0002%
-0.20	-3.00		-0.350	-2,833				-0.20	-0.20	-0.20					-$1			0.0003%
-0.25	-3.75		-0.438	-3,542				-0.25	-0.25	-0.25					-$2			0.0003%
-0.30	-4.50		-0.525	-4,250				-0.30	-0.30	-0.30					-$2			0.0004%
-0.35	-5.25		-0.613	-4,958				-0.35	-0.35	-0.35					-$3			0.0005%
-0.40	-6.00		-0.700	-5,667				-0.40	-0.40	-0.40					-$3			0.0007%
-0.45	-6.75		-0.788	-6,375				-0.45	-0.45	-0.45					-$4			0.0008%
-0.50	-7.50		-0.875	-7,083				-0.50	-0.50	-0.50					-$5			0.0011%
-0.55	-8.25		-0.963	-7,792				-0.55	-0.55	-0.55					-$7			0.0013%
-0.60	-9.00		-1.050	-8,500				-0.60	-0.60	-0.60					-$8			0.0016%
-0.65	-9.75		-1.138	-9,208				-0.65	-0.65	-0.65					-$10			0.0021%
-0.70	-10.50		-1.225	-9,917				-0.70	-0.70	-0.70					-$13			0.0026%
-0.75	-11.25		-1.313	-10,625				-0.75	-0.75	-0.75					-$16			0.0032%
-0.80	-12.00		-1.400	-11,333				-0.80	-0.80	-0.80					-$20			0.0040%
-0.85	-12.75		-1.488	-12,042				-0.85	-0.85	-0.85					-$26			0.0050%
-0.90	-13.50		-1.575	-12,750				-0.90	-0.90	-0.90					-$32			0.0063%
-0.95	-14.25		-1.663	-13,458				-0.95	-0.95	-0.95					-$40			0.0078%
-1.00	-15.00		-1.750	-14,167				-1.00	-1.00	-1.00					-$50			0.0098%
-1.05	-15.75		-1.848	-14,875				-1.05	-1.05	-1.05					-$56			0.0110%
-1.10	-16.50		-1.945	-15,584				-1.10	-1.10	-1.10					-$63			0.0123%
-1.15	-17.25		-2.043	-16,292				-1.15	-1.15	-1.15					-$71			0.0139%
-1.20	-18.00		-2.140	-17,000				-1.20	-1.20	-1.20					-$79			0.0155%
-1.25	-18.75		-2.238	-17,709				-1.25	-1.25	-1.25					-$89			0.0174%
-1.30	-19.50		-2.335	-18,417				-1.30	-1.30	-1.30					-$100			0.0196%
-1.35	-20.25		-2.433	-19,125				-1.35	-1.35	-1.35					-$112			0.0220%
-1.40	-21.00		-2.530	-19,834				-1.40	-1.40	-1.40					-$126			0.0246%
-1.45	-21.75		-2.628	-20,542				-1.45	-1.45	-1.45					-$141			0.0276%
-1.50	-22.50		-2.725	-21,250				-1.50	-1.50	-1.50					-$158			0.0310%
-1.55	-23.25		-2.823	-21,959				-1.55	-1.55	-1.55					-$177			0.0348%
-1.60	-24.00		-2.920	-22,667				-1.60	-1.60	-1.60					-$199			0.0390%
-1.65	-24.75		-3.018	-23,375				-1.65	-1.65	-1.65					-$223			0.0438%
-1.70	-25.50		-3.115	-24,084				-1.70	-1.70	-1.70					-$251			0.0491%
-1.75	-26.25		-3.213	-24,792				-1.75	-1.75	-1.75					-$281			0.0551%
-1.80	-27.00		-3.310	-25,500				-1.80	-1.80	-1.80					-$315			0.0618%
-1.85	-27.75		-3.408	-26,209				-1.85	-1.85	-1.85					-$354			0.0694%
-1.90	-28.50		-3.505	-26,917				-1.90	-1.90	-1.90					-$397			0.0778%
-1.95	-29.25		-3.603	-27,625				-1.95	-1.95	-1.95					-$446			0.0873%
-2.00	-30.00		-3.700	-28,333				-2.00	-2.00	-2.00					-$500			0.0980%
-2.05	-30.75		-3.798	-29,041				-2.05	-2.05	-2.05					-$517			0.1014%
-2.10	-31.50		-3.895	-29,750				-2.10	-2.10	-2.10					-$536			0.1050%
-2.15	-32.25		-3.993	-30,458				-2.15	-2.15	-2.15					-$555			0.1087%
-2.20	-33.00		-4.090	-31,166				-2.20	-2.20	-2.20					-$574			0.1126%
-2.25	-33.75		-4.188	-31,875				-2.25	-2.25	-2.25					-$594			0.1165%
-2.30	-34.50		-4.285	-32,583				-2.30	-2.30	-2.30					-$615			0.1206%
-2.35	-35.25		-4.383	-33,291				-2.35	-2.35	-2.35					-$637			0.1249%
-2.40	-36.00		-4.480	-34,000				-2.40	-2.40	-2.40					-$660			0.1293%
-2.45	-36.75		-4.578	-34,708				-2.45	-2.45	-2.45					-$683			0.1339%
-2.50	-37.50		-4.675	-35,416				-2.50	-2.50	-2.50					-$707			0.1386%
-2.55	-38.25		-4.773	-36,125				-2.55	-2.55	-2.55					-$732			0.1435%
-2.60	-39.00		-4.870	-36,833				-2.60	-2.60	-2.60					-$758			0.1485%
-2.65	-39.75		-4.968	-37,541				-2.65	-2.65	-2.65					-$784			0.1538%
-2.70	-40.50		-5.065	-38,250				-2.70	-2.70	-2.70					-$812			0.1592%
-2.75	-41.25		-5.163	-38,958				-2.75	-2.75	-2.75					-$841			0.1648%
-2.80	-42.00		-5.260	-39,666				-2.80	-2.80	-2.80					-$870			0.1706%
-2.85	-42.75		-5.358	-40,375				-2.85	-2.85	-2.85					-$901			0.1766%
-2.90	-43.50		-5.455	-41,083				-2.90	-2.90	-2.90					-$933			0.1828%
-2.95	-44.25		-5.553	-41,791				-2.95	-2.95	-2.95					-$966			0.1893%
-3.00	-45.00		-5.650	-42,500				-3.00	-3.00	-3.00					-$1,000			0.1960%
-3.05	-45.75		-5.748	-43,208				-3.05	-3.05	-3.05					-$1,083			0.2124%
-3.10	-46.50		-5.845	-43,917				-3.10	-3.10	-3.10					-$1,174			0.2302%
-3.15	-47.25		-5.943	-44,625				-3.15	-3.15	-3.15					-$1,273			0.2495%
-3.20	-48.00		-6.040	-45,333				-3.20	-3.20	-3.20					-$1,379			0.2704%
-3.25	-48.75		-6.138	-46,042				-3.25	-3.25	-3.25					-$1,495			0.2931%
-3.30	-49.50		-6.235	-46,750				-3.30	-3.30	-3.30					-$1,620			0.3176%
-3.35	-50.25		-6.333	-47,458				-3.35	-3.35	-3.35					-$1,756			0.3443%
-3.40	-51.00		-6.430	-48,167				-3.40	-3.40	-3.40					-$1,903			0.3731%
-3.45	-51.75		-6.528	-48,875				-3.45	-3.45	-3.45					-$2,063			0.4044%
-3.50	-52.50		-6.625	-49,583				-3.50	-3.50	-3.50					-$2,236			0.4383%
-3.55	-53.25		-6.723	-50,292				-3.55	-3.55	-3.55					-$2,423			0.4750%
-3.60	-54.00		-6.820	-51,000				-3.60	-3.60	-3.60					-$2,626			0.5149%
-3.65	-54.75		-6.918	-51,708				-3.65	-3.65	-3.65					-$2,846			0.5580%
-3.70	-55.50		-7.015	-52,417				-3.70	-3.70	-3.70					-$3,085			0.6048%
-3.75	-56.25		-7.113	-53,125				-3.75	-3.75	-3.75					-$3,344			0.6555%
-3.80	-57.00		-7.210	-53,833				-3.80	-3.80	-3.80					-$3,624			0.7104%
-3.85	-57.75		-7.308	-54,542				-3.85	-3.85	-3.85					-$3,928			0.7700%
-3.90	-58.50		-7.405	-55,250				-3.90	-3.90	-3.90					-$4,257			0.8345%
-3.95	-59.25		-7.503	-55,958				-3.95	-3.95	-3.95					-$4,614			0.9045%
-4.00	-60.00		-7.600	-56,667				-4.00	-4.00	-4.00					-$5,000			0.9802%
-4.05	-60.75		-7.698	-57,375				-4.05	-4.05	-4.05					-$5,177			1.0148%
-4.10	-61.50		-7.795	-58,084				-4.10	-4.10	-4.10					-$5,359			1.0506%
-4.15	-62.25		-7.893	-58,792				-4.15	-4.15	-4.15					-$5,548			1.0877%
-4.20	-63.00		-7.990	-59,500				-4.20	-4.20	-4.20					-$5,744			1.1260%
-4.25	-63.75		-8.088	-60,209				-4.25	-4.25	-4.25					-$5,946			1.1657%
-4.30	-64.50		-8.185	-60,917				-4.30	-4.30	-4.30					-$6,156			1.2068%
-4.35	-65.25		-8.283	-61,625				-4.35	-4.35	-4.35					-$6,373			1.2494%
-4.40	-66.00		-8.380	-62,334				-4.40	-4.40	-4.40					-$6,598			1.2934%
-4.45	-66.75		-8.478	-63,042				-4.45	-4.45	-4.45					-$6,830			1.3390%
-4.50	-67.50		-8.575	-63,750				-4.50	-4.50	-4.50					-$7,071			1.3863%
-4.55	-68.25		-8.673	-64,459				-4.55	-4.55	-4.55					-$7,321			1.4351%
-4.60	-69.00		-8.770	-65,167				-4.60	-4.60	-4.60					-$7,579			1.4858%
-4.65	-69.75		-8.868	-65,875				-4.65	-4.65	-4.65					-$7,846			1.5381%
-4.70	-70.50		-8.965	-66,584				-4.70	-4.70	-4.70					-$8,123			1.5924%
-4.75	-71.25		-9.063	-67,292				-4.75	-4.75	-4.75					-$8,409			1.6485%
-4.80	-72.00		-9.160	-68,000				-4.80	-4.80	-4.80					-$8,706			1.7067%
-4.85	-72.75		-9.258	-68,709				-4.85	-4.85	-4.85					-$9,013			1.7668%
-4.90	-73.50		-9.355	-69,417				-4.90	-4.90	-4.90					-$9,330			1.8291%
-4.95	-74.25		-9.453	-70,125				-4.95	-4.95	-4.95					-$9,659			1.8936%
-5.00	-75.00		-9.550	-70,833				-5.00	-5.00	-5.00					-$10,000			1.9604%

Appendix E: Scoring Sample – Growth Portfolio

1.0 PROJECT NAME, DESCRIPTION, SCORING RATIONALE & SUMMARY

Project Name

Central Vancouver Island

Project Description

Load growth in central Vancouver Island has resulted in the transmission system experiencing thermal constraints in two portions of the system, the 138 kV circuits 1L115/1L116 and the VIT transformers.

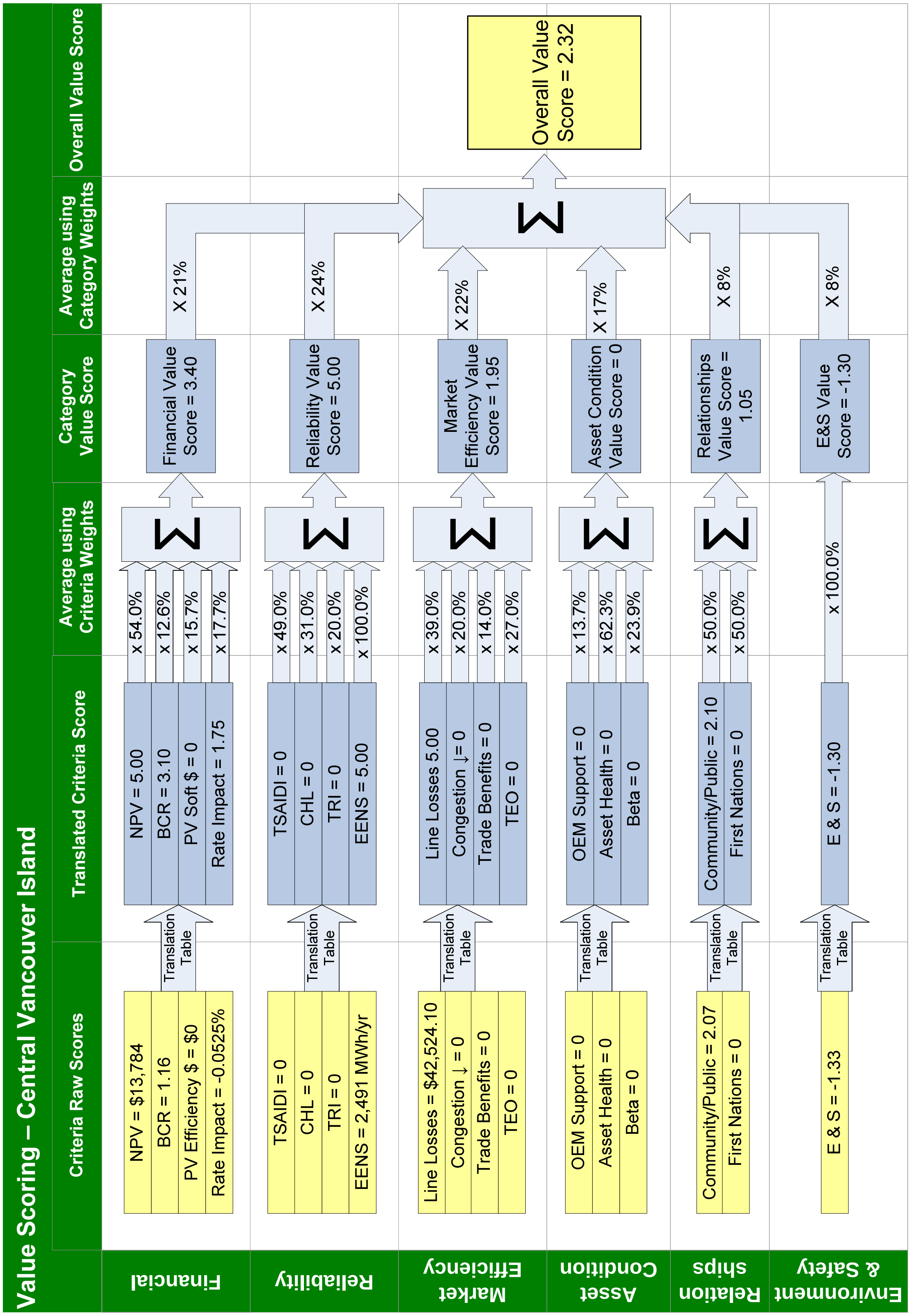
Definition Phase: Work is ongoing, as previously approved by the Commission in Order G-69-07.

Execution Phase: Build a new double circuit 230 kV overhead circuit and 230-138 kV substation to connect the existing 230 kV and 138 kV circuits in central VI.

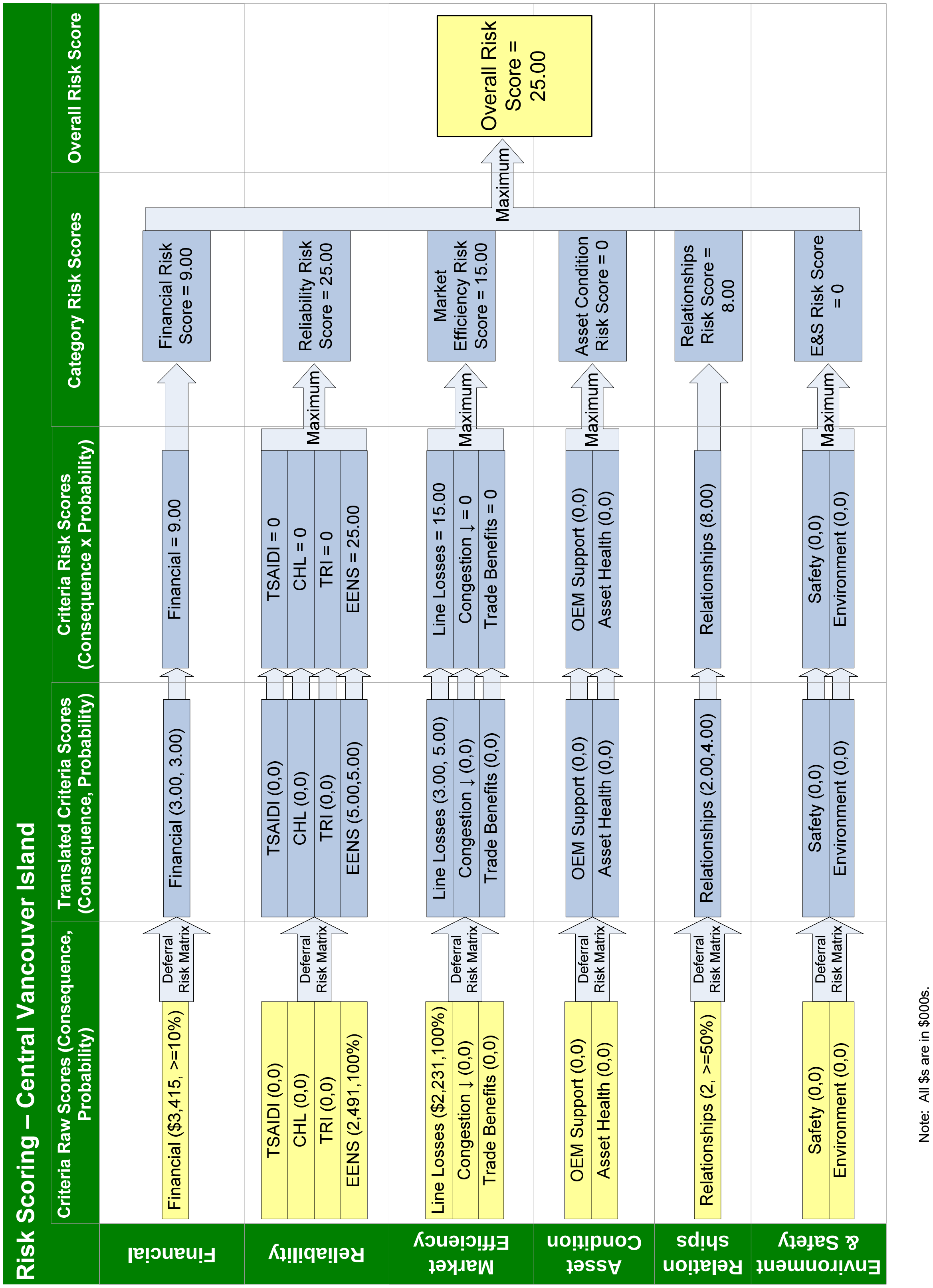
Scoring Rationale

Project scoring is based on proceeding with the Execution Phase and that Definition Phase work and costs are excluded. The project addresses load growth in the Central Vancouver Island only, which is currently supplied by transmission facilities (no local generation). The project does not incorporate any Sustaining Capital elements and will not result in retirements of existing facilities.

Scoring Summary



Note: All $s are in $000s.


Risk Scoring – Central Vancouver Island
Criteria Raw Scores (Consequence, Probability)
Translated Criteria Scores (Consequence, Probability)
Criteria Risk Scores (Consequence x Probability)
Category Risk Scores
Overall Risk Score
Financial
Financial ($3,415, >=10%)
Deferral Risk Matrix
Financial (3.00, 3.00)
Financial = 9.00
Financial Risk Score = 9.00
Reliability
TSAIDI (0,0)
CHL (0,0)
TRI (0,0)
EENS (2,491,100%)
Deferral Risk Matrix
TSAIDI (0,0)
CHL (0,0)
TRI (0,0)
EENS (5.00,5.00)
TSAIDI = 0
CHL = 0
TRI = 0
EENS = 25.00
Maximum
Reliability Risk Score = 25.00
Market Efficiency
Line Losses ($2,231,100%)
Congestion ↓ (0,0)
Trade Benefits (0,0)
Deferral Risk Matrix
Line Losses (3.00, 5.00)
Congestion ↓ (0,0)
Trade Benefits (0,0)
Line Losses = 15.00
Congestion ↓ = 0
Trade Benefits = 0
Maximum
Market Efficiency Risk Score = 15.00
Asset Condition
OEM Support (0,0)
Asset Health (0,0)
Deferral Risk Matrix
OEM Support (0,0)
Asset Health (0,0)
OEM Support (0,0)
Asset Health (0,0)
Maximum
Asset Condition Risk Score = 0
Relationships
Relationships (2, >=50%)
Deferral Risk Matrix
Relationships (2.00,4.00)
Relationships (8.00)
Relationships Risk Score = 8.00
Environment & Safety
Safety (0,0)
Environment (0,0)
Deferral Risk Matrix
Safety (0,0)
Environment (0,0)
Safety (0,0)
Environment (0,0)
Maximum
E&S Risk Score = 0
Maximum
Overall Risk Score = 25.00
Note: All $s are in $000s.

2.0 VALUE SCORING

2.1 FINANCIAL

Inputs, Assumptions & Justifications

Costs

Capital Costs ($,000):

The project direct uninflated cash flow is as follows:

Total	Plan	Implement	Implement	In-Service Year
	F2008	F2009	F2010	F2011
	T = -3	T = -2	T = -1	T = 0
66,703	335	8,235	25,888	32,245

% Allocation of Asset Type Costs:

The following allocation of asset type costs reflects the proportions of costs in the cost estimate, rounded to 5% increments.

- Transmission Line/Cable Costs: 25%
- Switchyard Equipment: 70%
- Land Purchases: 5%

Circuit Lengths:

- 230 kV Heavy Duty Double Circuit Steel Pole Transmission Line: 2.2 km
- 230 kV Heavy Duty Double Circuit Steel Tower Transmission Line: 9.5 km

Contributions in Aid:

No contributions in aid. The project is not triggered by a customer request.

Residual Equipment Book Value:

No residual value. No existing assets will be removed from service.

Average Number of Depreciable Years Remaining:

Not applicable. No existing assets will be removed from service.

OMA Investment Costs:

No OMA investment costs. All expenditures associated with the implementation of the project are classified as capital.

OMA Incremental Ongoing Costs:

Annual OMA estimated to be 1.1% of the direct capital cost. This is a standard estimating factor when detailed OMA estimates are not available.

Dismantling and Removal Costs:

No dismantling and removal costs. No existing assets will be removed from service.

<u>Savings and Benefits</u>

OMA Savings:

No OMA savings

Forecast Load Growth Applicable to the Project (in MW):

The portion of the BC Hydro forecast load growth supplied by this project is:

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
73.7	82.4	84.1	94.9	105.6	114.4	120.2	129.1	137.9	146.8

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
156.4	166	176	185	195	204	214	224	233	243

Project Capacity (in MW): 355 MW

MW served by existing capacity: 0 MW. System capacity is exceeded.

Load Factor of the Forecast Load Growth: 0.60. Capacity factor for mix of residential, commercial and industrial.

Firm PTP Service Sales:

No firm PTP sales. Load service is under a NITS contract.

Efficiency Labour Savings:

No efficiency labour savings

Avoided Costs:

No avoided costs

Other Efficiency Savings:

No other efficiency savings

2.1.1 NPV

Calculations, Calculated Score & Translated Score

The calculated score is the net of PV uninflated benefits and PV uninflated costs. See attached spreadsheet. The NPV score is $13,784K, which translates to a score of 5.

2.1.2 Benefit to Cost Ratio

Calculations, Calculated Score & Translated Score

The calculated score is the ratio of uninflated benefits to uninflated costs. See attached spreadsheet. The benefit to cost ratio score is 1.1535, which translates to a score of 3.10.

2.1.3 Rate Impact

Calculations, Calculated Score & Translated Score

See attached spreadsheet. The rate impact score is -0.0525%, which translates to a score of 1.75.

Financial Value Score Calculation

INVESTMENT NAME: CENTRAL VANCOUVER ISLAND

Financial Value Scores Summary

	Calculated Score	Translated Score
NPV	$13,784	5.00
Benefit to Cost Ratio	1.1535	3.10
PV of Efficiency Dollar Savings	$0	0.00
Rate Impact % (20+ Year Impact)	-0.0525%	1.75

SECTION I: DATA ENTRY AND CAPITAL COST CALCULATIONS	**Total**	**F2008 T=-3**	**Construct F2009 T=-2**	**Construct F2010 T=-1**	**Inservice Year F2011 T=0**	**F2012 T=1**	**F2013 T=2**	**F2014 T=3**	**F2015 T=4**	**F2016 T=5**	**F2017 T=6**	**F2018 T=7**	**F2019 T=8**	**F2020 T=9**	**F2021 T=10**	**F2022 T=11**	**F2023 T=12**	**F2024 T=13**	**F2025 T=14**	**F2026 T=15**	**F2027 T=16**	**F2028 T=17**	**F2029 T=18**	**F2030 T=19**
Capital Costs (Labor / Contractor Costs, Materials, Services, ROW costs, New Land Purchases)	$66,703	$335	$8,235	$25,888	$32,245																			

Transmission Line / Cable Costs		25%	%
69 kV Transmission Line or Underground Cable Circuit			km
138 kV Transmission Line or Underground Cable Circuit			km
230 kV Heavy Duty Double Circuit Steel Pole Transmission Line		2.2	km
230 kV Double Circuit Steel Pole Transmission Line			km
230 kV Heavy Duty Double Circuit Steel Tower Transmission Line		9.5	km
230 kV Double Circuit Steel tower Transmission Line			km
230 kV Wood or Concrete Pole Transmission Line			km
287 kV to 360 kV Single Circuit Wood or Concrete Pole Transmission Line			km
230 kV to 360 kV Single Circuit Steel Tower Transmission Line or			km
500 kV Steel Tower Transmission Line			km
500 kV AC Submarine Cable Circuit			km
230 kV DC Submarine Cable Circuit			km
138 kV AC Submarine Cable Circuit			km
Switchyard Equipment Costs		70%	%
Buildings / Structures Costs			%
Computer Costs			%
Communications Costs			%
ROW Costs (Associated w/ Lines/Cables)			%
ROW Depreciable Years			
Land Purchases (BCH owned - Associated with Switchyard Equipment and/or Buildings and Structures)		5%	%

		F2008 T=-3	**Construct F2009 T=-2**	**Construct F2010 T=-1**	**Inservice Year F2011 T=0**	**F2012 T=1**	**F2013 T=2**	**F2014 T=3**	**F2015 T=4**	**F2016 T=5**	**F2017 T=6**	**F2018 T=7**	**F2019 T=8**	**F2020 T=9**	**F2021 T=10**	**F2022 T=11**	**F2023 T=12**	**F2024 T=13**	**F2025 T=14**	**F2026 T=15**	**F2027 T=16**	**F2028 T=17**	**F2029 T=18**	**F2030 T=19**
Total	100%																							
Capital Overheads	$2,165	$11	$201	$859	$1,093																			
Interest During Construction Calculations																								
Capital Dollar Amount Used in IDC Calculation	$68,868	$346	$8,436	$26,747	$33,338																			
Interest During Construction (Compounded)	$5,594	$12	$315	$1,547	$3,720																			
Total Capital Construction Costs (Including Overheads and IDC)	**$74,462**	**$358**	**$8,751**	**$28,294**	**$37,058**																			
Total Capital Construction Costs (Overheads Only)	**$68,868**	**$346**	**$8,436**	**$26,747**	**$33,338**																			
Customer Contributions in Aid	$0																							
Interest During Construction (Compounded)	$0	$0	$0	$0	$0																			
Total Contributions in Aid	**$0**	**$0**	**$0**	**$0**	**$0**																			
Total Net Capital Construction Cost (less CIA)	**$74,462**	**$358**	**$8,751**	**$28,294**	**$37,058**																			
Total Net Capital Construction Costs (Less CIA & IDC)	**$68,868**	**$346**	**$8,436**	**$26,747**	**$33,338**																			

Average Number of Depreciable Years Remaining (Across All Assets Retired)		Years

OMA COSTS: (dollars in thousands)	**Total**	**F2008 T=-3**	**Construct F2009 T=-2**	**Construct F2010 T=-1**	**Inservice Year F2011 T=0**	**F2012 T=1**	**F2013 T=2**	**F2014 T=3**	**F2015 T=4**	**F2016 T=5**	**F2017 T=6**	**F2018 T=7**	**F2019 T=8**	**F2020 T=9**	**F2021 T=10**	**F2022 T=11**	**F2023 T=12**	**F2024 T=13**	**F2025 T=14**	**F2026 T=15**	**F2027 T=16**	**F2028 T=17**	**F2029 T=18**	**F2030 T=19**
OMA Investment Costs (OMA costs during Construction)	$0																							
OMA Incremental Ongoing Costs	$14,680				$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734
Dismantling and Removal Costs (Net of Salvage Value)*	$0																							
Total OMA Costs	**$14,680**	**$0**	**$0**	**$0**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**	**$734**

SAVINGS: (dollars in thousands) OMA Savings	Total	F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
OMA Savings – FTE Reductions, Overtime Savings, and Contractor Labor Savings	$0																							
Incremental Revenue for Growth Projects																								
Expected load growth in MW each year within the investment's area (Starting in in-service year)	242.8				73.7	8.7	1.7	10.8	10.7	8.8	5.8	8.9	8.8	8.9	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
MW of the above growth can be served by existing capacity (pre-investment)	0.0																							
Load Factor of the expected growth	0.60																							
MW of new capacity added by the investment	355.0																							
Load growth served by the investment					73.7	8.7	1.7	10.8	10.7	8.8	5.8	8.9	8.8	8.9	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Total MW of capacity served by new investment	3,085				73.7	82.4	84.1	94.9	105.6	114.4	120.2	129.1	137.9	146.8	156.4	166.0	175.6	185.2	194.8	204.4	214.0	223.6	233.2	242.8
Translation to KWHrs	16,215,285,600				387,367,200	433,094,400	442,029,600	498,794,400	555,033,600	601,286,400	631,771,200	678,549,600	724,802,400	771,580,800	822,038,400	872,496,000	922,953,600	973,411,200	1,023,868,800	1,074,326,400	1,124,784,000	1,175,241,600	1,225,699,200	1,276,156,800
Incremental Revenue	$142,938				$3,415	$3,818	$3,897	$4,397	$4,893	$5,300	$5,569	$5,981	$6,389	$6,802	$7,246	$7,691	$8,136	$8,581	$9,025	$9,470	$9,915	$10,360	$10,805	$11,249
Total Net Incremental Revenue for Growth Projects	$142,938				$3,415	$3,818	$3,897	$4,397	$4,893	$5,300	$5,569	$5,981	$6,389	$6,802	$7,246	$7,691	$8,136	$8,581	$9,025	$9,470	$9,915	$10,360	$10,805	$11,249
Forecast PTP Revenue																								
Firm PTP Sales (MW)	0.0																							
Forecast PTP Revenue ($000)	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Savings	**$142,938**	**$0**	**$0**	**$0**	**$3,415**	**$3,818**	**$3,897**	**$4,397**	**$4,893**	**$5,300**	**$5,569**	**$5,981**	**$6,389**	**$6,802**	**$7,246**	**$7,691**	**$8,136**	**$8,581**	**$9,025**	**$9,470**	**$9,915**	**$10,360**	**$10,805**	**$11,249**

EFFICIENCY SAVINGS: (enter dollars in thousands)	Total	F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
Efficiency Labor Savings (Efficiency Gains, Redirected Labor, etc.)	$0																							
Avoided costs (Materials/Equipment Costs avoided, e.g. OEM Support Costs avoided)	$0																							
Other Efficiency Savings (e.g. potential LMP savings)	$0																							
Total Efficiency Savings	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

SECTION II: NPV, BENEFIT TO COST, AND EFFICIENCY DOLLAR CALCULATION RESULTS:		F2008 T=-3 0	Construct F2009 T=-2 1	Construct F2010 T=-1 2	Inservice Year F2011 T=0 3	F2012 T=1 4	F2013 T=2 5	F2014 T=3 6	F2015 T=4 7	F2016 T=5 8	F2017 T=6 9	F2018 T=7 10	F2019 T=8 11	F2020 T=9 12	F2021 T=10 13	F2022 T=11 14	F2023 T=12 15	F2024 T=13 16	F2025 T=14 17	F2026 T=15 18	F2027 T=16 19	F2028 T=17 20	F2029 T=18 21	F2030 T=19 22
Total Net Capital Construction Costs	$68,868	$346	$8,436	$26,747	$33,338	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total OMA Costs	$14,680	$0	$0	$0	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734
Other Grants and Taxes - see SECTION V for details	$15,819	$0	$0	$0	$406	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811
Total Costs - Unadjusted	$99,367	$346	$8,436	$26,747	$34,478	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545	$1,545
Total Costs - Discounted to Current Fiscal Year Dollars	$87,544	$346	$8,230	$25,459	$32,016	$1,400	$1,366	$1,332	$1,300	$1,268	$1,237	$1,207	$1,178	$1,149	$1,121	$1,094	$1,067	$1,041	$1,016	$991	$967	$943	$920	$898
Dollar Benefits																								
OMA Savings	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Incremental Revenue for Growth Projects	$142,938				$3,415	$3,818	$3,897	$4,397	$4,893	$5,300	$5,569	$5,981	$6,389	$6,802	$7,246	$7,691	$8,136	$8,581	$9,025	$9,470	$9,915	$10,360	$10,805	$11,249
Forecast PTP Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Dollar Benefits - Unadjusted	$142,938	$0	$0	$0	$3,415	$3,818	$3,897	$4,397	$4,893	$5,300	$5,569	$5,981	$6,389	$6,802	$7,246	$7,691	$8,136	$8,581	$9,025	$9,470	$9,915	$10,360	$10,805	$11,249
Total Dollar Benefits - Discounted to Current Fiscal Year Dollars	$100,983	$0	$0	$0	$3,171	$3,459	$3,444	$3,791	$4,116	$4,350	$4,459	$4,673	$4,869	$5,057	$5,257	$5,443	$5,618	$5,780	$5,931	$6,072	$6,202	$6,322	$6,433	$6,534
Net Cash Flow - Unadjusted	**$43,571**	**($346)**	**($8,436)**	**($26,747)**	**($31,063)**	**$2,273**	**$2,351**	**$2,852**	**$3,347**	**$3,755**	**$4,024**	**$4,436**	**$4,844**	**$5,256**	**$5,701**	**$6,146**	**$6,591**	**$7,035**	**$7,480**	**$7,925**	**$8,370**	**$8,815**	**$9,259**	**$9,704**
Present Value - Discounted to Current Fiscal Year Dollars	**$13,438**	**($346)**	**($8,230)**	**($25,459)**	**($28,845)**	**$2,059**	**$2,078**	**$2,459**	**$2,816**	**$3,082**	**$3,222**	**$3,466**	**$3,692**	**$3,908**	**$4,136**	**$4,350**	**$4,551**	**$4,739**	**$4,916**	**$5,081**	**$5,236**	**$5,379**	**$5,513**	**$5,637**

Efficiency Dollar Benefits		F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
Efficiency Dollar Savings - Unadjusted	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Efficiency Dollar Savings - Discounted to Inservice Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow (incl efficiency savings) - Unadjusted	$43,571	($346)	($8,436)	($26,747)	($31,063)	$2,273	$2,351	$2,852	$3,347	$3,755	$4,024	$4,436	$4,844	$5,256	$5,701	$6,146	$6,591	$7,035	$7,480	$7,925	$8,370	$8,815	$9,259	$9,704
Net Cash Flow (incl efficiency savings) - Discounted to Inservice Year Dollars	$13,438	($346)	($8,230)	($25,459)	($28,845)	$2,059	$2,078	$2,459	$2,816	$3,082	$3,222	$3,466	$3,692	$3,908	$4,136	$4,350	$4,551	$4,739	$4,916	$5,081	$5,236	$5,379	$5,513	$5,637

NPV, BENEFIT TO COST RATIO, and PV OF EFFICIENCY SAVINGS:

NPV	**$13,438**
Benefit to Cost Ratio	**1.1535**
PV of Efficiency Dollar Savings	**$0**

SECTION III: REVENUE REQUIREMENT/RATE IMPACT CALCULATION	Total	F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
BCH Land Purchases/Non-Depreciable Rate Base - Yearly Amount	$3,723	$18	$438	$1,415	$1,853																			
Work in Progress / Depreciable Rate Base (less CIA) - Yearly Amount	$70,739	$340	$8,313	$26,880	$35,205																			
CIA (Yearly Amount)	$0	$0	$0	$0	$0																			
Opening Gross Assets (In Rate Base)					$0	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462
Additions (Work in Progress and ROW Purchases (In-Service Year))					$74,462																			
Closing Gross Assets					$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462	$74,462
Opening Accumulated Depreciation						($969)	($2,907)	($4,846)	($6,784)	($8,722)	($10,660)	($12,599)	($14,537)	($16,475)	($18,413)	($20,352)	($22,290)	($24,228)	($26,166)	($28,104)	($30,043)	($31,981)	($33,919)	($35,857)
Current Year Depreciation - see Section IV					($969)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)	($1,938)
Closing Accumulated Depreciaton					($969)	($2,907)	($4,846)	($6,784)	($8,722)	($10,660)	($12,599)	($14,537)	($16,475)	($18,413)	($20,352)	($22,290)	($24,228)	($26,166)	($28,104)	($30,043)	($31,981)	($33,919)	($35,857)	($37,796)
CIA Opening						$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Additions					$0																			
Closing CIA					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Opening Accumulated Depreciation						$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Current Year Depreciation					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Closing Accumulated Depreciaton					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Closing Accumulated Depreciation (Rate Base + CIA)					($969)	($2,907)	($4,846)	($6,784)	($8,722)	($10,660)	($12,599)	($14,537)	($16,475)	($18,413)	($20,352)	($22,290)	($24,228)	($26,166)	($28,104)	($30,043)	($31,981)	($33,919)	($35,857)	($37,796)
		F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
Working Capital and other					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Utility Rate Base (BCH Land and Depreciated Capital)					$73,493	$71,554	$69,616	$67,678	$65,740	$63,801	$61,863	$59,925	$57,987	$56,048	$54,110	$52,172	$50,234	$48,296	$46,357	$44,419	$42,481	$40,543	$38,604	$36,666
Mid Year Rate Base (opening + ending)/2					$73,977	$72,524	$70,585	$68,647	$66,709	$64,771	$62,832	$60,894	$58,956	$57,018	$55,079	$53,141	$51,203	$49,265	$47,326	$45,388	$43,450	$41,512	$39,573	$37,635
CIA (Annually Depreciated Amount)					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mid Year CIA (opening + ending)/2					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Retained Earning Calculation (Added Back into Equity Component)						$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Equity Component					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Component					$73,977	$72,524	$70,585	$68,647	$66,709	$64,771	$62,832	$60,894	$58,956	$57,018	$55,079	$53,141	$51,203	$49,265	$47,326	$45,388	$43,450	$41,512	$39,573	$37,635
Annual Equity cost	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual interest cost	$69,157				$4,483	$4,482	$4,362	$4,242	$4,123	$4,003	$3,883	$3,763	$3,643	$3,524	$3,404	$3,284	$3,164	$3,045	$2,925	$2,805	$2,685	$2,565	$2,446	$2,326
Annual Equity cost - CIAC	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual depreciation (Capital Depreciable Asset and CIA)	$37,796				$969	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938	$1,938
Net Annual OMA (Includes OMA, Removal Costs, and any OMA Benefits)	$14,680	$0	$0	$0	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734	$734
Net Book Value of Assets Retired (T=0)	$0				$0																			
Remaining Depreciation Credit for Assets Retired	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual other taxes and grants - see Section V	$15,819				$406	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811	$811
Total Annual Cost of Service	$137,452	$0	$0	$0	$6,592	$7,965	$7,846	$7,726	$7,606	$7,486	$7,367	$7,247	$7,127	$7,007	$6,887	$6,768	$6,648	$6,528	$6,408	$6,288	$6,169	$6,049	$5,929	$5,809
Change		$0	$0	$0	$6,592	$1,374	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)	($120)
Total Annual Cost of Service - Converted to Current Fiscal Year Dollars	$103,150	$0	$0	$0	$6,121	$7,216	$6,934	$6,662	$6,399	$6,144	$5,899	$5,661	$5,432	$5,210	$4,996	$4,790	$4,590	$4,397	$4,211	$4,032	$3,859	$3,691	$3,530	$3,374

RATE IMPACT PERCENTAGE

Rate Impact Excluding Load Growth Revenue

		F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
BCH Average Cost per kWh	$0.052668																							
BCH Total Forecast Energy - kWh	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394
BCH Total Energy Forecast - kWh	$1,210,281,838,252	$26,925,105,697	$52,536,791,604	$53,816,576,034	$53,849,369,998	$53,850,190,359	$53,850,210,868	$53,850,211,381	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394
Total BCH Revenue Requirement	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374
BCH Average Cost per kWh - Transmission	$0.008815																							

Revenue Requirement Increase*	$103,149,984
Rate Increase per kWh	$0.0000852281
New BCH Average Cost per kWh	$0.052753

Rate Impact Including Load Growth Revenue

		T=0	T=1	T=2	T=3	T=4	T=5	T=6	T=7	T=8	T=9	T=10	T=11	T=12	T=13	T=14	T=15	T=16	T=17	T=18	T=19
Total Net Incremental Revenue for Growth Projects*	$142,938,288	$3,414,655	$3,817,742	$3,896,506	$4,396,889	$4,892,640	$5,300,360	$5,569,084	$5,981,438	$6,389,158	$6,801,511	$7,246,296	$7,691,082	$8,135,867	$8,580,652	$9,025,438	$9,470,223	$9,915,009	$10,359,794	$10,804,580	$11,249,365
Total Net Incremental Revenue for Growth Projects - Converted to Inservice Year Dollars	$108,747,133	$3,414,655	$3,724,626	$3,708,750	$4,082,949	$4,432,490	$4,684,746	$4,802,204	$5,031,975	$5,243,879	$5,446,163	$5,660,795	$5,861,718	$6,049,472	$6,224,580	$6,387,548	$6,538,863	$6,678,997	$6,808,406	$6,927,528	$7,036,790

* Dollars converted from thousands

Adjusted Revenue Requirement Increase	-$5,597,149
PV of BCH Revenue Requirement - BCH TLoB	$10,668,675,082
BCH Rate Impact Percentage Increase including Load Growth Revenue (20+ Year Impact)	**-0.0525%**

SECTION IV: DEPRECIATION CALCULATIONS:

	Total	F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
Non-Depreciable Rate Base - BCH Owned New Land Purchases	$3,723	$18	$438	$1,415	$1,853																			
Accumulated Non-Depreciable Rate Base - BCH Land Purchases		$18	$455	$1,870	$3,723																			
Depreciable Rate Base (Unadjusted Dollars) for BCH TLoB	$70,739	$340	$8,313	$26,880	$35,205																			
Accumulated Depreciable Rate Base		$340	$8,654	$35,533	$70,739																			
Depreciation - Transmission Line / Cable Costs	$6,414				$164	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329
Depreciation - Switchyard Equipment Costs	$31,381				$805	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609	$1,609
Depreciation - Buildings / Structures Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Communications Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - ROW Costs (Associated with Lines / Cables)	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Leasehold Improvement	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Building	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Land	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Software	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Hardware	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciaion - Furniture Equipment	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Communicatioin	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA (Unadjusted Dollars)	$0	$0	$0	$0	$0																			
Accumulated Depreciable CIA		$0	$0	$0	$0																			
Depreciation - Transmission Line / Cable Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Switchyard Equipment Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Buildings / Structures Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Communications Costs	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - ROW Costs (Associated with Lines / Cables)	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SECTION V: TAXES CALCULATIONS

Taxes - Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land	Total	F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Total Yearly Dollars	$55,846	$269	$6,563	$21,221	$27,794																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Total Yearly Dollars (Less IDC)	$51,651	$260	$6,327	$20,061	$25,004																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Accumulated Dollars		$269	$6,832	$28,053	$55,846																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Accumulated Dollars (Less IDC)		$260	$6,587	$26,647	$51,651																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Yearly Taxes (School Taxes, etc.)	$11,206				$287	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575	$575
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Yearly Taxes (School Taxes, etc.) Less IDC	$5,315				$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266	$266
Grant Tax - BCH Owned Land (additional tax on land only)																								
BCH Owned Land (only) - Total Yearly Dollars	$3,723																							
BCH Owned Land (only) - Total Yearly Dollars (Less IDC)	$3,443																							
BCH Owned Land (only) - Accumulated Dollars																								
BCH Owned Land (only) - Accumulated Dollars (Less IDC)																								
BCH Owned Land (only) - General Grant Tax (4%)*					$74	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149
BCH Owned Land (only) - General Grant Tax (4%)* (Less IDC)					$69	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138

Taxes on Transmission Lines	km of line	F2008 T=-3	Construct F2009 T=-2	Construct F2010 T=-1	Inservice Year F2011 T=0	F2012 T=1	F2013 T=2	F2014 T=3	F2015 T=4	F2016 T=5	F2017 T=6	F2018 T=7	F2019 T=8	F2020 T=9	F2021 T=10	F2022 T=11	F2023 T=12	F2024 T=13	F2025 T=14	F2026 T=15	F2027 T=16	F2028 T=17	F2029 T=18	F2030 T=19
69 kV Transmission Line or Underground Cable Circuit	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
138 kV Transmission Line or Underground Cable Circuit	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Heavy Duty Double Circuit Steel Pole Transmission Line	2.2				$9	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17	$17
230 kV Double Circuit Steel Pole Transmission Line	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Heavy Duty Double Circuit Steel Tower Transmission Line	9.5				$35	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70
230 kV Double Circuit Steel tower Transmission Line	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Wood or Concrete Pole Transmission Line	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
287 kV to 360 kV Single Circuit Wood or Concrete Pole Transmission Line	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV to 360 kV Single Circuit Steel Tower Transmission Line or	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
500 kV Steel Tower Transmission Line	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
500 kV AC Submarine Cable Circuit	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV DC Submarine Cable Circuit	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
138 kV AC Submarine Cable Circuit	0.0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Taxes for Lines with Asset Classes	$1,709				$44	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88	$88
BCTC Property Tax	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BCTC Property Grant	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Taxes and Grants (Total Property Taxes)	$15,819				**$406**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**	**$811**
Total Other Taxes/Grants/Property Taxes (Excluding IDC)	$9,710				**$378**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**	**$491**

2.1.4 PV of Efficiency Dollar Savings

Calculations, Calculated Score & Translated Score

See attached spreadsheet. The PV of efficiency dollar savings score is 0, which translates to a score of 0.

2.1.5 Financial Value Score

Financial Value Score =

(5.00 x 54% + 3.10 x 12.6% + 0.0 x 15.7% + 1.75 x 17.7%) x 21.0%

= 0.71

2.2 RELIABILITY

2.2.1 TSAIDI

Not applicable. Growth project reliability benefit is assessed by EENS improvement.

2.2.2 Distribution Customer Hours Lost

Not applicable. Growth project reliability benefit is assessed by EENS improvement.

2.2.3 Transmission Reliability Index (TRI)

Not applicable. Growth project reliability benefit is assessed by EENS improvement.

2.2.4 Expected Energy Not Served (EENS)

Inputs, Assumptions & Justifications

Current and predicted EENS are calculated values for the project.

Current EENS (in the past year) prior to the investment:

4215 MWhr/yr

Predicted EENS after investment installation:

1724 MWhr/yr

<u>Calculations, Calculated Score & Translated Score</u>

Reduction in EENS = 4215 – 1724 = 2491 MWhr/yr

This translates to an EENS score of 5.

2.2.5 Reliability Value Score

Reliability Value Score = (5.00 x 100%) x 24.0% = 1.20

2.3 MARKET EFFICIENCY

2.3.1 Real Line Losses

<u>Inputs, Assumptions & Justifications</u>

GWHrs of line losses reduction over 20 years or over its predicted lifetime, whichever is less:

Losses reduction estimates are calculated for the project.

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
25.4	26.0	26.3	26.6	27.2	27.2	27.9	28.7	29.4	29.7

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3

<u>Calculation & Raw Calculated Score</u>

Based on $88/MWhr and 2.5% real discount rate, the calculated score is $41,524k, which translates to a score of 5.

2.3.2 Congestion Reduction

No congestion reduction attributed to this project. Additional transmission capacity is reflected in the EENS reduction.

2.3.3 Trade Benefits

Project is for an area reinforcement. No trade benefits attributed to this project.

2.3.4 Transmission Expansion Opportunities (TEO)

No transmission expansion opportunities are associated with this project.

2.3.5 Market Efficiency Value Score

Market Efficiency Value Score = (5.00 x 39%) x 22.0% = 0.43

2.4 ASSET CONDITION

No Sustaining Capital elements applicable to this project. Therefore, Asset Condition categories are not applicable to this project.

2.5 RELATIONSHIPS

2.5.1 Community/Public

<u>Inputs, Assumptions & Justifications</u>

Customer Satisfaction - Economic Impact:

Marginally Positive due to improved reliability – score: 2

Customer Satisfaction - Health & Safety Impact:

Marginally Negative due to construction of 11.7 km of new transmission lines – score: -2

Customer Satisfaction - Corporate Image & Reputation Impact:

Marginally positive due to addressing concern of reliable supply on central Vancouver Island. – score: 2

Customer Satisfaction - Aesthetics Impact:

Marginally negative due to construction of 11.7 km of overhead transmission. – score: -2

Customer Satisfaction - Property Value Impact:

Marginally negative due to construction of 11.7 km of overhead transmission. – score: -2

Customer Satisfaction - Quality of Transmission Service Impact:

Significantly positive due to improved reliability. – score: 5

Stakeholder Relationships – Industrials:

Significantly positive. – score: 5

Stakeholder Relationships – Commercial Customers:

Marginally positive. – score: 2

Stakeholder Relationships – IPPs & Wholesale Transmission Customers:

Marginally positive – score: 2

Stakeholder Relationships – Municipal Governments:

Significantly positive. – score: 5

Stakeholder Relationships – Provincial Governments:

Marginally positive – score: 2

Stakeholder Relationships – General Public:

Significantly positive. – score: 5

Population density of the investment's intended scope area:

Medium Density Area – Weighting Factor: 0.9

<u>Calculations, Calculated Score & Translated Score</u>

Customer Satisfaction Raw Calculated Score = ((2-2+2-2-2+5)/6) x 40% = 0.2

Stakeholder Impact Raw Calculated Score = ((5+2+2+5+2+5)/6) x 60% = 2.1

Total Raw Calculated Score = (0.2 + 2.1) x 0.9 = 2.07

This translates to a score of 2.10.

2.5.2 First Nations

<u>Inputs, Assumptions & Justifications</u>

First Nations Customer Satisfaction - Economic Opportunities Impact:

No significant First Nations Impact

First Nations Customer Satisfaction - Reserve Land and Resource Impact:

No significant First Nations Impact

First Nations Customer Satisfaction - Traditional Territory and Resource Impact:

No significant First Nations Impact

Impact of the investment on BCTC's relationship with any First Nation Bands:

No significant First Nations Impact

Number of First Nation Bands impacted:

No significant First Nations Impact

<u>Calculations, Calculated Score & Translated Score</u>

Score = 0

2.5.3 Relationships Value Score

Relationships Value Score = (2.1 x 50% + 0.0 x 50%) x 82.0% = 0.08

2.6 ENVIRONMENT AND SAFETY

<u>Inputs, Assumptions & Justifications</u>

Current state and degree of impact on of the Environment and Safety strategies:

	Current State	**Degree of Impact**
GHG (Green House Gas):	No Issues/Hazards	Neutral
Air Quality:	No Issues/Hazards	Neutral
Waste:	No Issues/Hazards	Neutral
Water:	No Issues/Hazards	Neutral
Land:	No Issues/Hazards	Marginally negative – land use for substation and transmission line
Species at Risk:	Existing species at risk – lotus pinnatus	Marginally negative for species at risk
Environment Management System:	No Issues/Hazards	Neutral
Employee / Workforce Safety:	No Issues/Hazards	Neutral
Public Safety:	No Issues/Hazards	Neutral

Impacts localized or dispersed:

Localized

<u>Calculations, Calculated Score & Translated Score</u>

Calculated Score = (((0 + 0 + 0) + ((-4) + (-1) + 0))) x 0.8 = -1.33333

This translates to a score of -1.30.

2.6.1 Environment and Safety Value Score

Environment and Safety Value Score = (-1.3 x 100%) x 8.0% = -0.10

3.0 RISK SCORING

3.1 Financial

Description of Most Likely Scenario

If the project is deferred one year, load curtailment will be necessary at peak load periods.

Consequence

Project Cost Increases:

Project cost is unlikely to increase specifically due to deferral.

Loss of Revenue:

Possible loss of revenue of up to $3,415,000 due to load curtailment. The first year revenue calculated in the Financial Value section is used for this revenue loss estimate.

Other Cost Implications:

No other cost implications due to deferral.

Consequence Score:

The total cost implication translates to a Consequence Score of 3.

Probability

The probability of the above consequence occurring was assessed to be 10% or greater, but less than 50%, which translates to a Probability Score of 3. Off peak load levels can be supplied without the project.

Financial Risk

The Financial Risk is the Consequence Score times the Probability Score = 9.

3.2 RELIABILITY

3.2.1 TSAIDI

Not applicable. Growth project reliability benefit is assessed by EENS improvement.

3.2.2 Distribution Customer Hours Lost

Not applicable. Growth project reliability benefit is assessed by EENS improvement.

3.2.3 Transmission Reliability Index (TRI)

Not applicable. Growth project reliability benefit is assessed by EENS improvement.

3.2.4 Expected Energy Not Served (EENS)

Consequence

The EENS consequence level is calculated from the EENS impact derived in the value section above. (EENS Before Investment – EENS After Investment). The risk of deferring the investment one year is essentially the foregone benefit of not undertaking the investment.

The EENS Calculated Score (in the Value Calculation) of 2491 MWhr/yr translates to a Consequence Score of 5.

Probability

The calculation for EENS already accounts for probability, so a probability of 5 (100% certain) is automatically applied to this criterion for calculating its risk score.

Reliability Risk

The Reliability Risk is the Consequence Score times the Probability Score = 25.

3.3 MARKET EFFICIENCY

3.3.1 Real Line Losses

Consequence

The consequence level is calculated by taking the GWHr loss reduction in year 1 (after in-service) and multiplying it by the applicable MWHr dollar rate (to convert the dollars into thousands). This value indicates the foregone reduction in losses if the investment is deferred one year and is spread on a consequence scale between 0 and 5.

The first year GWhr losses reduction of 25.4 GWhr times $88/MWhr equals $2,231,000, which translates to a Consequence Score of 3.

Probability

The probability level for (Real) Line Losses is assumed to be a 100% probability as it is 100% certain that the benefit will not be achieved if the investment is deferred.

Line Losses Risk

The Line Losses Risk is the Consequence Score times the Probability Score = 15.

3.3.2 Congestion Reduction

No congestion reduction is attributed to this project

3.3.3 Trade Benefits

No trade benefits are attributed to this project.

3.4 ASSET CONDITION

No Sustaining Capital elements applicable to this project. Therefore, Asset Condition categories are not applicable to this project.

3.5 RELATIONSHIPS

Description of Most Likely Scenario

Customer reliability will be impacted by deferral of the project.

Consequence

Should this project be deferred one year, it is expected that the Relationships consequence would be best described by Consequence Level 2 – External opposition resulting in a significant increase in complaints and/or external lobbying. Score = 2

Probability

50% or greater likelihood (but less than 90%) that the consequence will occur within the next year (if the investment is deferred). Score = 4

Relationships Risk

The Relationships Risk score is the consequence score time the probability = 8

3.6 ENVIRONMENT AND SAFETY

3.6.1 Environment

Description of Most Likely Scenario

There are no environmental risks due to not proceeding with this project.

3.6.2 Safety

Description of Most Likely Scenario

There are no safety risks due to not proceeding with this project.

Appendix F: Scoring Sample – Sustaining Portfolio

1.0 PROJECT NAME, DESCRIPTION, SCORING RATIONALE & SUMMARY

Project Name

F2009 Arcing Horn Installations

Project Description

On every transmission structure in the province, there is an insulator string at each phase of the transmission lines. Every year, insulators are damaged by power surges resulting from lightning strikes and switching operations. These damaged insulators can prevent the line from being energized resulting in a sustained outage.

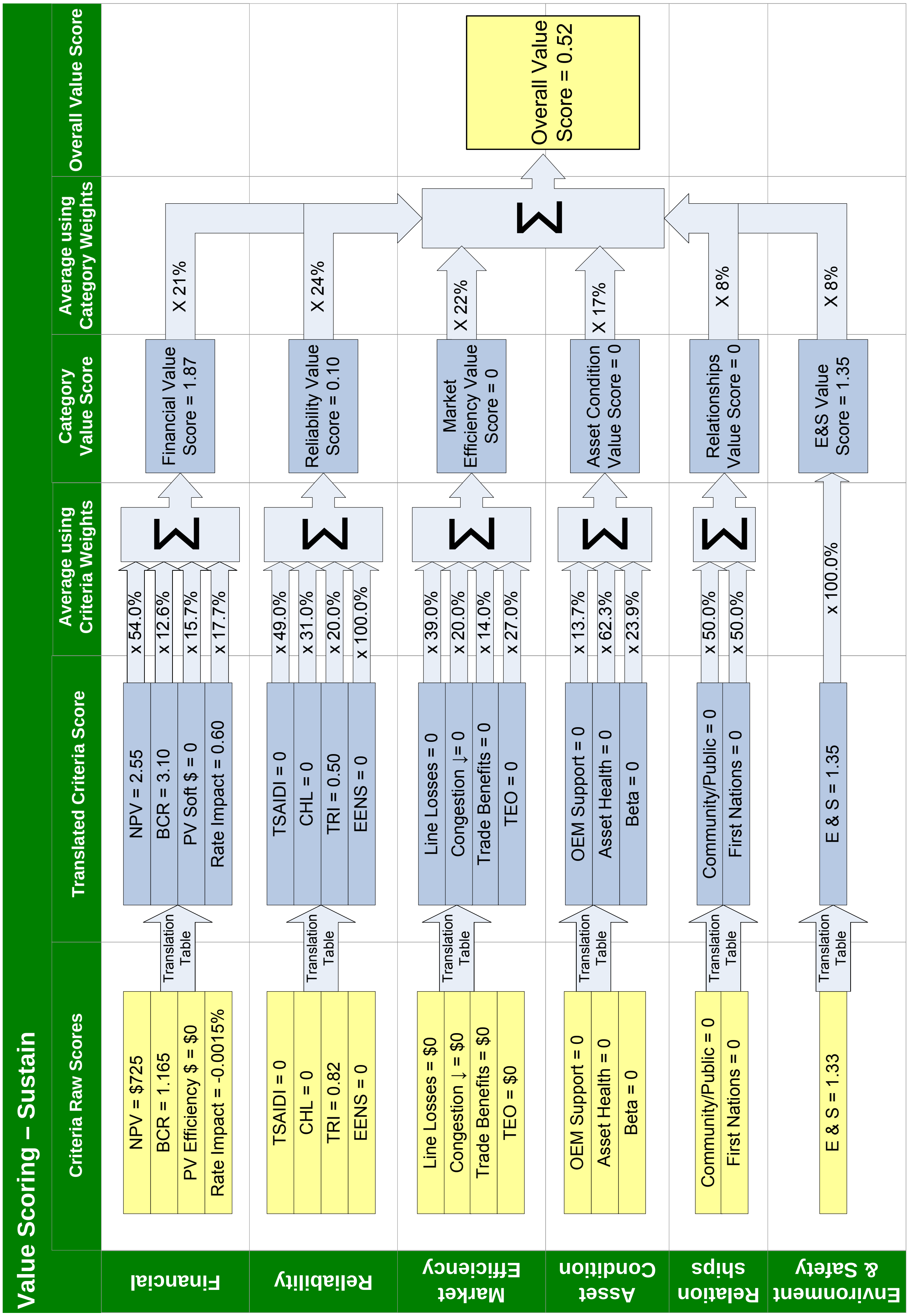
Arcing horns are a pair of conductors (usually steel) used to protect insulators or insulator strings from damage due to system overvoltage conditions. Arcing horns form a spark gap that enables any abnormal overvoltage to form an electrical arc. The hot arc then travels upwards, becomes increasingly longer as the wire climbs the horns, and is eventually extinguished as it approaches the top of the horns.

Under this program, arcing horns are added when the damaged insulators are replaced to prevent the power surge from traversing the insulators, thereby avoiding similar damage to the same insulator location in the future. Over time, the ongoing cost of insulator replacements will be reduced as increasing numbers of insulators are protected with arcing horns.

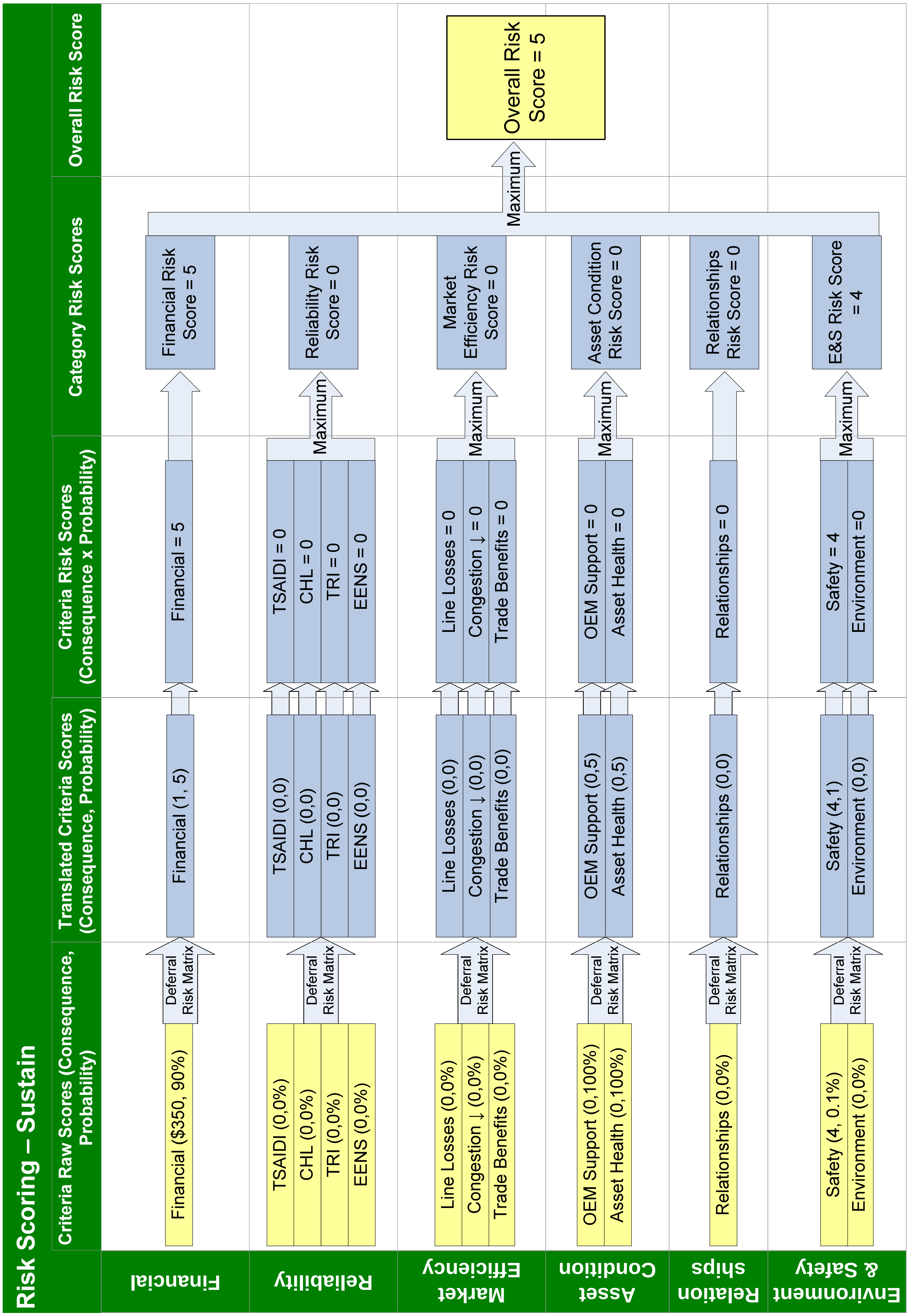
Scoring Rationale

Project scoring is primarily based on the maintenance savings resulting from future replacements of damaged insulators.

Scoring Summary



Note: All $s are in $000s.



Note: All $s are in $000s.

1.1 FINANCIAL

Inputs, Assumptions & Justifications

Costs

Capital Costs ($,000):

The project direct cash flow for F2009 is as follows:

Implement
F2009
4,261

% Allocation of Asset Type Costs:

The following allocation of asset type costs reflects the proportions of costs in the cost estimate.

- Transmission Line/Cable Costs: 100%

Circuit Lengths:

- Existing circuits – lengths non-applicable.

Contributions in Aid:

No contributions in aid. The project is not triggered by a customer request.

Residual Equipment Book Value:

Residual equipment book value for damaged insulators is zero.

Average Number of Depreciable Years Remaining:

Average number of depreciable years remaining is zero.

OMA Investment Costs:

No OMA investment costs. All expenditures associated with the implementation of the project are classified as capital.

OMA Incremental Ongoing Costs:

Annual OMA estimated to be negligible.

Dismantling and Removal Costs:

Dismantling and removal costs are for damaged insulators are estimated to be low at approximately 3% (i.e. 3% x $4,515k = $135k) of capital investments for arcing horns.

Savings and Benefits

OMA Savings:

OMA savings are estimated to be $350K per year, resulting from mitigating replacements of damaged insulators in the future.

Forecast Load Growth Applicable to the Project (in MW):

Not-applicable – this is a sustaining capital program.

Project Capacity (in MW):

Not-applicable – this is a sustaining capital program.

MW served by existing capacity:

Not-applicable – this is a sustaining capital program.

Load Factor of the Forecast Load Growth:

Not-applicable – this is a sustaining capital program.

Firm PTP Service Sales:

Not applicable – this is a sustaining capital program.

Efficiency Labour Savings:

No efficiency labour savings.

Avoided Costs:

No avoided costs.

Other Efficiency Savings:

No other efficiency savings

1.1.1 NPV

Calculations, Calculated Score & Translated Score

The calculated score is the net of PV benefits and PV costs. See attached spreadsheet. The NPV is $725K, which translates to a score of 2.55.

1.1.2 Benefit to Cost Ratio

Calculations, Calculated Score & Translated Score

The calculated score is the ratio of benefits to costs. See attached spreadsheet. The benefit to cost ratio is 1.165, which translates to a score of 3.10 based on OMA Savings.

1.1.3 Rate Impact

Calculations, Calculated Score & Translated Score

See attached spreadsheet. The rate impact score is -0.0015%, which translates to a score of 0.60.

1.1.4 PV of Efficiency Dollar Savings

Calculations, Calculated Score & Translated Score

None.

Financial

INVESTMENT NAME: ARCING HORN INSTALLATIONS

	Financial Value Scores	
	Calculated Score	Translated Score
NPV	$725	2.55
Benefit to Cost Ratio	1.165	3.10
PV of Efficiency Dollar Savings	$0	0.00
Rate Impact % (20+ Year Impact)	-0.0015%	0.60

SECTION I: DATA ENTRY AND CAPITAL COST CALCULATIONS

CAPITAL COSTS: (dollars in thousands)	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
Capital Costs (Labor / Contractor Costs, Materials, Services, ROW costs, New Land Purchases)	$4,261		$4,261																			

Transmission Line / Cable Costs	100%	%

	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
Total	100%																					
Capital Overheads	$104	$0	$104																			
Interest During Construction Calculations																						
Capital Dollar Amount Used in IDC Calculation	$4,365	$0	$4,365																			
Interest During Construction (Compounded)	$150	$0	$150																			
Total Capital Construction Costs (Including Overheads and IDC)	**$4,515**	**$0**	**$4,515**																			
Total Capital Construction Costs (Overheads Only)	**$4,365**	**$0**	**$4,365**																			
Customer Contributions in Aid	$0		$0																			
Interest During Construction (Compounded)	$0	$0	$0																			
Total Contributions in Aid	**$0**	**$0**	**$0**																			
Total Net Capital Construction Cost (less CIA)	**$4,515**	**$0**	**$4,515**																			
Total Net Capital Construction Costs (Less CIA & IDC)	**$4,365**	**$0**	**$4,365**																			

Average Number of Depreciable Years Remaining (Across All Assets Retired)		Years

OMA COSTS: (dollars in thousands)	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
OMA Investment Costs *(OMA costs during Construction)*	$0		$0																			
OMA Incremental Ongoing Costs *(Any OMA costs associated with the investment from in-service date forward.)*	$0		$0																			
Dismantling and Removal Costs (Net of Salvage Value)	$135		$135																			
Total OMA Costs	**$135**	**$0**	**$135**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

SAVINGS: (dollars in thousands) OMA Savings	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
O&M Savings – FTE Reductions, Overtime Savings, and Contractor Labor Savings	$6,650		$0	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350
Total Savings	**$6,650**	**$0**	**$0**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**	**$350**

EFFICIENCY SAVINGS: (dollars in thousands)	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
Efficiency Labor Savings (Efficiency Gains, Redirected Labor, etc.)	$0		$0																			
Avoided costs (Materials/Equipment Costs avoided, e.g. OEM Support Costs avoided)	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Efficiency Savings (e.g. potential LMP savings)	$0		$0																			
Total Efficiency Savings	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

SECTION II: NPV, BENEFIT TO COST, AND EFFICIENCY DOLLAR CALCULATION RESULTS

	Total	F2008 T=-1 0	F2009 (Inservice Year) T=0 1	F2010 T=1 2	F2011 T=2 3	F2012 T=3 4	F2013 T=4 5	F2014 T=5 6	F2015 T=6 7	F2016 T=7 8	F2017 T=8 9
Total Net Capital Construction Costs	$4,365	$0	$4,365	$0	$0	$0	$0	$0	$0	$0	$0
Total OMA Costs	$135	$0	$135	$0	$0	$0	$0	$0	$0	$0	$0
Other Grants and Taxes (Property Taxes)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs - Unadjusted	$4,500	$0	$4,500	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs - Discounted to Current Fiscal Year Dollars	$4,390	$0	$4,390	$0	$0	$0	$0	$0	$0	$0	$0
Dollar Benefits											
OMA Savings	$6,650	$0	$0	$350	$350	$350	$350	$350	$350	$350	$350
Total Dollar Benefits - Unadjusted	$6,650	$0	$0	$350	$350	$350	$350	$350	$350	$350	$350
Total Dollar Benefits - Discounted to Current Fiscal Year Dollars	$5,115	$0	$0	$333	$325	$317	$309	$302	$294	$287	$280
Net Cash Flow - Unadjusted	$2,150	$0	($4,500)	$350	$350	$350	$350	$350	$350	$350	$350
Present Value - Discounted to Current Fiscal Year Dollars	$725	$0	($4,390)	$333	$325	$317	$309	$302	$294	$287	$280

	F2018 T=9 10	F2019 T=10 11	F2020 T=11 12	F2021 T=12 13	F2022 T=13 14	F2023 T=14 15	F2024 T=15 16	F2025 T=16 17	F2026 T=17 18	F2027 T=18 19	F2028 T=19 20
Total Net Capital Construction Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total OMA Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Grants and Taxes (Property Taxes)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs - Unadjusted	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs - Discounted to Current Fiscal Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Dollar Benefits											
OMA Savings	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350
Total Dollar Benefits - Unadjusted	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350
Total Dollar Benefits - Discounted to Current Fiscal Year Dollars	$273	$267	$260	$254	$248	$242	$236	$230	$224	$219	$214
Net Cash Flow - Unadjusted	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350
Present Value - Discounted to Current Fiscal Year Dollars	$273	$267	$260	$254	$248	$242	$236	$230	$224	$219	$214

Efficiency Dollar Benefits	Total	F2008 T=-1	F2009 (Inservice Year) T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8
Efficiency Dollar Savings - Unadjusted	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Efficiency Dollar Savings - Discounted to Inservice Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow (incl. efficiency savings) - Unadjusted	$2,150	$0	($4,500)	$350	$350	$350	$350	$350	$350	$350	$350
Net Cash Flow (incl. efficiency savings) - Discounted to Inservice Year Dollars	$725	$0	($4,390)	$333	$325	$317	$309	$302	$294	$287	$280

Efficiency Dollar Benefits	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
Efficiency Dollar Savings - Unadjusted	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Efficiency Dollar Savings - Discounted to Inservice Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow (incl. efficiency savings) - Unadjusted	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350	$350
Net Cash Flow (incl. efficiency savings) - Discounted to Inservice Year Dollars	$273	$267	$260	$254	$248	$242	$236	$230	$224	$219	$214

NPV, BENEFIT TO COST RATIO, and PV of EFFICIENCY SAVINGS:

NPV	$725
Benefit to Cost Ratio	1.1650
PV of Efficiency Savings	$0

SECTION III: REVENUE REQUIREMENT/RATE IMPACT CALCULATION

	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
BCH Land Purchases/Non-Depreciable Rate Base - Yearly Amount	$0	$0	$0																			
Work in Progress / Depreciable Rate Base (less CIA) - Yearly Amount	$4,515	$0	$4,515																			
Opening Gross Assets (In Rate Base)	$85,787		$0	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515
Additions (Work in Progress and ROW Purchases (In-Service Year))	$4,515		$4,515																			
Closing Gross Assets	$90,302		$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515	$4,515
Opening Accumulated Depreciation	($15,159)			($42)	($126)	($210)	($294)	($378)	($462)	($546)	($630)	($714)	($798)	($882)	($966)	($1,050)	($1,134)	($1,218)	($1,302)	($1,386)	($1,470)	($1,554)
Current Year Depreciation - see Section IV	($1,638)		($42)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)	($84)
Closing Accumulated Depreciaton	($16,796)		($42)	($126)	($210)	($294)	($378)	($462)	($546)	($630)	($714)	($798)	($882)	($966)	($1,050)	($1,134)	($1,218)	($1,302)	($1,386)	($1,470)	($1,554)	($1,638)
Total Closing Accumulated Depreciation (Rate Base + CIA)	($16,796)		($42)	($126)	($210)	($294)	($378)	($462)	($546)	($630)	($714)	($798)	($882)	($966)	($1,050)	($1,134)	($1,218)	($1,302)	($1,386)	($1,470)	($1,554)	($1,638)

	Total	F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
Working Capital and other	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Utility Rate Base (BCH Land and Depreciated Capital)	$73,506		$4,473	$4,389	$4,305	$4,221	$4,137	$4,053	$3,969	$3,885	$3,801	$3,717	$3,633	$3,549	$3,465	$3,381	$3,297	$3,213	$3,129	$3,045	$2,961	$2,877
Mid Year Rate Base (opening + ending)/2	$74,325		$4,494	$4,431	$4,347	$4,263	$4,179	$4,095	$4,011	$3,927	$3,843	$3,759	$3,675	$3,591	$3,507	$3,423	$3,339	$3,255	$3,171	$3,087	$3,003	$2,919
Retained Earning Calculation (Added Back into Equity																						
Equity Component	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Component	$74,325		$4,494	$4,431	$4,347	$4,263	$4,179	$4,095	$4,011	$3,927	$3,843	$3,759	$3,675	$3,591	$3,507	$3,423	$3,339	$3,255	$3,171	$3,087	$3,003	$2,919
Annual Equity cost	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual interest cost	$4,511		$227	$247	$263	$263	$258	$253	$248	$243	$238	$232	$227	$222	$217	$212	$206	$201	$196	$191	$186	$180
Annual depreciation (Capital Depreciable Asset and CIA)	$1,638		$42	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84
Net Annual OMA (Includes OMA, Removal Costs (Treated like an expense), and any OMA Benefits)	-$6,515	$0	$135	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)	($350)
Net Book Value of Assets Retired (T=0)	$0		$0																			
Remaining Depreciation Credit for Assets Retired	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual other taxes and grants	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Annual Cost of Service	-$367	$0	$404	($19)	($3)	($3)	($8)	($13)	($18)	($23)	($29)	($34)	($39)	($44)	($49)	($54)	($60)	($65)	($70)	($75)	($80)	($86)
Change		$0	$404	($423)	$16	$0	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Total Annual Cost of Service - Converted to Current Fiscal Year Dollars	-$148	$0	$394	($18)	($2)	($2)	($7)	($11)	($15)	($19)	($23)	($26)	($30)	($33)	($36)	($39)	($41)	($44)	($46)	($48)	($50)	($52)
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

RATE IMPACT PERCENTAGE

Rate Impact Excluding Load Growth Revenue

		F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
BCH Average Cost per kWh	$0.052668																					
BCH Total Forecast Energy - kWh	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394
PV of BCH Total Energy Forecast - kWh	$1,102,581,415,464	$26,925,105,697	$52,536,791,604	$53,816,576,034	$53,849,369,998	$53,850,190,359	$53,850,210,868	$53,850,211,381	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394
Total BCH Revenue Requirement	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374
PV of BCH Revenue Requirement	$47,050,105,337	$2,836,195,374	$2,767,019,877	$2,699,531,588	$2,633,689,354	$2,569,453,028	$2,506,783,442	$2,445,642,382	$2,385,992,568	$2,327,797,628	$2,271,022,076	$2,215,631,293	$2,161,591,506	$2,108,869,762	$2,057,433,914	$2,007,252,599	$1,958,295,218	$1,910,531,920	$1,863,933,581	$1,818,471,786	$1,774,118,816	$1,730,847,625
BCH Average Cost per kWh - Transmission	$0.008815																					

Revenue Requirement Increase*	-$148,320	* Dollars converted from thousands
Rate Increase per kWh	-$0.0000001345	
New BCH Average Cost per kWh	$0.052668	

Rate Impact Including Load Growth Revenue

Total Revenue Requirement Increase	-$148,320
PV of BCH Revenue Requirement - BCH TLoB	$9,719,292,236
BCH Rate Impact Percentage Increase including Load Growth Revenue (20+ Year Impact)	**-0.0015%**

SECTION IV: DEPRECIATION CALCULATIONS

		F2008 T=-1	Inservice Year F2009 T=0	F2010 T=1	F2011 T=2	F2012 T=3	F2013 T=4	F2014 T=5	F2015 T=6	F2016 T=7	F2017 T=8	F2018 T=9	F2019 T=10	F2020 T=11	F2021 T=12	F2022 T=13	F2023 T=14	F2024 T=15	F2025 T=16	F2026 T=17	F2027 T=18	F2028 T=19
Depreciable Rate Base (Unadjusted Dollars) for BCH TLoB	$4,515	$0	$4,515																			
Accumulated Depreciable Rate Base		$0	$4,515																			
Depreciation - Transmission Line / Cable Costs	$1,638		$42	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84

1.1.5 Financial Value Score

Financial Value Score= (Net Present Value x 54%)+(Benefit Cost Ratio x 12.6%) + (Rate Impact x 15.7%) + (Present Value of Efficiency Dollar Savings x 17.7%)

= (2.55 x 54%) + (3.10 x 12.6%) + (0 x 15.7%) + (0.60 x 17.7%)

= 1.87

The weighted Financial Value Score = 1.87 x 21% = 0.39

1.2 RELIABILITY

1.2.1 TSAIDI

It is estimated the majority of arcing horn installations will be on looped transmission circuits, where there is an alternate circuit. Thus, the impact on TSAIDI is estimated to be negligible.

1.2.2 Distribution Customer Hours Lost

It is estimated the majority of arcing horn installations will be on looped transmission circuits, where there is an alternate circuit to customers. Thus, Customer Hours Lost is estimated to be negligible.

1.2.3 Transmission Reliability Index (TRI)

Inputs, Assumptions & Justifications

TRI for the targeted assets prior to the investment:

TRI is estimated using the top ten transmission circuits that had the most incidents of lightning. This is consistent with the approach taken in this investment, where arcing horns are installed on the portions of transmission circuits with the high incidents of lightning. In the past five years, there were 342 outages due to lightning. Thus,

TRI = (342 outages due to lightning / 10 circuits) / 5 years = 6.84

Expected percentage improvement in TRI post-investment:

Expected percentage improvement in TRI post investment is estimated to be 12%. Arcing horn installations mitigate sustaining outages caused by lightning. There are two classes of outages caused by lightning: temporary (less than 1 minute – successful re-energization via protective equipment) and sustaining (greater than 1 minute). Based on the same period as above, 12% of lightning caused outages are sustained.

Calculations, Calculated Score & Translated Score

Based on the above estimations, the calculated score is 6.84 x 12% = 0.82 and translated score is 0.5.

1.2.4 Expected Energy Not Served (EENS)

Not applicable.

1.2.5 Reliability Value Score

Reliability Value Score = (TSAIDI x 49%) + (Customer Hours Lost x 31%) + (TRI x 20%)

= (0 x 49%) + (0 x 31%) + (0.5 x 20%) = 0.1

The weighted Reliability Value Score = 0.1 x 24% = 0.024

1.3 MARKET EFFICIENCY

This investment has no impact on Market Efficiency criteria.

1.4 ASSET CONDITION

1.4.1 OEM Support/Availability of Spares

This investment has no impact on OEM Support/Availability of Spare.

1.4.2 Asset Health

There is no measurable impact on Asset Health.

1.4.3 Beta

Not applicable. The failure of the insulators is related to external events.

1.4.4 Asset Health Value Score

Asset Health Value Score = 0

Weighted Asset Health Value Score = 0

1.5 RELATIONSHIPS

This investment has no impact on Relationship criteria.

1.6 ENVIRONMENT AND SAFETY

Inputs, Assumptions & Justifications

Current state and degree of impact on of the Environment and Safety strategies:

	Current State	**Degree of Impact**
GHG (Green House Gas):	No Issues/Hazards	Neutral
Air Quality:	No Issues/Hazards	Neutral
Waste:	No Issues/Hazards	Neutral
Water:	No Issues/Hazards	Neutral
Land:	No Issues/Hazards	Neutral
Species at Risk:	No Issues/Hazards	Neutral
Environment Management System:	No Issues/Hazards	Neutral
Employee / Workforce Safety:	Imminent Threat of Safety Issues/ Hazards	Marginally Positive
Public Safety:	Imminent Threat of Safety Issues/ Hazards	Marginally Positive

Arcing Horns contain no materials that have negative impact on environment, including Green House Gas, Air Quality, Waste, Water, Land, and Species at Risk.

Without arcing horns, lightning can damage insulators, which may result in the insulators failing.

Damaged insulators represent a safety risk to employees who work on the transmission line and rely on the electrical insulation provided by the insulators to perform live line work.

Damaged insulators can lose their mechanical integrity which can lead to energized conductors falling to the ground. Fallen energized conductors pose life-threatening danger to employees or public members in the vicinity. The Degree of Impact for Employee/ Workforce and Public Safety has been rated Marginally Positive.

The above scenarios have a very low probability of occurrence.

Impacts localized or dispersed:

Impact is rated dispersed. Arcing horns will be installed at various locations.

Calculations, Calculated Score & Translated Score

Calculated Score

= ((average of 3 most positive scores) + (average of 3 most negative scores))x scope of impacted Environmental/Safety issues

Where 3 most positive scores are:

- Employee/Workforce Safety with Marginally Positive impact – which has a score of 2.
- Public Safety with Marginally Positive impact – which has a score of 2.
- Any one attribute (GHG, Air Quality,or others) with Neutral impact – which has score of 0.

Where 3 most negative scores are:

- Any 3 attributes (GHG, Air Quality,or others) with Neutral impact – which has score of 0.

= ((2 + 2 + 0)/3 + (0 + 0 + 0)/3)) x 1.0

= 1.33

Which translates to score of 1.35

1.6.1 Environment and Safety Value Score

Environment and Safety Value Score = (translated score x 100%)

= 1.35 x 100%

= 1.35

Weighted Environment and Safety Value Score

= 1.35 x 8%

= 0.11

2.0 RISK SCORING

2.1 Financial

Description of Most Likely Scenario

If the project is deferred one year, additional insulators will sustain damage from lightning and will have to be replaced.

Consequence

Project Cost Increases:

None.

Loss of Revenue:

None.

Other Cost Implications:

Maintenance cost of replacing damaged insulators is $350K.

Consequence Score:

The total cost implication based on $350K translates to a Consequence Score of 1.

Probability

The probability of the above consequence occurring was estimated to be 90%, which translates to Probability Score of 5.

Financial Risk

Risk is Consequence Score (1) times Probability Score (5) = 5.

2.2 RELIABILITY

2.2.1 TSAIDI

Impact of one year delay on TSAIDI is estimated to be negligible. Refer to Section 2.2.1.

2.2.2 Distribution Customer Hours Lost

Impact of one year delay on Customer Hours Lost is estimated to be negligible. Refer to Section 2.2.2

2.2.3 Transmission Reliability Index (TRI)

If this investment is not funded, the Most Likely Scenario for the expected TRI percentage decrease would be 0. Lightning is an external factor. Without this investment, incidents of outages due to lightning will continue to occur.

2.2.4 Expected Energy Not Served (EENS)

Not Applicable. This is Sustaining Capital.

2.3 MARKET EFFICIENCY

Delay of one year will have negligible impact on Market Efficiency.

2.4 ASSET CONDITION

Delay of one year will have negligible impact on Asset Health.

2.5 RELATIONSHIPS

Delay of one year will have negligible impact on Relationships.

2.6 ENVIRONMENT AND SAFETY

2.6.1 Environment

Delay of one year will have negligible impact on Environmental risks.

2.6.2 Safety

Description of Most Likely Scenario

Damaged insulator loses its mechanical strength resulting in energized conductor falling to the ground. Fallen energized conductor causes step potential, which poses danger to an employee or public member in the vicinity. Although such safety issues/hazards exists, the scenario described above would be rare. Thus, consequence is high but the corresponding probability is low.

Consequence

Consequence Level 4 – Permanent disability. This translates to Consequence Score of 4.

Probability

The corresponding probability is estimated to be 0.1% that the consequence will occur within the next year (if the investment is deferred). This translated to Probability Score of 1.

Environment and Safety Risk

Environment and Safety Risk is based on the higher of the two risks – environment and safety. Thus, based on the Safety Risk:

= Consequence Score (4) x Probability Score (1)

= 4

Appendix G: Scoring Sample – BCTC Portfolio

1.0 PROJECT NAME, DESCRIPTION, SCORING RATIONALE & SUMMARIES

Project Name

Reliability and Loss Program Integration F2009 and F2010

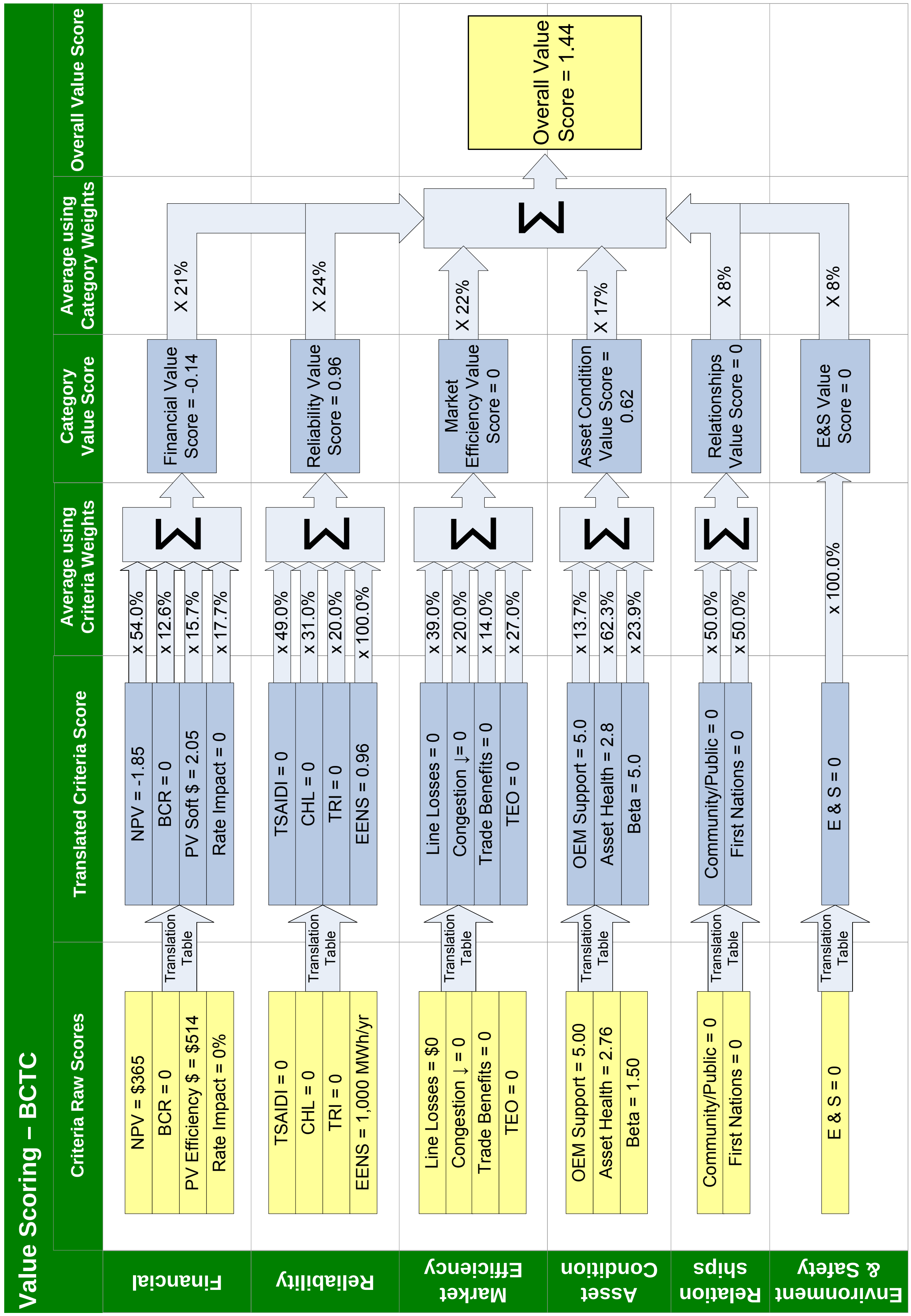
Project Description

Integrate five computer programs used to calculate system reliability and loss evaluation into the Reliability Database Management System (RDMS) to improve study turnaround time.

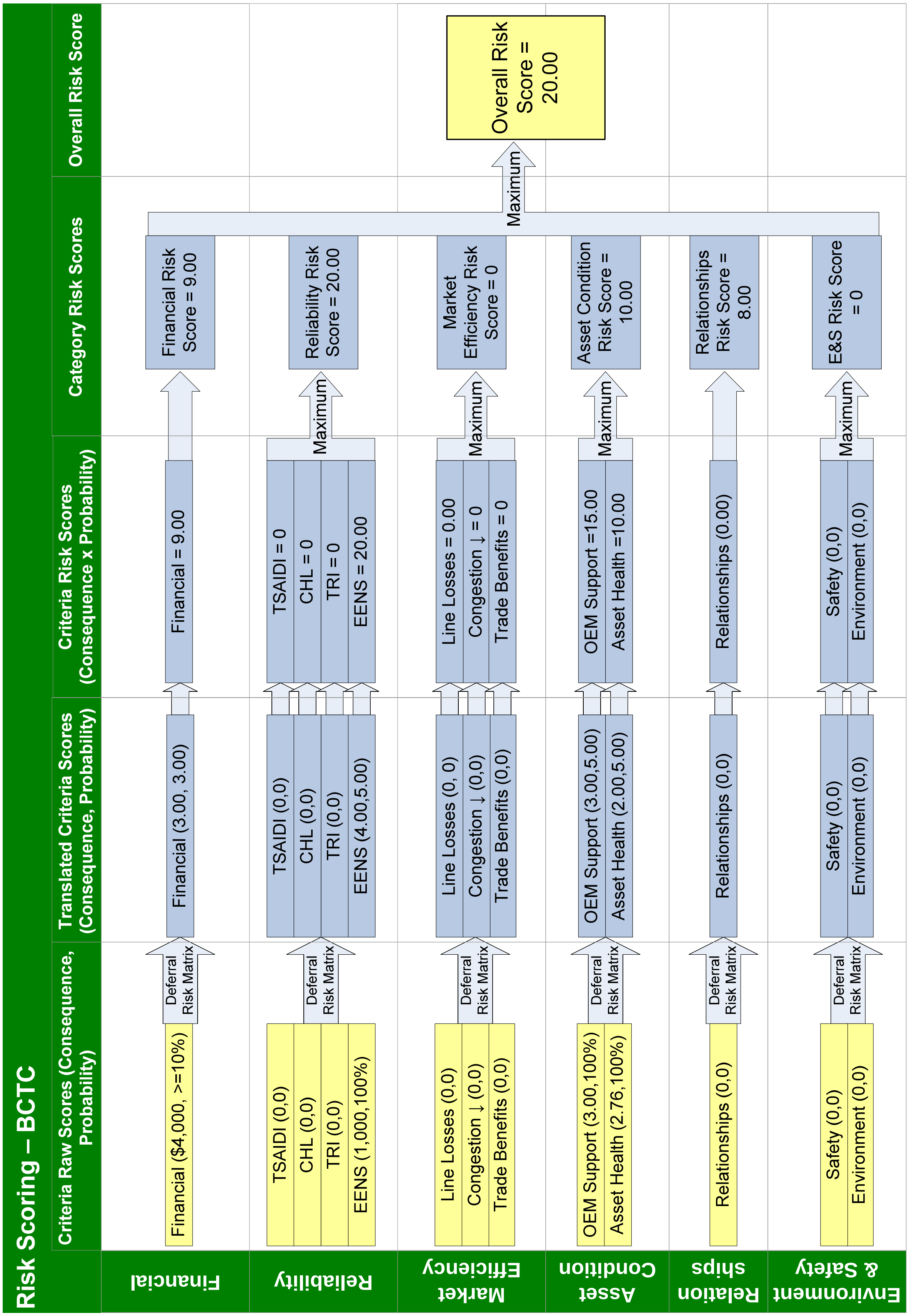
Scoring Rationale

This project is in the Execution Phase. The cost and the associated scoring are based exclusively on the execution.

Scoring Summaries



Note: All $s are in $000s.



Note: All $s are in $000s.

2.0 VALUE SCORING

2.1 FINANCIAL

Inputs, Assumptions & Justifications

Costs

Capital Costs ($,000):

The project direct uninflated cash flow is as follows:

Total	Implement	In-Service Year
	F2009	F2010
	T = -1	T = 0
$382K	$224K	$158K

% Allocation of Asset Type Costs:

- Computer Software: 80%
- Computer Hardware: 20%

Contributions in Aid:

No contributions in aid. The project is not triggered by a customer request.

Residual Equipment Book Value:

No residual value. No existing assets will be removed from service.

Average Number of Depreciable Years Remaining:

Not applicable. No existing assets will be removed from service.

OMA Investment Costs:

No OMA investment costs. All expenditures associated with the implementation of the project are classified as capital.

OMA Incremental Ongoing Costs:

No OMA incremental ongoing costs will be needed for this project.

Dismantling and Removal Costs:

No dismantling and removal costs. No existing assets will be removed from service.

Savings and Benefits

OMA Savings:

No OMA savings

Efficiency Labour Savings:

Labour efficiencies come from significantly less effort will be needed in data preparation. The data will be extracted from the Reliability Data Management System (RDMS) automatically. A savings of 4.5 days of data preparation per study can be achieved. Assuming an average of 25 studies per year and at a cost of $100/hr, this gives: $84.4k savings per year. Maintenance work reduction equivalent to 50% of a person's time is expected to be redirected each year from these systems to other systems. This is equivalent to $50k/yr.

Avoided Costs:

No avoided costs

Other Efficiency Savings:

No other efficiency savings

2.1.1 NPV

Calculations, Calculated Score & Translated Score

The NPV score =-365K which translates to a score of -1.85. See attached spreadsheet.

Financial Value Score Calculation

INVESTMENT NAME: Reliability and Loss Program Integration

Financial Value Scores Summary

	Calculated Score	Translated Score
NPV	-$365	-1.85
Benefit to Cost Ratio	0.0000	0.00
PV of Efficiency Dollar Savings	$599	2.30
Rate Impact % (20+ Year Impact)	0.0000%	0.00

SECTION I: DATA ENTRY AND CAPITAL COST CALCULATIONS	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
Capital Costs (Labor / Contractor Costs, Materials, Services, ROW costs, New Land Purchases)	$382		$224	$158																			

Leasehold Improvement			%
Building			%
Land			%
Computer Software		80%	%
Computer Hardware		20%	%
Furniture Equipment			%
Communication			%
Total		100%	

	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
Capital Overheads	$11	$0	$6	$5																			
Interest During Construction Calculations																							
Capital Dollar Amount Used in IDC Calculation	$393	$0	$230	$163																			
Interest During Construction (Compounded)	$26	$0	$7	$18																			
Total Capital Construction Costs (Including Overheads and IDC)	**$419**	**$0**	**$238**	**$182**																			
Total Capital Construction Costs (Overheads Only)	**$393**	**$0**	**$230**	**$163**																			
Customer Contributions in Aid (enter as positive number)*	$0																						
Interest During Construction (Compounded)	$0	$0	$0	$0																			
Total Contributions in Aid	**$0**	**$0**	**$0**	**$0**																			
Total Net Capital Construction Cost (less CIA)	**$419**	**$0**	**$238**	**$182**																			
Total Net Capital Construction Costs (Less CIA & IDC)	**$393**	**$0**	**$230**	**$163**																			

OMA COSTS: (enter dollars in thousands)	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
OMA Investment Costs (OMA costs during Construction - Please be sure to include any insurance during construction costs)	$0																						
OMA Incremental Ongoing Costs (Any OMA costs associated with the investment from in-service date forward. Be sure to include any increases in insurance costs)	$0																						
Dismantling and Removal Costs (Net of Salvage Value)*	$0																						
Total OMA Costs	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

*Treated like an expense in revenue requirement calculations and not taxed

COST SAVINGS: (enter dollars in thousands) OMA Savings	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
OMA Cost Savings – FTE Reductions, Overtime Savings, and Contractor Labor Savings	$0																						
Total OMA Savings	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

EFFICIENCY SAVINGS: (enter dollars in thousands)	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
Efficiency Labor Savings (Efficiency Gains, Redirected Labor, etc.)	$670				$134	$134	$134	$134	$134														
Avoided costs (Materials/Equipment Costs avoided, e.g. OEM Support Costs avoided)	$0																						
Other Efficiency Savings (e.g. potential LMP savings)	$0																						
Total Efficiency Savings	**$670**	**$0**	**$0**	**$0**	**$134**	**$134**	**$134**	**$134**	**$134**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

SECTION II: NPV, BENEFIT TO COST, AND EFFICIENCY DOLLAR CALCULATION RESULTS:

			Construct	Inservice Year																		
		F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029
		T=-2	T=-1	T=0	T=1	T=2	T=3	T=4	T=5	T=6	T=7	T=8	T=9	T=10	T=11	T=12	T=13	T=14	T=15	T=16	T=17	T=18	T=19
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Total Net Capital Construction Costs	$393	$0	$230	$163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total OMA Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Grants and Taxes - see SECTION V for details	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs - Unadjusted	$393	$0	$230	$163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs - Discounted to Current Fiscal Year Dollars	$365	$0	$218	$147	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Dollar Benefits																							
OMA Savings	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Incremental Revenue for Growth Projects	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Value of Losses ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Probabilistic PTP Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Dollar Benefits - Unadjusted	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Dollar Benefits - Discounted to Current Fiscal Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow - Unadjusted	($393)	$0	($230)	($163)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Present Value - Discounted to Current Fiscal Year Dollars	($365)	$0	($218)	($147)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

			Construct	Inservice Year																		
		F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029
Efficiency Dollar Benefits		T=-2	T=-1	T=0	T=1	T=2	T=3	T=4	T=5	T=6	T=7	T=8	T=9	T=10	T=11	T=12	T=13	T=14	T=15	T=16	T=17	T=18	T=19
Efficiency Dollar Savings - Unadjusted	$670	$0	$0	$0	$134	$134	$134	$134	$134	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Efficiency Dollar Savings - Discounted to Inservice Year Dollars	$514	$0	$0	$0	$114	$108	$102	$97	$92	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow (incl Efficiency Dollars) - Unadjusted	$277	$0	($230)	($163)	$134	$134	$134	$134	$134	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow (incl Efficiency Dollars) - Discounted to Inservice Year Dollars	$149	$0	($218)	($147)	$114	$108	$102	$97	$92	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

NPV, BENEFIT TO COST RATIO, and PV OF EFFICIENCY DOLLAR SAVINGS:

NPV	($365)
Benefit to Cost Ratio	0.0000
PV of Efficiency Dollar Savings	$514

SECTION III: REVENUE REQUIREMENT/RATE IMPACT CALCULATION

	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
BCH Land Purchases/Non-Depreciable Rate Base - Yearly Amount - Not Included until in-service	$0	$0	$0	$0																			
Work in Progress / Depreciable Rate Base (less CIA) - Yearly Amount - Not included until in-service	$0	$0	$0	$0																			
CIA (Yearly Amount) - Not included until inservice	$0	$0	$0	$0																			
Opening Gross Assets (In Rate Base)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Additions (Work in Progress and ROW Purchases (In-Service Year))	$0			$0																			
Closing Gross Assets	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Opening Accumulated Depreciation	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Current Year Depreciation - see Section IV	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Closing Accumulated Depreciaton	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Opening	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Additions	$0			$0																			
Closing CIA	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Opening Accumulated Depreciation	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Current Year Depreciation	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA Closing Accumulated Depreciaton	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Closing Accumulated Depreciation (Rate Base + CIA)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Total	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
Working Capital and other	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Utility Rate Base (BCH Land and Depreciated Capital)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mid Year Rate Base (opening + ending)/2	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA (Annually Depreciated Amount)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mid Year CIA (opening + ending)/2	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Retained Earning Calculation (Added Back into Equity Component)	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Equity Component	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Component	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Equity cost	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual interest cost	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Equity cost - CIAC	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual depreciation (Capital Depreciable Asset and CIA)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Annual OMA (Includes OMA, Removal Costs (Treated like an expense), and any OMA Benefits)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Book Value of Assets Retired (T=0)	$0			$0																			
Remaining Depreciation Credit for Assets Retired	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual other taxes and grants - see Section V	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Annual Cost of Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Annual Cost of Service - Converted to Current Fiscal Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

*Mid Year Rate Base Calculation includes an average of pre-and post depreciation WIP additions, plus ROW

RATE IMPACT PERCENTAGE (20+ Year Impact):

Rate Impact Excluding Load Growth Revenue

		F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
BCH Average Cost per kWh	$0.052668																						
BCH Total Forecast Energy - kWh	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394
PV of BCH Total Energy Forecast - kWh	$1,154,789,343,078	$26,925,105,697	$51,033,179,866	$53,686,626,097	$53,841,155,495	$53,849,711,429	$53,850,183,796	$53,850,209,871	$53,850,211,310	$53,850,211,390	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394	$53,850,211,394
Total BCH Revenue Requirement	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374	$2,836,195,374
PV of BCH Revenue Requirement	$37,591,355,744	$2,836,195,374	$2,687,827,307	$2,547,220,723	$2,413,969,601	$2,287,689,159	$2,168,014,745	$2,054,600,782	$1,947,119,771	$1,845,261,345	$1,748,731,373	$1,657,251,112	$1,570,556,398	$1,488,396,890	$1,410,535,339	$1,336,746,910	$1,266,818,527	$1,200,548,263	$1,137,744,753	$1,078,226,642	$1,021,822,064	$968,368,143	$917,710,522
BCH Average Cost per kWh - Transmission	$0.008815																						

Revenue Requirement Increase*	$0
Rate Increase per kWh	$0.0000000000
New BCH Average Cost per kWh	$0.052668

* Dollars converted from thousands

Rate Impact Including Load Growth Revenue

	Total	T=0	T=1	T=2	T=3	T=4	T=5	T=6	T=7	T=8	T=9	T=10	T=11	T=12	T=13	T=14	T=15	T=16	T=17	T=18	T=19
Total Net Incremental Revenue for Growth Projects*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Incremental Revenue for Growth Projects - Converted to Inservice Year Dollars	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

* Dollars converted from thousands

Adjusted Revenue Requirement Increase	$0
Value of Losses	$0
Total Revenue Requirement Increase	$0
PV of BCH Revenue Requirement - BCH TLoB	$10,179,506,872
BCH Rate Impact Percentage Increase including Load Growth Revenue (20+ Year Impact)	**0.0000%**

SECTION IV: DEPRECIATION CALCULATIONS:

		F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
Non-Depreciable Rate Base - BCH Owned New Land Purchases	$0	$0	$0	$0																			
Accumulated Non-Depreciable Rate Base - BCH Land Purchases		$0	$0	$0																			
Depreciable Rate Base (Unadjusted Dollars) for BCH TLoB	$0	$0	$0	$0																			
Accumulated Depreciable Rate Base		$0	$0	$0																			
Depreciation - Transmission Line / Cable Costs	$0			$0	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329	$329
Depreciation - Switchyard Equipment Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Buildings / Structures Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Communications Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - ROW Costs (Associated with Lines / Cables)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Leasehold Improvement	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Building	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Land	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Software	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Hardware	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciaion - Furniture Equipment	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Communicatioin	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CIA (Unadjusted Dollars)	$0	$0	$0	$0																			
Accumulated Depreciable CIA		$0	$0	$0																			
Depreciation - Transmission Line / Cable Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Switchyard Equipment Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Buildings / Structures Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Computer Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - Communications Costs	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation - ROW Costs (Associated with Lines / Cables)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SECTION V: TAXES CALCULATIONs

Taxes - Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land		F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Total Yearly Dollars	$0	$0	$0	$0																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Total Yearly Dollars (Less IDC)	$0	$0	$0	$0																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Accumulated Dollars		$0	$0	$0																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Accumulated Dollars (Less IDC)		$0	$0	$0																			
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Yearly Taxes (School Taxes, etc.)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Switchyard Equipment, Buildings, ROW (land rights) and BCH Owned Land - Yearly Taxes (School Taxes, etc.) Less IDC	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

*Please note: For Lines with no asset class, the 30% reduction for non-assessable costs and the 30% depreciation allowance were used.

Grant Tax - BCH Owned Land (additional tax on land only)

BCH Owned Land (only) - Total Yearly Dollars	$0	$0	$0	$0																			
BCH Owned Land (only) - Total Yearly Dollars (Less IDC)	$0	$0	$0	$0																			
BCH Owned Land (only) - Accumulated Dollars		$0	$0	$0																			
BCH Owned Land (only) - Accumulated Dollars (Less IDC)		$0	$0	$0																			
BCH Owned Land (only) - General Grant Tax (4%)*	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BCH Owned Land (only) - General Grant Tax (4%)* (Less IDC)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

*Based on Market Value of Land, so using the full Land value (no 30% reduction)

Taxes for Lines with Asset Classes

Please note: If scorer selects "No Asset Class", any km of line with asset class will be zeroed out.

	km of line	F2008 T=-2	Construct F2009 T=-1	Inservice Year F2010 T=0	F2011 T=1	F2012 T=2	F2013 T=3	F2014 T=4	F2015 T=5	F2016 T=6	F2017 T=7	F2018 T=8	F2019 T=9	F2020 T=10	F2021 T=11	F2022 T=12	F2023 T=13	F2024 T=14	F2025 T=15	F2026 T=16	F2027 T=17	F2028 T=18	F2029 T=19
69 kV Transmission Line or Underground Cable Circuit	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
138 kV Transmission Line or Underground Cable Circuit	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Heavy Duty Double Circuit Steel Pole Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Double Circuit Steel Pole Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Heavy Duty Double Circuit Steel Tower Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Double Circuit Steel tower Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV Wood or Concrete Pole Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
287 kV to 360 kV Single Circuit Wood or Concrete Pole Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV to 360 kV Single Circuit Steel Tower Transmission Line or	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
500 kV Steel Tower Transmission Line	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
500 kV AC Submarine Cable Circuit	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230 kV DC Submarine Cable Circuit	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
138 kV AC Submarine Cable Circuit	0.0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Taxes for Lines with Asset Classes	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BCTC Property Tax	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BCTC Property Grant	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Taxes and Grants (Total Property Taxes)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Taxes/Grants/Property Taxes (Excluding IDC)	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2.1.2 Benefit to Cost Ratio

Calculations, Calculated Score & Translated Score

The benefit to cost ratio score is 0, which translates to a score of 0.0. See attached spreadsheet.

2.1.3 Rate Impact

Calculations, Calculated Score & Translated Score

See attached spreadsheet. The rate impact score is 0%, which translates to a score of 0.

2.1.4 PV of Efficiency Dollar Savings

Calculations, Calculated Score & Translated Score

See attached spreadsheet. The PV of efficiency dollar savings score is $514K, which translates to a score of 2.05.

2.1.5 Financial Value Score

Financial Value Score =

(-1.85 x 54% + 0.0 x 12.6% + 2.05 x 15.7% + 0.0 x 17.7%) x 21.0%

= -0.14

2.2 RELIABILITY

2.2.1 TSAIDI

There is no impact on TSAIDI.

2.2.2 Distribution Customer Hours Lost

There is no impact on Distribution Customer Hours.

2.2.3 Transmission Reliability Index (TRI)

There is no impact on TRI.

2.2.4 Expected Energy Not Served (EENS)

Various studies in the past have reduced EENS between 200 and 2000 MWhr/yr. By being able to perform more reliability studies, the expected improvement is estimated at 1000 MWhr/yr. This translates to an EENS score of 4.

2.2.5 Reliability Value Score

Reliability Value Score = (4.00 x 100%) x 24.0% = 0.96

2.3 MARKET EFFICIENCY

2.3.1 Real Line Losses

Inputs, Assumptions & Justifications

A loss calculation computing program cannot reduce losses by itself but it can help evaluate losses and identify potential measures to reduce losses. For this project, no real line losses benefits were assigned. However, it is worth noting that the PLOSS program will be used for loss evaluations in support of the Energy Plan objective.

2.3.2 Congestion Reduction

There is no congestion reduction attributed to this project.

2.3.3 Trade Benefits

There is no trade benefits attributed to this project.

2.3.4 Transmission Expansion Opportunities (TEO)

There is no transmission expansion opportunities attributed to this project.

2.3.5 Market Efficiency Value Score

Market Efficiency Value Score = (1.15 x 39%) x 22.0% = 0.1

2.4 ASSET CONDITION

2.4.1 OEM Support/Availability of Spares

The existing programs were developed using the Fortran language and in the DOS environment by BCTC (previous BH Hydro's transmission unit) many years ago. Since these technologies, user interface and data interface to these programs are obsolete, the OEM is considered not supported. Integrating these programs into RDMS will make the interfaces more supportable, allowing reliability studies to be conducted more efficiently, more accurately and on a timelier basis. BCTC has been limited in its ability to conduct reliability studies for more capital projects partly because of the difficulties in data file preparation to use these programs. For scoring purposes, BCTC have considered these limitations to be failures.

Inputs, Assumptions & Justifications

Current (pre-investment) level of OEM Support: No OEM support

Current (pre-investment) Availability of Spares: Not applicable

Post-investment level of OEM Support: OEM support will be continued for greater than 5 years

Post-investment Availability of Spares: Not applicable

Calculations, Calculated Score & Translated Score

The calculated and translated score are both 5.0 **[NTD GH: This appears to be false – It should be 4.0]**

2.4.2 Asset Health

Inputs, Assumptions & Justifications

Current state of Remaining Life: <10%

Current state of Failure Rate: One failure per year

Current state of Asset Condition: Means the component has many problems and the potential for major failure

Post-investment state of Remaining Life: >90%

Post-investment state of Failure Rate: No failures (in foreseeable future)

Post-investment state of Asset Condition: Means the component is in "as new" condition

Criticality Lines/BCTC Assets:

Low Criticality. No or Low consequence to the power system in the event of a failure. Low probability of a prolonged customer or business outage in the event of a failure. Low cost of repair or disruption to the business in the event of a failure.

Calculations, Calculated Score & Translated Score

The calculated score is 2.76, which translates to a score of 2.8.

2.4.3 Beta

Inputs, Assumptions & Justifications

Current Beta value is 1.5

Calculations, Calculated Score & Translated Score

The calculated score is 1.5, which translates to a score of 5.0.

2.4.4 Asset Health Value Score

Asset Health Value Score = (5 x 13.7% + 2.8 x 62.3% + 5 x 23.9%) x 17.0% = 0.62

2.5 RELATIONSHIPS

This project has no impact on this category.

Total score and translated score = 0.

2.6 ENVIRONMENT AND SAFETY

This project has no impact on this category.

Total score and translated score = 0

3.0 RISK SCORING

3.1 Financial

Description of Most Likely Scenario

System reinforcement projects may be built that are in fact not needed to maintain reliability, due to the lack of adequate studies. In the absence of better information the SPPA planners will err on the conservative side, possibly resulting in significant unneeded expenditure. Last year one project for $40M was found to be not needed through this type of analysis. A conservative estimate of this benefit is therefore 1/10th the amount with a likelihood of once in ten years.

Consequence

Project Cost Increases:

Reinforcement cost of $4,000K may be avoided.

Consequence Score:

The total cost implication translates to a Consequence Score of 3.

Probability

The probability of the above consequence occurring was assessed to be once in ten year event, which translates to a Probability Score of 3.

Financial Risk

The Financial Risk Score is the Consequence Score times the Probability Score = 9.

3.2 RELIABILITY

3.2.1 TSAIDI

There is no deferral risk on TSAIDI due to not proceeding with this project.

3.2.2 Distribution Customer Hours Lost

There is no deferral risk on Distribution Customer Hours due to not proceeding with this project.

3.2.3 Transmission Reliability Index (TRI)

There is no deferral risk on TRI due to not proceeding with this project.

3.2.4 Expected Energy Not Served (EENS)

Consequence

The EENS consequence level is calculated automatically from the EENS impact derived in the value section above. (EENS Before Investment – EENS After Investment).

The EENS Calculated Score (in the Value Calculation) of 1000 MWhr/yr translates to a Consequence Score of 4.

Probability

The calculation for EENS already accounts for probability, so a probability of 5 (100% certain) is automatically applied to this criterion for calculating its risk score.

Reliability Risk

The Reliability Risk Score is the Consequence Score times the Probability Score = 20.

3.3 MARKET EFFICIENCY

There is no impact to Market Efficiency criteria associated with not proceeding with this project.

3.4 ASSET CONDITION

3.4.1 OEM Support/Availability of Spares

For OEM Support / Availability of Spares, the expected consequence level is equal to the current (pre-investment) level assessment and is calculated to be a Consequence Value of 3.

The probability level for OEM Support / Availability of Spares is assumed to be a 100% probability as the risk is based off a current state assessment. The Probability Score is 5.

The OEM Risk Score is the Consequence Score times the Probability Score = 15.

3.4.2 Asset Health

Consequence

The consequence score for Asset Health (what is the impact of not funding the investment) will be the pre-investment assessment of Remaining Life, Failures, Asset Condition, and Criticality and is calculated automatically from the information provided above. Specifically, the consequence score will be derived from the weighted sum of the Remaining Life, Failure Rates, and Asset Condition scores. The Criticality assessment score will be also weighted and summed with the other weighted scores. (Please note: the Criticality score for stations is calculated by scoring Load, Role, Redundancy, and Voltage. Each component is weighted to reflect its relative importance and summed to derive an overall criticality score. The Criticality score for lines and BCTC Assets is calculated solely by indicating the applicable system/circuit criticality level (A, B, or C).

The consequence Score is 2

Probability

The probability level for Asset Health is assumed to be a 100% probability as the risk is based off a current state assessment.

The Probability Score is 5

Asset Health Reduction Risk

The Asset Health Reduction Risk Score is the Consequence Score times the Probability Score = 10.

3.5 RELATIONSHIPS

There are no significant Community/Public/First Nations risks due to not proceeding with this project.

3.6 ENVIRONMENT AND SAFETY

3.6.1 Environment

There are no environmental risks due to not proceeding with this project.

3.6.2 Safety

There are no safety risks due to not proceeding with this project.

Appendix K

Planning Assumptions for IEP/LTAP/CRP Transmission Analyses and Subsequent NITS Application

BC hydro

British Columbia Transmission CORPORATION™

BCH_INTEGRATED ELECTRICITY PLAN (IEP)
EXHIBIT B-102

December 21, 2006

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

Dear Mr. Pellatt:

RE: British Columbia Utilities Commission (BCUC)
Project No. 3698419
British Columbia Hydro and Power Authority (BC Hydro)
2006 Integrated Electricity Plan and Long Term Acquisition Plan (2006 IEP/LTAP)

BC Hydro and British Columbia Transmission Corporation (BCTC) write to provide clarification regarding the planning assumptions and variables underlying the 2006 IEP/LTAP/Contingency Resource Plans (CRPs) transmission analyses.

At page 21 of the BCUC's June 20, 2005 decision concerning BCTC's application for an Open Access Transmission Tariff, the BCUC accepted that the Network Customer could include transmission reservation contingencies (identified as CRPs in the 2006 IEP/LTAP) in Network Integrated Transmission Service (NITS) applications where such CRPs are approved by the BCUC.

The clarity of the LTAP/CRPs for that purpose is an issue that was raised by BCTC in this proceeding. At page 487 of the transcript, the Panel Chair requested that BCTC assist the BCUC at some stage in the proceeding with respect to the clarity that it was seeking.

There has been a significant level of coordination between BCTC and BC Hydro with respect to the 2006 IEP and LTAP. That coordination is evident from Appendix H of BC Hydro's 2006 IEP and LTAP (Exhibit B-1C) and BCTC's responses to BCUC Information Request 1.1.2, 1.9.3, 1.14.1 and 1.15.1 (Exhibit C7-8). As a continuation of that coordination, BC Hydro and BCTC have had meetings during this proceeding resulting in the attached document, to assist the Commission and to reduce the hearing time necessary to obtain this evidence through cross-examination. The purpose of the document is to provide clarity for the LTAP/CRPs by summarizing the various planning assumptions and variables underlying the IEP/LTAP/CRP transmission analyses and defining the basis upon which BC Hydro anticipates making its NITS application/update following the conclusion of the 2006 IEP/LTAP proceeding.

Questions concerning this document may be addressed to BC Hydro's Panel 7 and to BCTC's Panel.

Yours sincerely,

Joanna Sofield
Chief Regulatory Officer
BC Hydro

A. Laurence Gray
Senior Regulatory Advisor
Regulatory Affairs
British Columbia Transmission Corporation

c. Projects 3698419 Intervenors

PLANNING ASSUMPTIONS FOR
2006 IEP/LTAP/CRP TRANSMISSION ANALYSES
AND SUBSEQUENT NITS APPLICATION

The 2006 Integrated Electricity Plan (2006 IEP) provides the planning foundation for current and future demand-side management (DSM) programs, private sector electricity acquisition processes and other Resource Smart options. The 2006 IEP describes how British Columbia Hydro and Power Authority (BC Hydro) could address its customers' electricity needs over the next 20 years and the resource options available to meet those needs under a variety of assumptions and risks. The 2006 IEP also includes the Long Term Acquisition Plan (LTAP), which itemizes the actions in the next ten years that will be taken to meet those needs.

To develop the planning foundation in the IEP and identify and itemize actions contained in the LTAP resulting from the IEP, a high level analysis of the transmission requirements was prepared by British Columbia Transmission Corporation (BCTC) (dated June 2005), as indicated in the BCTC response to BCUC IR 1.1.2 (Exhibit C7-8). BC Hydro and BCTC jointly studied the transmission requirements and prepared Appendix H which includes a summary of process and includes a list of technical issues that merit further analysis (Section 4.1 of Appendix H, Exhibit B1-C).

The purpose of this document is to clarify the planning assumptions and variables that BC Hydro provided to BCTC for the 2006 IEP/LTAP/CRP transmission analyses conducted by BCTC and to define the changes that may occur to those assumptions and variables between the approval of the Contingency Resource Plans (CRPs) and the submission of BC Hydro's Network Integrated Transmission Service (NITS) application or update following the conclusion of the 2006 IEP/LTAP Proceeding.

These clarifications further elaborate on those technical issues identified in Appendix H that were to be studied prior to or in the NITS application or update following the IEP/LTAP regulatory proceedings. These technical issues are:

1. Reliance on Coastal Region (Lower Mainland, Vancouver Island and Bridge River) generation as transmission Reliability-Must-Run (RMR), including the ratings of Coastal Region hydroelectric systems to defer new transmission reinforcement (i.e. to determine the appropriate trade-off between Coastal RMR generation and transmission reinforcement);
2. The amount of Interior Region Heritage Resources generation dispatch flexibility that should be provided by the transmission system (ranging from dependable to maximum continuous output); and
3. The appropriate transmission treatment of intermittent resources, such as wind.

Following discussions with BCTC, BC Hydro's application for approval of the LTAP and the CRPs contemplates the following processes and steps occurring between that approval and the submission of its NITS application:

- BC Hydro will request BCTC to study the three issues identified above and described more fully below.
- Based on the outcome of those studies, BC Hydro may modify its NITS application with respect to the variables and assumptions described in those three issues.

- Subject to any changes resulting from those studies, the NITS application assumptions will be as identified in the following sections of this report as well as any update to BC Hydro's Load Forecast net of planned DSM that may be available.

The CRPs will be as otherwise described in Appendix O to Exhibit B1-F, as amended.

BC Hydro understands that BCTC will also be investigating factors that contribute to the transfer capability of the Interior to Lower Mainland (ILM) transmission, such as the one hour rating series capacitor banks on the ILM path.

The following sections illustrate the relevance of these planning assumptions for transmission planning.

1. Reliance on Coastal Region Generation as Transmission Reliability-Must-Run

There has been some evolution in BC Hydro's thinking and thus commitments to Coastal Region RMR generation since the start of the 2006 IEP process. A comparison of key assumptions and associated levels of Coastal Region generation provided to BCTC are laid out in Table 1 and the resulting relative impact on the available coastal generation available for RMR is identified.

In summary, the assumed levels of Coastal Generation available as RMR for transmission planning purposes have a significant impact on the required in-service dates of ILM transmission reinforcements.

The assumed levels also have an effect on the Available Transmission Capacity (ATC) of the transmission system. In particular, the availability of ATC prior to the completion of ILM reinforcement is dependant on the treatment of the Burrard Thermal Generating Station (Burrard) as an RMR plant for other than Network customer usage. It is likely that without Burrard as an RMR plant, there will be very little ATC on the ILM path that would be available to Point-to-Point (PTP) customers. If ILM transmission reinforcement is completed, further study is required to determine ATC availability for PTP customers under both LTAP and CRPs.

Differences in estimated versus actual generation additions (F2006 Call for Tenders) also impact the relative timing of ILM reinforcement, but to a lesser extent. In addition, while DSM assumptions were consistent between the 2006 IEP portfolio analyses and the amended LTAP analyses, the expected DSM volumes become significant around 2015/16. For those 2006 IEP portfolios where the lower levels of Coastal Region RMR generation required an earlier ILM reinforcement in-service date (e.g., 2014), the reinforcement was already in service by the time the DSM volumes become significant. For the amended LTAP case, where the higher levels of Coastal Region RMR generation allowed a deferral of the ILM reinforcement, that deferral was extended by the additional DSM in later years.

Table 1: Coastal Generation Available for RMR assumed in the IEP Portfolio and Amended LTAP Analyses and Planned for the 2007 NITS

	IEP Portfolios	Amended LTAP	2007 NITS
Key Assumptions that Changed	• Total aggregate coastal dependable capacity reduced to provide regional generation reserves. • Assumes full Burrard plant capacity is used only to the extent necessary until ILM can be reinforced. • 39 MW of incremental coastal generation was assumed from the F2006 CFT	• No regional generation reserves. Total aggregate Coastal dependable capacity available as RMR. • Assumes full Burrard plant capacity is used to defer need for ILM reinforcement. • 160 MW of incremental coastal generation is assumed from the F2006 CFT	• No regional generation reserves. Total aggregate Coastal dependable capacity available as RMR. • Assumes full Burrard plant capacity is used only to the extent necessary until ILM can be reinforced. • 160 MW of incremental coastal generation will be assumed from the F2006 CFT
Impact			
F2009	1610+Burrard MW	2732 MW	1822+Burrard MW
F2013	1774+Burrard MW	2991 MW	2081+Burrard MW
F2014	1774 MW	2991 MW	2081 MW
F2016	1754 MW	2237 MW	2237 MW
F2020	1754 MW	2237 MW	2237 MW

BC Hydro's 2007 NITS application/update will be based on the RMR assumptions identified in Table 1, subject to the results of the further studies identified in this document.

2. Interior Regions Heritage Resources

There are two different assumptions that can be made with respect to the aggregate Heritage Resources generating capacity in the Interior regions:

- Total aggregate Maximum Continuous Rating (MCR) of the resources on the Peace side of the system, or total aggregate MCR from the resources on the Columbia side of the system; and
- Total aggregate Dependable Generating Capacity (DGC) of the resources on the Peace side of the system, or the total aggregate DGC of the resources on the Columbia side.

Currently the aggregate MCR of all Interior Heritage hydro plants is about 390 MW greater than the aggregate DGC. Therefore, assumed levels of Columbia and Peace Heritage Resources generation dispatch flexibility for transmission planning will likely have an impact on the timing of transmission reinforcements, such as ILM, and on ATC resulting from BC Hydro's LTAP and CRPs.

For the purposes of the high-level 2006 IEP portfolio and amended LTAP/CRP analyses, DGC was assumed for the Interior Heritage Resources.

BC Hydro has historically assumed that the transmission system be planned on the MCR for the Interior Heritage Resources, and has made its Network Resource nominations in previous NITS applications on that basis.

BC Hydro’s 2007 NITS application/update is expected to be based on operating the Interior plants at their total aggregate MCR levels, consistent with previous NITS Applications, subject to the results of the further analysis identified in this document.

3. Treatment of Intermittent Resources, Such as Wind

In both the 2006 IEP and in the LTAP/CRP analysis, the Expected Load Carrying Capabilities (ELCC) of intermittent wind resources and dependable capacities of small run-of-river hydroelectric resources were used for plants located in the Interior, and the dependable capacities were used for intermittent resources located in the Coastal region for the purposes of determining transmission requirements.

While assumptions with respect to intermittent resources were made for the 2006 IEP portfolio and LTAP/CRP analyses, those assumptions were preliminary. Further study and operational experience is necessary to determine if it is appropriate for BC Hydro to request less than full resource output in its transmission applications.

For BC Hydro’s 2007 NITS application/update and subject to the results of the further analysis identified in this document, the capacity of intermittent resources will be based on:

- Maximum Continuous Rated (MCR) MW Output: Ensuring transmission capable of delivering to and through the transmission system the continuous rated MW output that the IPPs have contracted to date with BCTC for the purposes of the interconnection facilities and future planned intermittent resources; and
- Dependable Generating Capacity (DGC): For the purposes of determining transmission system deferral (e.g., intermittent resources located in the Coastal Region). Assuming that the dependable capacity will be available for the purposes of determining transmission system deferral.

For illustration, the MCR, DGC and ELCC for a nominal 100 MW wind project and 10 MW run-of-river hydro projects are summarized in Table 2.

Table 2: Comparison of Capacity Ratings for Wind and Run-of-River Hydro Resources

	100 MW On-Shore Wind	**100 MW Off-Shore Wind**	**10 MW Run-of-River Hydro**
Maximum Continuous Rated Output (MCR)	100 MW	100 MW	10 MW
Dependable Generating Capacity (DGC)	7.5 MW	12 MW	2.5 MW
Effective Load Carrying Capability (ELCC)	21 MW	29 MW	2.5 MW

Appendix L

Draft Order

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473
and
An Application by British Columbia Transmission Corporation
for Approval of a
Transmission System Capital Plan F2009 to F2018

BEFORE: (Panel members) Month XX, 2008

ORDER

WHEREAS:

A. Commission Order No. G-69-07 dated June 15, 2007 responded to the British Columbia Transmission Corporation ("BCTC") Capital Plan F2008 to F2017; and

B. BCTC filed its Transmission System Capital Plan F2009 to F2018 dated December 21, 2007 (the "F2009 Capital Plan", the "Application") pursuant to Sections 45(6), 45(6.1) and 45(6.2) of the Utilities Commission Act ("the Act"); and

C. BCTC in the filing applies for an order which states that the F2009 Capital Plan meets the requirements of Sections 45(6) and 45(6.1) of the Act, approves the F2009 Capital Plan under subsection 45(6.2)(a) and, pursuant to Section 45(6.2)(b), determines that all projects and programs listed in Section 1.6.2 of the Application are in the public interest; and

D. The Commission, by Order No. G-xx-07, established a written public hearing process and Regulatory Timetable for the review of the Application; and

E. By Order No. G-xx-07, the Commission established a Procedural Conference on Month xx, 2007 regarding the regulatory process for the review of the Application; and

F. By Order No. G-xx-07, the Commission Panel established the Regulatory Timetable to review the Application; and

G. On Month xx, 2007, the Commission issued Information Request No. 1 to BCTC; and

H. The Commission received responses to Information Request No. 1 on Month xx, 2008; and

I. The evidentiary phase of the proceeding closed on Month xx, 2008, and

J. The Written Argument phase of the proceeding was completed when BCTC filed its Reply Submission on Month xx, 2008; and

K. The Commission Panel has considered the Application, evidence, and submissions of intervenors and the Applicant.

NOW THEREFORE pursuant to Section 45 of the Act the Commission orders as follows:

1. The Application meets the requirements of Sections 45(6) and 45(6.1) of the Act.

2. The F2009 Capital Plan is approved pursuant to Section 45(6.2)(a) of the Act.

DATED at the City of Vancouver, in the Province of British Columbia, this xx day of Month 2008.

BY ORDER

Panel Chair