FORTISBC

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June 27, 2008

Via Email
Original via mail

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

Dear Ms. Hamilton:

Re: FortisBC Inc.'s Application for Approval of 2009-2010 Capital Expenditure Plan

Please find enclosed for filing 20 copies of FortisBC Inc.'s ("FortisBC") Application regarding its 2009-2010 Capital Expenditure Plan ("2009/10 Capital Plan"). Also enclosed is FortisBC's 2009 System Development Plan Update ("2009 SDP Update").

The 2009/10 Capital Plan totals approximately $178.8 million for 2009 and $181.1 million for 2010. The most significant areas of expenditure are those required to expand and upgrade the bulk transmission and distribution system to keep pace with load growth, and to continue the ongoing program of life extension at FortisBC's generating plants.

In this Application, FortisBC is requesting approval of its proposed capital expenditures for a two-year period as it did for the 2007/08 Capital Plan. The Company believes that approval of a two-year Capital Plan has streamlined its planning and project management processes and will continue to reduce regulatory burden for the Company, the Commission and other stakeholders.

The majority of the capital projects in this application have been either previously approved, are, or will be the subject of, an application for a Certificate of Public Convenience and Necessity ("CPCN"). For this reason the Company suggests that the 2009/10 Capital Plan be disposed of by way of a written public hearing.

The Company will notify intervenors and interested parties registered in FortisBC Capital Plan, Revenue Requirements, and CPCN proceedings for the previous two year period.

Order Requested

Pursuant to the applicable sections of the UCA, FortisBC seeks an Order of the Commission that the 2009\10 Capital Expenditure Plan satisfies the requirements of Section 44.2 (1) (a) and (b) and Section 45(6), and that the Capital projects contained in the listed tables in the 2007\08 Capital Expenditure Plan are in the public interest pursuant to Section 44.2 (3) (a):

Table 2.1 Generation;

Table 3.1 Transmission and Stations;

Table 4.1 Distribution;

Table 5.1 Telecommunications, SCADA, and Protection and Control;

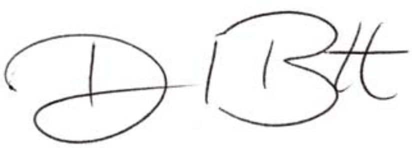
Table 6.1 Demand Side Management Expenditures; and

Table 7.1 General Plant,

with the exception of two of projects for which FortisBC proposes to submit applications for CPCN, the Benvoulin Substation Project and the Copper Conductor Replacement Program.

Should you require further information in this matter, please contact the undersigned at 250 717 0853.

Sincerely,



David Bennett
General Counsel and Corporate Secretary

FortisBC Inc.

2009-2010 Capital Expenditure Plan

("2009\10 Capital Plan")

June 27, 2008

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Appendices

1. Executive Summary

The 2009-2010 Capital Expenditure Plan ("2009\10 Capital Plan") of FortisBC Inc. ("FortisBC" or the "Company") consists of expenditures of $178.8 million in 2009 and $181.1 million in 2010. These expenditures are necessary to ensure the ability to provide service, public and employee safety and reliability of supply to the Company's growing customer base. The projects associated with these expenditures support the BC Government's energy objectives as defined in Section 1 of the Utilities Commission Act R.S.B.C. 1996, c.473 as amended by Bill 15-2008 (the "UCA"), and policy actions as outlined in the 2007 BC Energy Plan (the "Energy Plan"). These projects are considered by the Company to be in the public interest. The most significant areas of expenditure are those required to expand and upgrade the bulk transmission and distribution system to keep pace with load growth, and to continue the ongoing program of life extension at FortisBC's generating plants.

The 2009 System Development Plan Update ("2009 SDP Update") included with this Application identifies currently scheduled projects for the 2009-2010 timeframe. As described in the Executive Summary of the 2009 SDP Update, the majority of the changes from the 2005 SDP and 2007 SDP Update are related to timing. The completion of the projects listed in the 2009\2010 Capital Plan will substantially complete all of the major projects including the "Okanagan Transmission Reinforcement" that were included in the 2005 SDP. In 2010, the Company expects to develop another long range plan, taking into account the impact that these projects have had on its electrical system as well as the expected levels of growth within certain sections of its service territory.

In this Application, FortisBC is requesting approval of its proposed capital expenditures for a two-year period, as it did for its 2007\08 Capital Plan; which has streamlined its planning and project management processes and reduced regulatory burden for the Company, the Commission and other stakeholders. FortisBC believes that this streamlined regulatory process is compatible with its commitment to stakeholder consultation during the planning and implementation of its capital projects.

Table 1.1 below summarizes the planned expenditures for 2009 and 2010, and, in the case of multi-year projects, future years. It also shows the anticipated operations savings associated with these capital expenditures.

Table 1.1
2009\10 Capital Expenditure Plan

		2009 Expenditures	**2010 Expenditures**	**Future Expenditures**
		($millions)		
1	Generation	21.9	22.6	24.7
2	Transmission and Stations	96.1	88.7	3.0
3	Distribution	28.2	33.8	
4	Telecom, SCADA, Protection and Control	2.2	2.2	1.6
5	Demand Side Management	2.5	2.7	
6	General Plant	27.8	31.2	
7	**TOTAL Capital**	**178.8**	**181.1**	**29.3**
8	Annual Operating Savings	0.2	0.72	

The greatest portion of the expenditures is comprised of Transmission, Distribution and Telecommunications projects identified in the 2005 SDP. The 2007 SDP Update contained a forecast of 2009\10 expenditures for Transmission and Distribution and Telecommunications of $86.0 million for 2009 and $64.3 million for 2010 (2009 SDP Update, Appendix 3), for a total of $150.4 million. The forecast of 2009 and 2010 expenditures, as contained in the 2009\10 Capital Plan, now totals $251.1 million as summarized in Table 1.2 below, for reasons primarily related to the timing of project execution.

Table 1.2
2009-2010 Expenditures
Transmission and Distribution and Telecommunications

		2007 SDP update	2009\10 Capital Plan	Change
		($millions)		
1	**Plant Component**			
2	Transmission Growth	85.4	160.6	75.2
3	Transmission Line Sustaining	7.3	14.1	6.8
4	Stations Sustaining	6.6	10.1	3.5
5	Distribution	45.5	62.0	16.5
6	Telecommunications	5.6	4.4	(1.2)
7	**Total**	**150.4**	**251.1**	**100.7**

Note: Includes AFUDC and capitalized overhead at 2008 approved rates. Differences due to rounding.

The 2009\10 Capital Plan forecasts $100.7 million in capital expenditures for 2009\10 over the values listed in the 2007 SDP Update. Major changes in the SDP are summarized below by category. Details are included in the 2009 SDP Update.

Transmission Growth – Expenditure increases in this category total $75.2 million and are due to several factors, primarily made up of the following:

(1) The Tarrys Substation Upgrade Project, explained in detail later in this Application, is a new project for 2009 to address load at that substation, ($0.4 million);

(2) Unanticipated delays for the Naramata Project that have deferred a significant portion of this project from 2007 to 2009 and 2010, ($4.0 million);

(3) Unanticipated delays for the Black Mountain Substation Project that have deferred a significant portion of this project from 2008 to 2009, ($4.5 million);

(4) Unanticipated delays for the Benvoulin Substation Project that have deferred a significant portion of the project from 2008 to 2009, ($10.2 million); and

(5) Unanticipated delays that shifted the substantial completion date of the Okanagan Transmission Reinforcement ("OTR") Project from 2009 to 2010 and scope refinement associated with the completion of detailed engineering, ($71.6 million).

These expenditure increases were partially offset by the following factors:

(5) The 2010 Fault Level Reduction –Kelowna project has been cancelled as a result of an investigation and subsequent report contained in Appendix 8 in the 2007\08 Capital Expenditure Plan. The report concluded that upon completion of the Glenmore Substation in 2007, no further action was required in the foreseeable future, ($1.6 million);

(6) The Braeloch Distribution Source has been deferred from 2010 as a result of load relief that will be provided by the construction of the Benvoulin Substation, ($1.6 million);

(7) The Huth Substation rebuild has been deferred from 2010 to 2011 to avoid conflicts with the OTR construction schedule. Only the engineering and planning and some material acquisition is included in 2010, ($5.9 million); and

(8) The Grand Forks Conversion and Distribution Source has been deferred from 2010 to the 2011+ timeframe as permitted by the rate of load in the Boundary area, ($6.3 million).

Transmission Line Sustaining – Forecast expenditures in this category have increased by $6.8 million primarily due to:

(1) The requirement for increased transmission right-of-way expenditures associated with the removal of damaged trees resulting from the Pine Beetle infestation problem, ($2.0 million); and

(2) The requirement to rebuild sections of 20 Line and 27 Line to provide appropriate levels of safety and service reliability, ($4.8 million).

Stations Sustaining – An increase of $3.5 million is due to several factors, primarily made up of the following:

(1) The Slocan City –Valhalla upgrade which is a new project for 2009 to rectify issues associated with the existing the Slocan City transformer and substation, ($2.2 million);

(2) The Passmore Substation upgrade which is a new project for 2010 to address deficiencies associated with the existing transformer and line protection, ($2.0 million); and

(3) The Princeton Recloser Replacement which is a new project to address deficiencies at that substation, ($1.5 million).

These expenditure increases were partially offset by the following:

(4) The completion of the bulk oil breakers replacement project For DG Bell Substation and the Kaslo Substation upgrade in 2010 have been deferred to 2011+, ($1.8 million).

Distribution – An increase of $16.5 million in expenditures is explained primarily by:

(1) Forecast high customer growth rates and subsequent increase in the construction associated with the need to provide service, ($2.8 million);

(2) The requirement for increased distribution expenditures related to the removal of damaged trees resulting from the Pine Beetle infestation problem, ($1.3 million); and

(3) An assessment of aged copper conductor which has identified the conductor as a safety and reliability issue, ($11.4 million).

Telecommunications – A decrease of $1.2 million in this category is due primarily to the fact that the portion of the Trail to Oliver high capacity communications fibre between Trail and Grand Forks has been deferred from a completion date of 2010 to 2011+, ($2.4 million). This has been offset by an increase in the Distribution Substation Automation Project due to the schedule change, ($1.8 million).

Table 1.3 below provides a comparison of forecast 2009\10 Capital Plan expenditures relative to the 2007\08 Capital Plan approved by Commission Order G-147-06 and relative to the current 2007\08 forecast.

Table 1.3
Comparison of Expenditure Plans

		2007\08 Total Plan	2007\08 Total Forecast[(1)]	2009\10 Total Plan
	Plant Component	**($millions)**		
1	Transmission & Stations	123.7	136.9	184.8
2	Distribution	40.2	47.9	62.0
3	Telecommunication	8.0	3.6	4.4
4	Generation	40.7	38.9	44.5
5	Information Systems	9.5	11.0	9.7
6	Advanced Metering Infrastructure	0.0	0.6	36.7
7	Demand Side Management	3.1	3.1	5.2
8	General Plant	15.1	12.8	12.6
9	**TOTAL**	**240.2**	**254.3**	**359.9**

Note: Includes AFUDC and loadings at 2008 approved rates. Differences due to rounding.

(1) All forecast figures are based on forecasts as of April 30, 2008.

A discussion of significant items in the remaining categories is provided below.

Generation – FortisBC has a total of fifteen generating units in its four power plants. Since 1998 a major life extension project has been underway, including upgrades to generating capacity, when economic. By the end of 2008, seven units will have been completed, with the eighth to be completed in 2009, and the ninth and tenth forecast for completion in 2010. The upgrade and life extension project for the eleventh unit is scheduled to start in 2009 and be completed in 2012. In 2009 and 2010 approximately $16.5 million and $19.3 million respectively, or 75 percent and 85 percent of the planned generation expenditures, will be utilized to upgrade Units 1 and 3 at South Slocan, Unit 1 and 2 at Corra Linn, and to address civil and structural issues as well as the repowering of the original four Upper Bonnington units. The completion of these generation projects will negate the need for approximately $200,000 in maintenance costs in 2009\10.

Information Systems – Expenditures are planned to increase in 2009 and 2010 relative to 2008 expenditures. This is due to projects which provide enhancements to utilize the capabilities of the existing core applications, and the project to acquire a Distribution Design software solution in 2009.

Advanced Metering Infrastructure – FortisBC plans to replace all meters in its service territory with solid-state AMI-enabled meters, and to install the required communication infrastructure to facilitate remote meter reading capability. The principle benefits resulting from an AMI implementation include the operational savings from the elimination of manual meter reading, other benefits in customer service, transmission and distribution operations, system planning and revenue protection. The Company filed an application for a CPCN on December 19, 2007. A written public hearing on the application is expected to conclude on June 30, 2008. The total estimate for this project is $37.3 million. The Company anticipates operating expense reductions of approximately $518,000 in 2010 and $2.4 million annually thereafter. The net reduction in operating costs associated with the AMI Project will be offset against customer rates beginning in 2010.

Demand Side Management – Demand Side Management (“DSM”) or energy efficiency programs have been offered to FortisBC customers since 1989. DSM programs meet the economic test of costing less than the avoided cost of delivered power. The programs are available to all customers served by FortisBC and its wholesale customers in Grand Forks, Kelowna, Nelson, Penticton, and Summerland.

Planned expenditures for 2009 are $2.5 million ($3.7 million less income taxes of $1.2 million). Planned expenditures for 2010 are $2.7 million ($3.9 million less income taxes of $1.2 million). For regulatory purposes, the Commission has directed that DSM be recorded net of income tax, in a deferred cost account and included in rate base.

General Plant – Forecast expenditures for 2009 and 2010 show a decrease relative to the 2007\08 Capital Plan. This is primarily the result of the inclusion of $3.95 million in 2007 for the Benvoulin Property Expansion Project. This project has since been cancelled because the property could be acquired. This category includes sustaining expenditures for vehicles and facilities.

A report completed by MMK Consulting in 2007 (attached as Appendix 3), titled “BC Hydro – Construction Cost Trends and Outlook”, and previously filed as part of the FortisBC OTR Regulatory process, recommends a cost inflation allowance between four percent and six percent for 2007-2010 and between three percent and four percent for 2011-2015 for all construction projects. FortisBC has adopted an inflation rate of five percent for 2009 and 2010. Project costing within utilities has been very volatile during the past few years. Those projects for which a CPCN has been filed or for which FortisBC expects to file a CPCN in 2009, have a cost estimate with a +\- 10 percent level of accuracy. However since detailed engineering has not been completed for many other projects listed in the 2009\10 Capital Plan, the estimates for these projects are at a +\- 20 percent level of accuracy.

Public Consultation

FortisBC recognizes the value of stakeholder consultation in the planning and implementation of projects to meet customers’ needs. A consultation program is developed for each major project, and involves greater detail as project planning and engineering advances. A typical process is described below.

System Planning engineers remain in contact with community planners on an ongoing basis to remain familiar with current and planned development. Once a specific need is determined and potential solutions identified, FortisBC contacts stakeholders to discuss any issues in the community that can be addressed in the project planning stage. Such stakeholders normally consist of local and Provincial Governments and agencies, First Nations, potentially affected landowners, and other local groups such as tourism associations and community and\or residents’ associations.

A wider public consultation process may then be developed to elicit local issues and concerns, and allow various stakeholders to meet the project team, ask specific questions, and build constructive local relationships. Notice of such information sessions is provided through local newspapers and radio, and general mailings of notices. Known stakeholders are invited by way of mail, telephone, or email. Attendees are provided with a FortisBC contact person for future information, comment, or follow-up.

The Company continues to solicit input from its stakeholders throughout the planning, regulatory and construction stages to project completion. This input is critical in the Company's efforts to balance the needs of individuals, affected communities and other ratepayers.

Legislative and Regulatory Framework

On February 27, 2007, the Provincial Government released The BC Energy Plan: A Vision for Clean Energy Leadership, the "Energy Plan", which provides direction on energy policy in British Columbia and provides specific Policy Actions that have been considered within this 2009\10 Capital Plan. A majority of the projects contained in the 2009\10 Capital Plan support objectives of the Energy Plan, and where appropriate, this support is identified. FortisBC recognizes that some of the Policy Actions contained in the Energy Plan apply specifically to BC Hydro or the BC Transmission Corporation. However, when the Company undertakes projects that support these objectives and contribute to the security of the electrical system from a Provincial perspective, these contributions should be considered and highlighted within this Application.

In addition, Bill 15-2008, the Utilities Commission Amendment Act, 2008, received Royal Assent on May 1, 2008. The UCA further defines the government's energy objectives as:

(a) to encourage public utilities to reduce greenhouse gas emissions;

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

- (i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or
- (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

(f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation

Section 44.2 (5)(a) of the UCA states that in considering whether to accept an expenditure schedule such as this 2009\10 Capital Plan, the Commission must consider the government's energy objectives as described above. FortisBC believes that the projects contained in the 2009\10 Capital Plan meet these objectives and where appropriate, this support is identified in the individual sections.

Specifically, with respect to Sections 64.01 and 64.02 of the UCA, the portions of the this Application dealing with the sustaining and enhancement of generation facilities directly support the achievement of the Provincial goal of meeting resource requirements through clean or renewable resources.

Order Requested

Pursuant to the applicable sections of the UCA, FortisBC seeks an Order of the Commission that the 2009\10 Capital Expenditure Plan satisfies the requirements of Section 44.2 (1) (a) and (b) and Section 45(6), and that the Capital projects contained in the listed tables in the 2007\08 Capital Expenditure Plan are in the public interest pursuant to Section 44.2 (3) (a):

Table 2.1 Generation

Table 3.1 Transmission

Table 4.1 Distribution

Table 5.1 Telecommunications

Table 6.1 Demand Side Management

Table 7.1 General Plant

Proposed Regulatory Process

FortisBC proposes that this Application be disposed of by way of a written public hearing. In support of this proposal, the following table provides information with respect to the level of expenditures:

- that have been approved in previous Commission Orders;
- for which a CPCN has been submitted; and
- for which a CPCN will be submitted.

Table 1.4
2009\10 Capital Plan Summary

		2009	2010	Total
		($millions)		
1	Previously Approved	31.0	18.1	49.1
2	CPCN Submitted	81.8	78.1	159.9
3	CPCN to be Submitted	7.7	20.1	27.9
4	**Subtotal**	**120.5**	**116.4**	**236.9**
5	Remainder	58.3	64.7	123.0
6	**Total**	**178.8**	**181.1**	**359.9**

Note: Differences due to rounding.

The specific projects in each of these categories are identified in Tables 2.1, 2.2, 3.1, 4.1, 5.1, 6.1, and 7.1.

Of the forecast expenditures, 67 percent in 2009 and 64 percent in 2010 are either approved or are the subject of an existing or future CPCN application. This application therefore seeks approval for projects totalling $123.0 million in 2009 and 2010, of which the majority of expenditures are based on the 2005 SDP and upgrade life extension programs. The remaining expenditures are projects required to sustain the life of existing assets, or are expenditures on Demand Side Management or General Plant such as Vehicles, Information Systems, Buildings, and Furniture. Therefore, FortisBC submits that these remaining expenditures can be adequately examined in the context of a written hearing.

In its 2005 Revenue Requirement Application (Tab 9 - 2005 Capital Plan), FortisBC proposed the following criteria to determine if a project should be the subject of a CPCN application by FortisBC:

- the total project cost is $20 million or greater; or
- the project is likely to generate significant public concerns; or

- FortisBC believes for any reason that a CPCN application should proceed; or
- after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

In its Decision accompanying Order G-52-05, the Commission stated its general agreement with these criteria, but noted that the Commission intends to review each year's capital filing and will determine with reasons which project will require a CPCN.

FortisBC plans to file a CPCN for the Copper Conductor Replacement Program concurrently with this application and expects to file a CPCN for the Benvoulin Substation Project in the third quarter of 2008.

Commission Order G-58-06 approved a Negotiated Settlement Agreement ("NSA") between FortisBC and its major stakeholders that, among other things, defined a rate-setting process for the years 2007, 2008, and potentially 2009, in which the Company's Capital Expenditure Plans are to be disposed of in a process separate from annual Revenue Requirements. A goal of achieving firm rates by December 1 for the following year is embedded in the NSA.

FortisBC proposes the following regulatory timetable:

Commission Information Request No. 1 (IR1)	July 17, 2008
FortisBC Response to Commission IR1	August 7, 2008
Workshop	August 12, 2008
Commission IR No. 2 (IR2) and Intervenor IR1	August 15, 2008
FortisBC Response to BCUC IR2 and Intervenor IR1	September 5, 2008
Intervenor Comments	September 17, 2008
FortisBC Reply	September 24, 2008

The form of the Order requested by FortisBC is set out in Appendix 1of this Application.

SUMMARY OF EXPENDITURES BY CATEGORY

The following table provides a summary of the 2009\10 Capital Plan by major categories including AFUDC and loadings.

Table 1.5
2009\10 Capital Plan

		2009 Expenditures	2010 Expenditures	Future [(1)] Expenditures
1	**GENERATION**		**($000s)**	
2	Growth			
3	Sustaining	21,935	22,557	24,657
4	**Subtotal**	**21,935**	**22,557**	**24,657**
5	**TRANSMISSION AND STATIONS**			
6	Growth	84,396	76,178	3,000
7	Sustaining	11,727	12,497	
8	**Subtotal**	**96,123**	**88,675**	**3,000**
9	**DISTRIBUTION**			
10	Growth	12,158	15,433	
11	Sustaining	16,049	18,317	
12	**Subtotal**	**28,207**	**33,750**	
13	**TELECOM, SCADA, PROTECTION AND CONTROL**			
14	Growth	1,338	1,438	1,621
15	Sustaining	864	738	
16	**Subtotal**	**2,202**	**2,176**	**1,621**
17	**DEMAND SIDE MANAGEMENT**			
18	**Subtotal**	**2,513**	**2,707**	
19	**GENERAL PLANT**			
20	Vehicles	1,326	2,868	
21	Metering	526	559	
22	Information Systems	5,167	4,499	
23	Advanced Metering Infrastructure	16,492	20,240	
24	Telecommunications	105	106	
25	Buildings	3,248	1,981	
26	Furniture	347	393	
27	Tools and Equipment	572	575	
28	**Subtotal**	**27,783**	**31,221**	
29	**TOTAL**	**178,763**	**181,086**	
30	**Growth**	**97,892**	**93,049**	**4,621**
31	**Sustaining**	**50,575**	**54,109**	**24,657**
32	**Demand Side Management**	**2,513**	**2,707**	
33	**General Plant**	**27,783**	**31,221**	
34	**TOTAL**	**178,763**	**181,086**	**29,278**

[(1)] Future expenditures for ongoing sustaining programs have not been included in these tables.

2. Generation

FortisBC's generating plant capital requirements have been categorized into two capital improvement areas:

Major projects include items such as the upgrade and life extension program; and

Small sustaining projects are relatively small in scope and are necessary to maintain safe and efficient operation of the plants.

These hydroelectric generating plants, most of which have been in service for more than 60 years, are renewed by both the small capital sustaining projects and major projects which include the upgrade and life extension program that began in 1998. These planned projects will ensure the continued long-term reliability of the generating units.

By maintaining or increasing the capacity and energy of its hydroelectric generating facilities, the Company supports the Provincial Government's energy objectives. In particular the objective:

(c) to encourage public utilities to produce, generate and acquire energy from clean or renewable resources.

The projects also support the Policy Actions outlined in the Energy Plan. In particular:

(10) Ensure self-sufficiency to meet electricity needs, including insurance by 2016.

MAJOR PROJECTS

The scope of an upgrade and life extension ("ULE") project is a "water to wire" refurbishment of each of the generating units' systems. By the end of 2008 seven units will have been completed under the ULE program. The current program schedule sees the completion of South Slocan Unit 3 in 2009, South Slocan Unit 1 and Corra Linn Unit 1 in 2011 and Corra Linn Unit 2 in 2012. The program has been extended by one year compared to the 2007\08 CEP filing due to extended delivery times being experienced for major components.

FortisBC's four generating plants are comprised of fifteen units of which eleven have been selected for life extension. The remaining four units were subject to the "Upper Bonnington Old

Unit Repowering Study" completed in 2006. At that time the study determined that an upgrade was not feasible. However, recent energy cost increases have now made an upgrade feasible, with a project start presently planned for 2011\12.

The major generation projects in the 2009\10 Capital Plan include the completion of projects previously approved in the 2007\08 Capital Plan, the continuation of the unit-by-unit ULE program, the acquisition of a unit transformer, South Slocan Unit 1 Headgate Rebuild, South Slocan Unit Headgate Hoist and Control Wire Upgrade, Area Lighting Projects, and Station Service Supply Projects. With the completion of these generation projects, the Company anticipates a one time reduction in maintenance costs of approximately $200,000. Table 2.1 below lists the Generation projects in the 2009\10 Capital Plan.

Table 2.1
Generation Projects

		Previously Approved	Expenditures to Dec 31\08[1]	2009	2010	Future [2]	Total
			($000s)				
	Sustaining						
1	South Slocan Unit 1 Life Extension	G-52-05	6,729	7,832	3,261	39	17,861
2	South Slocan Unit 3 Life Extension	G-147-06	11,010	2,051	-	-	13,061
3	Corra Linn Unit 1 Life Extension	G-147-06	874	4,487	8,476	5,113	18,950
4	Corra Linn Unit 2 Life Extension		-	104	5,264	17,313	22,681
5	South Slocan Plant Completion	G-147-06	1,012	940	1,598	-	3,550
6	Upper Bonnington Civil \ Structural Upgrade and Old Unit Repowering (Phase 1)	G-147-06	4,142	1,094	651	-	5,887
7	South Slocan Unit 1 Headgate Rebuild	G-147-06	-	577	279	-	856
8	South Slocan Headgate Hoist, Control, Wire Rope Upgrade	G-147-06	669	434	-	-	1,103
9	Generating Plants Upgrade Station Service Supply	G-147-06	1,144	484	1,191	2,192	5,011
10	Generating Plants Area Lighting		-	478	338	-	816
13	All Plants Spare Unit Transformer		469	1,380	-	-	1,849
13	**Subtotal Major Projects**		**26,049**	**19,861**	**21,058**	**24,657**	**91,625**
14	**Subtotal Minor Projects from Table 2.2**		-	**2,074**	**1,499**	-	**3,573**
15	**Total Generation**		**26,049**	**21,935**	**22,557**	**24,657**	**95,198**

[1] Future expenditures for ongoing sustaining programs have not been included in these tables.

[2] All forecast figures are based on forecasts as of April 30, 2008.

The following gives an overview of the Generation Major Projects contained in the 2009\10 Capital Plan.

South Slocan Unit 1 Life Extension (Replace Turbine)

The South Slocan Unit 1 Life Extension project is the eighth unit in the program. It was approved by Commission Order G-52-05.

This project is a multi-year project with initial expenditures occurring in 2005\06. A condition assessment of the unit's major components and systems was done to determine the scope of work and cost estimate. The assessment showed cracks in several locations on the existing turbine runner; as a result it was determined that the turbine runner needs to be replaced. In this project, the unit will not be upgraded, rather it will be replaced in kind since the probability of achieving incremental energy and capacity output did not justify the additional cost of a new higher output turbine. As a result of an extended turbine runner delivery schedule the completion of this project has been delayed to 2010. The project now has a total estimated cost of $17.86 million compared to the original estimate of $13.3 million. The primary reasons for the change are due to escalation in the cost of materials. Examples of these escalations include an increase of $2.1 million in the cost of the new turbine, $0.34 million for turbine component refurbishment, $0.44 million for generator windings, $0.45 million for main lead cables, $0.44 million for other accessory electric equipment and $0.23 million for environmental upgrades to the transformer bay structure, which together account for $4.0 million of the $4.6 million increase.

South Slocan Unit 1 ULE

Year	To Dec 31 2008	2009	2010	2011	Total
Cost ($000s)	6,729	7,832	3,261	39	17,861

South Slocan Unit 3 Life Extension

The South Slocan Unit 3 Life Extension project is the ninth unit in the program and was approved by Commission Order G-147-06.

The project was initially scheduled as a multi-year undertaking including a turbine runner replacement with initial expenditures occurring in 2007. As with the previous Life Extension Projects, a condition assessment of major unit components and systems was completed by BC

Hydro in 2007 that indicated the turbine was in reasonable condition, and therefore, a new turbine runner would not be required. The project now has a total estimated cost of $13.06 million compared to the original estimate of $13.31, a reduction of $0.25 million. The elimination of the turbine runner from the project estimate resulted in a decrease in costs of ($1.7 million); however this was offset by increases due to escalation of materials. For example the turbine component refurbishment has increased by $0.45 million, main lead cables by $0.34 million, generator step-up transformer by $0.31 million, generator rewinding by $0.10 million, and the transformer bay upgrades by $0.13 million. The current estimated expenditures are noted in the table below.

South Slocan Unit 3 Life Extension

Year	To Dec 31 2008	2009	Total
Cost ($000s)	11,010	2,051	13,061

Corra Linn Unit 1 Life Extension (Replace Turbine)

The Corra Linn Unit 1 Life Extension project is the tenth unit in the program and was approved by Commission Order G-147-06. It is a multi-year project with initial expenditures occurring in 2007 and completion forecast for 2011.

The project now has a total estimated cost of $18.95 million compared to the original estimate of $11.8 million presented in the 2007\2008 Capital Plan. The original estimate based on market conditions in 2005, and significant escalation of material and labour for the unit's major components has since occurred. A new turbine has been added to the project scope.

As stated in the 2007\2008 Capital Plan a condition assessment of the existing turbine was to be completed. The assessment performed by BC Hydro in December 2006 provided the following recommendations:

> "The turbine runner is not in reasonable shape. There are significant concerns about its structural integrity if the inter-blade struts are removed since these were installed after

> blade cracking problems. These struts significantly affect the runner efficiency. An argument can be made that a new runner could result in an increase in turbine efficiency by as much as 4 to 6 percent. A study of the generator efficiency should be done to determine if further gains can be made to improve the overall unit efficiency and possibly unit capacity."

Based on this assessment the life extension scope and estimate have been updated to include the cost of a new turbine. With recent adjustments to the Canal Plant Agreement, analysis of upgrade capability is underway to determine if a turbine of higher output would be justified.

The cost of the new turbine increased the project cost by $2.5 million. Examples of materials escalations include $1.26 million for turbine component refurbishment, $0.70 million for generator windings, $0.66 million for the generator step-up transformer, $0.47 million for main lead cables, $0.66 million for other accessory electric equipment and $0.24 million for environmental upgrades to the transformer bay structure which together account for $6.5 million of the $7.2 million increase.

The project is forecast to be completed and closed in 2011. The estimated expenditures are shown in the table below.

Corra Linn Unit 1 Life Extension (Replace Turbine)

Year	To Dec 31 2008	2009	2010	2011	Total
Cost ($000s)	874	4,487	8,476	5,113	18,950

Corra Linn Unit 2 Life Extension (Replace Turbine)

The Corra Linn Unit 2 Life Extension project is the eleventh and last unit in the program. This project is required to maintain the generating capability of the hydroelectric unit.

The project is as a multi-year project with initial expenditures occurring in 2009 and project completion in 2012. The project will follow the same condition assessment of major unit components and systems as previous upgrade and life extension projects. A turbine condition assessment has yet to be completed. However as with the Corra Linn Unit 1, it is anticipated that a new turbine will be required, therefore the current budget estimate anticipates a new turbine.

Included in this project are the plant completion tasks that will be executed as all unit upgrades at Corra Linn will have been completed. These tasks collectively capture the necessary improvements required to bring the entire plant up to a current level of technology. Also included in this project are upgrades to the plants ancillary systems and completion of plant documentation.

This project has total estimated expenditures of $22.68 million, as shown in the table below. The project is forecast to be completed in 2012. Further details with respect to this project are contained Appendix 1.

Corra Linn Unit 2 Life Extension (Replace Turbine)

Year	2009	2010	2011	2012	Total
Cost ($000s)	104	5,264	9,330	7,983	22,681

South Slocan Plant Completion

A plant completion project is executed after all unit upgrades have been completed and collectively captures the necessary improvements required to bring the entire plant up to a current level of technology. Also included are upgrades to the plants ancillary systems and completion of plant documentation. This Project was approved by Commission Order G-147-06. As a result of delays in the South Slocan ULE for Units 1 and 3 the completion of this project has been delayed to 2010. The project now has a total estimated cost of $3.55 million compared to the original estimate of $1.9 million. The primary reason for the change is escalation of material costs and escalation of engineering costs. For example, the cost of the unit protection and control components has increased by $0.69 million and the engineering and environmental costs have increased by $0.35 million, which together account $1.04 million of the $1.65 million increase. The current estimated expenditures are noted below.

South Slocan Plant Completion

Year	To Dec 31 2008	2009	2010	Total
Cost ($000s)	1,012	940	1,598	3,550

Upper Bonnington Old Unit Repowering (Phase 1)

This project was approved by Commission Order G-147-06 and involves two areas; a safety and preservation investment to address civil, structural and environmental concerns, and minimal equipment restoration to allow for a five year operation. Much of this work is seasonally dependent. Availability of civil construction resources has extended the project completion date to 2010. The project now has a total estimated cost of $5.89 million compared to the original estimate of $5.49 million. The current estimated expenditures are noted below.

Upper Bonnington Old Unit Repowering (Phase 1)

Year	To Dec 31 2008	2009	2010	Total
Cost ($000s)	4,142	1,094	651	5,887

South Slocan Unit 1 Headgate Rebuild

This project involves headgate rebuilds for South Slocan Unit 1 and was approved by Commission Order G-147-06. Headgate rebuilds are being carried out in conjunction with the ULE projects to optimize the unit outage requirements.

The headgate rebuilds will increase the reliability of the gates' operation, preserve structural soundness, ensure operator safety (as this is the primary isolation to protect workers involved in maintenance) and will increase the gates' life an additional 50 years.

As a result of changes in the ULE schedule this project has been delayed to 2009. The project now has a total estimate cost of $0.86 million compared to the original estimate of $0.67 million. In the 2007\2008 Capital Plan the estimate was based on the scope and costing from the headgate rebuilds at Lower Bonnington. However, as the headgates at South Slocan are approximately 30 percent larger, proportional increases in labour and materials are required to complete the project. In addition the dam configuration at South Slocan required job procedures to be amended to accommodate the limited access.

The current estimated expenditures are noted below.

South Slocan Unit 1 Headgate Rebuild

Year	2009	2010	Total
Cost ($000s)	577	279	856

South Slocan Headgate Hoist, Control, Wire Rope Upgrade

This project, which was approved by Commission Order G-147-06, involves the replacement of the existing headgate hoist, control and wire rope system with individual hoist motor\brake units, controls and wire rope. These upgrades will increase the reliability of the gate operation and ensure operator safety. As a result of changes in the ULE schedule the completion of this project has been delayed to 2009. The project now has a total estimated cost of $1.1 million compared to the original estimate of $0.67 million. The primary reason for the change is escalation of materials and engineering cost. For example the hoists have increased by $0.20 million, the controls by $0.13 million, and the wire rope by $0.053 million, which together account for $0.38 million of the $0.43 million increase. The current estimated expenditures are noted below.

South Slocan Headgate Hoist, Control, Wire Rope Upgrade

Year	To Dec 31 2008	2009	Total
Cost ($000s)	669	434	1,103

Generating Plants Station Service Supply

The Station Service power supply equipment at all four FortisBC generating plants vary in age from 50 to 80 years old. The equipment is being replaced due to its deteriorated condition. This project, which was approved by Commission Order G-147-06, involves installing new equipment and back up power sources to ensure operational reliability and to address environmental concerns associated with the existing oil filled equipment. For each generating plant the project includes replacement of the transformers and switchgear feeding the 2300 Volt normal station service power, and the replacement of the existing overhead tie line with diesel generators for the emergency \ backup station service power. The project now has a total estimated cost of $5.01 million compared to the original estimate of $3.8 million. The primary reason for the change is escalation of materials and engineering cost. For example project engineering cost has increased by $0.40 million, transformers by $0.20 million, diesel generators by $0.37 million, electrical controls and switching equipment by $0.12 million, which together account for $1.09 million of the $1.21 million increase. The current estimated expenditures are noted below.

All Plants Upgrade Station Service Supply

Year	To Dec 31 2008	2009	2010	2011	2012	Total
Cost ($000s)	1,144	484	1,191	1,312	880	5,011

Generating Plants Lighting Upgrade

This project involves upgrading the lighting systems in the basements of the Corra Linn and South Slocan powerhouses and a full plant upgrade at the Lower Bonnington plant. The present lighting conditions at these plants are inadequate and do not meet WorkSafe BC occupational Health and Safety Regulations Part 4.65.

This project is required to address employee safety. The estimated expenditures are noted below.

Generating Plants Lighting Upgrade

Year	2009	2010	Total
Cost ($000s)	478	338	816

All Plants Spare Unit Transformer

The generator step-up unit transformers have been identified as having a high risk of failure due to age. If failure occurs, the result could be loss of generation for up to two years.

The Corra Linn Unit 1 and Unit 2 transformers present the highest risk. Originally installed in 1932, these transformers are well past their normal life expectancy of 35-40 years. In 2006 a failure of the Lower Bonnington Unit 2 generator step-up transformer occurred with substantial unit outage costs estimated at approximately $1.5 million. A spare transformer will mitigate this risk. As a result of the Lower Bonnington failure, FortisBC's insurer has revised the coverage for equipment damage and business interruption to $500,000 deductible and a ninety day wait period for business interruption from a previous deductible of $300,000 and a thirty day wait period for business interruption. The new transformer will be rated at 25 MVA and be of adequate size to replace any one of eleven unit transformers at the FortisBC Kootenay River plants. This includes all the units except the four small Upper Bonnington units. Due to the requirement for the spare transformer to be stored with the bushings, conservator and coolers off, a weatherproof storage facility is also required as part of this project.

This project is required to maintain the generating capacity of FortisBC's hydroelectric units. This project has total estimated expenditures of $1.85 million, as shown in the table below. The project is forecast to be completed in 2009.

All Plants Spare Unit Transformer

Year	To Dec 31 2008	2009	Total
Cost ($000s)	469	1,380	1,849

SMALL SUSTAINING PROJECTS

FortisBC's four generating plants are comprised of fifteen units. The plants contain turbines, generators, switchgear, civil structures (concrete dams, concrete powerhouse buildings and structure steel assemblies), cranes, gates, and gantries, cooling pumps and fans, roads and fences.

Consistent with previous years, the 2009\10 Generation capital expenditures include a number of plant sustaining projects that are necessary for the safe and efficient operation of the plants. These are relatively small projects that have been identified based on considerations of safety, environment, plant reliability and provincial and federal regulatory compliance. These have been selected from a list of projects that require completion in the near future. The actual timing may vary from the proposed schedule subject to identification of higher priority work. The 2009 and 2010 planned expenditures for small sustaining capital projects are $2.07 million and $1.50 million respectively.

The following Table 2.2 shows the Generation Small Sustaining Capital Projects with estimated expenditures less than $500,000 that is proposed for 2009 and 2010. A brief description of each project follows:

Table 2.2
Generation Small Sustaining Projects

	Generation Small Sustaining Projects	**2009**	**2010**
		($000s)	
1	All Plants Fire Safety Upgrade Phase 1	241	
2	All Plants Public Safety & Security Phase 1	82	52
3	Lower Bonnington Power House Crane Upgrade	174	
4	Corra Linn Power House Crane Upgrade	172	
5	Corra Linn East Wingdam Handrail Upgrade	78	
6	All Plants Portable Headgate Closing Device	50	
7	All Plants Spare Exciter Transformer	24	116
8	South Slocan Water Supply Phase 3	47	50
9	All Plants 2009 Pump Upgrades	233	
10	Upper Bonnington & Corra Linn Deluge Valves	50	
11	Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm System Upgrade	128	
12	Lower Bonnington & Upper Bonnington Upgrade Spillway Gate Control Phase 1	40	
13	Upper Bonnington & South Slocan Airwash Tank Rehabilitation	108	
14	South Slocan Tailrace Gate Corrosion Control		114
15	Queen’s Bay Level Gauge Building Phase 1	67	
16	Upper Bonnington Unit 5 & Unit 6 Tailrace Gate Corrosion Control		139
17	Upper Bonnington Trashrack Gantry Replacement.		417
18	Lower Bonnington Forebay Access Rd. and Intake Upgrade Phase 1 & 2	393	102
19	Corra Linn Spillway Gate Isolation Study	46	
20	South Slocan Dam Rehabilitation Study	46	
21	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade		212
22	Lower Bonnington & Upper Bonnington Communications Network Completion	95	297
23	**Total**	**2,074**	**1,499**

All Plants Fire Safety Upgrade Phase 1

The fire protection systems at the FortisBC plants are outdated, with some parts of the fire protection dating back to the original generating equipment installation. Fire protection assessments and upgrades are required at each plant to ensure they comply with the fire codes and\or insurer requests. FortisBC’s Generation group has recruited a Fire Safety expert to conduct an assessment of the facilities and equipment and to provide recommendations to ensure that the current fire protection systems meet good utility practices. The intention is to utilize this information to develop a scope of work in 2009 that will be submitted for regulatory approval as part of a subsequent Capital Plan.

This project is required to address employee and equipment safety and to maintain the generating capability of FortisBC's hydroelectric units. The estimated expenditures for this project is $241,000 in 2009

All Plants Public Safety & Security Phase 1

This project involves the design of systems at the four FortisBC Generating Plants to take proactive measures to address employee and public safety, and environmental concerns. The project will develop such items as signage using Canadian Electricity Association (CEA) nomenclature and fencing recommendations to prevent employee and public access to potential hazards. Detailed drawings with material lists for the systems will be produced from which a detailed scope of work and estimate will be developed for submission for regulatory approval as part of a subsequent Capital Plan

This project is required to address employee and public environment, health and safety and to maintain the generating capability of FortisBC's hydroelectric units. The estimated expenditures for this project are $82,000 in 2009 and $52,000 in 2010.

Lower Bonnington Power House Crane Upgrade

This project involves the installation of new equipment on the crane to meet WorkSafe BC Occupational Health and Safety Regulation Part 14.2. Recent assessments indicate that the powerhouse crane has deficiencies in various crane functions and also extensive wear from past usage.

This project is required to address employee and equipment safety and to maintain the generating capability of the Lower Bonnington hydroelectric units. The estimated expenditure for this project is $174,000 in 2009.

Corra Linn Power House Crane Upgrade

This project involves the installation of new equipment on the crane to meet WorkSafe BC Occupational Health and Safety Regulation Part 14.2. Recent assessments indicate that the powerhouse crane has deficiencies in various crane functions and also extensive wear from past usage.

This project is required to address employee and equipment safety and to maintain the generating capability of the Corra Linn hydroelectric units. The estimated expenditure for this project is $172,000 in 2009.

Corra Linn East Wingdam Handrail Upgrade

This project is to replace the three-foot tall east wingdam handrail. The existing handrail is in poor condition and of insufficient height to meet the WorkSafe BC Occupational Health and Safety Regulation of forty two inches.

This project is required to address employee and public safety. The estimated expenditure for this project is $78,000 in 2009.

All Plants Portable Headgate Closing Device

A portable headgate closing system is required for the FortisBC plants on the Kootenay River. The system will consist of a jacking device that can force the gate to close under full flow conditions. The results of a recent study performed by Agra Monenco indicated that the headgates did not have sufficient weight to close under a full flow runaway condition. This was later verified by FortisBC personnel at Corra Linn and Lower Bonnington by closing the headgates with the unit operating at no-load speed. This presents a risk to employee safety and may result in equipment damage. The use of a portable closing device reduces this potential risk.

This project is required to address employee and equipment safety and to maintain the generating capability of FortisBC's hydroelectric units. The estimated expenditure for this project is $50,000 in 2009.

All Plants Spare Exciter Transformer

This project involves the purchase of a spare static exciter transformer. The static exciter transformer has been identified as a high risk component, a failure of which would result in a forced outage. Based on replacement and delivery schedules, outage cost could range from $1.5 million to $2.5 million. All upgraded generating units have static exciters installed. These units have redundant power electronic and control units for increased reliability but the exciter transformer is not redundant. This transformer is a dry indoor type which is of a unique voltage and physical size making it difficult to find a replacement. Due to extended delivery schedule of a unit, a failure of the transformer will result in loss of generation for up to six months. A spare transformer will mitigate this risk.

This project is required to maintain the generating capability of FortisBC's hydroelectric units. The estimated expenditures for this project are $24,000 in 2009 and $116,000 in 2010.

South Slocan Water Supply Phase 3

The domestic water supply system has been providing fire protection and potable water to the South Slocan plant facilities for over 70 years. Phase one, completed in 2006, replaced the water line on the east side of the wingdam at South Slocan and phase two, completed in 2007, upgraded the Rover Creek suspension bridge.

Phase three of the project consists of the planning and engineering for the completion of the upgrade to the gravity water supply from Rover Creek to the South Slocan plant facilities. This project will form the basis to develop a scope of work that will be submitted in 2010 to be executed as phase 4 in 2011 and 2012.

This project is required to address employee and fire safety and provincial potable water regulations. The estimated expenditures for this project are $47,000 in 2009 and $50,000 in 2010.

All Plants 2009 Pump Upgrades

This project involves rehabilitation of the dewatering pumps and piping at all plants to ensure reliable service. The dewatering pumps are an integral part of FortisBC safety and isolation procedures. The pumps and piping are original vintage and have deteriorated from corrosion and wear of components.

This project is required to address the reliability of the dewatering system and to maintain the generating capability of FortisBC's hydroelectric units. The estimated expenditure for this project is $233,000 in 2009.

Upper Bonnington & Corra Linn Deluge Valves

The deluge system is the Unit Fire Safety System that protects and limits damage to the rotor and stator in the event of a fire. In 2005 the failure of a deluge valve at Corra Linn resulted in water escape causing damage to the generator windings and rotor. This required significant expenditures to dry the unit. The follow up investigation recognized the need for an improved valve system to eliminate this risk. The upgrade will also reduce the risk of a false trip wetting down the rotor and stator assemblies.

This project is required to address equipment protection and to maintain the generating capability of the Upper Bonnington and the Corra Linn hydroelectric units. The estimated expenditure for this project is $50,000 in 2009.

Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm System Upgrade

This project is required to upgrade the oil detection capabilities in the plant dewatering sumps. The existing sump oil detection and alarm system is inadequate. Malfunction of the system and alarms have resulted in the unnecessary call-out of personnel. This project will improve the oil detection capabilities in the plant dewatering sump in order to prevent the possible discharge of oil into the Kootenay River as well as improve the reliability of the system reducing unnecessary call-out situations.

This project is required to address environmental concerns and to maintain the generating capability of FortisBC's hydroelectric units. The estimated expenditure for this project is $128,000 in 2009.

Lower Bonnington & Upper Bonnington Upgrade Spillway Gate Control Phase 1

This project involves the planning and engineering to upgrade the spillway gate controls at Lower Bonnington and Upper Bonnington. This includes the upgrade of the gate controls and gate telemetry for the System Control Centre (SCC). The existing controls are obsolete and unreliable, and contain asbestos. The function of the controls has become a concern with respect to employee safety and system reliability. This phase of the project will be used to develop a scope of work that will be submitted for regulatory approval as part of a subsequent Capital Plan.

This project is required to address employee and equipment safety and to maintain the generating capability of the Lower Bonnington and Upper Bonnington hydroelectric units. The estimated expenditure for this project is $40,000 in 2009.

Upper Bonnington & South Slocan Airwash Tank Rehabilitation

This project involves the rehabilitation of the corrosion control through the application of an epoxy coating on the airwash tank, fan housing and associated equipment at both Upper Bonnington and South Slocan. The airwash equipment is crucial in maintaining 100 percent production from the hydroelectric generating units during the summer season.

The corrosion coating of the mild steel components has failed in several areas. The exposed mild steel is very susceptible to corrosion from the moist air in the equipment environment. If left unchecked the corrosion will affect the equipment structural integrity and lead to an unscheduled shutdown of the system.

This project is required to maintain the generating capability of the Upper Bonnington and South Slocan hydroelectric units. The estimated expenditure for this project is $108,000 in 2009.

South Slocan Tailrace Gate Corrosion Control

This project involves the rehabilitation of the corrosion control on the tailrace gates through the application of an epoxy coating. The gates are a vital component of the generating unit operations and function as a prime safety barrier for workers performing maintenance on the unit. The existing coating has failed in several areas of the gates and this will eventually lead to structure component failure. Corrosion control will increase the reliability of the gate operation, preserve the gate structural soundness, ensure employee safety and will increase the lifespan of the gates by an additional 50 years.

This project is required to maintain the generating capability of the South Slocan hydroelectric units. The estimated expenditure for this project is $114,000 in 2010.

Queen's Bay Level Gauge Building Phase 1

The Queen's Bay level gauge building built in 1939 is located 30 kilometres north of Nelson and provides information regarding the lake levels on Kootenay Lake pursuant to International Joint

Commission operating orders. The level measurement devices enclosed within the top of the structure are accessed from the shore line using an elevated steel walkway. In 2006 the water level measurement device was upgraded and the structure received a general visual inspection. The structure was reported to be in good physical condition at the time however certain BC Building and Canadian Electrical Code deficiencies were identified. The scope of this project includes electrical upgrades, corrosion control, signage and a new security fence with a personnel gate to limit public access.

This project is required to maintain employee safety. The estimated expenditure for this project is $67,000 in 2009.

Upper Bonnington Unit 5 and Unit 6 Tailrace Gate Corrosion Control

This project involves the rehabilitation of the corrosion control on the tailrace gates through the application of an epoxy coating. The existing coating has failed in several areas of the gates and this will eventually lead to structural component failure. The gates are a vital component of the generating unit operations and function as a prime safety barrier for workers performing maintenance on the unit. Corrosion control will increase the reliability of the gate operation, preserve the gate structural soundness, ensure employee safety and increase the gate’s life an additional 50 years.

This project is required to address employee safety and to maintain the generating capability of the Upper Bonnington hydroelectric units. The estimated expenditure for this project is $139,000 in 2010.

Upper Bonnington Extension Trashrack Gantry Replacement.

This project involves the replacement of the trash rack cleaning gantry at Upper Bonnington Units 5 and 6. The existing system which was installed in 1939 has exceeded its expected service life. The wiring and controls are fabricated with asbestos materials. The DC power system is obsolete and spare parts are not available. The age and condition of the gantry makes it non-compliant with current crane standards. Reliability and safety concerns require that this equipment be replaced.

This project is required to address employee safety and to maintain the generating capability of the Upper Bonnington hydroelectric units. The estimated expenditure for this project is $417,000 in 2010.

Lower Bonnington Forebay Access Road and Intake Upgrade Phase 1 & 2

This project involves an upgrade to the Lower Bonnington forebay access road and an engineering assessment of the intake area. The existing gravel roadway is narrow and does not allow for safe travel as there is no protection from the steep shoulders to the river or from steep banks that are currently sloughing onto the roadway. There is also a large bluff near a railway crossing which reduces visibility. Ongoing safety concerns require that this roadway be upgraded. This project involves the improvement of sightlines at the railway crossing, widening where practicable, slope stabilization, road resurfacing, installation of protective barriers and an engineering assessment of the intake area. The road upgrade is scheduled for 2009 and the engineering assessment of the intake area is scheduled for 2010.

This project is required to address employee safety and to maintain the generating capacity of the Lower Bonnington hydroelectric units. The estimated expenditures for this project are $393,000 in 2009 and $102,000 in 2010.

Corra Linn Spillway Gate Isolation Study

The Corra Linn Dam was designed and constructed in 1932 with no provisions for spill gate isolation. The embedded components relating to the spillway gate guides have not received a complete inspection since the original construction. Condition assessments are good utility practice. The Canadian Dam Association Dam Safety 2007 Guidelines sections 3.5.4 and 3.5.5 indicate that formal inspections should be conducted on spillway gates and related hardware every five years. To enable a formal condition assessment and refurbishment, the spillway gate and guide system must be completely isolated. The scope of the 2009 portion of this project is to undertake the planning and engineering study to determine a suitable solution for isolation of the gate. Based on this study, the expenditures to acquire and install the recommended solution will be submitted for regulatory approval as part of a subsequent Capital Plan application.

This project is required to address employee safety and to comply with Canadian Dam Association Dam 2007 Guidelines and to maintain the generating capability of the Corra Linn hydroelectric units. The estimated expenditure for this project is $46,000 in 2009.

South Slocan Dam Rehabilitation Study

This project involves the planning and engineering to upgrade the South Slocan Dam. The scope of this project is to complete the planning and engineering estimates for filing with a subsequent Capital Plan application. It is anticipated that the construction work involving the concrete rehabilitation of the spillway dam will commence in 2012 and be completed in 2013.

Construction of the South Slocan plant was completed in 1929. The life expectancy of concrete surfaces varies according to the quality of concrete as well as weather and environmental conditions. Concrete must be monitored for weathering or spalling as the deterioration process accelerates once the topmost surface is compromised. Freezing of the water present in the topmost portions of the concrete pushes that layer away from the underlying concrete. Once the seal is broken and water is absorbed year after year, additional layers freeze and are pushed away. In subsequent seasons, concrete deteriorates rapidly. Ongoing monitoring and assessment is necessary so as to repair the concrete in a timely manner to minimize repair cost. The portions of concrete most at risk are those adjacent to the water level. During the early 1990s an engineering consultant produced a concrete rehabilitation report for the South Slocan dam spillway. As a result of that review approximately 50 percent of the spillway concrete surface was rehabilitated in the mid 1990s.

This project is required to address dam safety as well employee and public safety and to maintain the generating capability of the South Slocan hydroelectric units. The estimated expenditure for this project is $46,000 in 2009.

Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade

This project involves the replacement of the existing obsolete PSI Quad 4 power meters used for generator revenue metering, with PML-7650 meters. Repair of the PSI meters is difficult as replacement parts are not readily available. The PML meters have been installed at most FortisBC transmission and distribution substations and are now the standard for FortisBC revenue metering. This project is required to ensure generation delivery is accurately recorded. The estimated expenditure for this project is $212,000 in 2010.

Lower Bonnington & Upper Bonnington Communication Network Completion

This project involves the completion of the communication networks at the Lower Bonnington & Upper Bonnington plants. It includes the removal of the obsolete System Control and Data Acquisition ("SCADA") Remote Terminal Unit ("RTU") and installation of the Schweitzer SEL 2030 communication processor and common software platform for the Human Machine Interface program. As a result this project will improve communication and data exchange between the plants and SCC and resolve the alarm time stamp errors. The communication processors will enable all the protection relays to be programmed and monitored from one central location. The Schweitzer SEL 2030 has been installed at most FortisBC transmission and distribution substations and this is now the consistent application for FortisBC protective relaying installations.

This project is required to maintain the generating capability of the Lower Bonnington and Upper Bonnington hydroelectric units. The estimated expenditures for this project are $95,000 in 2009 and $297,000 in 2010.

3. Transmission and Stations

The 2009 and 2010 capital requirements for Transmission and Distribution follow the direction of the 2005 SDP which was completed and filed with the Commission in 2004. The 2006 SDP Update was filed on August 16, 2005. The 2007 SDP Update was filed on July 26, 2006. The 2009 SDP Update accompanies this 2009\10 Capital Plan.

The 2005 SDP was a comprehensive plan including protection and control facilities, communication facilities plus analysis of the maintenance requirements. The 2005 SDP included a long-term (20 year) study of the transmission system, a shorter (5 year) study for the distribution system, a review of the maintenance programs and a detailed assessment of all lines and equipment.

The 2009 SDP Update is based on the peak loads experienced in the past few years and expected load growth identified in the substation load forecast. It identifies necessary reinforcements and upgrades to the bulk transmission system, the regional transmission and distribution systems, the telecommunications and SCADA networks, and protection systems owned and operated by FortisBC.

The Okanagan region consisting of the Kelowna, Penticton, Oliver, Osoyoos and Princeton areas continues to experience robust customer growth, most notably in the Kelowna area. In its 2005 SDP the Company expressed concern regarding the reliability of supply to the City of Kelowna and proposed that an N-1-1 reliability planning criteria would be appropriate. The 2007 SDP Update recognized this need and outlined a transmission system development program to meet both the increasing loads in the Okanagan area and the level of reliability expected in large urban environments. A CPCN Application was filed on December 14, 2007 for this multi-year project which is referred to as the Okanagan Transmission Reinforcement (“OTR”) project. An oral public hearing for this project was held on June 23 and June 24, 2008. The 2005 SDP also identified areas where continued load growth warranted additional transformer capacity. In additional to capacity increase projects approved in previous Capital Expenditure Plans, a transformer addition is required at the Recreation Substation in Kelowna in 2010 to meet forecast load.

The Kootenay and Boundary areas including Castlegar, Grand Forks, Kaslo, Crawford Bay, Creston, Slocan and Trail, have lower forecast load growth than the Okanagan Region. At Tarrys Substation cumulative load growth over the past few years has necessitated a minor addition in 2009.

A complete review of the maintenance plans and equipment condition was undertaken as part of the 2005 SDP. The 2005 SDP documents both the age and condition of the facilities and recommends capital spending levels to adequately maintain the safety and reliability of the system. The recommended levels are based on a combination of condition based analysis and criticality of facilities.

The completion of these transmission and substation projects supports the Provincial Government's energy objectives. In particular the objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

The projects also support the Policy Actions outlined in the Energy Plan. In particular Policy Action:

(12) 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.

Table 3.1
Transmission and Stations Projects

		Previously Approved	CPCN Filed	Expenditures to Dec 31\08(1)	2009	2010	Future(2)	Total
1	**GROWTH**			**($000s)**				
2	Ellison Distribution Source	C-4-07		15,434	1,734			17,168
3	Black Mountain Source	C-7-07		9,913	4,517			14,430
4	Naramata Substation	G-124-07		3,562	3,962			7,524
5	Okanagan Transmission Reinforcement		Dec 14, 2007	18,250	65,265	57,893		141,408
6	Ootischenia Substation	C-10-07		7,702	389			8,091
7	Benvoulin Substation		Q3 2008	1,200	2,930	13,554		17,684
8	Recreation Capacity Increase				178	3,401		3,579
9	Kelowna Distribution Capacity Requirements				518	517		1,035
10	Tarrys Capacity Increase				403			403
11	Huth Substation Upgrade					413	3000	3,413
12	30 Line Conversion				4,500			4,500
13	Static var Compensators					400		400
14	**SUBTOTAL GROWTH**			**56,061**	**84,396**	**76,178**	**3,000**	**219,635**

Table 3.1 cont'd
Transmission and Stations Projects

		Previously Approved	CPCN Filed	Exp. to Dec 31\08[1]	2009	2010	Future [2]	Total
15	**SUSTAINING**					($000s)		
16	**Transmission**							
17	Transmission Line Urgent Repairs				288	293		
18	Right-of-Way Enhancements				311	345		
19	Right-of-Way Reclamation				550	602		
20	Transmission Pine Beetle Hazard Allocation				1,218	821		
21	Transmission Line Condition Assessment				427	496		
22	Transmission Rehabilitation				1,639	1,888		
23	Switch Additions					132		
24	20 Line Rebuild				1,943	1,540		
25	27 Line Rebuild				648	642		
26	30 Line Lake-Crossing Rebuild					350		
27	**Stations**							
28	Station Condition Assessment & Minor Projects				620	680		
29	Ground Grid Upgrades				572			
30	Station Urgent Repairs				473	448		
31	Bulk Oil Breaker Replacement					292		
32	Transformer Load Tap Changers Oil Filtration Project				32	64		
33	Slocan City-Valhalla Substation Upgrade				2,173			
34	Passmore Substation Upgrade					1,987		
35	Pine Street Substation – Distribution Breaker Replacement				345			
36	Princeton Substation Distribution Recloser Replacement					1,513		
37	Joe Rich Transformer Protection Upgrade					404		
38	Creston Substation Protection Upgrade				488			
39	**SUBTOTAL SUSTAINING**				**11,727**	**12,497**		**24,224**
40	**TOTAL**			**56,061**	**96,123**	**88,675**	**3,000**	**243,859**

(1) Future expenditures for ongoing sustaining programs have not been included in this table.

(2) All forecast figures are based on forecasts as of April 30, 2008.

Listed below are further details of the projects contained in the 2009\10 Capital Plan.

TRANSMISSION AND STATION GROWTH PROJECTS

Ellison Distribution Source

This project which was approved by Commission Order C-4-07 involves the construction of a substation in the north end of Kelowna. The northern portion of Kelowna experienced rapid growth in the 2004-2007 timeframe, creating a capacity shortfall with the existing distribution supply. A CPCN Application was filed on October 26, 2006 to construct a new substation in the area between Sexsmith and Duck Lake Substations to meet the forecast distribution demand and to partially offload these stations. Approval for expenditures of $17.19 million was received in Order C-4-07 on May 10, 2007. The current estimate and schedule for this project is shown below.

Ellison Distribution Source (Ellison Project)

Year	To Dec 31 2008	2009	Total
Cost ($000s)	15,434	1,734	17,168

Black Mountain Distribution Source

This project involves the construction of a distribution source substation approximately 5 kilometres east of the Hollywood Substation and 5 kilometres south of FA Lee Terminal station in the Black Mountain area of Kelowna. The project also involves the construction of a transmission line tie and the necessary distribution feeder connections to tie the substation into the existing distribution network. As outlined in the CPCN Application filed on December 19, 2006 the need for this project is driven by several distinct factors as noted below:

- additional capacity to meet load growth;
- existing risk to the bulk power supply in the Kelowna area, where the FA Lee Terminal station power transformer tertiary windings are being used to supply significant and growing distribution load;

- the confluence of transmission lines at the emerging load center;
- the backup capability for Hollywood Substation creating an increased risk of a longer than acceptable outage for customers in the event of equipment failure; and
- a need to reduce the increased reliability exposure that will be created upon completion of the Big White Project.

A CPCN Application was filed on December 19, 2006 and approval for expenditures of $14.43 million was received by Commission Order C-7-07 on July 9, 2007. The current estimate and schedule for this project is shown below.

Black Mountain Source (Black Mountain Substation Project)

Year	To Dec 31 2008	2009	Total
Cost ($000s)	9,913	4,517	14,430

Naramata Rehabilitation (Naramata Substation)

This project, originally approved by Commission Order G-52-05, involves the replacement of the Naramata substation as well as the equipment and station facilities, due to age-related deterioration. The new Naramata Substation project was planned for 2005\06 however difficulties acquiring an appropriate site have delayed the project completion to 2009. Following an oral public hearing to determine the substation site, approval for expenditures of $7.27 million was received by Order G-124-07 on October 12, 2007. The current estimate and schedule for this project is shown below. The primary reason for the increase is to address aesthetic issues.

Naramata Rehabilitation

Year	To Dec 31 2008	2009	Total
Cost ($000s)	3,562	3,962	7,524

Okanagan Transmission Reinforcement ("OTR")

This project is the subject of CPCN Application that was filed on December 14, 2007 and is an aggregate of several discrete but related projects that were previously identified in the 2005 SDP. The OTR is the umbrella project that includes the following list of 2005 SDP projects:

- Double Circuit 230 kV Vaseux Lake Terminal to RG Anderson Terminal;
- 230\161\138 kV Bentley Terminal Station;
- 230 kV Vaseux to Bentley;
- Kelowna Shunts; and
- Convert Existing Oliver to 138\63\13 kV Distribution Source Station.

This project is required to provide capacity and reliable service to the customers in the Penticton Summerland and Kelowna areas. It supports the Provincial Government's energy objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

It also supports the Energy Plan policy action:

(12) 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.

An oral hearing for the project is scheduled for June 23, 2008. The current cost estimate and schedule for this project is shown below

OTR Project

Year	To Dec 31 2008	2009	2010	Total
Cost ($000)	18,250	65,265	57,893	141,408

Castlegar Area Capacity Increase (Ootischenia Substation Project)

This project involves the construction of a new distribution source substation on the east side of the Columbia River in Ootischenia, together with the necessary transmission and distribution feeder facilities to tie the substation into the existing transmission and distribution network. The project is required to increase distribution capacity in the Castlegar and Blueberry areas. It will provide backup capability for existing Castlegar, Ootischenia, and Blueberry customers. A CPCN Application was filed on September 7, 2007 and approval for expenditures of $8.16 million was received by Commission Order C-10-07 on December 18, 2007. The current cost estimate and schedule for this project is shown below.

Ootischenia Substation Project

Year	To Dec 31 2008	2009	Total
Cost ($000s)	7,702	389	8,091

Benvoulin Substation

This project involves the construction of a distribution source substation in the central Kelowna area together with a transmission line connected to the existing 138 kV, 51 Line and the necessary distribution facilities to tie the substation into the existing distribution network. The need for a new substation in the south\central area of Kelowna is driven primarily by increasing demand. The growing load in the Kelowna area will overload the 28.0 MVA summer rated capacity of Hollywood Transformer 1 (T1) in the summer of 2009 and the winter rated capacity of 31.5 MVA of both Hollywood Transformer 3 (T3) and OK Mission Transformer 1 (T1) in the winter of 2010. In addition, the pace of growth has resulted in the inability of the stations to meet FortisBC backup criteria.

An analysis of various options concluded that a new distribution source substation in central\south Kelowna able to accommodate the forecast load growth at the Hollywood Substation, OK Mission Substation and DG Bell Terminal stations is the most viable solution for customer growth in the central\south Kelowna area.

This project is required to provide increased capacity and reliable service to customers in the central Kelowna area. It supports the Provincial Government's energy objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

It also supports the Energy Plan policy action:

(12) 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.

FortisBC expects to file a CPCN Application for this project in the third quarter of 2008. The current cost estimate and schedule for this project is shown below.

Benvoulin Substation Project

Year	To Dec 31 2008	2009	2010	Total
Cost ($000s)	1,200	2,930	13,554	17,684

Recreation Capacity Increase

This project is required to provide increased capacity and reliable service to customers in the central Kelowna area. It supports the Provincial Government's energy objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

It also supports the Energy Plan policy action:

(12) 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.

The project involves the purchase and installation of an additional 24\32\40 MVA transformer at the existing Recreation Substation. The distribution load served by the City of Kelowna by way of the Recreation Substation is growing at a rate greater than the system average. Several 20+ storey residential and commercial buildings have recently been proposed for this area. These proposals are in addition to several 10+ story residential complexes and numerous civic, commercial and institutional developments that have already been constructed or are in progress. The transformer currently at Recreation Substation is designed to deliver a maximum load of 31.5 MVA and based on current load projections for this station it is anticipated that the transformer demand will exceed capacity during the winter peak of 2010\2011 as shown in the table below.

Recreation Substation Load Forecast

	2007\08	2008\09	2009\10	2010\11	2011\12	2012\13	2013\14	2014\15
	kVA							
Summer	24,641	28,105	28,895	29,685	30,475	31,265	32,652	34,101
Winter	25,732	30,354	31,352	32,351	33,349	34,348	35,872	37,464

Two options were considered, load transfers to other substations and the addition of a second transformer. The option to transfer load is not feasible since it would result in capacity deficiencies at the other substations. The current cost estimate and schedule for this project is shown below.

Recreation Capacity Increase

Year	2009	2010	Total
Cost ($000s)	178	3,401	3,579

Kelowna Distribution Capacity Increase

As noted in the 2009 SDP Update, the peak load for the Kelowna area is forecast to increase by over 100 MW by 2012. While the Ellison, Black Mountain and the proposed Benvoulin substations will address immediate concerns, the increasing load will continue to place pressure on the distribution infrastructure in the area. It is anticipated that in addition to the distribution substations and transformers being added to the system as part of the 2009\10 Capital Plan, other capacity increases will be required in 2012 and beyond.

Funding for this project is required to conduct a detailed investigation and recommendation to provide a long term solution for capacity increases in the greater Kelowna area. This process will require expenditures of approximately $500,000 in each of 2009 and 2010.

The project is required to provide capacity and reliable service to the customers in the greater Kelowna area. It supports the Provincial Government's energy objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

It also supports the Energy Plan policy action:

(12) 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.

Tarrys Capacity Increase

This project is required to increase distribution capacity in order to service the load at Tarrys Substation near Castlegar.

This project involves the installation of cooling fans and regulators to increase the capacity of the Tarrys Substation. Tarrys is a single transformer substation that primarily feeds the Kalesnikoff Lumber Mill and has a nameplate capacity of 2.0 MVA without cooling, and 2.5 MVA with cooling. Currently there are no cooling fans installed. The peak load for this station in 2007 was 2.9 MVA causing the transformer to be overloaded. Several alternatives to address this issue were evaluated including:

- Rehabilitate an existing 5.6 MVA transformer for installation at Tarrys; or
- Install three 400 amp regulators and an electronic recloser on an adjacent substation feeder and salvage the Tarrys Substation; or
- Install cooling fans on the Tarrys transformer to increase the capacity and install three 200 amp regulators on an adjacent substation feeder for backup purposes.

An analysis determined that the option to install cooling fans on the Tarrys transformer is the least expensive. This project is planned for 2009 with forecast expenditures of $0.40 million.

Huth Substation Upgrade

This project is required to maintain service reliability for the growing customer base in the south Okanagan area.

The Huth Substation in Penticton, the three substations (Trout Creek, Summerland and West Bench) connected to it via 49 Line, and the RG Anderson Substation serve a population base in excess of 50,000 in the area along Okanagan Lake from Summerland in the north to Skaha Lake the south. The combined peak load for these substations is in excess of 40 MVA. Huth was constructed in the 1950s and has been modified many times over the years. The bus arrangement at this station does not meet FortisBC or general utility standards and is considered "non-standard". At the present time Huth Substation is connected to the RG Anderson Substation in Penticton via 52 Line and 53 Line, and to Oliver Substation in the south via 42 Line. The circuit arrangements at Huth are such that the three lines cannot be operated in parallel. The substation is normally operated with either 52 Line or 53 Line closed and 42 Line open. When the circuit that is serving Huth is subject to an unplanned outage, crews must be dispatched to reconfigure the 63 kV supply to the substation requiring approximately two hours to reconfigure the system and to restore power. A two hour interruption to a population base of approximately 50,000 is considered unacceptable. This project will upgrade the 63 kV facilities at Huth Substation. It involves the installation of three termination towers and circuit breakers, a rearrangement of the existing 63 kV bus work and an upgrade to the circuit protection to provide necessary circuit coordination. A complete ring bus alternative was considered and rejected primarily because the extra cost did not justify the small increase in reliability that would have been gained. Instead, the recommended option is to modify the existing bus arrangement to convert it into a typical single-bus configuration with two source lines (operated in parallel) and five load breakers (two local transformers and three transmission lines). The recommended alternative meets all of the current FortisBC transmission planning criteria and the modifications are consistent with a long-term 63 kV sub-transmission development between Oliver and RG Anderson. Essentially both Oliver and Huth Substations will be supplied by two 63 kV lines each with 42 Line as a tie between the two substations. Overall area reliability and capacity will increase as a result.

This project was originally identified as part of the 1998 System Development Plan and subsequently scheduled to be completed in 2010 as part of the 2005 SDP Plan. The construction of this project requires 41 Line and 42 Line to be out of service. However the completion of the OTR project requires that 76 Line be out of service. Outages on 41 Line or 42 Line at the same time as an outage on 76 Line increases the risk of interruptions to customers in this area. Consequently the Huth Substation Rebuild Project is rescheduled to 2011 following the completion of the OTR with the planning and engineering scheduled for 2010.

The current estimated cost and schedule for this project is shown below.

Huth Substation Upgrade

Year	2010	2011	Total
Cost ($000s)	413	3,000	3,413

30 Line Conversion and the installation of Capacitors at Coffee Creek and Kaslo

This project is required to maintain service reliability for the customers in the Kaslo, Ainsworth, and Crawford Bay areas.

The project involves the installation of 63 kV breakers at Coffee Creek and Crawford Bay substations; the installation of capacitors at Kaslo and Coffee Creek substations; and the removal of 161 kV equipment at South Slocan, Crawford Bay, and Coffee Creek Substations.

The central Kootenay area consists of the north-west area (Coffee Creek, Kaslo, Ainsworth and Crawford Bay) supplied by a 161 kV transmission line (30 Line) from South Slocan; and the south-east area (Creston and Wynndel) supplied by a 230 kV transmission line (BC Hydro 2L294) via Lambert Terminal station. Until recently, 30 Line was also connected to BC Hydro (Kimberley) via a Teck Cominco owned portion of 30 Line. This provided a backup source of supply for the north-west area in the event of an outage on 30 Line anywhere between South Slocan and Coffee Creek.

This backup supply is no longer available due to the decommissioning of the Teck Cominco line. However, system studies have confirmed that with adequate reactive compensation at Coffee Creek and Kaslo, if 30 Line was converted to 63 kV, the loads at Crawford Bay Terminal, Coffee Creek Terminal and Kaslo Substation can be served from Lambert Terminal station via 32 Line and the lake crossing segment of 30 Line in the event of an outage on 30 Line between South Slocan and Coffee Creek.

Several options were reviewed to address this issue. These include:

Remove the 161 kV transformers from Coffee Creek, South Slocan and Crawford Bay, install 63 kV breakers at Coffee Creek and Crawford Bay, and install capacitors at Coffee Creek and Kaslo; or

Remove the 161 kV transformers from Coffee Creek, South Slocan and Crawford Bay, install two 63 kV breakers and a ring bus at Coffee Creek and one 63 kV breaker at Crawford Bay, and install capacitors at Coffee Creek and Kaslo; or

Do not convert, but replace deteriorated transformers at Coffee Creek and Crawford Bay.

A review of the options indicate that conversion to 63 kV is preferred since it cancels the need to replace deteriorated transformers at Coffee Creek and Crawford Bay and removes a significant amount of non standard (161 kV) oil filled equipment from the system consequently reducing environmental as well as reliability risk. Option 1 is preferred over Option 2 since it provides similar benefits at a lower cost.

This project is planned for completion in 2009 with forecast expenditures of $4.50 million.

Static var Compensators (SVC) Kelowna

As discussed in the 2005 SDP and in the OTR CPCN Application, FortisBC requires the installation of a 150 Mvar SVC at the DG Bell Terminal in 2011 to provide reliable service.

In addition to the transmission limitations identified in the OTR CPCN Application, the lack of dynamic reactive compensation facilities in the Okanagan for Terminal Station loads north of Vaseux Lake, results in power delivery constraints under various scenarios. In the event of a contingency, (both during and after a fault has occurred) there can be a significant voltage change in the system leading to total voltage collapse. Provision of dynamic reactive support, which is an instantaneous injection of reactive power provided by a SVC, assists in restoring the system voltage and avoiding a voltage collapse.

The installation is required to maintain the N-1 and N-1-1\N-2 capacity that will be provided by the OTR project. Given the current scope of the OTR project, the SVC will be required to continue to satisfy the N-1-1\N-2 criterion when the Terminal loads for Kelowna and Penticton exceed 430 MW. In the 2005 SDP the load was forecast to exceed this level in 2010\2011. The current update shows this load level being exceeded in 2008\2009.

To meet the N-1 criterion the SVC needs to go into service when the load is approximately 562 MW. The load is forecast to exceed this level in 2013\14.

The project is required to provide reliable service to the customers in the greater Kelowna area. It supports the Provincial Government's energy objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

It also supports the Energy Plan policy action:

(12) 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.

The estimated expenditures of $400,000 shown in 2010 are necessary to conduct the preliminary work to define the scope of the project, prepare detailed estimates and to obtain regulatory approval.

SUSTAINING PROJECTS

Transmission Line Sustaining Projects

FortisBC has approximately 58 transmission lines consisting of approximately 1,600 kilometres of line and 16,000 poles. Approximately 65 percent of these lines are more than 30 years old. Some, including 20 Line and 27 Line, are in excess of 75 years old. The transmission line sustaining projects are required for rehabilitation and ongoing upgrades of the transmission system to ensure safe, reliable service.

Transmission line sustaining programs and projects planned for 2009\10 are listed in Table 3.2 below and described in more detail following.

Transmission Line Sustaining Projects

		2009	2010
		($000s)	
1	Transmission Line Urgent Repairs	288	293
2	Right-of-Way Easements	311	345
3	Right-of-Way Reclamation	550	602
4	Transmission Pine Beetle Hazard Allocation	1,218	821
5	Transmission Condition Assessment	427	496
6	Transmission Line Rehabilitation	1,639	1,888
7	Switch Additions		132
8	20 Line Rebuild	1,943	1,540
9	27 Line Rebuild	648	642
10	30 Line Lake-Crossing Rehabilitation		350
11	**Total**	**7,024**	**7,109**

Transmission Line Urgent Repairs

The urgent repair project is required to replace transmission line facilities that fail in service due to severe weather, vandalism or other unexpected reasons. The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The estimate for this project is based on historical information adjusted for inflation, however in recognition of the rebuild of 32 Line in 2007, and the proposed rebuilds of 20 Line and 27 Line, the estimate for 2009 and 2010 has been reduced by approximately $50,000 per year. The following table shows the expenditures for the past four years as well as plan for 2009 and 2010.

Transmission Line Urgent Repairs

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	268	347	351	312	288	293

Right-of-Way Easements

This project is required for acquiring rights-of-way and easements for power systems that cross over customer property. This project is to obtain easements to address existing trespass situations. Easements for new projects are obtained as part of the new project and are not included in this estimate. Expenditures will also address access issues with respect to existing rights-of-way. Many of the transmission lines have no road access to sections of the right-of-way. Access is required for operation and maintenance of these lines. The estimate for this project is based on historical information adjusted for inflation. The following table shows the expenditures for the past four years and plan for 2009 and 2010.

Right-of-Way Easements

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	360	223	332	350	311	345

Right-of-Way Reclamation

The reclamation project is required to allow FortisBC to remove trees and expand the tree-free zone around the transmission lines. The expanded tree-free zones increase clearances improving both safety and reliability of the transmission system. The trees included are those that FortisBC can economically remove versus cycle trim or brush.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers

The estimate for this project is based on historical information adjusted for inflation. The 2007 costs include expenditures for the Mountain Pine Beetle Hazard which have been removed from 2008-2010 for forecasting purposes. The following table shows the expenditures for the past four years and plan for 2009 and 2010.

Right-of-Way Reclamation

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	443	421	821	359	550	602

Right–of-Way Reclamation - Pine Beetle Kill Hazard Trees

This project involves the removal of hazard trees killed by the Mountain Pine Beetle ("MPB") that have a high probability of falling directly onto energized distribution and transmission lines. This issue was first addressed in the Company's 2008 Revenue Requirements Application. As noted on page 7 of BCUC Order G-147-07 "FortisBC and the Participants hold differing views on the treatment of removal costs for Pine Beetle Kill. The Parties agree that the 2008 removal costs will be recorded in a rate-base deferral account, amortized over 10 years, without prejudice to the treatment of future expenditures". Pursuant to this order the Company files the 2009 and 2010 forecast expenditures for Right–of-Way Reclamation - Pine Beetle Kill Hazard Trees project as part of its 2009\10 Capital Expenditure Plan Application.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

Recent consecutive mild winters have accelerated the MPB infestation within the FortisBC service area. Provincial infestation concentration maps for 2001 and 2006 show that MPB infestation has spread from the north central region of the province into the southern reaches of the province. Concentrations of MPB infestation are now very evident in the FortisBC service territory and are certain to increase in severity. The cost to eliminate hazard trees killed by the MPB has increased accordingly. This was recognized in the FortisBC 2007-2008 Capital Expenditure Plan Application, page 79, and also in the Preliminary 2008 Revenue Requirements Application Tab 7, page 17.

Trees that have been attacked by the MPB will deteriorate quickly, losing stem wood strength. BC Hydro experience indicates that dead stem wood is failing much quicker than anticipated and that Ponderosa pine is failing quicker than Lodgepole pine.

When trees identified within this program fail, they have a high probability of falling directly onto energized lines. The size of tree involved can break conductors, insulators, cross-arms and possibly even the poles themselves. Risks include:

- Downed conductors remaining energized and creating an electrical contact situation;
- Risk of fire due to arcing and ignition of the tree and surrounding foliage even if the conductor does not break; and
- The impact on reliability of an outage which at a minimum requires a line patrol to visually locate the fallen tree and clear it, and may require replacement of damaged components.

The following table shows the forecast expenditures for 2008 and plan for 2009 and 2010.

Transmission Right-of-Way Reclamation - MPB Kill Hazard Trees

Year	To Dec 31 2008	2009	2010
Cost ($000s)	1,500	1,218	821

Transmission Line Condition Assessment

The transmission line assessment program is based on an eight-year cycle of patrolling and testing all FortisBC transmission line facilities. The program consists of a pole-testing program involving drilling test holes in each pole to confirm the condition of the pole, addition of a pole treatment to reduce internal rot in the pole, and placement of a pole wrap to reduce surface rot on the pole at ground line.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The program extends the life of the pole and ensures the integrity of the lines as well as employee and public safety. The program is managed in an eight-year cycle to levelize both the budget and the resources required. The condition assessment project will include the following lines in 2009 and 2010.

Table 3.2(a)
Transmission Line Condition Assessment Projects 2009

	Line	Location	Poles
1	1	Warfield to Stoney Creek	15
2	25	Slocan to Playmor to Tarrys to Brilliant	299
3	29	Slocan Valley	140
4	31	Lambert to Creston	105
5	30	Coffee Creek to Crawford Bay	26
6	50	FA Lee to Sexsmith to Glenmore to Recreation to Saucier	320
7	49	Huth to West Bench to Trout Creek to Summerland	310

Table 3.2(b)
Transmission Line Condition Assessment Projects 2010

	Line	Location	Poles
1	41	Huth to Waterford to Kaleden to OK Falls to Oliver	580
2	42	Huth to Waterford to Kaleden to OK Falls to Oliver	420
3	45	RG Anderson to Westminster to Naramata	290
4	45A	45 Line to Downtown Penticton	48
5	46	FA Lee to Duck Lake	87
6	47	Huth to Waterford	50

The following table shows the expenditures for the transmission line condition assessment project for the past four years as well as plan for 2009 and 2010. The estimates are based on historical information adjusted for inflation and knowledge of the transmission lines being assessed.

Table 3.2(c)
Transmission Line Condition Assessment

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	57	248	152	845	427	496

Transmission Line Rehabilitation

The specific rehabilitation projects for various transmission lines involve expenditures for structural stabilization of the defects identified for rehabilitation in previous years' assessments. Included in the scope of work is stubbing of poles, replacement of cross-arms and poles, maintenance of structures, insulator changes and guy wire changes.

In 2009 and 2010 the Company will undertake rehabilitation on the transmission lines that will have been assessed in 2008 and 2009 respectively.

This project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The following table shows the expenditures for the transmission line rehabilitation project for the past four years as well as planned for 2009 and 2010. The estimates are based on historical information adjusted for inflation and knowledge of the transmission lines being assessed.

Transmission Line Rehabilitation

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	3,468	993	336	3,443	1,639	1,888

Switch Additions

This project is required to improve service reliability to customers in the Castlegar area.

This project involves the addition of motor operators and remote control to the existing 63 kV switches on 6 Line and 26 Line at Castlegar Substation in 2009. Castlegar is normally supplied by either 6 Line or 26 Line. At the present time if the normal supply line is forced out of service for any reason, a call-out is placed to a power line technician who must physically go to the site and operate the switches to transfer the station to the other transmission line. With remote operated motorized switches, the switching function can be performed immediately by the SCC, minimizing outage duration to customers.

The estimated cost of this project is $132,000 in 2010.

20 Line Rebuild

This project is required to maintain service reliability for the customers in the Trail, Waneta, Montrose, Fruitvale and Salmo areas.

The 20 Line is a 63 kV circuit that was constructed in 1931. It is approximately 46 kilometres in length, and runs from Warfield Terminal Station to distribution substations at Glenmerry, to Beaver Park, to Fruitvale, to Hearns, to Salmo, and includes three phase distribution underbuild (in particular from Beaver Park to Salmo) along much of its length. The Beaver Park to Salmo section is also primarily along road and highway rights-of way and is in close proximity to the tree line. A large percentage of the outages have been a direct result of tree related contacts. There have been some structure changes to the line over the years; however the conductors themselves have had only selected change-outs or re-conductoring in small portions. During the last 30 years, there has been considerable focus on keeping the lines “functional” and not necessarily improved or upgraded.

In 2007\08 a detailed engineering assessment was conducted on the line. The engineering assessment was undertaken to address the concerns and issues with respect to the line problems that have been experienced over the past several years, as well as to bring a consolidated approach to the options and alternatives for rehabilitation work to achieve a more reliable system. The assessment concluded that in general the circuit is in relatively poor condition with numerous steel stubbed structures and conductor splices, particularly within the original copper conductor sections. It recommended that an extensive rebuild of 20 Line be undertaken in order to maintain its integrity. The report considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centers, however these were eliminated as not being feasible. The current cost estimate and schedule for the project is shown below.

20 Line Rebuild

Year	2009	2010	Total
Cost ($000s)	1,943	1,540	3,483

27 Line Rebuild

This project is required to maintain service reliability for the customers in the Nelson, Whitewater, Ymir and Salmo areas.

The 27 Line is a 63 kV circuit that was constructed in 1930. It is approximately 57 kilometres in length and runs from Corra Linn (COR) to Rosemont Switching Station (RSM) to Cottonwood (COT) to Ymir (YMR) to Salmo (SAL). 27 Line has a variety of configurations consisting primarily of three phase and single phase distribution underbuild, as well as some single circuit transmission with no underbuild. The line has many sections with significant setback from the highway and is generally on its own separate right-of-way. As with 20 Line, there have been some structure changes to the line over the years; however the conductors themselves have had only selected change-outs or re-conductoring in small portions. During the last 30 years, there has been considerable focus on keeping the lines “functional” and not necessarily improved or upgraded.

In 2007\08 a detailed engineering assessment was conducted on the line. The engineering assessment was undertaken to address the concerns and issues with respect to the line problems that have been experienced over the past several years, as well as bring a consolidated approach to the options and alternatives for rehabilitation work to achieve a more reliable system. The assessment concluded that in general the circuit is in relatively poor condition with numerous steel stubbed structures and conductor splices, particularly within the original copper conductor sections. An extensive rebuild of 27 Line is recommended in order to maintain its integrity. The report considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centers, however these were eliminated as not being feasible. The current cost estimate and schedule for this project is shown below.

27 Line Rebuild

Year	2009	2010	Total
Cost ($000s)	648	642	1,290

30 Line Lake-Crossing Rehabilitation

This project is required to maintain service reliability for the customers in the Kaslo\Ainsworth\Crawford Bay areas.

30 Line is a 161 kV line that connects Coffee Creek Substation to Crawford Bay Substation spanning Kootenay Lake. The lake crossing was first installed in the early 1950s and was rebuilt in 1962 after the towers were sabotaged. The crossing is an 11,300 foot span consisting of a 1.25 inch diameter 91 strand galvanized steel continuous cable. It is supported by steel lattice type towers anchored back using lattice works (integral to the tower) into concrete foundations. The crossing is marked using 66 inch diameter marker cones on each of the phases. The termination for each tower includes a conductor stress relief section that extends approximately 70 feet out from the deadends. This stress relief design is used to transition the termination stresses across 3 sets of conductors going into tower termination points and to also mitigate possible long term vibration issues. A comprehensive assessment consisting of a combination of detailed ground, bucket and helicopter inspections of the towers, insulation, conductor tower terminations, and related hardware that were accessible was completed in 2006. It identified a number of deficiencies that need to be addressed in order to maintain the long term integrity of the crossing. These are listed in the table below.

30 Line Lake Crossing – Deficiencies

TOWER	DEFICIENCY DESCRIPTION
West Side - Center Phase	Numerous insulator bells with grout checks and cracks
West Side - Center Phase	Paint overspray on insulation – more concentrated on cold end
West Side - South Phase	Numerous broken grounding wire strands on compression tension legs
West Side - South Phase	Paint overspray on insulation – more concentrated on cold end
West Side - South Phase	Numerous insulator bells with grout checks and cracks
East Side – North Phase	Jumper support wood poles have no recent pole tests completed on them
East Side – North Phase	Cold end of one insulator (south side) is missing clevis tongue to yoke plate
East Side – North Phase	Some old 5\8" hardware pins have old steel keys that are rusting
East Side – Center Phase	Connections to ground cable grid is made with split bolts – not preferred
East Side – Center Phase	Considerable paint overspray has occurred on jumper pole insulator string
East Side – South Phase	Center yoke joint cylinder has small crack – appears as a freeze expansion crack; but cannot be verified. Crack is approx 0.004 inch thick at widest point and shows up as small swelled "X"
East Side – South Phase	Numerous insulator bells with grout checks, cracks or pin separation from grout
General	Few 5\8 inch hardware pins have keys only partly inserted.
General	Numerous marker cones are missing and\or are damaged on each of the phases
General	Numerous 5\8 inch hardware pins showing signs of minor bending from tension applied

This project will address these deficiencies and is scheduled for 2010 at a cost of $350,000.

Station Sustaining Programs and Projects

The station sustaining projects involve the rehabilitation and ongoing upgrades of the substation system. These projects are necessary to ensure continuous service of the substation system which includes transformers, breakers, batteries, ground grids and related equipment.

These projects are required to maintain service reliability for customers, a safe work environment for employees and to address any environmental or public safety issues identified during the assessment process.

Table 3.3
Station Sustaining Programs and Projects

		2009	2010
		($000s)	
1	Station Assessments & Minor Planned Projects	620	680
2	Ground Grid Upgrades	572	
3	Station Urgent Repairs	473	448
4	Bulk Oil Breaker Replacement Program		292
5	Transformer Load Tap Changer Oil Filtration Project	32	64
6	Slocan City-Valhalla Substation Upgrade	2,173	
7	Passmore Substation Upgrade		1,987
8	Pine Street Substation –Distribution Breaker replacement	345	
9	Princeton Substation Distribution Recloser replacement		1,513
10	Joe Rich Transformer Protection Upgrade		404
11	Creston Substation Protection Upgrade	488	
12	**Total**	**4,703**	**5,388**

Station Assessments and Minor Planned Projects

The station condition assessment program reviews the environmental, safety and reliability issues at the Company's 64 transmission and distribution stations on a ten year cycle. Required work as indicated by the condition assessments is then planned for the following year as minor planned projects.

The station assessment and minor planned projects for 2009 and 2010 are listed below.

Replace DC Protection Systems at Various Substations

In 2009, the Company plans to initiate a program to replace DC batteries that have deteriorated to a state where the integrity of the system may be compromised. This is required to maintain service reliability for customers, a safe work environment for employees and to address potential environmental or public safety issues.

A DC system is required to operate substation protection and control equipment. The batteries supply these systems in the event of a power outage at the station. The protection and control equipment operates station breakers and switches and communicates vital information to the SCC regarding the status of system alarms and transformer monitoring devices. If the DC batteries were to fail the system control center would lose all visibility of the station and transformer condition alarms and switch\breaker status. In addition, station equipment cannot be operated, even by a crew onsite, until DC power is restored.

This project will include replacement of battery banks that meet the following criteria:

- Any gel type bank that has not been kept in a temperature controlled environment or is older than 10 years; and
- Any battery bank that tests below 70 percent of capacity or is older than 20 years.

Locations receiving new batteries will also receive an insulated temperature-controlled battery room to maximize battery life. The following substation DC supply will be updated in 2009 and 2010.

2009	**2010**
Glenmerry	Tarrys
Cascade	Glenmore
Playmor	Hollywood
	OK Mission

Replace Gap-Type Silicon Carbide Arrestors

In 2009, the Company plans to initiate a four year program to replace Gap-Type Silicon Carbide Arresters with industry standard Gapless Metal Oxide Varistor (“MOV”) Arresters. This is required to maintain service reliability for customers, a safe work environment for employees and to address potential environmental or public safety issues.

Surge arrestors are used to protect electrical equipment and other assets from lightning and switching surges that can damage equipment. There are two reliability issues involving gapped surge arresters, adequacy of protection and consequential damage resulting from in service failure. Gap-Type Silicon Carbide Surge Arresters have a higher rate of failure than Gapless MOV arresters. As well, research has shown that Gapless MOV Arresters provide substantially improved protection over Gap-Type Silicon Carbide Arresters. Replacement of aging and failing Gap-Type Surge Arresters will provide greater protection for existing assets from lightning and switching surges, and because of the potential for explosive failure of surge arresters, replacing the gapped arresters will also improve work site safety. The Company will replace arresters in approximately 20 locations in 2009 and 2010.

Stations Assessment and Minor Planned Projects

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	871	1,132	2,043	1,603	620	680

Ground Grid Upgrades

During the past few years the Company has undertaken ground grid assessments at various substations. The Ground Grid Upgrades Project is required to address grid deficiencies identified in these assessments. This is required to provide a safe work environment for employees and to address potential public safety issues.

Preliminary studies have concluded that under certain fault conditions the existing substation ground grid at Castlegar Substation does not provide safe step and touch potential inside the substation fence, but that it can be upgraded to the required standards. This will include the installation of a new ground grid, additional ground rods, new ground wells and an upgrade of the insulating gravel.

The following table shows the expenditures for this project for the previous four years as well as the planned expenditures for 2009 at Castlegar Substation.

Ground Grid Upgrades

Year	2005	2006	2007	2008F	2009
Cost ($000s)	182	393	160	446	572

Station Urgent Repairs

The urgent repair project is required to replace station equipment that fails in service due to severe weather, vandalism, or other unexpected reasons. The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. The estimate for this project is based on historical information adjusted for inflation. The following table shows the expenditures for the past four years and plan for 2009 and 2010.

Station Urgent Repairs

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	279	562	416	393	473	448

Bulk Oil Breaker Replacement Program

This program involves the replacement of worn or deteriorated bulk oil circuit breakers with modern SF6 breakers. It is required to address potential public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The Kootenay 12 MVA mobile substation circuit breaker will be replaced in 2010. The estimated cost for this project in 2010 is $292,000.

Transformer Load Tap Changers Oil Filtration Project

The operation of transformer load tap changers results in coke deposits on the contacts and switches. This is a result of the carbon deposits caused by arcing during the connection and disconnection of the contacts. The carbon resides in the oil until it saturates and then forms a high resistance path (coke) on the contacts causing heating and pitting of the contacts.

This project involves installation of permanent oil filtration systems on three tap changers in 2009 and 2010 as listed below. This will extend the life of the transformer and increase the cycle time to maintain the tap changer. This project is required to maintain reliable service to FortisBC customers.

The following transformers will be retrofitted in 2009 and 2010:

2009	2010
Summerland T2	Westminster T2
	OK Mission T1

Table 3.13 below shows the expenditures for the past four years and plan 2009 and 2010.

Oil Filtration Installations

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	119	81	191	278	32	64

Slocan City-Valhalla Substation Upgrade

This project is required to maintain service reliability for the customers in Slocan City and to minimize environmental risk associated with oil-filled equipment near domestic water supplies.

The Slocan City Substation is located approximately 30 meters from Springer Creek which drains into Slocan Lake. The substation site is adjacent to Springer Creek Forest Products Ltd. within the Village of Slocan. The substation was built to serve the mill and constructed on the mill property. The immediate area around the station is a mix of industrial, commercial and residential properties. The substation is located in the Springer Creek floodplain and the soil substrate is a mix of gravelly till.

The project, scheduled for 2009, involves the installation of a spare refurbished 10 MVA transformer at the Valhalla Substation, transfer of the Slocan City Substation load to the Valhalla Substation and the salvage of the Slocan City Substation transformer. The transformer at Slocan City is a 4.2 MVA unit that was purchased in 1965. It is in need of major repair since it is seeping oil in several locations. As indicated by maintenance test records, the transformer is nearing the end of its useful life. The substation is in an environmentally sensitive location and would benefit by a reduction in the amount of oil-filled equipment installed at the site. The Valhalla Substation, which was built in 2002, has adequate space for expansion and is located only one kilometre away from the Slocan City Substation. Based on the fact that the transformer needs to be replaced, the most feasible solution is to install the transformer at the Valhalla Substation to mitigate the environmental concerns. This project is planned for 2009 with forecast expenditures of $2.17 million.

Passmore Substation Upgrade

This project is required to maintain service reliability for the customers located along Highway 6 and through the communities of Slocan Park, Winlaw, Village of Slocan and Valhalla.

The project, scheduled for 2010, involves the expansion of the Passmore Substation to accommodate the addition of a circuit breaker on 19 Line as well as space for a mobile substation. The 63 kV transmission line (19 Line) which serves Passmore Substation is radial and also supplies the Village of Slocan and Valhalla Substations in the Slocan valley. The transmission line north of the Passmore Substation follows the highway in a very tight corridor and has a high outage rate. With the current configuration of the line, an unplanned outage anywhere on the line will cause the entire circuit to trip off as the only line protection is located at the source (South Slocan Generating station). This can cause unnecessary outages to the Passmore Substation customers. The breaker addition on the north side of the Passmore Substation will prevent the majority of transmission outages to the north of the station from affecting the Passmore customers, and further improve reliability by improving restoration switching. This project is planned for 2010 with forecast expenditures of $1.99 million.

Pine Street Substation –Distribution Breaker Replacement

This project is required to address potential employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers in the town of Oliver.

The project involves the replacement of the air-blast “arc chute” breakers at the Pine Street Substation. These breakers were installed in 1967 and have reached the end of their service life. As parts for the units are no longer available, replacement of failed or deteriorated parts is achieved by custom machining. Due to the age and condition of these breakers there are safety hazards associated with operating the equipment and putting the units back into service after maintenance. Personal Protective Equipment (PPE), such as a flash suits are required by employees who operate this equipment. Failure of the breaker also risks damage to station equipment with the potential to damage public and private property and an increased risk of injury to persons external to the substation.

Due to ongoing issues of reliability and safety, all other air-blast "arc chute" breakers (with the exception of Fruitvale which is planned for the 2011 timeframe) have been replaced. Replacement of these units is deemed necessary to provide increased reliability and safety. This project is planned for 2009 with forecast expenditures of $345,000.

Princeton Substation Distribution Recloser Replacement

This project is required to address potential public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers in the Princeton area.

The project involves the replacement of the distribution circuit reclosers at the Princeton Substation with circuit breakers of adequate capacity to interrupt the calculated fault current that could occur during fault conditions.

The increase in capacity at the Princeton Substation in recent years has also increased the calculated fault current level to 9 kA. This is the available fault current that all 13 kV equipment within the substation must be capable of interrupting without damaging any components. The interrupting capacity of the reclosers at Princeton Substation is listed in the table below. FortisBC protection standards require that the calculated available fault levels must be no more than 80 percent of the equipment fault interrupting rating. This is to allow for potential variations from the calculated value as well as future growth in the area. As can be seen from the table below, four of the units fail to meet protection requirements. Failure of the reclosers poses a risk of damage to station equipment, the potential to damage public and private property, and an increased risk of injury to persons external to the substation.

Manufacturer	Model	Year	Rating
McGraw-Edison	CWE	Pre 1965	10 kA
McGraw-Edison	WS	Pre 1965	10 kA
McGraw-Edison	VSA	Undetermined (2000)	12 kA
Kyle	WE	1991	10 kA
Kyle	WE	1991	10 kA

The replacement breakers will be rated to match the existing circuit breakers currently at Princeton (fault interrupting rating of 25 kA) or to meet existing engineering standards. Three of the replaced units will be retained for use at other locations.

Replacement of these units is deemed necessary to provide increased reliability and safety. This project is planned for 2010 with forecast expenditures of $1.51 million.

Joe Rich Transformer Protection Upgrades

This project is required to maintain service reliability for the customers in the Joe Rich area, southeast of Kelowna, and to minimize public and employee safety issues associated with transformer failure.

In 2010 the Company plans to upgrade the protection on the 20 MVA Joe Rich Transformer 1 which is currently equipped with high side fuses. This is the only 138 kV transformer in the FortisBC system protected by high side fuses. This initiative is undertaken to:

1. Minimize the risk of transformer damage and potential risk to employees, public and the environment that may result from transformer failure;
2. Provide customer service and to maintain service reliability; and
3. To comply with FortisBC standards which have been developed in conjunction with industry practice and IEEE guidelines.

The primary guiding principle for all protection systems is to provide fast and secure detection and clearing of faults within a protection zone. Fusing and relaying are the two primary protection alternatives for distribution power transformer protection.

The main advantages of fuses are that they are low cost and that they require no DC power supply, however, they have numerous disadvantages including:

- Poor coordination with upstream transmission line protection;
- No power transformer overload protection;
- Poor backup for downstream devices;
- Very long (typically > 3 seconds) clearing times for low-voltage bus faults;
- Single-phasing and unbalanced distribution voltages when only one HV fuse blows; and
- Aging from downstream fault events resulting in fuse failure and unnecessary outages.

The preferred protection for transformers is by differential relaying, however, this is a higher cost option due to the requirements for a high-voltage fault interrupting device and a DC battery supply. The main advantage of relay protection is that it provides near instantaneous clearing for faults located anywhere between the high-voltage bus and the low-voltage feeder breakers. The high-speed operation increases personnel safety and reduces equipment damage as tripping times are reduced from values typically greater than three seconds down to approximately 0.2 seconds.

The following excerpts are taken from the IEEE standard C37.91-1995 "Guide for Protective Relay Applications to Power Transformers":

> "[Fuses] provide limited protection for internal faults. Generally, more sensitive means for protection from internal faults are provided for transformers of 10 MVA and higher." (Section 5.1)

> "Current-differential relaying is the most commonly used type of protection for transformers of approximately 10 MVA (self-cooled rating) and above." (Section 5.2)

In the interests of balancing economics with protection the following substation protection standards have been adopted by FortisBC:

High-Voltage Bus and Transformer Protection

Protection for 6\8 MVA transformers:

- High-voltage fuses

Protection for 12\16\20 MVA and 24\32\40 MVA transformers

- High-voltage circuit breaker, circuit switcher or fault-throwing switch with trip inputs from protective relays.

In 2010 the high side fuse T1-F on the 20 MVA Joe Rich transformer will be replaced with a breaker and protective relays at an estimated cost of $404,000.

Creston Substation Protection Upgrade

This project is required to address employee safety issues and to improve service reliability for the customers in the Creston area.

The project consists of an upgrade of the fusing and protection at Creston Central Substation by installing circuit switchers and protection for each transformer. These devices will coordinate with the Lambert Terminal 63 kV protection scheme and eliminate potential nuisance trips to the Creston Central Substation. The project is required to address a number of deficiencies at the Substation. These include the following:

- Lack of protection coordination. At the present time a fault anywhere on the 63 kV line side of Transformer 1 or internal to Transformer 1 or Transformer 2 at Creston Central will trip 31 Line (the transmission line between Creston and Lambert) because the relay at Lambert senses the fault and clears it before the fuses have time to melt and isolate the system at Creston. This results in a complete station outage at Creston, even though the other non-faulted transformer is healthy. By installing circuit switchers the individual transformer protection will operate more quickly and protection coordination will be achievable.
- Transformer 2 cannot be picked up from a de-energized state without causing a station outage due to the location of the next upstream switching device. This causes unnecessary outages to customers in the Creston area. Replacing the fuses with circuit

switchers will allow Transformer 2 to be energized or de-energized without interfering with Transformer 1.

- Safe operation. The 69 kV fuses are currently mounted on a horizontal plane, and are difficult to operate due to their physical location and how close they are to the grounded transformer tank during switching. Circuit switchers will operate automatically\remotely and will be mounted in more appropriate location.

The project which is scheduled for 2009 is estimated at $488,000

4. Distribution

The 2009\10 Capital Plan for distribution consists of three major categories, Customer Connects, Distribution Growth and Distribution Sustaining.

Customer Connects involves projects to provide service to new customers. During the past few years, increasing economic development in the FortisBC service territory has resulted in significant growth in both the residential and commercial customer base.

The second category which is very closely linked to customer connects is designated Distribution Growth. The projects in this category are driven by normal load growth that over a period of time require capacity upgrades or additions to lines in order to meet legislated and industry standards.

The third category, Distribution Sustaining Projects includes those projects necessary to rehabilitate or upgrade distribution lines in order to ensure employee and public safety, and reliable customer service.

The completion of these distribution growth and sustaining projects supports the Provincial Government's energy objectives. In particular the objective:

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

It also supports the Energy Plan policy action:

(12) 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.

The following table shows the planned distribution expenditures for 2009 and 2010.

Table 4.1
Distribution Projects Expenditures

		Previously Approved	2009 Total	2010 Total
			($000s)	
1	**GROWTH**			
2	New Connects - System-wide		9,788	10,670
3	**Distribution Growth Projects**			
4	Glenmore -New Feeder		788	
5	Airport Way Upgrade Feeder			1,551
6	Hollywood Feeder 3- Sexsmith Feeder 4 Tie			365
7	Christina Lake Feeder 1 Upgrade		608	489
8	Beaver Park-Fruitvale Tie			1,227
9	Small Growth Projects			137
10	Unplanned Growth Projects		974	994
11	**TOTAL GROWTH**		**12,158**	**15,433**
12	**SUSTAINING**			
13	**Distribution Sustaining Programs and Projects**			
14	Distribution Line Condition Assessment		599	667
15	Distribution Line Rehabilitation		3,124	3,470
16	Distribution Right-of-Way Reclamation		621	646
18	Distribution Pine Beetle Hazard Allocation		722	551
19	Distribution Line Rebuilds		1,178	1,167
20	Small Planned Capital		668	747
21	Forced Upgrades and Line Moves		1,255	1,461
22	Distribution Urgent Repair		1,911	1,805
23	PCB Program	G-52-05	1,073	1,117
24	Aesthetic and Environment Upgrades	G-58-06	100	100
25	Copper Conductor Replacement Program	CPCN to be filed	4,798	6,586
26	**TOTAL SUSTAINING**		**16,049**	**18,317**
27	**TOTAL**		**28,207**	**33,750**

New Connects System Wide

This project includes the installation of new electric services requiring additions to FortisBC overhead and underground distribution facilities. These capital expenditures allow FortisBC to meet its obligations to provide reliable service to customers in the service area. This supports Energy Plan policy action:

(12) 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.

All costs except the transformer, drop service and metering equipment (as set out in Schedule 74 of FortisBC's Electric Tariff) are charged to the customer as a Contribution In Aid of Construction ("CIAC"). This project will also fund any "forced upgrade" costs associated with upgrading FortisBC facilities to provide service for the extension or drop service.

The cost of new connects is based on projected customer growth, average CIAC and historical forced upgrade costs.

The estimated expenditures for this project are $9.8 million for 2009 and $10.7 million for 2010.

DISTRIBUTION GROWTH PROJECTS

Capacity upgrades and line extensions are required periodically to keep pace with normal load growth on the distribution system and to ensure continuing acceptable standards of service. These service standards include operation of facilities at or below normal continuous thermal limits, voltage levels consistent with Canadian Standards Association ("CSA") recommended levels and short circuit levels in a range to allow for safe operation of the electrical system. Capacity increases must also be designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system.

The distribution feeder network is evaluated for capacity performance for the forecast load growth in each of the service areas. Utilizing load models, the network is tested for voltage, thermal loading, and backup capabilities during loss of supply. Where standards of service are not met, appropriate upgrade options are modeled and evaluated for performance improvement. The set of solutions used are load transfer, load balancing, voltage regulation, shunt capacitors, re-conductoring, line additions, load splitting and new source locations. Growth capacity increase projects also include new feeders to new load centers, which may cross un-serviced areas to provide a tie to an adjacent supply point if necessary**.**

For voltage, thermal loading, and short circuit level deficiencies the appropriate solution will be scheduled for completion in the year before the service standard is breached.

Requirements for backup performance are dependent on the nature of the service area. Typically supply arrangements are different between low density rural and high density urban centers. Rural areas usually have a single transformer supply point with one or two radial feeders. The feeders are expected to provide reciprocal redundancy, however, failure of the single supply transformer will result in an outage until mobile transformation is installed. Distribution systems in high density urban centers, such as the City of Kelowna, incorporate multiple transformer supply points with many interconnected feeders. Each feeder, after normal manual switching operations, will be backed up from a combination of adjacent feeders, and failure of any one supply transformer should be capable of being backed up through a combination of local and remote transformation after normal manual switching of interconnected feeders.

In high density urban areas, two transformer substations generally have a combined load above the rating of a single transformer. The excess load is expected to be transferred to an adjacent substation transformer during maintenance or failure of one of the two transformers. In this way, transformer capacities are more highly utilized while still maintaining backup standards. As such, feeder ties and capacity increases, which require a much lower capital investment than transformer capacity increases, are preferred to maximize utilization of existing transformation capacity.

As high density urban areas expand their perimeters new supply points are required to serve these new load centers. Feeders from existing supply points are first extended into those areas and will become part of the feeder network when the new supply point is built. This staged approach to development of a distribution network in this type of area provides optimum use of capital investment. This project includes several of these feeder extension projects, but the ultimate new supply substations are described in separate projects.

The following table lists the major Distribution Growth Projects planned for 2009 and 2010 and is followed by a description of each project.

Table 4.2
Distribution Growth Capacity Projects

	Project	2009	2010
		($000s)	
1	Glenmore - New Feeder	788	
2	Airport Way Upgrade Feeder		1,551
3	Hollywood Feeder 3 - Sexsmith Feeder 4 Tie		365
4	Christina Lake Feeder 1 Upgrade	608	489
5	Beaver Park-Fruitvale Tie Upgrade		1,227
6	**Total**	**1,396**	**3,632**

Glenmore - New Feeder

This project involves the installation of underground cables from the Glenmore Substation to the Spall Road\Dickson Avenue area. It is required to supply the necessary capacity to service new customers and to maintain reliable service to FortisBC customers.

The project consist of a new 750 MCM underground circuit installed underground from a breaker cell in the Glenmore station along Spall Road to Highway 97, west along Highway 97 to Kirschner Road, south on Kirschner to an existing overhead line. The approximate circuit length is 850 meters. The load in the Dickson Avenue, Kirschner Road, Highway 97, and Spall Road area is served by OK Mission Feeder 4 and Glenmore Feeder 1 which are currently peaking at 12.4 MVA and 12.6 MVA respectively. The maximum capacity of each individual feeder is 13 MVA. Developers in this area have plans to construct new office towers which will result in an additional load of 3 MVA by 2010. There is also a residential development of multi-family apartments on Dickson Avenue with an estimated load requirement of 1 MVA by 2010. Based on the load growth in this area, an additional feeder is required by 2009. An alternative involving the construction of a feeder from the OK Mission Substation was considered, however it proved to be more expensive than the Glenmore Feeder option. The estimated cost of this project is $788,000.

Airport Way Capacity Upgrade

This project involves the upgrade of an existing underground circuit along Airport Way from a 200 amp capacity circuit to a 600 amp capacity circuit in 2010. The project is required to supply the necessary capacity to service new customer load and to maintain reliable service to FortisBC customers. It is proposed that the existing two kilometres of No. 2 Copper cable running the length of Airport Way be upgraded to a 750 MCM cable together with associated switches and overhead ties.

At the present time all commercial customers with premises along Airport Way as well as the Kelowna International Airport are served by a 200 amp underground cable system that runs the length of Airport Way. This circuit has a maximum capacity of 4.6 MVA. The airport recently approved an expansion of the runway and terminal complex to accommodate larger aircraft and hence an increase in international long haul flights from Europe and North America. The expected increase in load associated with this expansion is 1 MVA. The Kelowna Flight Centre has also made application to add an additional 2 MVA of load. With these increases and with increases at other commercial industries located along Airport Way, a conservative estimate of an additional 1.5 MVA is expected by 2009\2010. Based on these load increases, it is anticipated that the current distribution circuit will be unable to serve the load in 2011. The proposed upgrade to the 750 MCM cable will provide the necessary capacity to accommodate the forecast load growth in this commercial corridor. The estimated cost of this project, scheduled for 2010, is $1.55 million.

Hollywood Feeder 3 - Sexsmith Feeder 4 Tie

This project involves the construction of approximately 150 metres of a new 477 MCM overhead circuit and the installation of 350 metres of a new 750 MCM underground circuit along Highway 33 in order to meet the Company’s planning criteria for feeder backup in high density urban centers by providing backup for Hollywood Feeder 3. It is required to provide reliable service to FortisBC customers.

Currently, if Hollywood Feeder 3 experiences a failure close to the substation, only 58 percent of the customers could have their service restored in a timely manner. This project will provide backup for Hollywood Feeder 3 via Sexsmith Feeder 4 and increase the backup capability for

Hollywood Feeder 3 from 58 percent to 100 percent. An evaluation of these two feeders indicates that there are no other viable options for this project. The estimated cost of this project scheduled for 2010 is $365,000.

Christina Lake Feeder 1 Capacity Upgrade

The project is required to supply the necessary capacity to service customers at the appropriate voltage levels and to maintain reliable service to FortisBC customers in the Christina Lake area.

Christina Lake Feeder 1 serves about 1,300 customers in the Christina Lake area. The feeder is approximately 12 kilometres long and sections have been reconductored to No. 266 ACSR with the remainder primarily No. 6 copper conductor which supplies the east side of the lake. System planning studies indicate that the Christina Lake Feeder 1 is experiencing end-of-line voltages below standard voltage level criteria of 113 volts during peak periods of the year in both the summer and winter.

This project scheduled for 2009 and 2010 involves reconductoring approximately 5 kilometres of No. 6 copper conductor and load balancing the feeder to ensure all customers are supplied with acceptable voltages. In addition to providing appropriate voltages levels to customers, this project supports the Company’s safety and reliability objectives by removing deteriorated copper conductor from the system. The estimated cost of this project is $608,000 in 2009 and $489,000 in 2010.

Beaver Park Feeder 1 - Fruitvale Feeder 2 Tie Upgrade

This project is required to supply the necessary capacity to service new customer load and to maintain reliable service to FortisBC customers in the Fruitvale, Montrose, and Trail areas.

The Beaver Park and Fruitvale Substations are currently at approximately 80 percent and 93 percent of capacity respectively. The load forecast for the Beaver Park station due to residential growth alone is anticipated to be 1.5 percent over the next 5 years. In addition, further significant commercial and industrial load developments have been forecast for the Beaver Park Substation in the next year. Currently, distribution load from Beaver Park can be transferred to the neighbouring Glenmerry Substation (20 MVA) if required through an existing distribution tie. The Fruitvale Transformer 1 (8 MVA) transformer has reached about 93 percent of its nameplate rating during peak periods. The Fruitvale area has an overall base growth forecast of one percent for the next five years, however, current new developments will add an additional 500 kVA of connected load to this distribution system, therefore Fruitvale Transformer 1 is forecast to reach its nameplate capacity within the next few years. Currently, the only station that could help off-load the Fruitvale transformer is the Beaver Park Substation, however, the distribution tie through the Beaver Valley is made up of several sections of copper wire that reduces the amount of load that can be transferred. The tie between the two substations consists mainly of No. 4 and No. 6 legacy copper conductor. This project will upgrade approximately 5.3 kilometres of line between Beaver Park Feeder 2 and Fruitvale Feeder 1 to allow for a transfer of load from the Fruitvale Substation to the Beaver Park Substation. Currently, this area does not meet the FortisBC planning criteria for station backup. However this project provides distribution system flexibility to mitigate the forecast capacity issues at the Fruitvale Substation defers a station upgrade project and supports the Company's safety and reliability objectives by removing deteriorated No. 6 and No. 4 copper conductors from the system. The estimated cost of this project, scheduled for 2010 is $1.23 million.

Small Growth Projects

The following table outlines the small distribution growth projects with estimated expenditures less than $250,000 that are proposed for 2009 and 2010.

Small Growth Projects

	Project	**2009**	**2010**
		($000s)	
1	Oliver Feeder 1 New Regulator		137
2	**Total**		137

There is only one proposed small growth project. It is required to provide acceptable voltage to the customers served by Oliver 1 Feeder. It involves the replacement of an existing 50 amp regulator bank with a 150 amp regulator bank.

The five year load forecast for the Oliver Feeder 1 shows a modest but sustained growth of 2 percent with a projected 2010\2011 winter peak of 7.0 MVA. With this peak, the capacity of the existing 50 amp regulator bank is exceeded and sections of the feeder will experience 112.1 volts for three phase and 111.2 volts for single phase. Both are below accepted voltage level criteria of 115.0 volts and 113.0 volts respectively.

Unplanned Growth Projects

Experience has shown that unforeseen load emergence will require capacity upgrades and voltage correction projects not accounted for in the capital plan. The projects typically include service upgrades, voltage regulation, ties to accommodate load splitting, single to three phase upgrades and conductor upgrades. This project is required to provide for such items that were unforeseen at the time the expenditure plan was prepared.

The following table shows the expenditures for the unplanned growth project for the past four years and plan for 2009 and 2010. The estimates are based on historical information adjusted for inflation.

Unplanned Growth Projects

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	962	954	1,063	817	974	994

DISTRIBUTION SUSTAINING PROGRAMS AND PROJECTS

The distribution sustaining projects are for rehabilitation and ongoing upgrades of the distribution system to ensure safe, reliable service. The following table shows the projects for 2009 and 2010.

Table 4.3
Distribution Line Sustaining Programs and Projects

	Project	2009	2010
		($000s)	
1	Distribution Line Condition Assessment	599	667
2	Distribution Line Rehabilitation	3,124	3,470
3	Distribution Right-of-Way Reclamation	621	646
4	Distribution Pine Beetle Hazard Allocation	722	551
5	Distribution Line Rebuilds	1,178	1,167
6	Small Planned Capital	668	747
7	Forced Upgrades and Line Moves	1,255	1,461
8	Distribution Urgent Repairs	1,911	1,805
9	PCB Program	1,073	1,117
10	Aesthetics and Environmental Upgrades	100	100
11	Copper Conductor Replacement Program	4,798	6,586
12	**Total**	**16,049**	**18,317**

Distribution Line Condition Assessment

The distribution system requires a proactive program to manage the risk to employee and public safety, and ensure an acceptable level of service.

The distribution line assessment program is based on an eight-year cycle of patrolling and testing all FortisBC distribution line facilities. In overhead systems, the program consists of a pole-testing program involving drilling test holes in each pole to confirm the condition of the pole, in addition to a pole treatment to reduce internal rot in the pole, and placement of a pole wrap to reduce surface rot on the pole at ground line. The program extends the life of the pole and ensures the integrity of the lines as well as employee and public safety. The program is managed in an eight-year cycle to levelize both budgets and resources for testing and treating the poles in the distribution system.

The following tables show the distribution lines scheduled for assessment in 2009 and 2010 including the number of poles and associated overhead and underground infrastructure including transformers, cross-arms, guy wire, etc.

Table 4.4(a)
2009 - Distribution Line Condition Assessment Projects

	Area	Feeder	Poles	Underground units	Overhead units
1	Kootenay	Blueberry 2	594	45	255
2	Kootenay	Midway 1	891	2	396
3	Kootenay	Salmo 1	869	1	482
4	Kootenay	Salmo 2	172	0	126
5	Kootenay	Cottonwood 1	141	0	20
6	Kootenay	Ymir 1	300	0	100
7	Kootenay	Stoney Creek 1	319	17	163
8	Kootenay	Stoney Creek2	288	2	153
9	Okanagan	OK Mission 1	604	199	347
10	South Okanagan	Princeton 1	1	0	0
11	South Okanagan	McKinley Mtn. 1	0	0	1
12	South Okanagan	North Warfield 1	87	0	0
13	South Okanagan	Princeton (EAS) 1	631	8	234
14	South Okanagan	Princeton (4160)	101	0	62
15	South Okanagan	Princeton (BUR)1	244	8	126
16	South Okanagan	Princeton (LIM) 1	373	22	184

Table 4.4(b)
2010 - Distribution Line Condition Assessment Projects

	Area	Feeder	Poles	Underground units	Overhead units
1	Kootenay	Creston 2	1830	5	829
2	Kootenay	Creston 4	970	3	398
3	Kootenay	Lambert 1	989	0	431
4	Kootenay	Lambert 2	121	3	70
5	Okanagan	Hollywood 1	1085	167	481
6	Okanagan	Hollywood 3	317	82	136
7	Okanagan	Sexsmith2	425	284	176
8	South Okanagan	Kaleden 2	166	0	0

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. It supports the Energy Plan policy action:

(12) 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.

The following table shows the expenditures for the distribution line condition assessment project for the past four years and plan for 2009 and 2010. The estimates are based on historical information adjusted for inflation and knowledge of the distribution lines being assessed.

Distribution Line Condition Assessment

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	575	431	928	386	599	667

Distribution Line Rehabilitation

The specific rehabilitation work for the various distribution lines involve expenditures for stubbing poles, replacing poles, replacing crossarms, guy wires, hot tap connectors, and other defects identified for rehabilitation in previous years assessments.

In 2009 and 2010 the Company will undertake rehabilitation of the distribution lines that will be assessed in 2008 and 2009 respectively.

In 2009, the Company will undertake another initiative in conjunction with the other distribution rehabilitation initiatives noted above. This initiative commonly referred to as "Hot Tap Connector Replacement", involves the removal of hot tap connectors that are connected directly to the primarily line and the installation of a device called a stirrup to provide a location to which the hot tap connector can be safely attached. This initiative is required to address employee and public safety, and reliability issues associated with conductor burn off caused by deteriorated hot tap connectors. These hot tap connectors are widely used in overhead distribution line systems to connect devices such as transformers, switches or branch-off lines into the main primary conductor. While hot tap connectors play a pivotal role in the efficient transfer of electrical energy, they can be a weak link in the power delivery system due to failure from aging or improper installation. An improperly installed hot tap connector may become loose or an old hot tap connector may undergo galvanic corrosion due to aging, creating a hot point. If the connector is positioned directly on the primary conductor it may result in conductor burn down. To avoid a conductor burn down it is essential to ensure that hot tap connectors are never installed directly on the primary current carrying conductor, but are used in combination with a stirrup. A survey carried out by the Overhead Distribution Lines Subcommittee of the National Rural Electric Cooperative Association's (NRECA) Transmission and Distribution Engineering Committee on 517 distribution cooperatives concluded that with the use of hot tap connectors in conjunction with stirrups, the failure rate is expected to be no greater than other components of the distribution system.

Today, the use of hot tap connectors in conjunction with stirrups is the accepted common utility practice. FortisBC standardized the use of stirrups when applying hot tap connectors on primary conductors in 2001. However, it is estimated that there are several thousand locations without stirrups in the system. In order to mitigate this safety issue the Company plans to replace connectors in priority areas in 2009 and 2010, and then replace connectors in conjunction with its normal rehabilitation cycle. Additional funds of $750,000 per year have been included in the Distribution Line Rehabilitation project for 2009 and 2010. It is anticipated that approximately

$500,000 per year will be required for the following six years, until such time as the Company completes one full eight year rehabilitation cycle.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. It supports the Energy Plan policy action:

(12) 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.

The following table shows the expenditures for the distribution line rehabilitation project for the past four years as well as plan for 2009 and 2010. The estimates are based on historical information adjusted for inflation and knowledge of the distribution feeders being assessed, supplemented with funds for the hot tap connector replacement initiative.

Distribution Line Rehabilitation

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	569	1,961	1,231	2,582	3,124	3,470

Distribution Right-of-Way Reclamation

The reclamation project is required to allow FortisBC to increase the tree-free zone around the distribution lines. The increased tree-free zones improve clearances enhancing both safety and reliability of the distribution system. The trees included are ones that FortisBC can economically remove versus cycle trim or brush.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. It supports the Energy Plan policy action:

(12) 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.

The planned expenditures for 2009 and 2010 are based on historical spending. The 2007 cost include expenditures for the Pine Beetle Hazard and have been removed for forecasting purposes.

The following table shows the expenditures for the past four years and plan 2009 and 2010:

Distribution Right-of-Way Reclamation

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	478	572	641	593	621	646

Right-of-Way Reclamation - Pine Beetle Kill Hazard Trees

This project involves the removal of trees to eliminate the hazard trees killed by the Pine Beetle that have a high probability of falling directly onto energized distribution and transmission lines. This issue was first addressed in the Company's 2008 Revenue Requirements Application. As noted on page 7 of BCUC Order G-147-07 "FortisBC and the Participants hold differing views on the treatment of removal costs for Pine Beetle Kill. The Parties agree that the 2008 removal costs will be recorded in a rate-base deferral account, amortized over 10 years, without prejudice to the treatment of future expenditures". Pursuant to this order the Company files the 2009 and 2010 forecast expenditures for Right–of-Way Reclamation - Pine Beetle Kill Hazard Trees project as part of its 2009\-2010 Capital Expenditure Plan Application.

Recent consecutive mild winters have accelerated the MPB infestation within the FortisBC service area. Provincial infestation concentration maps for 2001 and 2006 show that MPB infestation has spread from the north central region of the province into the southern reaches of the province. Concentrations of MPB infestation are now very evident in FortisBC's service territory and are certain to increase in severity. The cost to eliminate hazard trees killed by the MPB has increased accordingly. This was recognized in FortisBC Inc. 2007-2008 Capital Expenditure Plan Application, page 79, and also in the Preliminary 2008 Revenue Requirements Application Tab 7, page 17.

Trees that have been attacked by the MPB will deteriorate quickly, losing stem wood strength. BC Hydro experience indicates that dead stem wood is failing much quicker than anticipated and that Ponderosa pine is failing quicker than Lodgepole pine.

Trees identified by this program have a high probability of falling directly onto energized lines. The size of tree involved can break conductors, insulators, cross-arms and possibly even the poles themselves. Risks include:

- Downed conductors remaining energized and creating an electrical contact hazard;
- Risk of fire due to arcing and ignition of the tree and surrounding foliage even if the conductor does not break, and
- The impact on reliability of an outage which at a minimum requires a line patrol to visually locate the fallen tree and clear it, and may require replacement of damaged components.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. It supports the Energy Plan policy action 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.

The following table shows the forecast expenditures for 2008 and plan for 2009 and 2010

Distribution Right-of-Way Reclamation - Pine Beetle Kill Hazard Trees

Year	To Dec 31 2008	2009	2010
Cost ($000s)	1,000	722	551

Distribution Line Rebuilds

This project involves the replacement of aged and deteriorated equipment. Items include rebuilding failing overhead and underground conductor, replacing rotted poles and platforms, replacing leaking transformers, and installing ground grids at ungrounded services. These deficiencies were identified through site assessments and normal daily operations.

The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. It supports the Energy Plan policy action:

(12) 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.

The forecast for this project has been reduced by approximately one million dollars for 2009 and 2010 as a result of the initiation of Copper Conductor Replacement Project. The following table shows the expenditures for the past four years and plan for 2009 and 2010.

Distribution Line Rebuilds

Year	**2005**	**2006**	**2007**	**2008F**	**2009**	**2010**
Cost ($000s)	1,230	3,847	1,470	1,972	1,178	1,167

The items associated with this project for 2009 and 2010 are listed in the following tables.

Table 4.5 (a)
2009 Distribution Line Rebuilds

	Project No.	Description	Driver (Safety, Compliance, Capacity, Reliability, Other)
1	Crawford Feeder 4 Underground cable Selkirk subdivision, Crawford Bay.	This installation is one of the oldest underground subdivisions in the FortisBC service area. The conductors were installed about 30 years ago. The installation has deteriorated and does not meet current standards.	Safety, Compliance, Reliability
2	Creston Feeder 3 6th Ave Creston.	This line has several long spans and non standard pole heights leading to clearance and reliability related issues.	Safety, Compliance, Reliability
3	Lambert Feeder 2 Thompson Repeater	This is a single phase distribution line feeding a mountain top repeater site that is in poor condition and involves substandard construction. This project will rebuild sections of this line.	Safety, Compliance, Reliability, Access
4	KLO Road	The section of line from Hall Rd. to McCullough Rd. is in the middle of an old creek valley. The line has deteriorated and also has access problems. Approximately 20 spans of this section will be rebuilt on the KLO Rd. right-of-way.	Safety, Compliance, Reliability, Access
5	OK Mission Feeder 2 Lanfranco Road. Kelowna	The section of underground radial line serving several commercial sites including Taco Time and Dairy Queen will be rebuilt to provide a loop feed.	Reliability

Table 4.5 (b)
2010 Distribution Line Rebuilds

	Project No.	Description	Driver (Safety, Compliance, Capacity, Reliability, Other)
1	Blueberry Feeder 2 107th Street Blueberry.	This project involves the rebuild of a section of the main distribution feeder through the community of Blueberry. The existing construction is sub standard on 25 to 30 foot poles, with clearance issues under the 230 kV transmission line.	Safety, Compliance, Reliability
2	Blueberry Feeder 1 and 2 Minto Rd. Highway crossing Blueberry	This is an existing double circuit highway crossing that has a history of reliability and condition related issues, due to substandard phase to phase and phase to neutral spacing.	Safety, Compliance, Reliability
3	Playmor Feeder 3 Slocan Ridge	This is a single phase distribution line feeding a mountain top repeater site that is in poor condition and involves substandard construction. This project will rebuild sections of the line.	Safety, Compliance, Reliability, Access
4	Redwing Subdivision, Penticton	The section of underground radial line serving this subdivision will be rebuilt to provide a loop feed.	Reliability
5	Airport, Penticton	The section of line serving the airport has deteriorated, and also has access issues. The line will be rebuilt with improved access.	Reliability, Access
6	White Lake Road., west of Penticton	The poles in this section of line are deteriorated. As well there is limited access to the line. The line will be rebuilt and the access improved.	Safety, Compliance, Reliability, Access

Small Planned Capital

This project is similar to the Distribution Condition Assessment and Rehabilitation projects but captures off-cycle work required to keep the distribution lines safe and reliable. Each year operational and safety concerns on the distribution system including storm damage, clearance problems and aging equipment are identified by field staff outside of the normal assessment cycle. Repairs to address these concerns are required to maintain a safe and reliable distribution system. The repairs are generally non-urgent in nature and consequently are not completed under the distribution urgent repair project. They are normally completed within one year of the initial request. The planned expenditures for this project are based on historical information adjusted for inflation. The following table shows the expenditures for the past four years as well as plan for 2009 and 2010.

Small Planned Capital

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	305	515	1,030	435	668	747

Forced Upgrades and Line Moves

This project is required to complete distribution upgrades driven by third party requests. Relocation of distribution lines due to highway\road widening or improvements will be initiated based on requests from the BC Ministry of Transportation and\or municipalities. Miscellaneous customer line move requests where FortisBC does not have sufficient land rights for the facilities located on customer property are also included in this project. Upgrades resulting from new customer connects are included in the expenditure estimate. The planned expenditures for this project are based on historical information adjusted for inflation. The following table shows the expenditures for the past four years as well as plan for 2009 and 2010.

Forced Upgrades and Line Moves

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	1,418	716	1,564	1,370	1,255	1,461

Distribution Urgent Repairs

Component failures on the distribution system (e.g. due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions etc.) can cause outages or present risks that must be addressed in an expedient manner. This project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The planned expenditures for this project are based on historical information adjusted for inflation, however in recognition of the commencement of the Copper Conductor Replacement Project, the estimate for 2010 has been reduced by approximately $50,000. The following table shows the expenditures for the past four years as well as plan for 2009 and 2010.

Distribution Urgent Repairs

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	1,001	2,123	2,030	1,411	1,911	1,805

PCB Program

This project was previously approved by Commission Order G-52-05. At that time FortisBC had approximately 31,000 in service, oil filled distribution transformers that do not undergo oil testing as part of regular maintenance. Federal legislation is pending that will require that all in service equipment containing PCB concentrations greater than 50 parts per million (ppm) be inventoried and reported annually. A requirement also exists to label any equipment that is found to contain concentrations greater than 50 ppm. To meet these requirements, FortisBC must first determine the concentrations in each device.

The gathering of equipment data and identification of sensitive locations will be undertaken over a six-year period. This project which began in 2005 is expected to be completed in 2010. The following table shows the expenditures for the past four years as well as plan for 2009 and 2010.

PCB Program

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	691	1,560	961	239	1,073	1,117

Aesthetics and Environmental Upgrades

This project which was approved by Commission Order G-58-06 involves sharing with local governments the cost to upgrade FortisBC's distribution facilities beyond the Company's distribution standards for aesthetic and\or environmental reasons.

The purpose of FortisBC's participation in the aesthetic and environmental upgrades program is to cooperate with local governments with respect to environmental concerns and visual objectives.

Local governments may request FortisBC to share one third of the costs to upgrade FortisBC distribution facilities beyond the Company's usual distribution standards for aesthetic and\or environmental reasons. The determination of usual distribution standards and costs of the upgrade will be at the Company's sole discretion. The estimated expenditures for this project are $100,000 in 2009 and 2010.

Copper Conductor Replacement Program

Copper conductor ranging in sizes from No. 8 gauge to No. 4 gauge as well as No. 90 MCM was commonly used for distribution lines 40-50 years ago due to its excellent electrical characteristics. During the past number of years, the Company has experienced a number of conductor failures associated with this particular conductor. An analysis of the issue has identified a requirement to replace a significant amount of this legacy conductor with modern aluminium standard conductors to avoid safety risk to employees and the public.

This project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. It supports the Energy Plan policy action:

(12) 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.

A CPCN application for this project accompanies the 2009\10 Capital Plan. The 2009 and 2010 cost estimate for this project is shown below.

Copper Conductor Replacement Program

Year	2009	2010	Future	Total
Cost ($millions)	4,798	6,586	91,086	**102,470**

5. Telecommunications, SCADA, and Protection and Control Projects

FortisBC operates a telecommunications system to support protection, control and monitoring of the power system, as well as operations and business communications requirements. Approximately 102 locations are presently or potentially served by the telecommunications system, including 49 distribution stations, 11 terminal stations, 4 generation stations, 12 mountain-top radio repeaters and 6 office locations. The telecommunications system also connects to other utilities for the exchange of protection signals and operational voice and data communications.

The completion of the Telecommunication Projects facilitates the Company's support for the Provincial Government energy objectives. In particular the objectives:

(c) to encourage public utilities to produce, generate and acquire energy from clean or renewable resources; and

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

These projects also facilitate the Policy Actions contained in the Energy Plan. In particular:

(12) 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; and

(14) to ensure the province remains consistent with North American transmission reliability standards.

Table 5.1 below shows planned expenditures for 2009 and 2010.

Table 5.1
Telecom, SCADA, and Protection and Control Projects Expenditures

		CPCN Approved	Expenditures to Dec 31\08	2009	2010	Future[1]	Total
			($000s)				
1	**GROWTH**						
2	Distribution Substation Automation Program	C-11-07	1,982	1,338	1,438	1,621	6,379
3	**SUBTOTAL GROWTH**		**1,982**	**1,338**	**1,438**	**1,621**	**6,379**
4							
5	**SUSTAINING**						
6	Harmonic Remediation			117	119		
7	Protection Upgrades			448	508		
8	Communication Upgrades			299	111		
10	**SUBTOTAL SUSTAINING**			**864**	**738**		
11	**TOTAL**		**1,982**	**2,202**	**2,176**	**1,621**	**6,379**

(1) Future expenditures for ongoing sustaining programs have not been included in these tables.

Distribution Substation Automation Program

This project involves the provision of remote monitoring and control to distribution level substations, including power-quality monitoring of lines, transformers and feeders, fault recording and locating, and equipment condition monitoring. FortisBC has already developed standardized protection, control and monitoring systems that are applied to new substation construction. This project will be undertaken to retrofit these systems to the remainder of the legacy distribution substations. The scope of the project and the location of the substations to be addressed was the subject of a CPCN Application which was approved by Commission Order C-11-07.

The total estimate for the project is $6.38 million with planned expenditures as shown below. FortisBC will file an updated +\- 10 percent level estimate as part of the first semi-annual report as set out in the Order.

Distribution Substation Automation Program

Year	To Dec 31 2008	2009	2010	2011	Total
Cost ($millions)	1.98	1.34	1.44	1.62	6.38

SUSTAINING PROJECTS

These are multiyear projects that include harmonic remediation, and protection and fault locating upgrades, utility systems standards compliance and communication upgrades. They will enhance the protection, control and monitoring of the FortisBC power system as well as operations and business communications requirements.

Harmonic Remediation

The production and transmission of electrical energy occasionally produces harmonic signals that interfere with the operation of utility and customer-owned equipment. As well, some types of customer equipment also inject harmonics into the utility system. This project provides for investigating and resolving harmonic problems as they arise. Investigation typically involves installing test equipment for a period of time, then analyzing the resulting data. Resolving harmonic problems typically involves the installation of harmonic filters, replacing defective transmission equipment or working with customers to reduce the production of the offending harmonics. The estimated expenditures for this project is $117,000 in 2009 and $119,000 in 2010.

Protection Upgrades

This project will upgrade protection and control equipment in several locations. Most of the relays associated with the proposed projects are electromechanical and are 40 to 50 years old. The individual components are unreliable and spare parts have not been available for many years. As well, this equipment does not provide modern protection functions such as fault locating, event recording and data logging. Another important function incorporated in modern relaying is continuous self-monitoring. Each device is capable of immediately alarming to the SCC following the detection of a relay failure. Even with periodic function testing to ensure fitness for service, old-style electromechanical relays may fail at any time without warning. A failure of the relay to operate when required can place system equipment, Company personnel and the general public at risk.

With the completion of recent protection upgrade projects all FortisBC transmission lines are now protected by modern microprocessor-based relays. The only remaining electromechanical devices are transformer protection relays. Pending completion of the Okanagan Transmission Reinforcement, the 30 Line Voltage Conversion, and the Huth Substation Upgrade Projects most of the remaining electromechanical protective relays will have been removed. The only remaining electromechanical devices (primarily transformer differential relays) will be located at the following stations:

- Hollywood Transformers 1 and 3
- Sexsmith Transformer 1
- Saucier Transformer 1
- Summerland Transformer 2
- Westminster Transformer 1 and 2

In 2009 projects will be completed to replace the relaying at Hollywood and Sexsmith Substations with modern microprocessor-based devices as per current FortisBC standards.

In 2010 projects will be completed to replace the relaying at Westminster, Summerland and Saucier Substations with modern microprocessor-based devices as per current FortisBC standards.

With the completion of the above work, and in combination with the Distribution Substation Automation Program, all FortisBC transmission and distribution will be protected by microprocessor-based relays and all electro-mechanical relays will have been retired by the end of 2011. This is a significant achievement and will continue to show benefits such as improved reliability and safety well into the future. The estimated expenditures for this project is $448,000 in 2009 and $508,000 in 2010

Communication Upgrades

This project will upgrade telecommunications routes and will improve emergency response capability. With the recent upgrades approved in previous capital plans much of the FortisBC communications infrastructure has been modernized. However, there still remains some telecommunication equipment which is near or beyond its designed operational life. Individual components are unreliable, and the manufacturers no longer supply spare parts. In some extreme cases, equipment can no longer be regularly tested and adjusted because it fails when test systems are operated, which results in it not being able to be put back into service in a timely manner. This equipment can cause failure of the transmission and distribution systems it supports, or prevent restoration efforts, exposing the system to possible equipment damage, extended outage times, or possibly causing public safety issues.

In 2009, communication upgrades will take place in the Kootenay region on the backbone fibre-optic multiplexing system. The optical laser components of this system will be upgraded to use new higher-speed units that are now available from the manufacturer. This improvement will significantly increase the bandwidth of the existing Kootenay backbone system, in addition to improving reliability as the new devices have much lower power requirements (and thus lower failure rates). As well, in 2009 aging SCADA remote terminal units (RTUs) in the Kelowna area will be upgraded. The existing units were installed in the mid-1990s and spare parts are no longer available. Since these RTUs provide remote visibility of the Kelowna-area distribution substations it is critical that these devices have high reliability to ensure that outages to the Kelowna sub-transmission and distribution system are identified and resolved quickly and safely.

In 2010 communications upgrades will take place at the FA Lee Terminal for the teleprotection equipment on 72 and 74 Lines. These 230 kV lines are the major supply path into the Kelowna area from the BC Transmission Corporation (BCTC) system, and thus secure and dependable communications for these circuits is critical.

In both 2009 and 2010, a number of smaller projects will add high-speed network connectivity to a number of substations throughout the service area. As well, aging leased-line modems will be replaced with new digital cellular modems which offer higher bandwidth, improved reliability and significantly lower monthly lease costs. Together, this work will provide improved real-time monitoring of FortisBC substations to assist operations personnel in making correct decisions and restoring outages more quickly. The estimated expenditures for this project is $299,000 in 2009 and $111,000 in 2010

6. Demand Side Management

OVERVIEW

Demand Side Management ("DSM") or energy efficiency programs have been offered to FortisBC customers since 1989. DSM Programs are listed in the Company's filed tariff and approved by the Commission. The DSM programs meet the economic test of costing less than the avoided cost of delivered power. The programs are available to all customers served by FortisBC and its wholesale customers of Grand Forks, Kelowna, Nelson Hydro, Penticton, and Summerland.

DSM expenditures of $3.7 million ($2.6 million net of tax) in 2009 and $3.9 million ($2.8 million net of tax) in 2010 are planned. The DSM initiatives that comprise the FortisBC PowerSense program provide information, co-fund engineering studies and provide incentives (grants or loans) towards energy conservation purchases and projects undertaken by customers. FortisBC offers financial incentives to the Residential, General Service, and Industrial customer classes for energy efficiency upgrades beyond baseline technologies for both existing facilities as well as for new construction enhancements.

The completion of these projects supports the Provincial Government's energy objectives, including the objective:

(b) to encourage public utilities to take demand-side measures.

These projects also support Policy Actions No. 1, 2, and 3 contained within the Energy Plan:

(1) Set ambitious conservation targets to acquire 50 percent incremental resource needs through conservation by 2020;

(2) Ensure coordinated approach to conservation and efficiency is actively pursued in British Columbia; and

(3) Encourage utilities to pursue cost effective and competitive demand side management opportunities.

Table 6.1 below shows the DSM expenditures (nominal and net of tax) planned for 2009 and 2010.

Table 6.1
Demand Side Management Expenditures

		2009 Total	2010 Total	Total
		($000s)		
1	**Nominal Cost**	3,668	3,952	7,620
2	**Tax effect**	(1,155)	(1,245)	(2,400)
3	**Net Cost**	2,513	2,707	5,220

Expenditures in 2009 and 2010 are planned to exceed 2008 spending. This decision reflects the major shift in provincial policy that places demand side management as the priority resource to meet growing electricity demand in BC. The Energy Plan and the Utilities Commission Amendment Act 2008 (Bill 15) will require utilities to increase the acquisition rate of DSM resources.

Table 6.2 below is a summary by customer sector of DSM costs (before income tax adjustments) and energy savings planned for 2009 and 2010. The approved 2008 plan figures are shown for comparison purposes. In response to the Energy Plan, the two-year plan, 2009 ($3.67 million and 25.3 GWh) and 2010 ($3.95 million and 27.5 GWh), contain higher levels of expenditures, and energy savings, than the 2008 plan ($2.35 million approved expenditure with 19.5 GWh savings).

Table 6.2
Expenditures and Savings by Sector

	Sectors	2008 Plan Costs ($000s)	2008 Plan Savings GWh	2009 Plan Costs ($000s)	2009 Plan Savings GWh	2010 Plan Costs ($000s)	2010 Plan Savings GWh
1	**Residential**						
2	Existing Residential base	1,023	8.4	1,023	8.4	1,023	8.4
3	Change to 2008 Base	-	-	(9)	0.7	107	2.1
4	New programs\incentives	-	-	377	1.6	386	1.6
5	**Residential Total**	**1,023**	**8.4**	**1,391**	**10.7**	**1,516**	**12.1**
6	**General Service**						
7	Existing General Service base	754	9.1	754	9.1	754	9.1
8	Change to 2008 Base	-	-	98	-	188	0.5
9	New programs\incentives	-	-	436	2.5	438	2.5
10	**General Service Total**	**754**	**9.1**	**1,287**	**11.6**	**1,380**	**12.1**
11	**Industrial**						
12	Existing Industrial base	200	2.0	200	2.0	200	2.0
13	Change to 2008 Base	-	-	58	0.3	100	0.7
14	New programs\incentives	-	-	87	0.7	88	0.7
15	**Industrial Total**	**200**	**2.0**	**345**	**3.0**	**388**	**3.4**
16	**All Programs**						
17	2008 Base	1,977	20	1,977	20	1,977	20
18	Change to 2008 Base	-	-	147	1	395	3
19	New programs\incentives	-	-	899	5	912	5
20	**Total All Programs**	**1,977**	**20**	**3,023**	**26**	**3,284**	**28**
21	Conservation Culture	-	-	141	-	148	-
22	Planning & Evaluation	378	-	503	-	519	-
23	**Total**	**2,355**	**20**	**3,668**	**26**	**3,952**	**28**

The Company is supportive of the Energy Plan goal of having conservation offset 50 percent of cumulative load growth by 2020. Over the last number of years, DSM has offset approximately 25 percent of FortisBC's annual energy growth requirements, thus effectively requiring an overall doubling of the current DSM resource acquisition rate in order to meet the Provincial

Government's objective. New programming will include collaboration with government agencies and the other energy utilities in the province to work towards the objectives of the Energy Plan, and to ensure customers in BC are receiving a consistent DSM message. New funding has been included for a "conservation culture" communications plan that will be built on the Company's "Bright Ideas" messaging.

FortisBC is preparing a long-term Strategic DSM Plan for filing with the BCUC by the end of 2008. The Strategic DSM Plan will provide and build upon the programs outlined for 2009 and 2010, which are a mix of sustained growth in existing programs, customer education and new program development.

2009 TO 2010 PROGRAMMING

Staff will be added in 2009 to increase the Company's capability to effectively deliver, manage, monitor and evaluate programs and to implement DSM communications campaigns.

Program incentive levels are increased by 0.5 cents per kilowatt-hour (kWh) as shown in Table 6.3 below. The 2009 and 2010 planned expenditures shown in Table 6.2 above reflect the incentive level increase, which is intended to encourage and support higher take-up rates.

Table 6.3
Incentive Levels (Cents per kWh)

		2008	**2009**	**2010**
		(¢)		
1	**Residential**	6.0	6.5	7.0
2	**General Service**	4.5	5.0	5.5
3	**Industrial**	6.5	7.0	7.5

While it is expected that increased incentive levels will accelerate program participation, actual results will be monitored to determine the impact on program results.

Residential Sector

Residential sector programs support renovations to existing housing stock and efficiency enhancements to new home construction. A number of DSM measures, outlined as follows, are common to both market segments.

The Compact Fluorescent Light ("CFL") offer is a rebate for the lesser of $5 or one-half of the actual cost on speciality CFLs (for example: 3-way, dimmable, or reflector). The offering will be broadened to include hard-wired CFL light fixtures, and emerging Light Emitting Diode ("LED") lamps. A lighting package for new home construction consists of sample kits of CFL products. Sample CFLs are also given away through targeted channels (trade shows, Welcome Wagon etc.)

The Heat Pump program incentive is either a rebate at $0.05 per annual kWh saved or a fixed rate 10-year loan. Both air source and ground source heat pumps are supported. Multi-unit residential construction, where electric heating is prevalent, continues to be a market where efficient Packaged Terminal Heat Pumps ("PTHP") find a niche.

New Residential Programs

FortisBC is collaborating with the Provincial Government to launch the LiveSmart BC home retrofit program, under which homeowners are encouraged to upgrade existing housing stock. The program is a tri-party arrangement, in conjunction with the federal ecoEnergy initiative, which encourages homeowners to improve the energy rating of their homes to the greatest extent possible by undertaking a comprehensive retrofit.

Another new offering, as a partner in SolarBC, is a DSM incentive for solar thermal systems that preheat water to electric domestic hot water tanks, thus reducing electrical usage for a significant household energy end-use.

The January 2009 implementation date of the provincial regulation mandating EnergyStar qualified new windows will effectively end the current window rebate offer for new housing. The focus will shift to other identified envelope technologies such as Structural Insulated Panels ("SIP"), as well as a whole house performance approach through an Energuide 80 ("EG80") rating. A number of “near” Net Zero Energy model homes are expected to be built to showcase the future of energy efficient housing.

In collaboration with the provincial working group on affordable housing, FortisBC will be focusing on ensuring that our DSM programs are designed or revamped to reach traditionally underserved customers.

The nominal cost of the Residential programs is estimated at $1.39 million in 2009 and $1.52 million in 2010.

General Service Sector

This sector offering consists of programs for improvements to existing facilities or upgrades to higher efficiency levels for new construction in the General Service sector. The General Service sector consists of non-residential customers such as commercial, institutional, government and small manufacturing facilities.

Building Improvements program targets building and process improvements to existing facilities. Technology efficiency measures include lighting upgrades, improvements to building envelope, heating ventilation and air conditioning, and wastewater and sewage treatment process improvements.

The New Facilities Construction category includes the same technology improvement measures as those applied to the existing facility stock, and aims to increase the energy efficiency aspects beyond baseline building code requirements.

New General Service Programs

A new offering, begun as a pilot project in Kelowna in 2008, is the Cool Shops program for small businesses, primarily retail storefronts. The store owner is provided with a lighting audit, energy reduction tips and advice, as well as various sample products such a reflector CFL. The Cool Shops program will be expanded to all three sub-regions of the Company’s service area.

The Company is negotiating a key delivery role in the Public Sector Energy Conservation Agreement (“PSECA”) operating under a Memorandum of Agreement with the Provincial Government. PSECA targets provincially owned and funded facilities such schools, hospitals and BC Housing stock for accelerated energy efficiency retrofits. PowerSense representatives will canvas public sector customers for eligible projects to this new funding channel, and the Company will provide matching incentives under its DSM programs.

The fees to cover the Company's sponsorship of the Destination Conservation (DC) program in elementary schools throughout the Company's service area are included in the 2009 and 2010 budgets. The company is sponsoring year two, of this three year program, in conjunction with Terasen Gas and the school districts.

The nominal cost of the General Service programs is estimated at $1.29 million in 2009 and $1.38 million in 2010

Industrial Sector

This sector consists of programs for improvements to existing facilities or upgrades to higher efficiency levels for new facilities in the industrial sector. This sector consists of non-residential customers that have a minimum demand of 500 kVA and includes sawmills, mining and other processing facilities such as a pulp mill.

Industrial program offerings for both existing and new facilities offer rebates for energy efficiency improvements and co-fund engineering review to identify and implement efficiency measures. The energy management committee process is used to identify energy conservation opportunities for this sector.

The Industrial Efficiency program applies to the retrofit of existing facilities including measures to improve process efficiencies, install variable speed drives for pumps and fans, and install sequencers and controls for compressed air systems. The New Process Design plan promotes efficiency upgrades to new facilities and uses much of the same technology profile as the industrial efficiency program.

New Industrial Sector Programs

The existing programs provide a solid framework under which to provide incentives to rebate industrial efficiency projects. New enabling workshops will be offered to interested customers in the 2009\10 plan years. The Sustainable Energy Plan ("SEP") workshops provide an opportunity for a cross-section of operations managers to work together to create an energy plan for their companies. Much of the successes of the SEP workshops come from integrating energy efficiency decisions into daily operational practices, and not just capital upgrade projects.

The nominal cost of the Industrial programs is estimated at $345,000 in 2009 and $388,000 in 2010.

Conservation Culture

Included in the existing base DSM budget is a $150,000 annual allowance for advertising and promotion of DSM programs and the Company's "Bright Ideas" low-cost energy efficiency tips.

The 2009\10 Capital Plan includes a new line item for Conservation Culture. A full time equivalent resource will be designated to address conservation culture issues such as behavioural and lifestyles changes.

No specific energy savings have been attributed to this expenditure, but it is expected to condition the market to accelerate take-up in new and existing DSM program offerings.

The estimated cost of this program is $141,000 in 2009 and $148,000 in 2010.

Planning and Evaluation

This component of the DSM budget includes provision for the manager, technical and reporting staff, as well as the external expertise, the Strategic Plan, and facilitating the DSM Advisory Committee. Additional management, planning and evaluation of the increased DSM activities are required to properly plan and control the increased DSM resource acquisition.

The company has committed to filing a Monitoring and Evaluation (M&E) plan in 2008, as well as filing an M&E report. The 2009\10 budgets contain provisions to produce an additional report in each year of the filing period.

While the 2009\10 Capital Plan will provide resources needed to immediately accelerate program participation and to advance the development of consistent province-wide DSM communications, the Company has recognized its need for a longer term view of DSM resource acquisition and its impact on utility business. A DSM strategy report is being prepared to bring together the information that the Company can use to assess the long term energy supply needs of its customers and the economic needs of its business, and will be filed with the Utilities Commission by the end of 2008. The resource acquisition strategy in the document will focus on a ten year period beginning in 2011 and will provide a continuum of 2009 and 2010 programming.

The Company is a participant on the provincial DSM steering committee, ensuring high level co-ordination, harmonization of programs and standardized economic criteria by which DSM initiatives are evaluated.

The estimated cost of planning and evaluation is $503,000 in 2009 and $519,000 in 2010.

7. General Plant

General plant consists of vehicles, metering, information systems, telecommunications, buildings, furniture and fixtures, and tools and equipment.

The completion of most of the General Plant Projects facilitates the Company's support for the Provincial Government energy objectives. In particular the objectives:

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire energy from clean or renewable resources; and

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility.

One of the larger general plant projects is the Advanced Metering Infrastructure ("AMI") Project. Consistent with Section 64.04 (4) of the Utilities Commission Act this project supports "the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority."

The following table shows the 2009 and 2010 expenditures for General Plant.

Table 7.1
General Plant Expenditures

	General Plant	CPCN filed	Expenditures to Dec 31\08 (1)	2009	2010
			($000s)		
1	Vehicles			1,326	2,868
2	Advanced Metering Infrastructure	Dec. 19, 2007	568	16,492	20,240
3	Metering Changes to Uninstalled Meter Inventory			526	559
4	Information Systems			5,167	4,499
5	Telecommunications			105	106
6	Buildings			3,248	1,981
7	Furniture and Fixtures			347	393
8	Tools and Equipment			572	575
9	**TOTAL**		**568**	**27,783**	**31,221**

(1) All forecast figures are based on forecasts as of April 30, 2008.

The following sections provide a brief description of the general plant requirement for 2009 and 2010.

VEHICLES

This project involves the replacement and\or addition of heavy fleet vehicles, service vehicles, passenger vehicles, equipment and off road vehicles necessary for FortisBC to conduct its operation in a safe and efficient manner.

FortisBC has 347 units in its fleet; 266 units are owned and 81 units are leased.

Thirteen of eighteen vehicles used by meter readers are leased. As the AMI project is implemented the Company will return these vehicles to the vendor. The remaining five which are owned by the Company will be retired or redeployed.

In 2009 and 2010 FortisBC plans to replace nine units and twenty four units respectively. In support of the Energy Plan, the Company currently has one hybrid low emission passenger vehicle with plans to acquire five more before September 2008 and to acquire a hybrid low emission service truck as part of its 2010 vehicle replacement program. The Company is planning to continue to monitor progress with hybrid vehicle technology and evaluate such units as part of its ongoing purchases.

Replace Vehicles

FortisBC's equipment replacement guidelines are listed in the table below. Simply meeting the replacement guidelines does not dictate that a unit will be replaced and occasionally a unit will be replaced prior to meeting the criteria.

In making the actual replacement decision many key issues are considered including, suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, and compliance with regulations. Replacement decision is done on a unit by unit basis.

Table 7.2
Replacement Criteria Trigger

Class #	Description	Trigger
1	Passenger Vehicles	5 years 160,000 kms
2	3\4 Tons & Smaller	5 years 160,000 kms
3	Service Vehicles (3\4 and 1 Tons) 2 Wheel Drive	5 years 160,000 kms
4	Service Vehicles (3\4 and 1 Tons) 4 Wheel Drive	5 years 160,000 kms
5	Single Axle Line Truck (Digger or Aerial) 2 Wheel Drive	10 years 160,000 kms
6	Single Axle Line Truck (Digger or Aerial) 4 Wheel Drive	10 years 160,000 kms
7	Specialty and Small Horsepower (Forklifts, Snowmobiles, ATV's, etc.)	Individual Review
8	Trailers	20 years
9	Tandem Axle Line Truck (Digger or Aerial)	10 years 160,000 kms

All units to be replaced have either exceeded their planned life cycle or are becoming a safety, reliability or compliance risk.

Table 7.3 below lists the nine units to be replaced in 2009 at an estimated cost of $1.23 million and the twenty four units to be replaced in 2010 at an estimated cost of $2.77 million. Also included in the expenditure forecast is an allowance for approximately $100,000 per year to address any unanticipated requirements or unplanned replacements. This may include upgrading the specification on an existing vehicle that is to be replaced, replacing a damaged unit, or adding a new unit to the fleet.

Table 7.3
Replace Vehicles

	Category	No. of Units 2009	No. of Units 2010
1	Heavy Fleet Vehicles	3	6
2	Service Vehicles	2	5
3	Passenger Vehicles	3	7
4	Off-Road Vehicles\Trailers	1	6
5	**Total Units**	**9**	**24**
6	**Total Replacement Cost ($000s)**	**1,226**	**2,768**
7	**Contingency ($000s)**	**100**	**100**
8	**Total Cost ($000s**	**1,326**	**2,868**

METERING

Advanced Metering Infrastructure ("AMI")

This project involves the replacement of all meters in FortisBC's service territory with solid-state AMI-enabled meters, and installation of the required communication infrastructure to facilitate remote meter reading capability. The principal benefits resulting from an AMI implementation include numerous operational savings and other related benefits in customer service, transmission and distribution operations and planning, revenue protection, finance and forecasting, as well as the immediate realization of operational savings relating to the eliminated need for certain labour and non-labour costs associated with the manual meter reading function. The Company anticipates operating expense reductions of approximately $518,000 in 2010 associated with the completion of this project.

A CPCN Application was filed for this project on December 19, 2007. As a result of continued discussions with the Ministry of Energy, Mines, and Petroleum Resources, FortisBC submitted an amendment to the original CPCN Application to include additional functionality to provide increased flexibility and support for the Energy Plan on March 28, 2008. The additional functionality in the Amended Application is estimated to increase project costs to $37.3 million compared to an estimated capital investment of $31.3 million as presented in the original CPCN application. Pending BCUC approval, the completion of the AMI implementation, in addition to the benefits discussed above, will allow FortisBC to begin designing and implementing innovative rate structures in support of the conservation and demand side management objectives of the Energy Plan.

Advanced Metering Infrastructure

	Expenditures to Dec 31\08	2009	2010	Total
Cost ($000s)	568	16,492	20,240	37,300

Changes to Uninstalled Meter Inventory

This budget item reflects the final change to inventory at year end 2009 and 2010 taking into consideration the following activities:

- Meter purchases;
- Meter retirements;
- Impact of returns and issues of meters from the field; and
- Issue of meters, current transformers and potential transformers to the field for new connects.

The expected 2009 change to uninstalled meters inventory is $324,000 in 2009 and $326,000 in 2010.

The acquisition of meters associated with the meter retest exchange program is forecast at $202,000 in 2009 and $233,000 in 2010. These costs are required until such time as the AMI project is approved and FortisBC receives an exemption approval from Measurement Canada to discontinue the meter retest program.

INFORMATION SYSTEMS

Information Systems at FortisBC have seen major changes since the Company transitioned to an independent stand-alone company in 2004\05. Since that time the Company has focused on acquiring and upgrading its information system infrastructure and core applications. FortisBC relies on its own base of core applications, including SAP (Financial, Human Resources, Project Management and Materials Management), CIS (Customer Information System), Java based Intranet\Internet, AM/FM (Asset and Facilities Management), SCADA (System Control and Data Acquisition), and Cascade (Plant management). These applications are used to support the Company's business and technology requirements. FortisBC carefully selected these core systems for their scalability and technology, which allow them to be upgraded, enhanced and integrated without having to acquire and implement a totally new solution. The Company's strategy is to utilize the capabilities of these applications to improve safety, reliability, efficiency and customer service.

Enhancements to existing systems are initiated on a regular basis when a business requirement or opportunity arises that requires a long term solution. This has proven to be a more productive and manageable approach than collecting requirements over time and then implementing a large scale and all encompassing upgrade. These enhancements do not generally include additional licenses or hardware, but do include configuration, integration and process modification to take advantage of the particular applications inherent functionality.

Upgrades are undertaken when existing infrastructure, database or application versions are outdated to the point that they have the potential to cause productivity or reliability issues. The 2009 and 2010 upgrade projects are associated with both the System Infrastructure and the Desktop Infrastructure.

The 2009 and 2010 capital expenditures for information and business systems are primarily based on enhancing and upgrading existing technologies, system and business applications to leverage the capabilities of the existing applications and to sustain the existing infrastructure. These enhancements have been identified by the application users in conjunction with the information systems group as being necessary to maintain or improve business operations. This is common practice in other organizations that recognize the benefit of enhancing existing systems as compared to acquiring and implementing new systems, and is consistent with FortisBC's previous capital expenditure filings as approved by the BCUC. The 2009 plan also includes expenditures to acquire a Distribution Design Software Solution. The FortisBC Distribution Design group is planning to acquire a commercial off-the-shelf software tool to manage the design and estimating functions of distribution facilities. The proposed software solution will allow this work to be done with one application, as opposed to the many applications currently used by the group to perform design activities.

The following projects have been recognized as being critical to improving safety, productivity, customer service and efficiency by enhancing functionality and operability.

The following table shows the projects planned for 2009 and 2010.

Table 7.4
Information Systems

		2009 Total	**2010 Total**
		($000s)	
1	Infrastructure Upgrade	789	794
2	Desktop Infrastructure Upgrade	842	847
3	SAP & Operations System Enhancements	947	953
4	AM/FM Enhancements	211	423
5	Customer Service Systems Enhancements	789	794
6	SCADA Enhancements	790	688
7	Distribution Design Software	799	
8	**TOTAL**	**5,167**	**4,499**

The following provides details with respect to the projects planned for 2009 and 2010.

Infrastructure Upgrade

The infrastructure upgrade project includes replacing outdated hardware and software (operating systems and related server software) in the data centre and supporting infrastructure (switches and routers that tie the Wide Area Network together). There is approximately $2.6 million worth of hardware and software associated with the Company's Information System infrastructure. The life expectancy of the hardware infrastructure components is five years based on industry standards and manufacturer's support, while operating systems are typically upgraded every two years to maintain vendor support. The budget is predicated on a 20 percent replacement of the asset based on this five year life cycle. This avoids the complete replacement of all equipment once every five years and the resource issues and work disruption that would result.

Equipment and software designated for upgrade typically include servers at end of life, disk drives that have passed maximum life expectancy (over three terabytes of disk space in the data centre), networking infrastructure replacements (failed switches, routers and hubs) and operating system and database upgrades.

The following table show the expenditures for the past two years and forecast for 2009 and 2010. The increased upgrade requirement is due to the increased infrastructure that has been repatriated to FortisBC since 2004.

Infrastructure Upgrade

Year	2007	2008F	2009	2010
Cost ($000s)	357	255	789	794

Desktop Infrastructure Upgrade

The Desktop Infrastructure Upgrade includes Microsoft Office Suite and other job specific hardware and software upgrades for FortisBC's PC environment. It is a phased approach to keeping approximately 600 personal computers (PCs) current and supportable, rather than replacing all PC equipment and software every five years. The life expectancy of the desktop hardware is a maximum of five years based on industry standards and manufacturer's support. The phased strategy avoids the resourcing issues that happen with large wholesale changes. The total value of desktop hardware and related peripherals is approximately $2.9 million. The budget is predicated on a 20 percent replacement of the asset based on this five year life cycle. This avoids the complete replacement of all equipment every 5 years and the resource issues and work disruption that would result.

This project also includes the cost necessary to replace fax machines, telephones and photocopiers\printers to maintain reliability and compatibility with industry standards. This is also a staged approach based on standard lifecycles.

An asset management tool is used to track the age of all technology assets at FortisBC to ensure they are replaced in a timely manner and to realize maximum life expectancy without jeopardizing productivity.

The estimate for 2009 and 2010 is based on historical requirements. The following table shows the expenditures for the past two years and forecast for 2009 and 2010.

Desktop Infrastructure Upgrade

Year	2007	2008F	2009	2010
Cost ($000s)	657	769	842	847

SAP and Operations Based Application Enhancements

This project will fund any SAP and Operations based application enhancements that are required during the year. FortisBC has implemented much of the SAP suite to support a variety of the Company business functions which include Human Resources, Finance, Materials Management and Project Management.

This project also includes a number of Operations based applications, including Utility Risk Management used to track training and incidents, as well as the Cascade maintenance management system used for substation and generation equipment maintenance scheduling and planning.

SAP enhancement priorities include:

- enhancements to the financial module, such as International Financial Reporting Standards (IFRS) accounting requirements;
- payroll enhancements to the general ledger to meet business needs, such as changes to collective agreements, tax changes and reporting requirements; and

- enhancements to the Materials Management module, such as offline document processing and increased service Purchase Order functionality, material requirements planning to improve inventory control and pick list enhancements including consolidation of existing lists.

Operations Systems enhancement priorities include:

- interfacing SAP and Cascade maintenance management system;
- leveraging portal for single point of entry and employee self service, such as offline time management;
- continuing development of data cubes in the Business Warehouse to meet added reporting requirements;
- interfacing Utility Risk Management software with SAP Human Resources module;
- adding triggers to Generation maintenance management system; and
- access via Personal Digital Assistants devices, such as SAP requisitioning process.

The estimate for 2009 and 2010 is based on historical requirements and available resources. The following table show the expenditures for the past two years and forecast for 2009 and 2010.

SAP and Operations Based Applications Enhancements

Year	2007	2008F	2009	2010
Cost ($000s)	1,927	1,227	947	953

AM/FM Enhancements

FortisBC completed the implementation of the ESRI AM/FM system in 2008 which delivers comprehensive GIS, Asset Management and Facilities Management functionality and is identified as a core application. The ESRI system was chosen for its delivered functionality and the ability to accommodate enhancements to meet changing business needs.

AM/FM enhancement priorities include:

- enhancement of the field user's interface in the field to improve ease of use and productivity;
- data integrity tools to improve productivity when processing information packets submitted from the field;
- job processing enhancements to improve performance;
- implementing advanced tracing tools; and
- configuration changes to automate data entry.

The estimate for 2009 and 2010 is based on historical requirements and available resources. The following table show the expenditures for 2008 and forecast for 2009 and 2010.

AM/FM Enhancements

Year	**2008F**	**2009**	**2010**
Cost ($000s)	883	211	423

Customer Service System Enhancements

This project will fund enhancements to customer service related applications. The applications associated with the provision of customer service include the following: Customer Information System (CIS billing systems); the FortisBC internet web site (fortisbc.com) and FortisBC Intranet site; Contact Centre systems (Monet Contact Centre resource scheduling software); bill printing software (Metavante CSF) and a dispatch application. The enhancements undertaken in this project are focused on improving safety, customer service, employee services, productivity and access to customer and employee information.

Customer Service System enhancement priorities include:

- rate updates and tariff changes;
- interfacing CIS with dispatch and work management – single point of entry;

- upgrades and enhancements to Monet scheduling software to meet changing Contact Centre requirements and improve efficiency;
- enhancements to Metavante CSF bill print software to meet print vendor and Canada Post requirements;
- enhancements to the FortisBC Intranet to better serve employees and improve sharing and accessibility of departmental information;
- enhancements to the FortisBC Internet site to increase and improve customer self service capabilities, as well as improving the delivery of company information to the public, such as safety and PowerSense information; and
- enhancements to the dispatch system to improve field information for safety and productivity, such as a GPS interface for employees working in isolation.

The estimate for 2009 and 2010 is based on historical requirements and available resources. The following table show the expenditures for the past two years and forecast for 2009 and 2010.

Customer Service Systems Enhancements

	2007	**2008F**	**2009**	**2010**
Cost ($000s)	1,021	1,067	789	794

System Control Centre SCADA Enhancements

FortisBC completed an upgrade to the SCADA system in 2007. The Survalent Worldview SCADA system provides the system control center dispatchers control and visibility over the electrical network. It has been in place since 1989 and is a core application. The reliability of the power system in general and the supply to FortisBC customers is highly dependent on the reliability of the SCADA system.

SCADA enhancement priorities include:

- interfacing the Worldview SCADA software with ESRI AM/FM system for better continuity and safety;

- delivering SCADA information as a web service to better serve business partners, such as BC Hydro, Teck Cominco and Columbia Power Corporation;
- enhanced logging system for power wheeling transactions;
- enhancements to meet NERC requirements for system security and reliability; and
- enhancements to SCADA control systems to meet Energy Plan requirements or recommendations.

The estimate for 2009 and 2010 is based on historical requirements and available resources. The following table show the expenditures for the past two years and forecast for 2009 and 2010.

SCADA Systems Enhancements

Year	2007	2008F	2009	2010
Cost ($000s)	212	102	790	688

Distribution Design Software Solution

The FortisBC Distribution Design group is planning to acquire a commercial off-the-shelf software tool such as AutoDesk or Minor & Minor to manage the design and estimating function of distribution facilities. The proposed software solution will allow this work to be done in one tool as opposed to the many applications currently used by the group to perform design activities.

The new tool will improve the quality and efficiency with which construction packages are delivered by the Distribution Design group. Implementation of the new software will automate and regulate the application of FortisBC engineering and design criteria for both the external and internal design workforce. It will also ensure standards (distribution and drafting) are applied consistently. Further, it is intended that the software will integrate with core FortisBC applications eliminating the need to enter like data into multiple systems. Ultimately, the new application will produce a high quality, consistent and efficient product for the construction crews while improving the maintenance of data. The estimated cost of implementing the Distribution Design Software Solution is $799,000 in 2009. For further information on this system see Appendix 2.

TELECOMMUNICATIONS

The telecommunications capital budget is used to purchase new or replacement communications equipment.

This equipment includes landline equipment, VHF field communications equipment, microwave substation controls and the installation of isolation equipment when installing Telus lines into substations. These installations will provide voice as well as data and control communications as required.

The communications budget also covers upgrades and\or replacement of equipment that is used for remote control and operation of field devices from the SCC.

Telecommunications

Year	2009	2010
Cost ($000)	105	106

BUILDINGS

FortisBC has fifteen sites (ranging in age from 5 to 85 years) throughout the West Kootenay, Okanagan Valley and Princeton regions totalling approximately 228,800 square feet of office, shop, and warehouse space and approximately 51 acres of yard space. Of this, 125,000 square feet is owned and 104,500 square feet is leased.

The Facility Upgrades Project is primarily required to carry out property upgrades and building repairs necessary to conduct operational requirements in a safe, efficient and environmentally conscious manner. Site audits have been carried out at all facilities and the information has been utilized to identify deficiencies and upgrades to each facility. Site visits were also conducted with operations personnel to indentify any upgrades required for safety, health, and work efficiencies.

The increase in 2009 is the result of several initiatives including upgrades for safety and conservation purposes, and the acquisition of several emergency generators. A recent building audit identified a number of items directly impacting security, safety, health and environment.

These have been included as part of the 2009 upgrades at an estimated cost of $560,000. As part of FortisBC's environmental and energy conservation responsibility and in support of the Energy Plan, the Company has committed to reduce energy consumption and to support the environmental initiatives. Under this commitment each building will be audited and environmental upgrades unique to that site will be implemented. These upgrades will include such items as: drainage control, recycle systems, heat pump replacements, window replacements, insulation upgrades**,** Information Technology controls on servers, alternate energy projects, lighting upgrades with motion detection. The funds for these upgrades are estimated at $300,000 in 2009 and $290,000 in 2010. Following a review of the Company's Emergency Response Plan, FortisBC have also identified requirements for backup generators at a cost of approximately $350,000 to be installed at three designated emergency site facilities in 2009.

The Facility Emergency Project is required to address unforeseen items that arise that cannot be deferred to the next planning cycle.

The Construction Project Requirements are the facility additions or upgrades that are required as a result of increased material handling and warehousing associated with the construction of major capital projects.

FortisBC is undertaking a study in 2008 which will review security standards from a cross section of electric utilities. Following a review of these standards together with the Company's site information, any identified security deficiencies will be ranked and projects initiated accordingly. Due to a significant increase in the number of substation and storage yard break-ins, and the associated inherent risk to public safety, some of the upgrades may include the installation of security cameras, intrusion detection systems, and motion activated lighting.

Table 7.5
Buildings

	Location	Project	2009	2010
			($000s)	
1	All	Facility Upgrades	2,637	1,368
2	All	Facilities Emergency	88	89
3	All	Construction Projects Requirements	218	219
4	All	Security System upgrades	305	305
5	**Total**		**3,248**	**1,981**

FURNITURE AND FIXTURES

This project is required for the replacement of deteriorated furniture and the addition and modification of furniture to accommodate changing needs within the organization.

In 2003, the Company undertook an inventory of furniture at all sites. At that time the condition of the furniture was assessed, placing it in one of three categories (disposal, poor, and good). Using this process, together with the Company's Environment, Health and Safety Standard 108, (section 2.2) Monitoring the Work Environment, the capital requirements are updated each year. Typically chairs are replaced every five years and workstations reviewed for functionality every eight to ten years.

The estimated expenditure for this project is noted below.

Furniture and Fixtures

Year	2009	2010
Cost ($000)	347	393

TOOLS AND EQUIPMENT

This project involves the purchase of tools and equipment necessary to construct, operate, and maintain the generation, transmission, and distribution system. This budget covers all capital expenditures for tools and equipment in excess of $500 and includes replacement tools that have reached the end of their service life and additional tools that are more appropriate for the various trades from an ergonomic and\or safety perspective.

The estimated expenditure for tools and equipment is noted below.

Tools and Equipment

Year	**2009**	**2010**
Cost ($000)	572	575

Appendix 1

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-08

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for 2009/10 Capital Expenditure Plan

BEFORE: XXXXXX, Panel Chair and Commissioner
XXXXXX, Commissioner

Month XX, 2008

O R D E R

WHEREAS:

A. FortisBC Inc. filed its 2009-2010 Capital Expenditure Plan dated June 27, 2008 (the "2009/2010 Capital Plan", the "Application") pursuant to Sections 44.2(b) of the Utilities Commission Act ("the Act"); and

B. FortisBC Inc., in the filing applies for an order which states that the 2009/2010 Capital Plan meets the requirements of Section 44.2 (1) (a) and (b) and Section 45(6) of the Act, and, that the projects described in the 2009/2010 Capital Plan public interest pursuant to Section 44.2 (3) (a):

C. The Commission, by Order No. G-xx-08, established a written public hearing process and Regulatory Timetable for the review of the Application; and

D. On Month xx, 2008, the Commission issued Information Request No. 1 to FortisBC; and the Commission received responses to Information Request No. 1 on Month xx, 2008; and

E. On Month xx, 2008, a workshop was held with stakeholders;

F. On Month xx, 2008, the Commission issued Information Request No. 2 and Intervenors Information Request No. 1 to FortisBC; and FortisBC responded to Commission Information Request No. 2 and Intervenor Information Request No. 1 on Month xx, 2008; and

G. The Written Argument phase of the proceeding was completed when FortisBC filed its Reply Submission on Month xx, 2008; and

H. The Commission Panel has considered the Application, evidence, and submissions of intervenors and the Applicant.

NOW THEREFORE the Commission orders as follows:

1. The Application meets the requirements of Sections 44.2(1) and 45(6) of the Act.

2. The 2009/2010 Capital Plan is approved pursuant to Section 44.2(3) (a) of the Act.

DATED at the City of Vancouver, in the Province of British Columbia, this XX day of month 2008.

BY ORDER

Original signed by:

XXXXXXX
Panel Chair

Attachments

Appendix 2: Corra Linn Unit 2 Life Extension

Executive Summary

The Corra Linn Unit 2 life extension project is the eleventh project to be undertaken in the FortisBC generating station upgrade and life extension program that began in 1997. The program will address eleven of the fifteen FortisBC generating units on the Kootenay River, and is currently scheduled to be completed by 2012.

The scope of this project encompasses all activities required to replace or extend the life of all components of the Corra Linn Unit 2 generator. Many of the major components of this generating unit date back to the original commissioning date of 1932. The generator was last re-wound in 1940. The replaced or refurbished components will have expected life spans of between 30 and 50 years.

Each generating unit in the overall upgrade and life extension program is individually analyzed for the feasibility of increasing its capacity or energy output. This analysis is performed according to the terms of the FortisBC Entitlement Adjustment Agreement, which was negotiated with BC Hydro as part of the Canal Plant Agreement extension. In the case of Corra Linn Unit 2, the probability of achieving the incremental energy and capacity output does not justify the additional investment in an upgraded hydraulic turbine. However as with Corra Linn Unit 1 it is anticipated that the turbine is deteriorated and the existing turbine will be replaced in kind.

The project will follow the same condition assessment of major unit components and systems as previous upgrade and life extension projects. A turbine replacement condition assessment has yet to be completed which will determine if a new turbine or turbine refurbishment is required. The work scope and cost estimate have assumed that a turbine replacement is required.

Included in this project are the plant completion tasks that will be executed as all unit upgrades at Corra Linn have been completed. These tasks collectively capture the necessary improvements required to bring the entire plant up to a current level of technology, this also include upgrades to the plants ancillary systems and completion of plant documentation.

The life extension project being proposed is the least cost alternative of the three options considered. The other options were: 1) running the unit to failure and then mothballing, and; 2) running the unit to failure and then performing repair and life extension work. The comparison of Net Present Value (NPV) costs is shown in the table below:

Option	NPV Cost ($millions)	Assumptions
Run to failure in 2011 and do not repair	34.8	Purchase future replacement energy at blended rate of $38.0/MW.h
Run to failure in 2011, then do life extension	22.7	The unit does not fail before 2011
Planned life extension	18.4	The proposed project

The estimated capital cost for the proposed project is approximately $22.7 million, with expenditures of $0.1 million in 2009, $5.3 million in 2010, $9.3 million in 2011, and $8.0 million in 2012.

A financial analysis shows that if this unit failed and was not rebuilt, replacement power at a blended cost of no more than $15.53/MW.h would have to be sourced in order for the rate impact to be equivalent to the proposed project. This rate is significantly lower than FortisBC's current blended rate estimate of $38.0/MW.h which reasonably represents the cost of contracted long-term energy and capacity. The levelized rate impact of this project is 0.05 percent.

The shutdown period of the unit will be from August 2011 to December 2011, and the project is scheduled for overall completion by the end of 2012.

Background

In February 1997, Hatch Acres (then Acres International Ltd.) was commissioned to perform the "Kootenay River Hydroelectric Resource Optimization Study" which confirmed the feasibility of performing major life extension work on FortisBC's Kootenay River hydroelectric plants. In November 1998, Hatch Acres updated the study using current life extension and energy costs. The alternatives examined were:

- Run the plants until failure without life extension;
- Perform life extension; and

- Perform turbine upgrades.

The results of the analysis confirmed that the overall life extension program would provide robust benefits with net present value (“NPV”) benefits between $50 and $130 million, dependent on sensitivity analyses, for all four plants. In addition, the study concluded that taken as a whole, at least one turbine upgrade at each plant was justifiable.

Based on this analysis, a proposal was made to the FortisBC Board of Directors as well as the BC Utilities Commission to embark upon a multi-year upgrade and life extension program. The projects that have been completed or initiated under this program are as follows:

- 1997-1998 Lower Bonnington Unit 2 Upgrade and Life Extension;
- 1999-2000 Corra Linn Unit 3 Life Extension;
- 2000-2001 South Slocan Unit 2 Upgrade and Life Extension;
- 2003-2004 Upper Bonnington Unit 5 Upgrade and Life Extension;
- 2004-2005 Upper Bonnington Unit 6 Life Extension;
- 2005-2006 Lower Bonnington Unit 1 Upgrade and Life Extension;
- 2006-2007 Lower Bonnington Unit 3 Upgrade and Life Extension;
- 2007-2011 South Slocan Unit 1 Life Extension;
- 2007-2009 South Slocan Unit 3 Life Extension; and
- 2008-2011 Corra Linn Unit 1 Life Extension.

FortisBC crews have also gained considerable experience in performing generating unit upgrading and life extension through the successful completion of the following projects for external clients:

- 1995-1996 Waneta Unit 3 Upgrade;
- 1999-2000 Brilliant Unit 2 Upgrade and Life Extension;
- 2001-2002 Brilliant Unit 1 Upgrade and Life Extension;
- 2001-2002 Brilliant Unit 4 Upgrade and Life Extension;
- 2002-2003 Brilliant Unit 3 Upgrade and Life Extension;
- 2002-2003 Waneta Unit 1 Upgrade and Life Extension;
- 2003-2004 Waneta Unit 2 Upgrade and Life Extension; and

- 2006-2007 Waneta Unit 4 Upgrade and Life Extension.

The Corra Linn Unit 2 life extension project is scheduled for completion in 2012.

Options Considered

Three options have been considered in the analysis of Corra Linn Unit 2. These options are:

- run to failure and mothball with purchased energy replacement;
- run to failure followed by emergency repair and life extension; or
- a planned life extension.

Financial Analysis/Assumptions Used

The energy and capacity available from Corra Linn Unit 2 is defined in the re-negotiated Canal Plant Agreement ("CPA"). The CPA came into effect on April 12, 2006 and will continue for at least 30 years, after which time in may be terminated on five years notice. The CPA specifies that the failure of Corra Linn Unit 2 will reduce the CPA entitlements by 92 Gigawatt-hours (GW.h) and 15 Megawatts (MW) annually.

The long-term replacement cost for this energy and capacity is difficult to quantify, for two reasons. First, there is forward energy market uncertainty, and second, certain existing power supply contracts provide portions of energy and/or capacity in unequal proportions, thus affecting the "blended rate" of the replacement energy. A "blended rate" of $38.0 per MW.h is proposed to reasonably represent the cost of long-term energy and capacity replacement.

As described in the previous section, the key comparison for this project is the difference between the planned life extension option and the emergency life extension option. The other option (mothball) is an extension of the run-to-failure option. The financial comparisons, as shown earlier, are repeated below:

Option	NPV Cost ($millions)	Assumptions
Run to failure in 2011 and do not repair	34.8	Purchase future replacement energy at blended rate of $38/MW.h
Run to failure in 2011, then do life extension	22.7	The unit does not fail before 2011
Planned life extension	18.4	The proposed project

The NPV of the revenue requirements for the proposed planned life extension project is approximately $18.2 million and the supporting spreadsheet is included as Appendix A. This is based on a project estimate of approximately $22.7 million. The levelized one-time rate impact is 0.05%.

The analysis for the "run to failure and repair" option shows that if the unit lasted until 2011 and then failed, the NPV of the revenue requirement would be $22.7 million. This is due primarily to the fact that the estimated incremental cost for an emergency life extension repair is approximately $5.8 million. Given that the unit's components have already lasted far longer than their expected lifetimes and the condition assessments of the unit show continued deterioration it is unlikely that the unit will last until 2011. Furthermore, with the Brilliant Expansion project in service as of September 2007, it is expected that the FortisBC Kootenay River Plants will be required to cycle between full load and no load much more often than had been the past practice. This additional cycling will cause thermal stresses that rapidly increase the rate of deterioration.

The mothball option, where all the lost entitlement energy after unit failure is replaced from the market or other power supply contracts (instead of unit repair in 2011) shows that the NPV of the revenue requirement is over $34.8 million.

Option Selected

The probability of continuing to operate until 2011 without a failure is very low considering the age and condition of equipment. Therefore, the option selected is a planned life extension (with possible turbine replacement) by 2011. This timing is considered "just in time" with respect to life expectancy of the equipment, as discussed below.

The unit was installed in 1932 and the generator was last re-wound in 1940. Components have expected life spans of between 30 and 50 years, depending on usage. The 1997 Hatch Acres "Kootenay River Hydroelectric Resource Optimization Study" estimated that the Corra Linn Unit 2 windings were likely to fail by 2005. Therefore, there is a high risk the generator windings may fail at any time. This would involve an estimated unit out of service time of approximately 50 weeks along with a premium for manufacturing under emergency conditions. The estimated incremental cost for an emergency life extension repair is $5.8 million, which includes the incremental outage cost associated with the longer down time.

Implementation Process

The timeline for the project is as follows:

Second Quarter 2008

FortisBC's Board of Directors approves the expenditure of $22.7 million to proceed with the life extension of Unit 2 at Corra Linn.

Third Quarter 2008

Commission approval of Capital Expenditure Plan.

Fourth Quarter 2009

Contracts will be executed for large and long delivery equipment items, e.g. turbine, transformer, excitation equipment, generator rewind, unit control, governor, protection, and control.

May 2011

Work begins on installation of equipment that can be installed prior to the unit outage, e.g. cable trays and cable, governor, excitation equipment and cabinets.

August 2011

Unit 2 taken out of service for life extension work.

December 2011

Unit 2 returned to service.

December 31, 2012

Formal project completion.

Other Considerations

None

Appendix A

Corra Linn Unit 2 Life Extension (Preferred Option)

Line		0	1	2	3	4	5	6	11	16	26	36	46
No.		**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-20**	**Dec-25**	**Dec-35**	**Dec-45**	**Dec-55**
	Summary												
	Revenue Requirements												
1	Annual Operating Expense	0	0	(100)	(100)	0	0	0	0	0	0	0	0
2	Depreciation Expense	0	0	0	320	493	493	493	493	493	493	493	493
3	Carrying Costs	0	0	589	1,467	1,736	1,699	1,662	1,477	1,291	921	551	180
4	Income Tax	(2)	(101)	(329)	(276)	(57)	(22)	11	130	199	245	230	188
5	Yearly Revenue Requirement for Project	(2)	(101)	161	1,410	2,172	2,170	2,165	2,100	1,983	1,659	1,274	861
	Net Present Value of Revenue Requirements at a Discount Rate of 6%	**1,504**											
	Net Present Value of Revenue Requirements at a Discount Rate of 8%	**1,492**											
6	**Net Present Value of Revenue Requirements at a Discount Rate of 10%**	**1,452**											
7	**Rate Impact**												
8	Revenue Requirement Inflation	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
9	Cumulative Revenue Requirement Inflation	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	26.82%	40.02%	70.69%	108.07%	153.63%
10	Forecast Revenue Requirements	225,369	229,874	234,373	239,324	245,356	250,997	255,972	282,336	311,393	378,832	461,041	561,309
11	Incremental Revenue Requirements	(2)	(99)	262	1,249	762	(1)	(5)	(18)	(27)	(36)	(40)	(42)
12	Rate Impact	0.0%	0.0%	0.1%	**0.5%**	**0.3%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Cumulative Rate Impact	0.00%	-0.04%	0.07%	0.59%	0.90%	0.90%	0.90%	0.88%	0.84%	0.74%	0.65%	0.57%
14	Discounted Yearly Revenue Requirement for Project at a Discount Rate of 6%	(2)	(94)	233	1,049	603	(1)	(3)	(9)	(10)	(8)	(5)	(3)
15	Discounted Yearly Revenue Requirement for Project at a Discount Rate of 8%	(2)	(92)	224	992	560	(1)	(3)	(8)	(8)	(5)	(3)	(1)
14	Discounted Yearly Revenue Requirement for Project at a Discount Rate of 10%	(2)	(90)	216	939	520	(1)	(3)	(6)	(6)	(3)	(1)	(1)
	NPV of Project / Total Revenue Requirements at a Discount Rate of 6%	**0.03%**											
	NPV of Project / Total Revenue Requirements at a Discount Rate of 8%	**0.04%**											
15	**NPV of Project / Total Revenue Requirements at a Discount Rate of 10%**	**0.05%**											
		1	2	3	4	5	6	7	12	17	27	37	47
16	**Discounted Cash Flow**												
17	Net Power Purchase Expense	0	0	(100)	(100)	0	0	0	0	0	0	0	0
18	Income Tax	(2)	(101)	(329)	(276)	(57)	(22)	11	130	199	245	230	188
19	Capital Cost	0	0	14,696	7,984	0	0	0	0	0	0	0	0
20	Total Revenue Requirement for Project	(2)	(101)	14,268	7,607	(57)	(22)	11	130	199	245	230	188
	Project Net Present Value at at a Discount Rate of 6%	**20,815**											
	Project Net Present Value at at a Discount Rate of 8%	**19,388**											
21	**Project Net Present Value at at a Discount Rate of 10%**	**18,245**											

Line		0	1	2	3	4	5	6	11	16	26	36	46
No.		**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-20**	**Dec-25**	**Dec-35**	**Dec-45**	**Dec-55**
22	**Regulatory Assumptions**												
23	Equity Component	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
24	Debt Component	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
25	Equity Return	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
26	Debt Return	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
27	AFUDC	6.30%	6.40%	6.40%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
28	**Capital Cost**												
29	Labour	0	3,736	3,930	4,420								
30	Contractors	80	305	2,390	525								
31	Materials	0	135	300	475								
32	Other	10	315	855	425								
33	AFUDC	1	106	583	1,145								
34	Capitalized Overheads	5	263	598	468								
35	Absorption Overheads	8	404	673	526								
36	Total Construction Cost in Year (Less Land Cost)	104	5,264	9,328	7,984	0	0	0	0	0	0	0	0
37	Cumulative Construction Cost	104	5,368	14,696	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
38	Land	0	0										
40	Total Capital Cost in Year	104	5,264	9,328	7,984	0	0	0	0	0	0	0	0
41	Cumulative Capital Cost	104	5,368	14,696	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
39	Cost of Removal	0	0	1,005	0							0	0
41	Total Construction Cost in Year	104	5,264	10,333	7,984	0	0	0	0	0	0	0	0
42	Additions to Plant in Service	0	0	14,696	7,984	0	0	0	0	0	0	0	0
43	Cummulative Additions to Plant	0	0	14,696	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
44	CWIP	104	5,368	0	0	0	0	0	0	0	0	0	0
45	**Annual Operating Costs / (Savings)**												
46	Operating & Maintenance Cost Savings	-	-	(100)	(100)								
47	Total Incremental Operating Costs (Savings)	0	0	(100)	(100)	0	0	0	0	0	0	0	0
48	**Depreciation Expense**												
49	Opening Cash Outlay	0	0	0	14,696	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
50	Additions in Year (Without Land-Since no Depreciation for Land)	0	0	14,696	7,984	0	0	0	0	0	0	0	0
51	Cumulative Total	0	0	14,696	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
52	Depreciation Rate - composite average	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%
53	Depreciation Expense (Without Land)	0	0	0	320	493	493	493	493	493	493	493	493
54	**Net Book Value**												
55	Gross Property (With land)	0	0	14,696	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680	22,680
56	Accumulated Depreciation (net of cost of removal)	0	0	1,005	685	192	(301)	(795)	(3,261)	(5,727)	(10,660)	(15,593)	(20,526)
		0	0	15,701	23,366	22,872	22,379	21,886	19,419	16,953	12,020	7,087	2,154

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	46 Dec-55
57	Land (included in gross property above)	0	0	0	0	0	0	0	0	0	0	0	0
58	Net Book Value	0	0	15,701	23,366	22,872	22,379	21,886	19,419	16,953	12,020	7,087	2,154
59	Carrying Costs on Average NBV												
60	Return on Equity	0	0	283	705	834	816	799	710	621	443	265	87
61	Interest Expense	0	0	306	762	902	882	863	767	671	478	286	94
62	Total Carrying Costs	0	0	589	1,467	1,736	1,699	1,662	1,477	1,291	921	551	180
63	**Income Tax Expense**												
64	Combined Income Tax Rate	30.00%	29.00%	27.50%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
65													
66	Income Tax on Equity Return												
67	Return on Equity	0	0	283	705	834	816	799	710	621	443	265	87
68	Gross up for revenue (Return / (1- tax rate)	0	0	391	952	1,127	1,103	1,079	959	839	598	358	117
69	Income tax on Equity Return	0	0	107	248	293	287	281	249	218	155	93	30
70	Income Tax on Timing Differences												
71	Depreciation Expense	0	0	0	320	493	493	493	493	493	493	493	493
72	Capitalized OH - 100% deduction	5	263	598	468	0	0	0	0	0	0	0	0
72	Less: Capital Cost Allowance	(0)	(15)	552	1,344	1,491	1,372	1,262	832	548	238	103	45
73	Total Timing Differences	(4)	(247)	(1,150)	(1,492)	(998)	(878)	(769)	(338)	(55)	255	390	448
74	Gross up for tax (Total Timing Differences/(1-tax rate))	(6)	(348)	(1,586)	(2,016)	(1,348)	(1,187)	(1,039)	(457)	(74)	345	527	606
75	Income tax on Timing Differences	(2)	(101)	(436)	(524)	(351)	(309)	(270)	(119)	(19)	90	137	158
76	Total Income Tax	(2)	(101)	(329)	(276)	(57)	(22)	11	130	199	245	230	188
77	**Capital Cost Allowance**												
78	Opening Balance - UCC (Undepreciated Capital Cost)	0	(6)	(359)	13,609	18,637	17,146	15,774	10,397	6,852	2,976	1,293	562
79	Total Plant in Service (includes salvage, excludes capitalized OH and AFUDC)	(6)	(368)	14,521	6,371	0	0	0	0	0	0	0	0
80	Subtotal UCC	(6)	(374)	14,161	19,980	18,637	17,146	15,774	10,397	6,852	2,976	1,293	562
81	Capital Cost Allowance Rate	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
82	CCA on Opening Balance	0	(0)	(29)	1,089	1,491	1,372	1,262	832	548	238	103	45
83	CCA on Capital Expenditures (1/2 yr rule)	(0)	(15)	581	255	0	0	0	0	0	0	0	0
84	Total CCA	(0)	(15)	552	1,344	1,491	1,372	1,262	832	548	238	103	45
85	Ending Balance UCC	(6)	(359)	13,609	18,637	17,146	15,774	14,512	9,565	6,304	2,738	1,190	517

Corra Linn Unit 2 Run-till-failure & Life Extension/Emergency Repair

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	44 Dec-53
	Summary												
	Revenue Requirements												
1	Annual Operating Expense	0	0	(100)	(100)	0	0	0	0	0	0	0	0
2	Depreciation Expense	0	0	0	613	613	613	613	613	613	613	613	613
3	Carrying Costs	0	0	1,054	2,085	2,039	1,993	1,947	1,717	1,487	1,026	566	197
4	Income Tax	0	0	(196)	(122)	(75)	(32)	7	151	233	287	267	226
5	Yearly Revenue Requirement for Project	0	0	759	2,477	2,578	2,575	2,568	2,482	2,333	1,927	1,446	1,037
6	Net Present Value of Revenue Requirements at a Discount Rate of 10%	**1,820**											
7	**Rate Impact**												
8	Revenue Requirement Inflation	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
9	Cumulative Revenue Requirement Inflation	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	26.82%	40.02%	70.69%	108.07%	143.79%
10	Forecast Revenue Requirements	225,369	229,876	234,474	239,922	246,423	251,404	256,377	282,723	311,750	379,109	461,224	539,733
11	Incremental Revenue Requirements	0	0	759	1,718	101	(3)	(7)	(23)	(34)	(45)	(50)	(52)
12	Rate Impact	0.0%	0.0%	0.3%	**0.7%**	**0.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Cumulative Rate Impact	0.00%	0.00%	0.32%	1.04%	1.08%	1.08%	1.08%	1.05%	1.00%	0.88%	0.77%	0.68%
14	Discounted Yearly Revenue Requirement for Project at a Discount Rate of 10%	0	0	627	1,291	69	(2)	(4)	(8)	(7)	(4)	(2)	(1)
15	**NPV of Project / Total Revenue Requirements at a Discount Rate of 10%**	**0.06%**											
		1	2	3	4	5	6	7	12	17	27	37	45
16	**Discounted Cash Flow**												
17	Net Power Purchase Expense	0	0	(100)	(100)	0	0	0	0	0	0	0	0
18	Income Tax	0	0	(196)	(122)	(75)	(32)	7	151	233	287	267	226
19	Capital Cost	0	0	27,077	0	0	0	0	0	0	0	0	0
20	Total Revenue Requirement for Project	0	0	26,782	(222)	(75)	(32)	7	151	233	287	267	226
21	Project Net Present Value at at a Discount Rate of 10%	**22,917**											
22	**Regulatory Assumptions**												
23	Equity Component	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
24	Debt Component	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
25	Equity Return	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
26	Debt Return	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
27	AFUDC	6.30%	6.40%	6.40%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	44 Dec-53
28	**Capital Cost**												
29	Labour	0		13,516									
30	Contractors	0		5,632									
31	Materials	0		3,379									
32	Other	0		0									
33	AFUDC	0		721									
34	Capitalized Overheads	0		1,802									
35	Absorption Overheads	0		2,027									
36	Total Construction Cost in Year (Less Land Cost)	0	0	27,077	0	0	0	0	0	0	0	0	0
37	Cumulative Construction Cost	0	0	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077
38	Land	0	0										
40	Total Capital Cost in Year	0	0	27,077	0	0	0	0	0	0	0	0	0
41	Cumulative Capital Cost	0	0	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077
39	Cost of Removal	0	0	1,005	0							0	0
41	Total Construction Cost in Year	0	0	28,082	0	0	0	0	0	0	0	0	0
42	Additions to Plant in Service	0	0	27,077	0	0	0	0	0	0	0	0	0
43	Cummulative Additions to Plant	0	0	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077
44	CWIP	0	0	0	0	0	0	0	0	0	0	0	0
45	**Annual Operating Costs / (Savings)**												
46	Operating & Maintenance Cost Savings	-	-	(100)	(100)								
47	Total Incremental Operating Costs (Savings)	0	0	(100)	(100)	0	0	0	0	0	0	0	0
48	**Depreciation Expense**												
49	Opening Cash Outlay	0	0	0	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077
50	Additions in Year (Without Land-Since no Depreciation for Land)	0	0	27,077	0	0	0	0	0	0	0	0	0
51	Cumulative Total	0	0	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077
52	Depreciation Rate - composite average	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%
53	Depreciation Expense (Without Land)	0	0	0	613	613	613	613	613	613	613	613	613
54	**Net Book Value**												
55	Gross Property (With land)	0	0	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077	27,077
56	Accumulated Depreciation (net of cost of removal)	0	0	1,005	392	(222)	(835)	(1,448)	(4,515)	(7,581)	(13,714)	(19,847)	(24,754)
		0	0	28,082	27,469	26,856	26,243	25,629	22,563	19,496	13,363	7,230	2,324
57	Land (included in gross property above)	0	0	0	0	0	0	0	0	0	0	0	0
58	Net Book Value	0	0	28,082	27,469	26,856	26,243	25,629	22,563	19,496	13,363	7,230	2,324

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	44 Dec-53
59	Carrying Costs on Average NBV												
60	Return on Equity	0	0	507	1,002	980	958	936	825	714	493	272	95
61	Interest Expense	0	0	548	1,083	1,059	1,035	1,011	892	772	533	294	103
62	Total Carrying Costs	0	0	1,054	2,085	2,039	1,993	1,947	1,717	1,487	1,026	566	197
63	**Income Tax Expense**												
64	Combined Income Tax Rate	30.00%	29.00%	27.50%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
65													
66	Income Tax on Equity Return												
67	Return on Equity	0	0	507	1,002	980	958	936	825	714	493	272	95
68	Gross up for revenue (Return / (1- tax rate)	0	0	699	1,354	1,324	1,294	1,265	1,115	966	666	367	128
69	Income tax on Equity Return	0	0	192	352	344	337	329	290	251	173	96	33
70	Income Tax on Timing Differences												
71	Depreciation Expense	0	0	0	613	613	613	613	613	613	613	613	613
72	Capitalized OH - 100% deduction	0	0										
72	Less: Capital Cost Allowance	0	0	1,022	1,963	1,806	1,661	1,529	1,007	664	288	125	64
73	Total Timing Differences	0	0	(1,022)	(1,350)	(1,193)	(1,048)	(915)	(394)	(51)	325	488	549
74	Gross up for tax (Total Timing Differences/(1-tax rate))	0	0	(1,410)	(1,824)	(1,612)	(1,416)	(1,237)	(533)	(68)	439	659	742
75	Income tax on Timing Differences	0	0	(388)	(474)	(419)	(368)	(322)	(138)	(18)	114	171	193
76	Total Income Tax	0	0	(196)	(122)	(75)	(32)	7	151	233	287	267	226
77	**Capital Cost Allowance**												
78	Opening Balance - UCC (Undepreciated Capital Cost)	0	0	0	24,537	22,574	20,768	19,107	12,593	8,300	3,605	1,566	804
79	Total Plant in Service (includes salvage, excludes capitalized OH and AFUDC)	0	0	25,559	0	0	0	0	0	0	0	0	0
80	Subtotal UCC	0	0	25,559	24,537	22,574	20,768	19,107	12,593	8,300	3,605	1,566	804
81	Capital Cost Allowance Rate	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
82	CCA on Opening Balance	0	0	0	1,963	1,806	1,661	1,529	1,007	664	288	125	64
83	CCA on Capital Expenditures (1/2 yr rule)	0	0	1,022	0	0	0	0	0	0	0	0	0
84	Total CCA	0	0	1,022	1,963	1,806	1,661	1,529	1,007	664	288	125	64
85	Ending Balance UCC	0	0	24,537	22,574	20,768	19,107	17,578	11,585	7,636	3,317	1,441	739

Corra Linn Unit 2 Run-till-failure (Mothball) and Purchase Energy Replacement

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	44 Dec-53
	Summary												
	Revenue Requirements												
1	Annual Operating Expense	0	0	3,129	3,195	3,262	3,331	3,401	3,773	4,186	5,153	6,344	7,491
2	Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0
3	Carrying Costs	0	0	80	159	159	159	159	159	159	159	159	159
4	Income Tax	0	0	(18)	(30)	(26)	(22)	(18)	(2)	8	18	23	25
5	Yearly Revenue Requirement for Project	0	0	3,191	3,324	3,396	3,468	3,542	3,930	4,353	5,331	6,526	7,675
6	**Net Present Value of Revenue Requirements at a Discount Rate of 10%**	**3,364**											
7	**Rate Impact**												
8	Revenue Requirement Inflation	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
9	Cumulative Revenue Requirement Inflation	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	26.82%	40.02%	70.69%	108.07%	143.79%
10	Forecast Revenue Requirements	225,369	229,876	234,474	242,355	247,271	252,221	257,270	284,068	313,648	382,361	466,123	546,165
11	Incremental Revenue Requirements	0	0	3,191	133	72	73	74	80	88	107	131	154
12	Rate Impact	0.0%	0.0%	1.4%	**0.1%**	**0.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Cummulative Rate Impact	0.00%	0.00%	1.36%	1.42%	1.45%	1.48%	1.50%	1.65%	1.79%	2.08%	2.36%	2.59%
14	Discounted Yearly Revenue Requirement for Project at a Discount Rate of 10%	0	0	2,637	100	49	45	42	28	19	9	4	2
15	**NPV of Project / Total Revenue Requirements at a Discount Rate of 10%**	**0.11%**											
		1	2	3	4	5	6	7	12	17	27	37	45
16	**Discounted Cash Flow**												
17	Net Power Purchase Expense	0	0	3,129	3,195	3,262	3,331	3,401	3,773	4,186	5,153	6,344	7,491
18	Income Tax	0	0	(18)	(30)	(26)	(22)	(18)	(2)	8	18	23	25
19	Capital Cost	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Revenue Requirement for Project	0	0	3,112	3,165	3,237	3,309	3,383	3,771	4,194	5,172	6,367	7,516
21	**Project Net Present Value at a Discount Rate of 10%**	**34,492**											
22	**Regulatory Assumptions**												
23	Equity Component	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
24	Debt Component	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
25	Equity Return	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
26	Debt Return	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
27	AFUDC	6.30%	6.40%	6.40%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	44 Dec-53
28	**Capital Cost**												
29	Labour	0											
30	Contractors	0											
31	Materials	0											
32	Other	0											
33	AFUDC	0											
34	Capitalized Overheads	0											
35	Absorption Overheads	0											
36	Total Construction Cost in Year (Less Land Cost)	0	0	0	0	0	0	0	0	0	0	0	0
37	Cumulative Construction Cost	0	0	0	0	0	0	0	0	0	0	0	0
38	Land	0	0										
40	Total Capital Cost in Year	0	0	0	0	0	0	0	0	0	0	0	0
41	Cumulative Capital Cost	0	0	0	0	0	0	0	0	0	0	0	0
39	Cost of Removal	0	0	2,118	0							0	0
41	Total Construction Cost in Year	0	0	2,118	0	0	0	0	0	0	0	0	0
42	Additions to Plant in Service	0	0			0	0	0	0	0	0	0	0
43	Cummulative Additions to Plant	0	0	0	0	0	0	0	0	0	0	0	0
44	CWIP	0	0	0	0	0	0	0	0	0	0	0	0
45	**Annual Operating Costs / (Savings)**												
46	Operating & Maintenance Cost Savings	-	-	3,129	3,195	3,262	3,331	3,401	3,773	4,186	5,153	6,344	7,491
47	Total Incremental Operating Costs (Savings)	0	0	3,129	3,195	3,262	3,331	3,401	3,773	4,186	5,153	6,344	7,491
48	**Depreciation Expense**												
49	Opening Cash Outlay	0	0	0	0	0	0	0	0	0	0	0	0
50	Additions in Year (Without Land-Since no Depreciation for Land)	0	0	0	0	0	0	0	0	0	0	0	0
51	Cumulative Total	0	0	0	0	0	0	0	0	0	0	0	0
52	Depreciation Rate - composite average	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%
53	Depreciation Expense (Without Land)	0	0	0	0	0	0	0	0	0	0	0	0
54	**Net Book Value**												
55	Gross Property (With land)	0	0	0	0	0	0	0	0	0	0	0	0
56	Accumulated Depreciation (net of cost of removal)	0	0	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
		0	0	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
57	Land (included in gross property above)	0	0	0	0	0	0	0	0	0	0	0	0
58	Net Book Value	0	0	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
59	Carrying Costs on Average NBV												
60	Return on Equity	0	0	38	76	76	76	76	76	76	76	76	76
61	Interest Expense	0	0	41	83	83	83	83	83	83	83	83	83
62	Total Carrying Costs	0	0	80	159	159	159	159	159	159	159	159	159

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	11 Dec-20	16 Dec-25	26 Dec-35	36 Dec-45	44 Dec-53
63	**Income Tax Expense**												
64	Combined Income Tax Rate	30.00%	29.00%	27.50%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
65													
66	Income Tax on Equity Return												
67	Return on Equity	0	0	38	76	76	76	76	76	76	76	76	76
68	Gross up for revenue (Return / (1- tax rate)	0	0	53	103	103	103	103	103	103	103	103	103
69	Income tax on Equity Return	0	0	14	27	27	27	27	27	27	27	27	27
70	Income Tax on Timing Differences												
71	Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0
72	Capitalized OH - 100% deduction	0	0										
72	Less: Capital Cost Allowance	0	0	85	163	150	138	127	83	55	24	10	5
73	Total Timing Differences	0	0	(85)	(163)	(150)	(138)	(127)	(83)	(55)	(24)	(10)	(5)
74	Gross up for tax (Total Timing Differences/(1-tax rate))	0	0	(117)	(220)	(202)	(186)	(171)	(113)	(74)	(32)	(14)	(7)
75	Income tax on Timing Differences	0	0	(32)	(57)	(53)	(48)	(45)	(29)	(19)	(8)	(4)	(2)
76	Total Income Tax	0	0	(18)	(30)	(26)	(22)	(18)	(2)	8	18	23	25
77	**Capital Cost Allowance**												
78	Opening Balance - UCC (Undepreciated Capital Cost)	0	0	0	2,033	1,871	1,721	1,583	1,044	688	299	130	67
79	Total Plant in Service (includes salvage, excludes capitalized OH and AFUDC)	0	0	2,118	0	0	0	0	0	0	0	0	0
80	Subtotal UCC	0	0	2,118	2,033	1,871	1,721	1,583	1,044	688	299	130	67
81	Capital Cost Allowance Rate	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
82	CCA on Opening Balance	0	0	0	163	150	138	127	83	55	24	10	5
83	CCA on Capital Expenditures (1/2 yr rule)	0	0	85	0	0	0	0	0	0	0	0	0
84	Total CCA	0	0	85	163	150	138	127	83	55	24	10	5
85	Ending Balance UCC	0	0	2,033	1,871	1,721	1,583	1,457	960	633	275	119	61

Appendix 3: Distribution Design Software Solution

Executive Summary

The FortisBC Distribution Design group is seeking a commercial off-the-shelf software tool to manage the design and estimating function of distribution facilities. The proposed software solution will allow this work to be done in one tool as opposed to the many applications currently used by the group to perform design activities.

The new tool will improve the quality and efficiency with which construction packages are delivered by the Distribution Design group. Implementation of the new software will automate and regulate the application of FortisBC engineering and design criteria for both external and internal design workforce. Likewise, it will ensure standards (distribution and drafting) are applied consistently. Further, it is intended the software will integrate with core FortisBC applications and eliminate the need to enter like data into multiple systems. Ultimately, the new application will provide a high quality, consistent and efficient product to our construction crews while improving the maintenance of data. It is anticipated that the new software will provide savings of approximately $320,000 in capital expenditures based on a decrease in redundant data entry and a reduction in costs incurred by warehouse staff, designers and power line technicians to make necessary corrections associated with unsuitable designs.

This project is scheduled to be completed in 2009 with an estimated cost of approximately $800,000.

Background

FortisBC currently utilizes several applications to design, estimate, reserve materials and produce a construction package for distribution line work.

Work is initiated by way of a customer request for a new connect at the Contact Center or through system upgrade requirements recognized by FortisBC's planning department. All design work requests are entered by the requesting party into the Open Items Database (OID). This tool houses the project activity data and measures performance on key project deliverables. Designers are assigned work through the OID.

Depending on the complexity of the design, the assigned designer may choose to create the design drawing in either AutoCad (AC) or Field View (FV), and to a limited extent AM/FM. Both of these design drawing tools (AC & FV) produce a drawing that has no ability to communicate compatible unit and design related data to FortisBC's AM/FM or SAP systems.

To produce a design, the designer must refer to company design criteria and standards manuals to ensure the design conforms to pre-determined design parameters.

Project estimates are created in the 'Workbook'. The 'Workbook' is a Microsoft Excel based file that contains standard construction package forms. A compatible unit and loadings calculator is also contained within the Workbook that determines both company and 3rd party costs for a project.

Once a list of compatible units is determined in the Workbook, this information is entered into SAP within an order created for the project. SAP creates a list of materials based on the compatible units entered, and this list is made available through SAP to the companies' purchasing and warehouse staff in order that they may procure the materials for the project based on material requirement dates established by design staff in SAP.

Once materials are arranged for the project, and all design requirements are completed (these requirements are tracked and measured through the OID), the project is either dispatched or scheduled by distribution design staff with the Dispatch, Resource and Scheduling group through either a Outlook based dispatch system (small work orders) or face to face negotiations with construction and scheduling staff into a project scheduling tool (large projects). As construction activities commence, all actual costs related to the project are recorded against the order created in SAP.

Upon project completion, the OID is updated with that project status, marked up 'as built' construction drawings are returned from the field and entered by a draftsman into AM/FM. SAP orders are then reconciled and closed by administration staff. CIS related data is extracted by Customer Service staff from both the Open Items Database and /or the related dispatch order(s).

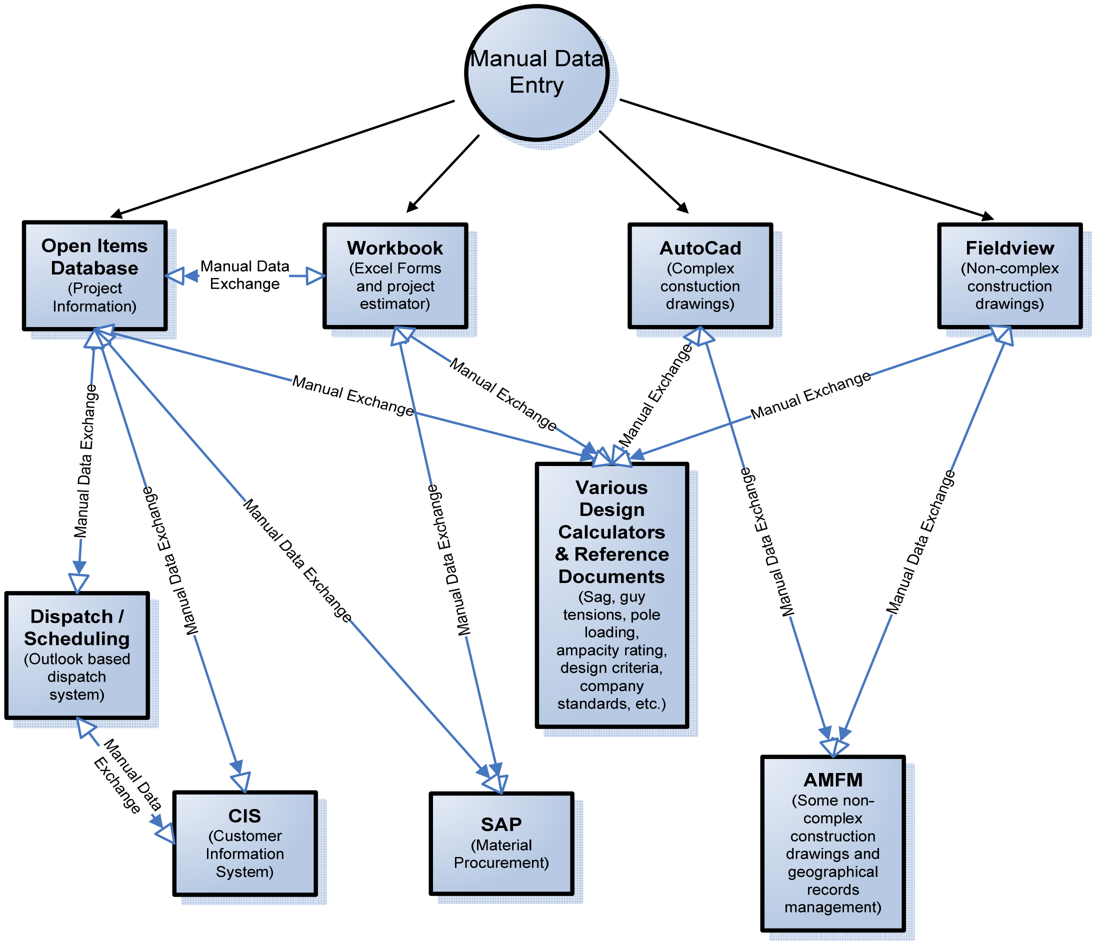

Figure 1 - FortisBC Distribution Projects
Current State

With the exception of AutoCad and CIS, the current complement of tools used by the FortisBC Distribution Design group has been in use since approximately 2002. These systems were adopted from FortisAlberta, although some minor modifications have occurred to some of the tools to better fit FortisBC's operating environment.

NEED FOR AN INTEGRATED DESIGN TOOL

Reduce data entry into multiple systems:

Although the various systems used by the Distribution Design Group each provide a reasonable level of functionality, they are all stand-alone systems with no integration or automated data sharing between them. This forces design staff to re-enter the same data into multiple applications to produce any one project. Obviously this existing requirement for repetitive entry of like information into several systems is an inefficient use of design staff's time. Further, because the same data is manually entered several times there is an increased risk the data will be entered incorrectly in one or more of the databases, and may significantly compromise the integrity of the data. It is anticipated that the new distribution design software would reduce the redundant data entry cost by approximately $90,000 per year.

Maintain adherence to FortisBC standards and design criteria:

FortisBC has developed and documented a comprehensive set of distribution design criteria and distribution standards manuals, however due to ongoing updates in standards as well as staffing changes, there is difficulty in maintaining a high level of familiarity with these documents among both internal and external design staff. Consequently, many designs are returned to the Designer for edits until designs meet FortisBC design criteria and standards. This increases the costs and compromises the quality of the designs issued. When inappropriate designs are issued additional cost are incurred by warehouse staff, designers and power line technicians to make necessary corrections. It is anticipated that the new distribution design software would reduce this cost by approximately $130,000 per year.

Maintain adherence to FortisBC drafting standards:

Drafting standards are not currently consistent between AutoCad, the company's AM/FM system and drawing tools used by external designers. Consequently, construction package design drawings end up with different symbols for like equipment. This inconsistent use of symbols confuses field construction staff. FortisBC has done work to develop a drafting standard, but this standard has not been applied to all the drawing tools used by internal and external designers.

Maximize ability to respond quickly to business opportunities:

Currently in British Columbia, there exists opportunities to have designs for external utilities (telephone, cable & gas) performed by the electric utility designer. As the electric utilities' facilities are more commonly used for joint use, there is opportunity for cost, design and construction efficiencies if design for all service facilities is done by one party. This concept applies to both overhead distribution lines and underground trench systems. Placement conflict problems and overall time to produce a design would be reduced under such a scheme. Under the current design process employed by FortisBC, the utility would have to undertake additional training to educate their designers on the external utilities standards, design criteria and principles. However, this effort could be reduced by having the information contained within a design software package that could provide structure on how 3rd party design criteria and standards were applied.

Maintain distribution design knowledge base:

There is an increased demand for qualified distribution design personnel across North America. To further compound this issue, construction activity in Western Canada is at record levels. As a result there is an increased need to use the knowledge base of existing staff to work more efficiently. To accomplish this, FortisBC must examine ways of doing things more efficiently by removing tasks from the designers that can be performed by automation.

Increase communication and maintenance of FortisBC mapping records:

The FortisBC Line System Operations group is under increased pressure to use the Company's AM/FM system as a single line operating representation of the field distribution facilities. Conformity to lockout compliancy is now established by a series of paper single line prints. However, the System Operations group relies heavily on the electronic single line representation. It is the goal of this group to have the AM/FM system fully lockout compliant so they can abandon the paper copy representation. To help them in this endeavor, distribution design drafting staff is now entering AutoCad and Field View drawings into AM/FM in a "proposed state" in order that the facilities under construction are visible to the operating group. The proposed state electronic drawing then has to be updated with as-built information and "energized" in the AM/FM system after construction is complete. To alleviate the need to re-create design drawings in separate systems, FortisBC plans to automate this process through integration of design drawing and AM/FM systems.

Options Considered

Option 1: Implement a Distribution Design Software solution such as AutoDesk or Minor & Minor.

Cost: $800,000

Pros:

- Integration of existing functions of separate systems into a single tool for distribution design activities
- Leverage company distribution standards and criteria into a Distribution Design software solution
- Establish drafting standards consistent with the companies AM/FM system in a Distribution Design software solution
- Adoption of a Distribution Design software solution allows the company to more easily expand into design of joint use partner's facilities
- Adoption of a common Distribution Design software solution would be used by both internal and external design resource thereby bringing consistency and improving quality of distribution designs
- Improve the efficiency and productivity of existing internal and external design staff.
- Reduce the learning curve of new hires into the Distribution Design group (internal and external)
- Increased visibility of proposed distribution facilities by the System Operations group

Cons:

- Cost associated with the acquisition of the software

Option 2: Implement a Distribution Design Software solution such as AutoDesk or Minor & Minor in phases over a multi-year program. Implementation would be done in three stages:

1. Standalone design software loaded with company compatible units and design criteria / standards.
2. Integration to SAP for automated material ordering.
3. Integration to ESRI for automated as-built upload of new facilities.

Pros:

- Integration of existing functions of separate systems into a single tool for distribution design activities
- Leverage company distribution standards and criteria into a Distribution Design software solution
- Establish drafting standards consistent with the companies AM/FM system in a Distribution Design software solution
- Adoption of a Distribution Design software solution allows the company to more easily expand into design of joint use partner's facilities
- Adoption of a common Distribution Design software solution would be used by both internal and external design resource thereby bringing consistency and improving quality of distribution designs
- Improve the efficiency and productivity of existing internal and external design staff.
- Reduce the learning curve of new hires into the Distribution Design group (internal and external)
- Increased visibility of proposed distribution facilities by the System Operations group
- The investment of a distribution design software solution is spread over multiple years thus reducing the rate impact in a single budget year.
- Spreads the impact to IT and distribution design resources over an extended period.
- Allows more time to negotiate alternate proposals to integrate the software that may result in costs savings in year 2 & 3 of implementation.

Cons:

- The productivity efficiencies and increases in quality resulting from the SAP and AM/FM integrations will not be realized as quickly.

Option 3: Do nothing

Pros:

- No IT investment required

Cons:

- Integrity of data compromised by data entry replication
- Continued difficulty in managing compliance to company design standards / criteria
- Continued difficulty in managing compliance to company drafting standards
- FortisBC will not be positioned to react as efficiently and effectively to business opportunities associated with producing partner utility designs
- Increases to quality and quantity of design effort will be slower to implement and will likely not reach the level that could be achieved with the software
- Continued high learning curve for new entry design employees
- Continued requirement to re-draw facilities in ArcFM.

Option Selected

Option 1: This option will allow productivity efficiencies and increases in quality to be realized as soon as possible.

Implementation Process

Stage 1 – implementation will be largely done by the vendor with minimal impact to internal IT resources.

Stage 2 – upon investigation by internal IT resources, it may prove to be cost effective to FortisBC to internally handle the integrations of the design software to SAP with minimal support from the vendor.

Stage 3 – upon investigation by internal IT resources, it may prove to be cost effective to FortisBC to internally handle the integrations of the design software to ArcFM with minimal support from the vendor.

Other Considerations

Risks

Not implementing the design software solution will allow the design related issues recognized above to persist.

Appendix A

Distribution Design Software Preferred Option

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	7 Dec-16
	Summary								
	Revenue Requirements								
1	Annual Operating Expense	0	0	0	0	0	0	0	0
2	Depreciation Expense	0	51	16	(288)	(324)	(361)	(399)	(437)
3	Carrying Costs	18	22	(6)	(21)	(24)	(25)	(23)	(19)
4	Income Tax	(53)	(4)	47	(30)	(22)	(23)	(28)	(35)
5	Yearly Revenue Requirement for Project	(35)	68	57	(339)	(370)	(409)	(450)	(491)
6	**Net Present Value of Revenue Requirements at a Discount Rate of 10%**	**(374)**							
7	**Rate Impact**								
8	Revenue Requirement Inflation	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
9	Cummulative Revenue Requirement Inflation	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%
10	Forecast Revenue Requirements	225,369	229,841	234,542	239,220	243,608	248,455	253,394	258,429
11	Incremental Revenue Requirements	(35)	103	(11)	(396)	(31)	(38)	(41)	(42)
12	Rate Impact	0.0%	**0.0%**	0.0%	-0.2%	0.0%	0.0%	0.0%	0.0%
13	Cummulative Rate Impact	-0.02%	0.03%	0.02%	-0.14%	-0.15%	-0.17%	-0.19%	-0.20%
14	Discounted Yearly Revenue Requirement for Project at a Discount Rate of 10%	(35)	94	(9)	(297)	(21)	(24)	(23)	(21)
15	**NPV of Project / Total Revenue Requirements at at a Discount Rate of 10%**	**-0.02%**							
16	**Discounted Cash Flow**								
17	Net Power Purchase Expense	0	0	0	0	0	0	0	0
18	Income Tax	(53)	(4)	47	(30)	(22)	(23)	(28)	(35)
19	Capital Cost	477	(328)	(335)	(342)	(348)	(355)	(362)	(370)
20	Total Revenue Requirement for Project	424	(332)	(288)	(372)	(371)	(378)	(390)	(405)
21	**Project Net Present Value at at a Discount Rate of 10%**	**(1,693)**							
22	**Regulatory Assumptions**								
23	Equity Component	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
24	Debt Component	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
25	Equity Return	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
26	Debt Return	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
27	AFUDC	6.30%	6.40%	6.40%	6.50%	6.50%	6.50%	6.50%	6.50%

Line No.		0 Dec-09	1 Dec-10	2 Dec-11	3 Dec-12	4 Dec-13	5 Dec-14	6 Dec-15	7 Dec-16	8 Dec-17	9 Dec-18
28	**Capital Cost**										
29	Labour	30									
30	Contractors	527									
31	Materials	180									
32	Other	0									
	Capital Cost Savings	(322)	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
33	AFUDC	23									
34	Capitalized Overheads	39									
35	Direct Overheads	0									
36	Total Construction Cost in Year (Less Land Cost)	477	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
37	Cumulative Construction Cost	477	149	(186)	(528)	(876)	(1,232)	(1,594)	(1,964)	(2,341)	(2,725)
38	Land	0	0								
40	Total Capital Cost in Year	477	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
41	Cumulative Capital Cost	477	149	(186)	(528)	(876)	(1,232)	(1,594)	(1,964)	(2,341)	(2,725)
39	Cost of Removal	0	0								
41	Total Construction Cost in Year	477	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
42	Additions to Plant in Service	477	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
43	Cummulative Additions to Plant	477	149	(186)	(528)	(876)	(1,232)	(1,594)	(1,964)	(2,341)	(2,725)
44	CWIP	0	0	0	0	0	0	0	0	0	0
45	**Annual Operating Costs / (Savings)**										
46	Operating & Maintenance Cost Savings		-	-	-	-	-	-	-	-	-
47	Total Incremental Operating Costs (Savings)	0	0	0	0	0	0	0	0	0	0
48	**Depreciation Expense**										
49	Opening Cash Outlay	0	477	149	(186)	(528)	(876)	(1,232)	(1,594)	(1,964)	(2,341)
50	Additions in Year (Without Land-Since no Depreciation for Land)	477	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
51	Cumulative Total	477	149	(186)	(528)	(876)	(1,232)	(1,594)	(1,964)	(2,341)	(2,725)
52	Depreciation Rate - composite average	**10.60%**	10.60%	10.60%	10.60%	10.60%	10.60%	10.60%	10.60%	10.60%	10.60%
53	Depreciation Expense (Without Land)	0	51	16	(288)	(324)	(361)	(399)	(437)	(476)	(516)
54	**Net Book Value**										
55	Gross Property (With land)	477	149	(186)	(528)	(876)	(1,232)	(1,594)	(1,964)	(2,341)	(2,725)
56	Accumulated Depreciation (net of cost of removal)	(0)	(51)	(66)	222	546	907	1,306	1,743	2,220	2,736
		477	98	(253)	(306)	(330)	(324)	(288)	(220)	(121)	11
57	Land (included in gross property above)	0	0	0	0	0	0	0	0	0	0
58	Net Book Value	477	98	(253)	(306)	(330)	(324)	(288)	(220)	(121)	11
59	Carrying Costs on Average NBV										
60	Return on Equity	9	10	(3)	(10)	(11)	(12)	(11)	(9)	(6)	(2)
61	Interest Expense	9	11	(3)	(11)	(12)	(13)	(12)	(10)	(7)	(2)
62	Total Carrying Costs	18	22	(6)	(21)	(24)	(25)	(23)	(19)	(13)	(4)

63	**Income Tax Expense**										
64	Combined Income Tax Rate	30.00%	29.00%	27.50%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
65											
66	Income Tax on Equity Return										
67	Return on Equity	9	10	(3)	(10)	(11)	(12)	(11)	(9)	(6)	(2)
68	Gross up for revenue (Return / (1- tax rate)	12	15	(4)	(14)	(16)	(16)	(15)	(12)	(8)	(3)
69	Income tax on Equity Return	4	4	(1)	(4)	(4)	(4)	(4)	(3)	(2)	(1)
70	Income Tax on Timing Differences										
71	Depreciation Expense	0	51	16	(288)	(324)	(361)	(399)	(437)	(476)	(516)
72	Capitalized OH - 100% deduction	39	0	0	0	0	0	0	0	0	0
72	Less: Capital Cost Allowance	93	71	(110)	(213)	(272)	(308)	(331)	(347)	(359)	(369)
73	Total Timing Differences	(132)	(20)	126	(75)	(52)	(53)	(68)	(91)	(118)	(148)
74	Gross up for tax (Total Timing Differences/(1-tax rate))	(189)	(29)	174	(102)	(70)	(72)	(92)	(122)	(159)	(200)
75	Income tax on Timing Differences	(57)	(8)	48	(26)	(18)	(19)	(24)	(32)	(41)	(52)
76	Total Income Tax	(53)	(4)	47	(30)	(22)	(23)	(28)	(35)	(44)	(53)
77	**Capital Cost Allowance**										
78	Opening Balance - UCC (Undepreciated Capital Cost)	0	322	(77)	(302)	(431)	(507)	(554)	(586)	(609)	(627)
79	Total Plant in Service (includes salvage, excludes capitalized OH and AFUDC)	415	(328)	(335)	(342)	(348)	(355)	(362)	(370)	(377)	(385)
80	Subtotal UCC	415	(7)	(412)	(644)	(779)	(862)	(917)	(955)	(986)	(1,012)
81	Capital Cost Allowance Rate	**45.00%**	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
82	CCA on Opening Balance	0	145	(35)	(136)	(194)	(228)	(249)	(264)	(274)	(282)
83	CCA on Capital Expenditures (1/2 yr rule)	93	(74)	(75)	(77)	(78)	(80)	(82)	(83)	(85)	(87)
84	Total CCA	93	71	(110)	(213)	(272)	(308)	(331)	(347)	(359)	(369)
85	Ending Balance UCC	322	(77)	(302)	(431)	(507)	(554)	(586)	(609)	(627)	(643)

RECOMMENDED PROJECT INFLATION RATES

EARG
Appendix 4
16 MAY 2008

BACKGROUND

The rapid growth in B.C. in both the residential and non-residential construction sectors has caused construction costs to increase at rates not seen since the early 1980's. Between 1991 and 2001, the B.C. Consumers Price Index (CPI) allowed our budgets and estimates to keep up with actual market conditions; however, in about 2001, the CPI and the non-residential construction indices began to diverge. By 2004 the divergence had become significant, and Engineering has in recent years been including an additional construction inflation allowance in our estimates. This allowance is now being expressed as a task activity in INFO_PM.

Estimating the rate of inflation into the future has proved to be difficult, especially on multi-year projects. To keep up with construction inflation, a concerted effort has and is being made by EARG to reflect this in our estimating practices.

In January 2007, Engineering awarded MMK Consulting (a Vancouver-based firm specializing in economic and financial consulting) a contract to prepare a report every six months to forecast construction inflation in the non-Residential Construction sector as it relates to BC Hydro and BCTC Capital works. In February 2008 the Engineering Divisional Managers asked that the report be enhanced to reflect Global Impacts, adding indices outside of North America, as well as providing additional information on local market conditions. The third of four reports was received on April 4, 2008 and is the basis of this briefing note.

KEY FINDINGS IN MMK SPRING 2008 REPORT

Some of the key findings in MMK's third report are:

- Statistics Canada's Vancouver industrial construction index increased 3.7% in the last 6 months of 2007 (second quarter 2007 to fourth quarter 2007). This rate of increase is down from the 6.3% recorded for the previous six month period

- Statistics Canada's Canadian electric utility construction indices indicate that the transmission price index increased 3.2% between 2007 and 2006, while the distribution price index increased 3.6% and the stations index increased 5.7%. These increases are less than half of the rate of the broader industrial construction price index.

- Similar construction price trends were also experienced in the US, based on US Bureau of Reclamation (USBR) indices.

- US equipment price indices for electric power and specialty transformer manufacturing (in US dollars) also continued their strong upward trend, rising 12% in 2007 following increases of approximately 25% in the prior two years. By contrast, price trends have been relatively flat for generation (turbine and power transmission) equipment manufacturing.

- In Japan and Korea, domestic price indices for electrical transformers increased by 2.9% and 2.4% respectively. Generator price index trends were more modest, increasing 1.7% in Japan while remaining flat in Korea.

- Price trends for commodities were mixed during the second half of 2007, with less volatility than in 2005 and 2006.

- Regional BC, data on construction activity levels (building permit values, construction industry employment trends) indicate that market (activity levels) pressures are being experienced in most BC regions, including some interior regions showing flatter trends in previous reports.

- BTY Group has recently projected that construction costs (including residential) in the BC Lower Mainland will increase 7% in 2008, 6% in 2009, 5% in 2010 and 3% thereafter.

- B.C. Ministry of Transportation's current policy on major projects is to estimate cost escalation impacts on a project-by-project basis. For other projects, cost escalation allowances are 5% annually for the next two years, 3% annually thereafter.

- MMK is recommending an inflation rate allowance of 4% to 6% from 2008 to 2010, and 3% to 4% from 2011 onward, for all BCHydro construction projects.

RECOMMENDED ALLOWANCES

Based on the MMK report, discussions with other Utilities (Manitoba Hydro and Hydro Quebec), other owners' recommended rates (e.g. YVR and MOTH) and our own experiences, we are recommending as a guide for cost estimating our projects the following cost inflation allowances be used:

Fiscal Year	% Inflation
FY09	5%
FY10	5%
FY11	4%
FY12	3%
FY13 and beyond	3%

These allowances are unchanged from those of September 2007, and reflect the mixed market signals reported by MMK (lower price index trends, coupled with higher reported activity levels)..

It is also recommended that these rates be applied for projects with less than two years of construction and dollar values less than $10 million. For long term projects and projects greater than $10 million, cost components and inflation rates should be analyzed in more detail.

CONCLUSION

Project/construction costs are still increasing at rates that far exceed B.C. CPI. The recommended allowances are based on the entire Capital program we manage, and should not be adopted blindly. The inflationary outlook in the construction sector of our economy continues to be uncertain but there is evidence the rate of increase is beginning to soften. So stay tuned again for the next report in six months.

John Boots

MMK CONSULTING

— BC HYDRO —

CONSTRUCTION COST TRENDS

AND OUTLOOK

--- SPRING 2008 ---

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April 23, 2008

Contents

1. Introduction and Executive Summary

This report reviews non-residential and industrial construction cost trends in British Columbia, and the implications for BC Hydro's cost inflation allowances on its major construction projects. This edition (Spring 2008) is the third of four semi-annual reviews being performed by MMK Consulting for BC Hydro during 2007 and 2008.

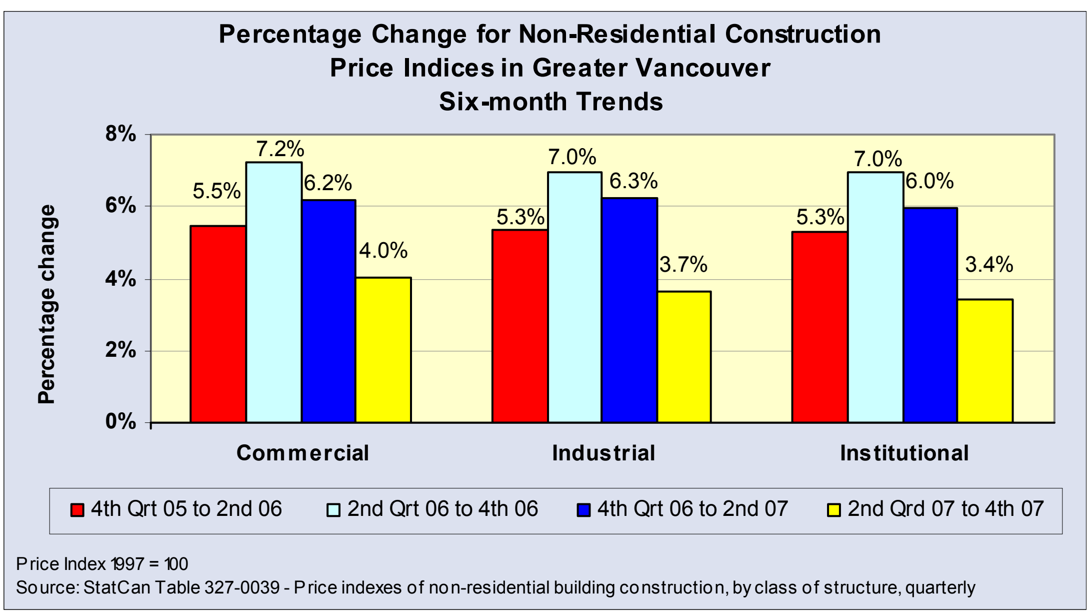
1.1 General price and activity level trends

During the second half of 2007, there was a moderate easing of upward price pressures for the BC industrial construction industry. As illustrated in Exhibit 1a, the industrial construction price index rose 3.7% during the six-month period. While this rate of increase was the lowest in the past two years, it still represents a significantly higher rate of increase than long-term trends prior to 2004.

With regard to activity levels, the value of industrial building permits in BC in the last six months of 2007 was also down from the first six months, continuing the trend of the previous six months. Industrial construction activity levels are still much higher than pre-2004 levels, and strong demand in Alberta continues to put pressure on prices in BC.

While the statistical evidence indicates a moderate weakening of cost inflation pressures during 2007, a number of industry sources (especially suppliers) have recently indicated that industrial construction activity levels in early 2008 are up from the same time in 2007.

Exhibit 1a — Changes in non-residential construction price indices in the past four six-month periods - Greater Vancouver



1.2 Trends in the electric utility industry

1.2.1 Canadian electric utility construction trends

As measured by Statistics Canada, the twelve-month increase in Canadian price indices for 2007 over 2006 was 3.2% for transmission lines, 3.6% for distribution lines, and 5.7% for substations. (Part-year data are not available.) Over the past four years, electric utility price indices have risen at less than half the rate of the broader industrial construction price index.

1.2.2 US construction and equipment price trends[1]

For electric utility construction, price indices (US Bureau of Reclamation) for switchyards/substations and steel tower transmission lines increased by 4.9% and 4.2% respectively, while declining 0.8% for wood pole transmission lines, between 2006 and 2007. US industry publications are forecasting high levels of transmission and distribution construction activity over the next few years.

For electric utility production, producer price indices (US Bureau of Labor Statistics) indicate a 3.8% increase in the electric power generation index, and a 3.4% increase in the electric power transmission, control, and distribution index, between 2006 and 2007.

Equipment price indices (US Bureau of Labor Statistics) for electric power and specialty transformer manufacturing (in US dollars) have continued their upward trends, rising 12% in 2007, following increases of approximately 25% in the prior two years. By contrast, price trends have been relatively flat with respect to turbine and power transmission equipment manufacturing.

1.2.3 Overseas equipment price trends

In Japan and Korea, domestic price indices for electrical transformers increased by 2.9% (Japan) and 2.4% (Korea) in 2007. Generator price index trends were more modest, increasing by 1.7% in Japan while remaining flat in Korea.

Hydro's equipment purchasing staff also indicate that they have experienced significant increases in international equipment prices over the past few years. Strong international demand for electric utility equipment is resulting in both upward price pressures and deferred production/delivery schedules.

1.3 Price trends by component cost

Price trends for component costs have been mixed during the second half of 2007, with far less volatility than in 2005 and 2006. Commodity prices (such as fuel and metals) are still generally very high compared to pre-2006 levels.

Component cost trends are highly visible, and as such are important indicators of cost inflation trends in the BC industrial construction industry. However, they do not account for some "soft" cost factors (such as engineering and construction management), nor do they account for supply and demand factors within the industry. Thus, they are only partial indicators of overall price trends.

[1] In US dollars.

1.4 Regional trends in BC

While direct price index data are not available on a regional basis in BC, construction activity indicators provide an indirect measure of regional cost inflation pressures.

The available data on construction activity levels (building permit values, construction industry employment trends) indicate that market (activity level) pressures are being experienced in most BC regions, including interior regions.

1.5 Other agencies' estimates and forecasts

Other agencies have a wide range of approaches to estimating and forecasting construction cost inflation. For example, BTY Group has recently projected that construction costs (including residential) in the BC Lower Mainland will increase by 7% in 2008, 6% in 2009, 5% in 2010, and 3% in 2011. Other agencies' approaches are also described in the main report.

1.6 Recommended construction cost inflation allowances

Our September 2007 report noted that 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." Since then, this weakening has been observed, as the rate of increase in the Metro Vancouver industrial construction price index has declined from 6.3% (13% annualized) in the first half of 2007 to 3.7% (7.5% annualized) in the second half.

On balance, we expect that price inflation will continue throughout 2008, at rates similar to those recorded in the second half of 2007. While high US demand is expected to put price pressure on transmission and distribution equipment, international competition and the strong Canadian dollar will assist in mitigating these impacts.

Actual trends since our previous September 2007 report have been in line with expectations. Accordingly, as illustrated in Exhibit 1b, our recommended cost inflation allowances are unchanged. These recommended allowances are for "hard" construction costs only, and do not include "soft" costs such as design and project management. They also assume that BC Hydro takes appropriate measures to dampen the impact of construction cost inflation through procurement strategies, value engineering, and other cost mitigation initiatives.

The recommended allowances are based on the general assumption that the strong construction market in BC between 2003 and 2008 will continue through 2010, and that the market will have a "soft landing" in 2011 and beyond, as market demand and supply forces come more into balance.

Exhibit 1b — Recommended construction cost inflation allowances

Previous reports vs. this edition		2008 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%
Apr. 2008	• All construction projects	4% to 6%	3% to 4%

All projections and forecasts are by nature uncertain, and we cannot represent that any of the projections contained in this report will be achieved in whole or in part.

2. General Price and Activity Level Trends

This chapter presents overall price and activity level trends for non-residential and industrial construction.

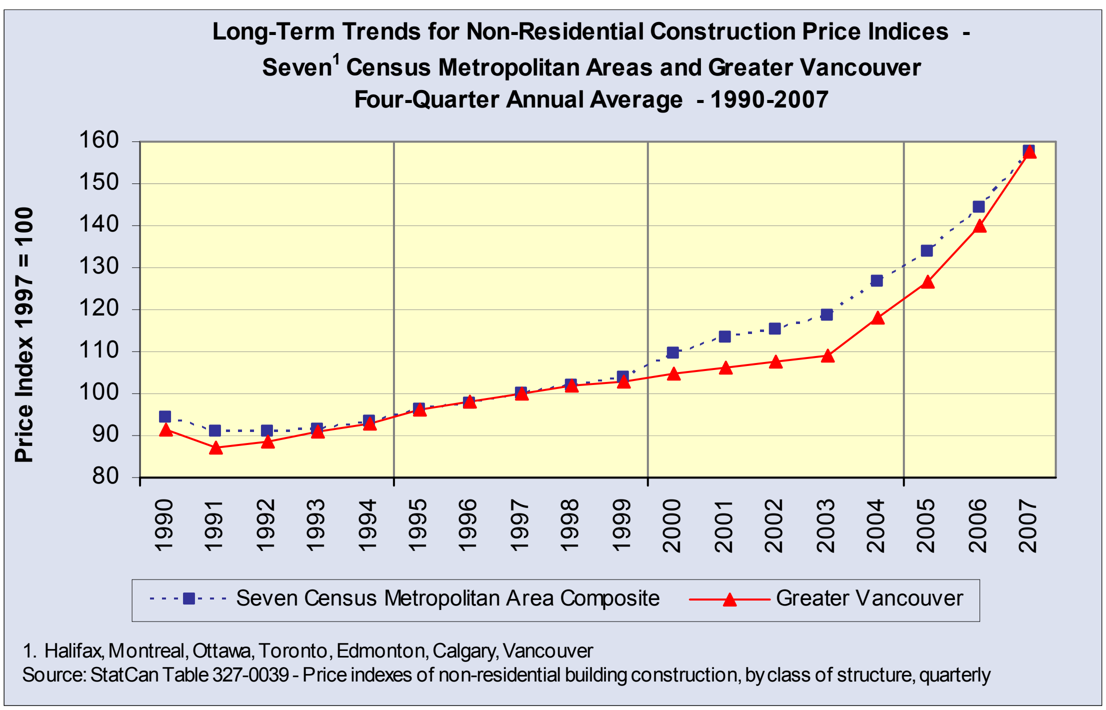
2.1 Non-residential construction price index

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 has increased by an average of approximately 10% per year over the past four years.

The seven Canadian Metropolitan Areas (CMA) 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



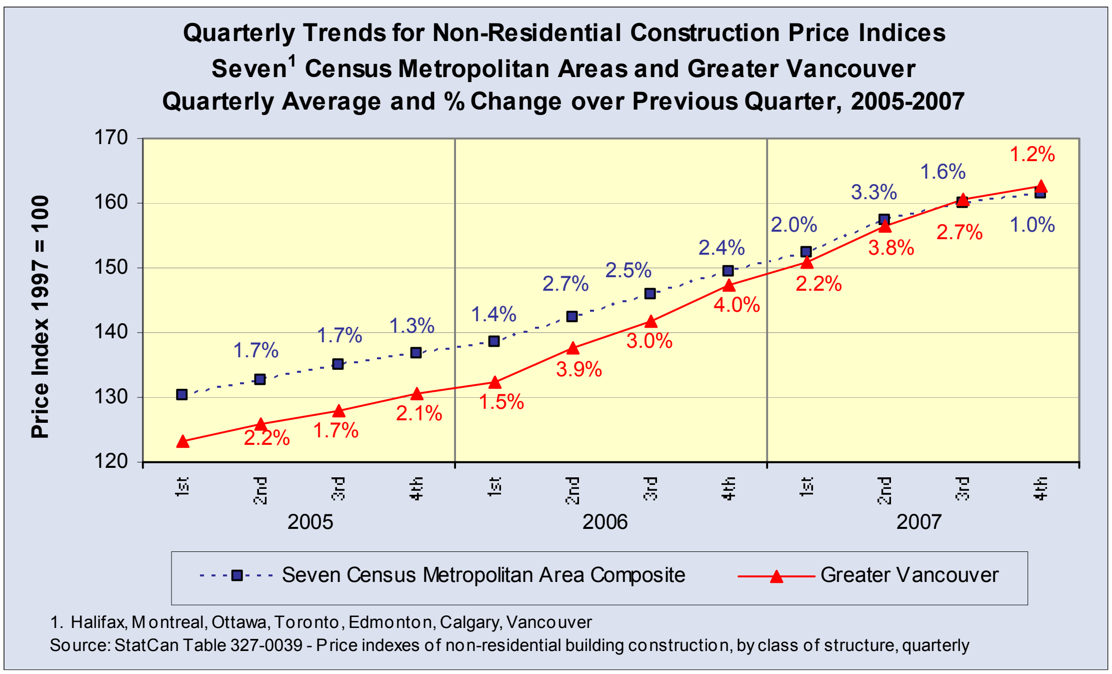
[1] The non-residential construction price index (NRBCPI) is defined by Statistics Canada as "…a quarterly series measuring the changes in contractors' selling prices of non-residential building construction (i.e. commercial, industrial and institutional)". It includes both general and trade contractors' work, but excludes the cost of land, land assembly, design, development and real estate fees.

b) *Quarterly trends*

Exhibit 2b illustrates price index trends for non-residential construction, for both Vancouver and the seven-city CMA composite[1]:

- Between the first quarters of 2005 and 2006, both indices show similar upward trends, with quarterly price index increases in the range of 1.3% to 2.1%.
- Between the first quarter of 2006 and second quarter of 2007, upward pressures further intensified, with quarterly increases ranging from 2.0% to 4.0%. Rates of increase were particularly high for the Vancouver index.
- Between the second and fourth quarters of 2007, rates of increase have declined. Between the third and fourth quarter of 2007, rates of increase were in the range of 1.0%-1.2%.

Exhibit 2b — Short-term quarterly trends for non-residential construction price indices



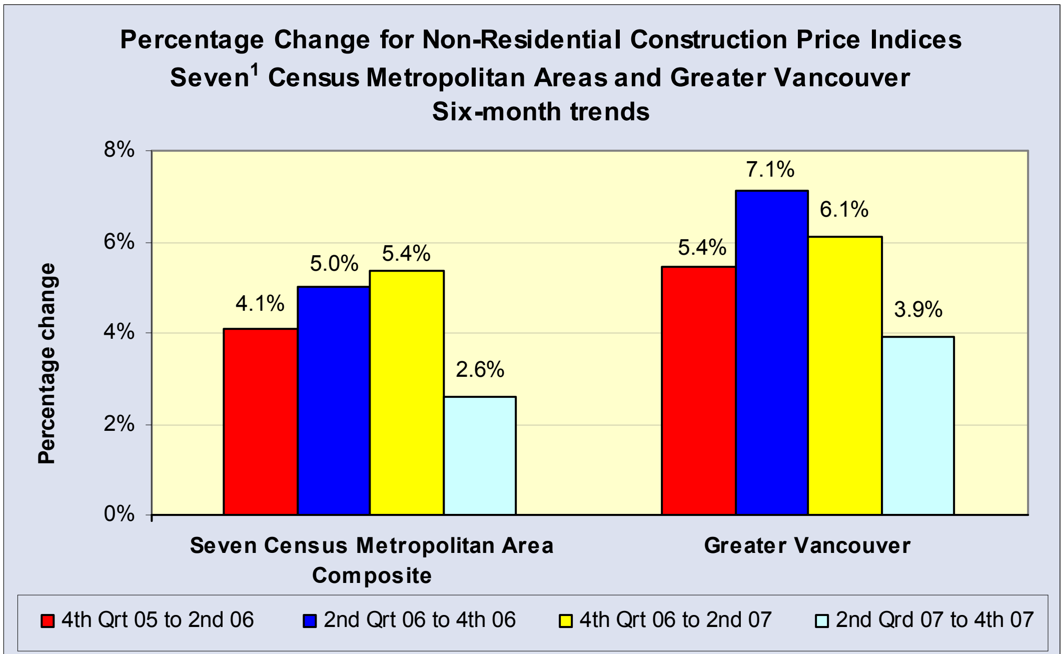
[1] For BC Hydro, the Vancouver index in more relevant to smaller Lower Mainland projects, while the seven-City CMA composite (Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver) is more relevant to larger nationally-sourced projects.

c) *Six-month trends (since previous report)*

Between the second quarter of 2007 and the fourth quarter of 2007, the Vancouver non-residential price index increased 3.9%, and the CMA composite price index increased 2.6% over six months.

These rates of increase were significantly lower than for any other six-month period over the past two years.

Exhibit 2c — Changes in non-residential construction price indices in the past four six-month periods



Price index 1997 = 100
1. Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver
Source: Table 327-0039 - Price indexes of non-residential building construction, by class of structure, quarterly

2.2 Commercial, industrial, and institutional

a) Annual trends

Statistics Canada's non-residential construction price index may be broken out into (1) commercial, (2) institutional/government and (3) industrial construction (of most interest to BC Hydro). Exhibit 2d(i) illustrates long-term annual trends for each of these subgroups, for both Greater Vancouver and the seven-city CMA composite.

Over the past decade, industrial construction price index upward trends have been slightly greater for industrial construction than for commercial and institutional/government construction.

Exhibit 2d(i) — Non-residential construction price index trends, by sector

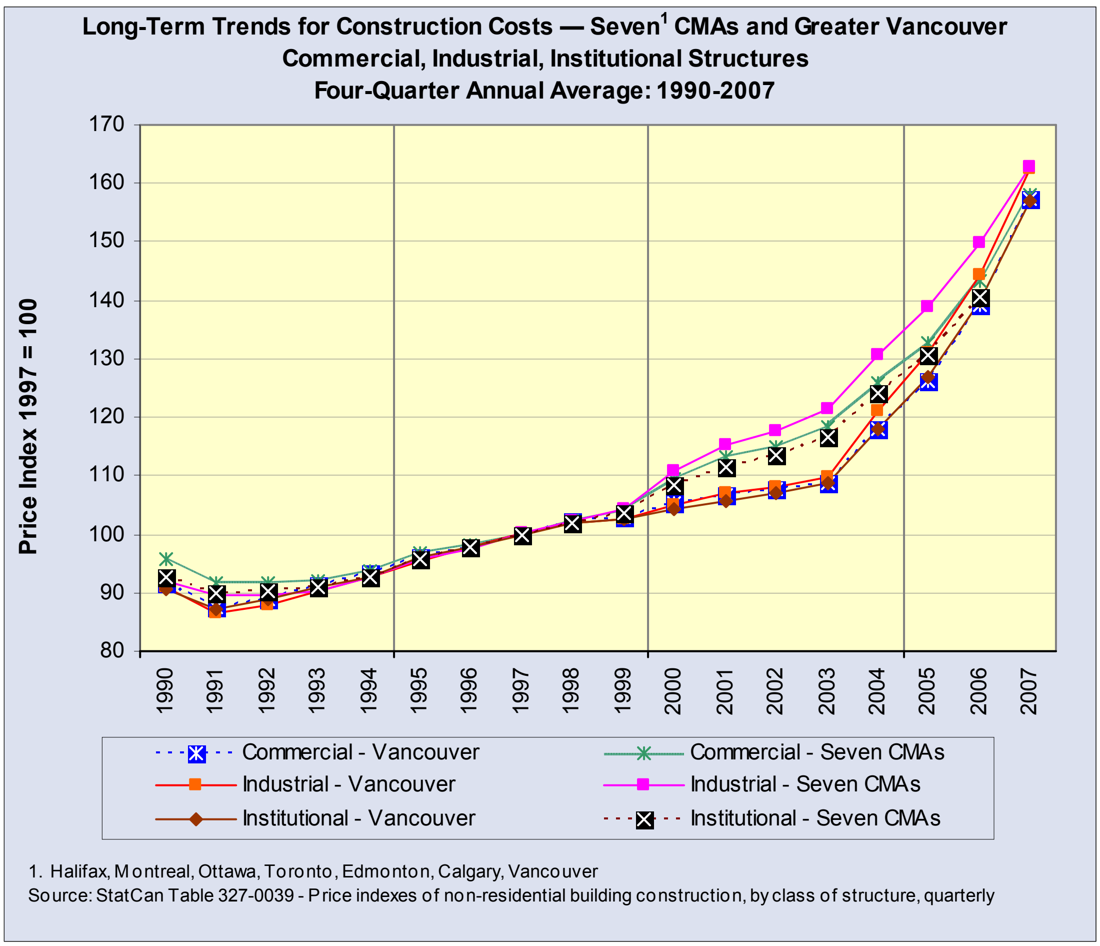
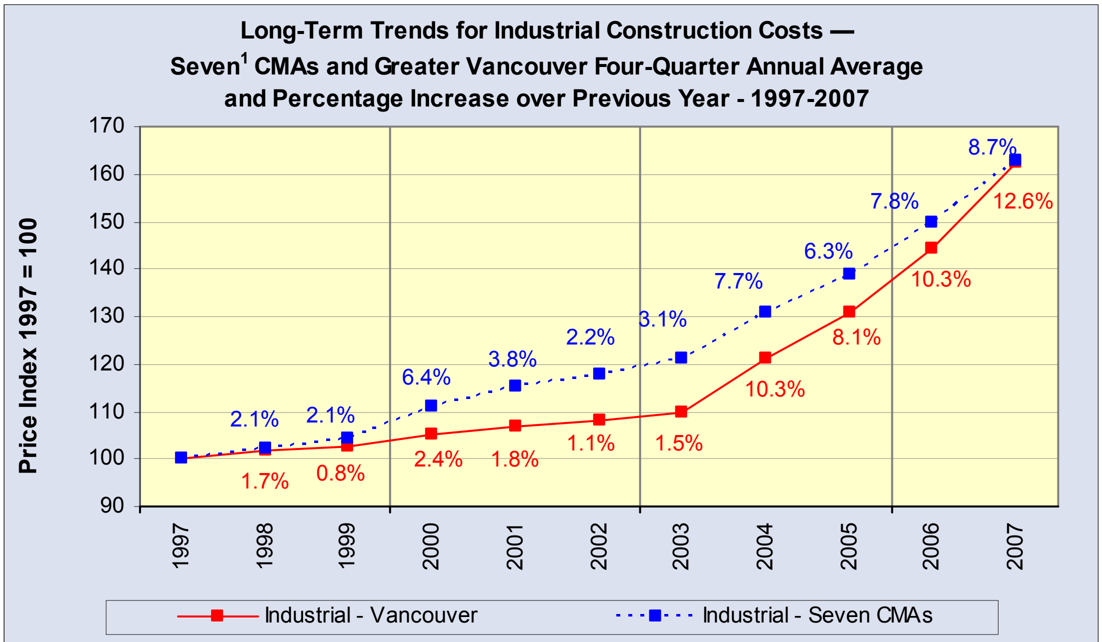


Exhibit 2d(ii) focuses on the specific results for industrial construction, also illustrating the annual percentage increase over the preceding year.

Price trends are generally similar to those for the overall non-residential construction sector index, with the significant change in trends occurring between 2003 and 2004. As for the overall non-residential index, upward price index trends in industrial construction were stronger for the CMA composite between 1997 and 2003, and have been stronger for Vancouver since 2003.

Exhibit 2d(ii) — Industrial construction price index trends

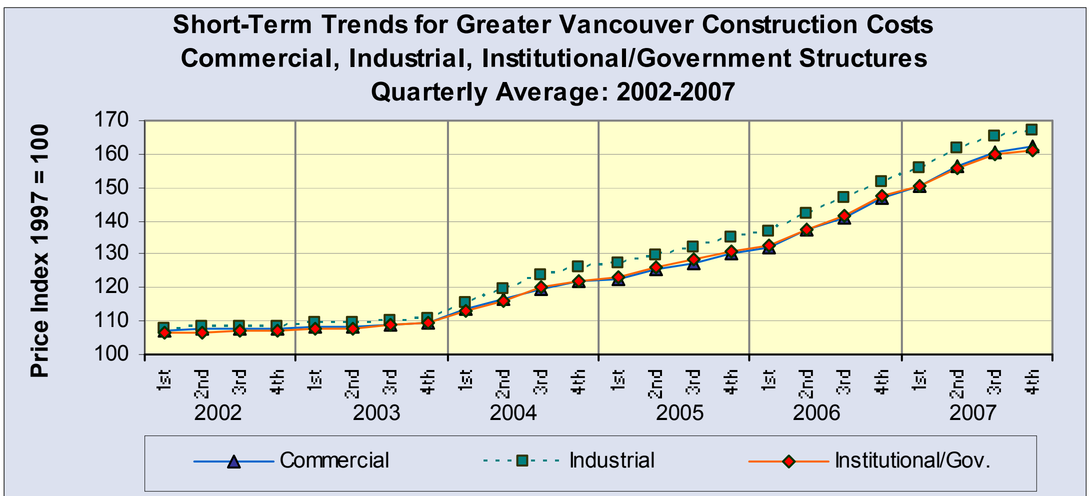


1. Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver
Source: StatCan Table 327-0039 - Price indexes of non-residential building construction, by class of structure, quarterly

b) *Quarterly trends*

As illustrated in Exhibit 2e, quarterly price index trends have been similar for all three categories of non-residential construction over the past three years.

Exhibit 2e — Short-term quarterly trends for different types of building structure

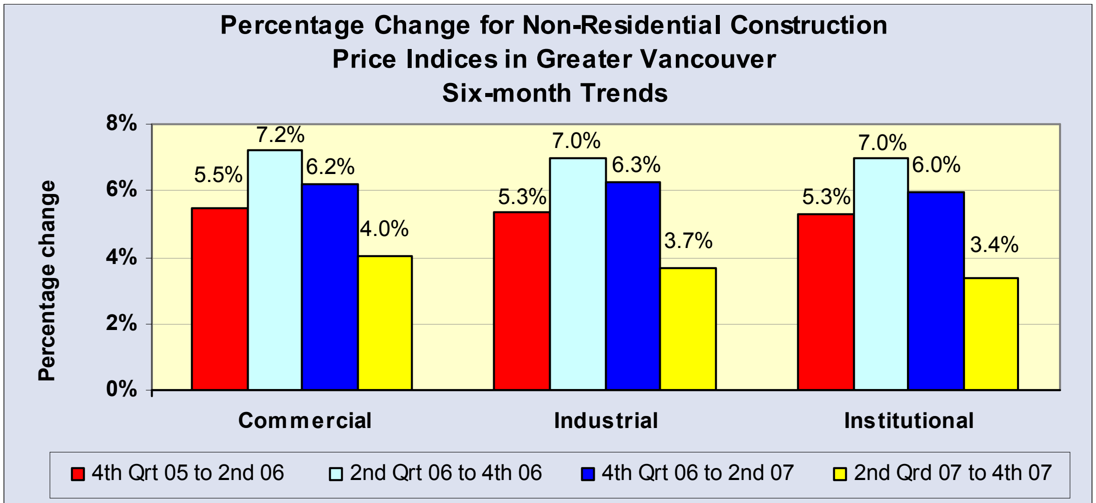


Source: StatCan Table 327-0039 - Price indexes of non-residential building construction, by class of structure, quarterly

c) *Six-month trends (since previous report)*

As illustrated in Exhibit 2f, six-month price index trends have been fairly similar for all three types of non-residential construction, with industrial construction price index trends (3.7% in six months) being in the mid-range. Rates of increase have declined in the second half of 2007, and are the lowest 6-month increase in the past two years.

Exhibit 2f — Changes in non-residential construction price indices in the past four six-month periods - Greater Vancouver



Price Index 1997 = 100
Source: StatCan Table 327-0039 - Price indexes of non-residential building construction, by class of structure, quarterly

2.3 Building construction activity levels

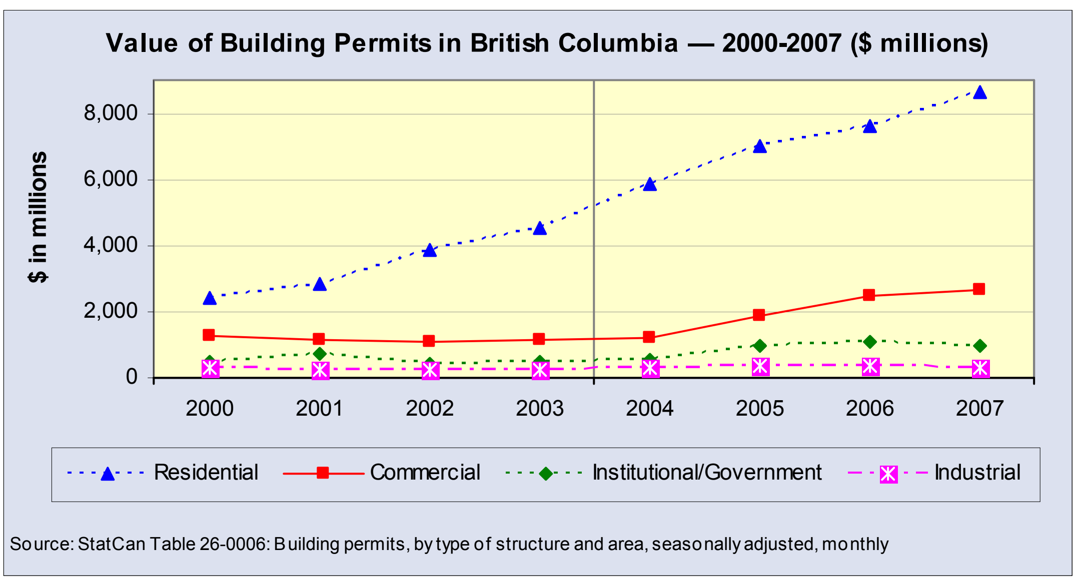
a) Annual trends

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]. However, for industrial construction, the value of building permits has been fairly stable between 2003 and 2007, ranging between $324 million and $358 million.

Exhibit 2g — Value of BC building permits ($ million) by sector, 2001 to 2007

	Annual trends								Six-month data		
	2001	2002	2003	2004	2005	2006	2007	Change 06-07 (%)	Jan-Jun 07	Jul-Dec 07	6-mth change (%)
Residential	2,830	3,888	4,514	5,869	6,979	7,621	8,612	13.0%	4,366	4,246	-2.8%
- as % of total	57.1%	68.7%	70.6%	73.9%	68.5%	66.0%	68.6%		66.6%	70.9%	
Non-residential											
▪ Industrial	221	230	244	328	346	358	324	-9.6%	148	176	18.6%
- as % of total	4.5%	4.1%	3.8%	4.1%	3.4%	3.1%	2.6%		2.3%	2.9%	
▪ Commercial	1,171	1,117	1,130	1,228	1,886	2,494	2,648	6.2%	1,544	1,104	-28.5%
- as % of total	23.6%	19.7%	17.7%	15.5%	18.5%	21.6%	21.1%		23.6%	18.4%	
▪ Institut./Govt	732	424	506	514	980	1,068	961	-10.0%	495	467	-5.7%
- as % of total	14.8%	7.5%	7.9%	6.5%	9.6%	9.3%	7.7%		7.5%	7.8%	
BC Total	4,955	5,659	6,394	7,939	10,191	11,541	12,545	8.7%	6,553	5,992	-8.6%

Source: StatCan Table: 26-0006 - Building permits, by type of structure and area, seasonally adjusted, monthly.

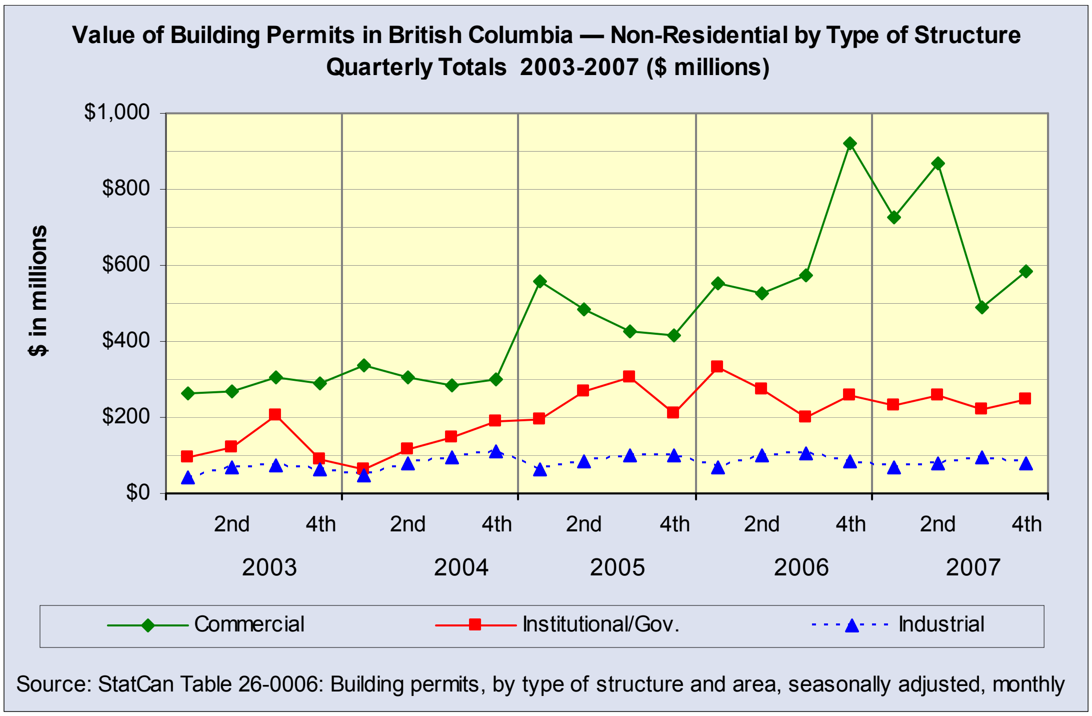


[1] BC Hydro and some other agencies (MoTH, BCTC, etc.) do not require building permits for industrial construction, so statistics do not include these types of project.

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 in BC non-residential building permit values, by type of structure



Industrial building activity, the sector most relevant to BC Hydro, has shown the greatest stability on a quarterly basis.

c) *Six-month trends (since previous report)*

As illustrated in Exhibits 2g and 2h, commercial construction activity continues to dominate the non-residential market, but has slowed down in recent months, with the value of commercial building permits in BC down by 28% between the first and second half of 2007.

By contrast, industrial building permit values in BC increased by 19% between the first and second half of 2007, mainly as a result of high third-quarter values.[1] This finding is consistent with anecdotal evidence from BC Hydro's suppliers, who indicate generally strong industrial construction markets in early 2008.

[1] Caution should be exercised in interpreting the significance of quarterly and semi-annual values in assessing general trends, since results may be impacted by seasonal factors and the potential impact on overall results of a small number of relatively large industrial building projects.

2.4 Price and activity trends — BC vs. Ontario/Alberta

BC Hydro's bidders for major projects tend to be large firms that operate at the national and international levels. All significant industrial contractors in BC are affected, directly or indirectly, by industrial construction trends in other national and provincial jurisdictions, particularly in Ontario and Alberta.

2.4.1 Price index trends -— Toronto, Calgary and Vancouver

a) Annual trends

Exhibit 2i compares annual price index trends for non-residential construction in Toronto, Calgary and Vancouver:

- Vancouver experienced the greatest price index increases in 2004 and 2005, and the rate of increase has been even greater in 2006 and 2007
- In Calgary, price indices have increased dramatically over the past two years, reaching 17.6% between 2006 and 2007
- In Toronto, price indices have also increased in recent years, but at lower rates than in Calgary and Vancouver.

Exhibit 2i — Annual non-residential construction price index 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%
2007	158.3	6.7%	180.8	17.6%	157.7	12.7%

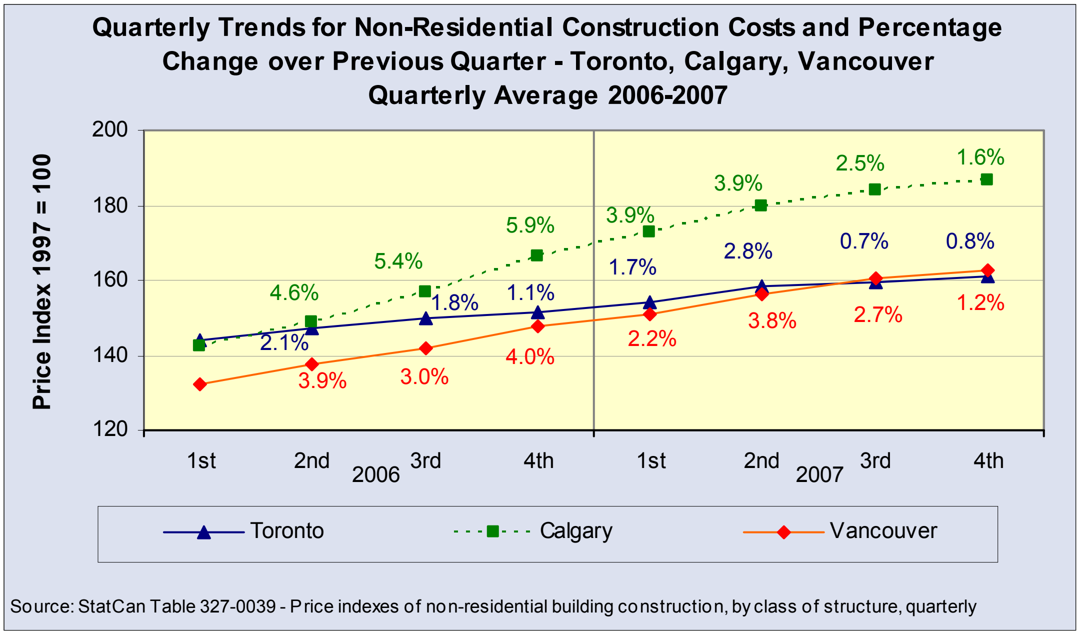
Source: StatCan Table 327-0039: Price indices of non-residential building construction, by class of structure, annually.

b) Quarterly and six-month trends

Exhibit 2j illustrates quarterly cost inflation rate trends in recent years for non-residential construction. (Results are similar for industrial construction.)

As Exhibit 2j shows, rates of increase dropped significantly in the second half of 2007, in all three cities. Calgary and Vancouver continued to experience significant price index increases, at somewhat lower rates than in previous quarters, while Toronto's price index increased by only 1.5% in the last two quarters of 2007.

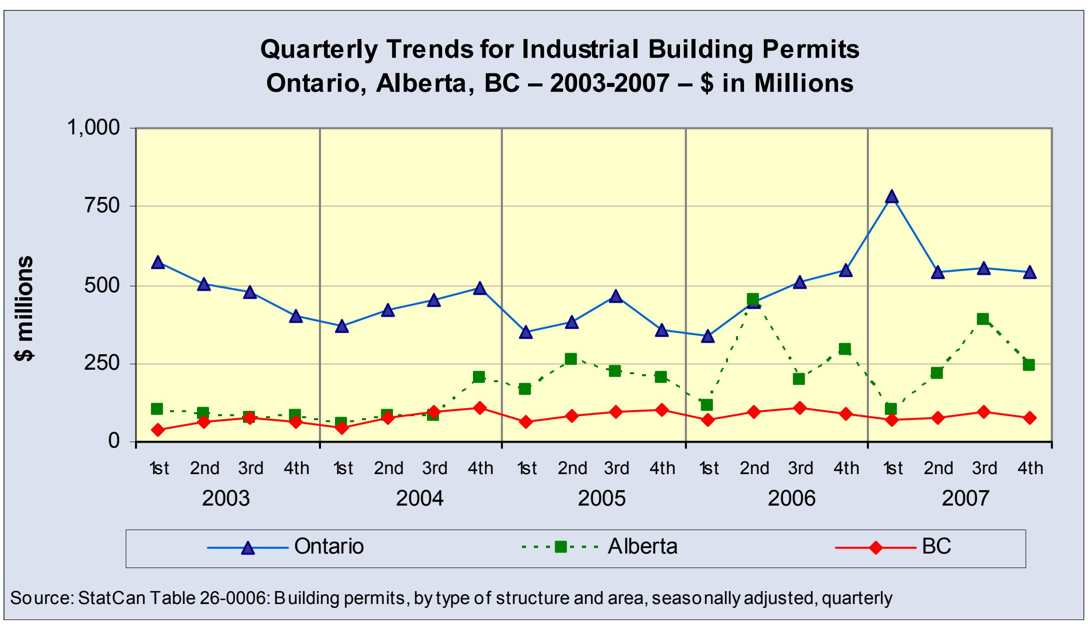
Exhibit 2j – Recent quarterly trends for non-residential construction costs – Toronto, Calgary and Vancouver



2.4.2 Activity level trends — Ontario, Alberta and BC

Quarterly trends in the value of industrial building permits, for Ontario, Alberta and BC, are illustrated in Exhibit 2k.

Exhibit 2k – Quarterly activity trends — Ontario, Alberta, BC



While industrial construction activity levels in BC have been relatively flat compared to Alberta and Ontario, the strength of these other markets has put price pressure on BC industrial construction projects.

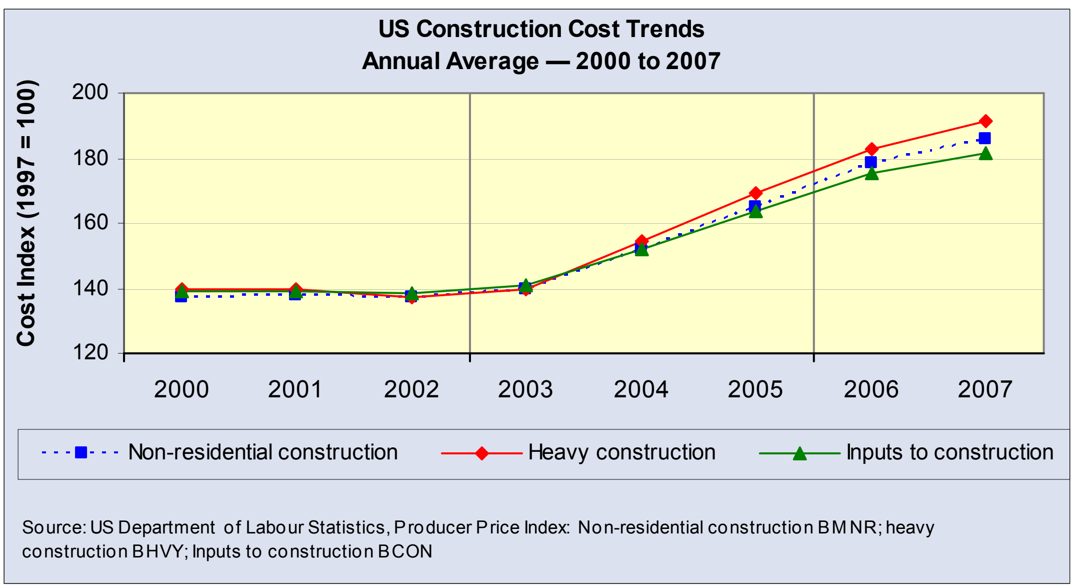
The recently released 2008 first quarter bulletin by Statistics Canada on investment in non-residential building construction, reported that "… last year's pace for investment in non-residential building construction in Canada continued into the first three months of 2008, again the result of major construction activity… in Alberta and Ontario".

2.5 US construction price trends

US construction price index trends have been fairly similar to those experienced in Canada. As illustrated in Exhibit 21(i) and 21(ii), US data indicate flat price indices for US non-residential and heavy construction between 2000 and 2003. In 2004, price indices started to increase at a higher rate, averaging 7% to 9% annually for 2004 through 2006.

For 2007, the rates of increase declined, but were still significantly upward, consistent with Canadian and BC trends.

Exhibit 21
(i) US annual construction price trends



(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	185.6	3.9%	191.2	4.7%	181.4	3.4%
Jul-Dec 06	180.5	-	185.0	-	177.0	-
Jan-Jun 07	183.7	1.8%	188.2	1.7%	179.5	1.4%
Jul-Dec 07	188.1	2.7%	194.2	3.2%	183.3	2.1%

Source: US Department of Labor Statistics, Producer Price Index.

2.6 Conclusion — General price and activity level trends

There was a moderate easing of upward price pressures for the BC industrial construction industry during the second half of 2007, with the Vancouver industrial construction price index rising 3.7% during the six-month period. While this rate of increase was the lowest in the past two years, it still represents a significantly higher rate of increase than long-term trends prior to 2004.

With regard to activity levels, the value of industrial building permits in BC in the last six months of 2007 was also down from the first six months, continuing the trend of the previous six months. Industrial construction activity levels are still much higher than pre-2004 levels, and strong demand in Alberta continues to put pressure on prices in BC.

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 3a 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. Data are only available on an annual basis.

3.1.1 Long-term trends

Long-term price index trends for electric utility construction in Canada have been significantly lower than for the broader non-residential construction price indices:

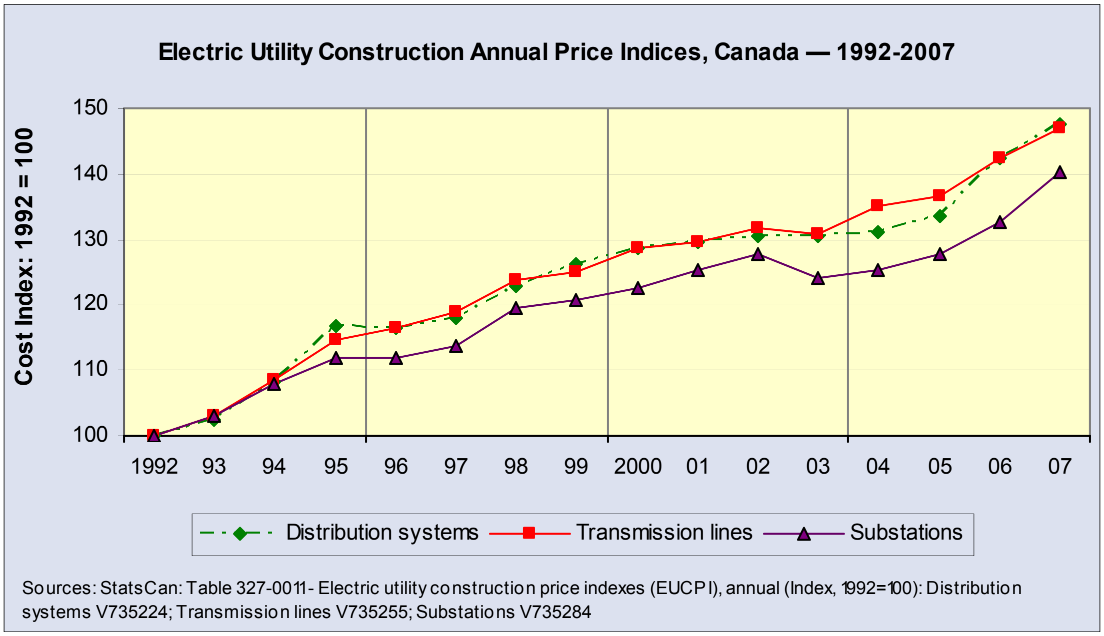
- As illustrated in Exhibit 3a(i), between 1992 and 2007, the cumulative 15-year increase in price indices for the three categories has been in the range of 40% to 48%.

- By contrast, as illustrated earlier in Exhibit 2d, the 15-year increase in non-residential construction price indices between 1992 and 2007 has been in the range of 80% (depending on the specific index).

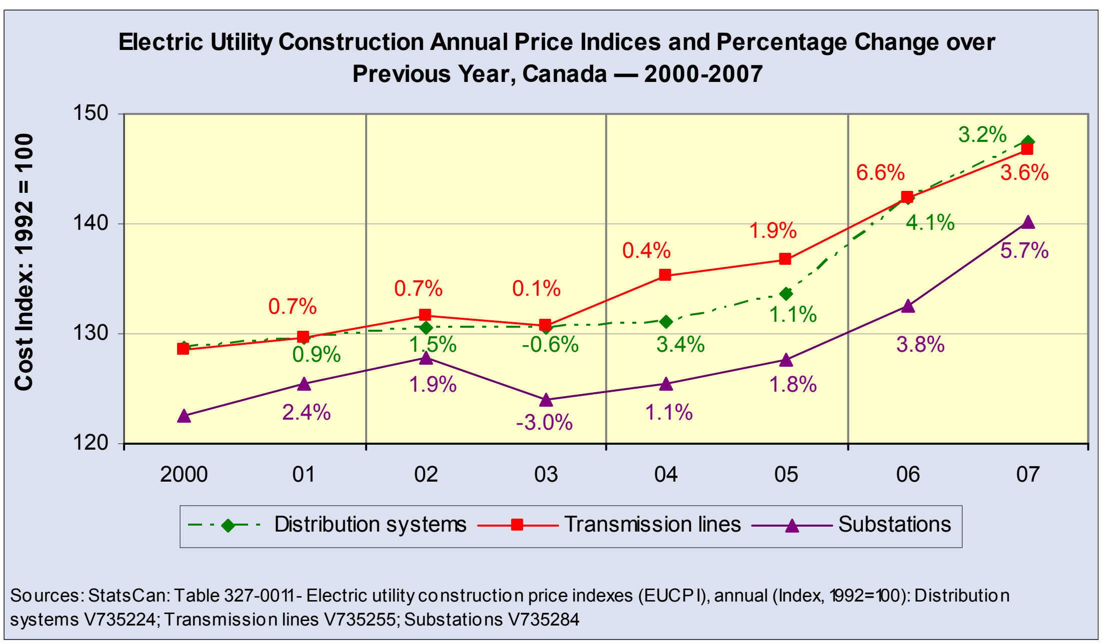
3.1.2 Recent-year trends

Recent-year annual percentage changes are illustrated in Exhibit 3a(ii). Price index increases between 2006 and 2007 are higher than in recent previous years, ranging from 3.2% (transmission lines) to 5.7% (substations). However, these price index increases are still relatively low in relation to the increases in the broader industrial construction price index (see next section).

Exhibit 3a — Electric utility construction price trends – Canada
(i) Long-term annual trends



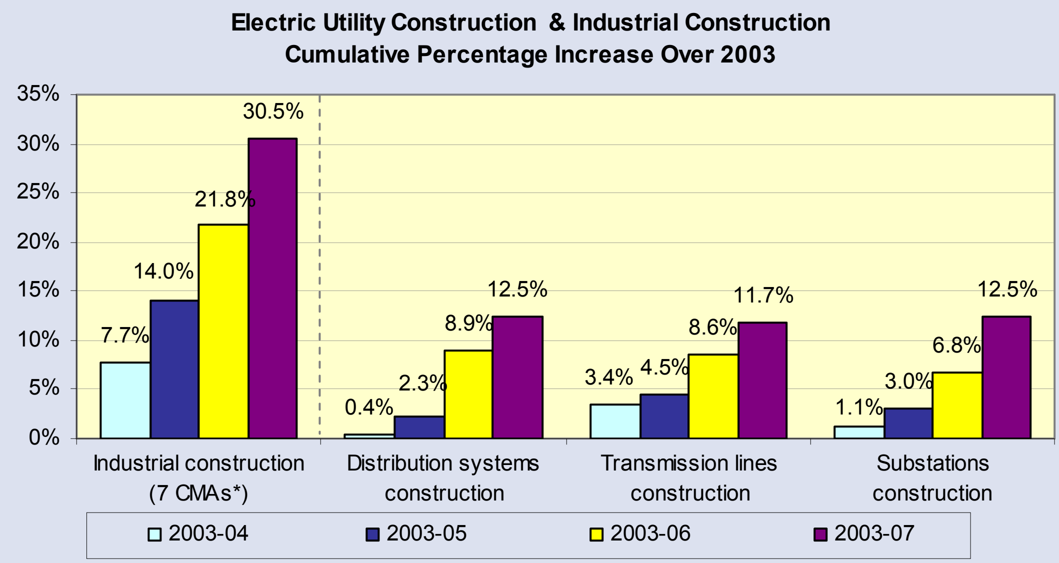
(ii) Recent-year annual trends



3.1.3 Price index comparison — Electric utility vs. industrial construction

Exhibit 3b compares four-year cumulative trends in Statistics Canada's electric utility construction indices to the 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.

Over the past four years, Statistics Canada's distribution system, transmission, and substation price indices have increased by approximately 12% — less than half of the 30.5% increase in industrial construction price indices during the same period.

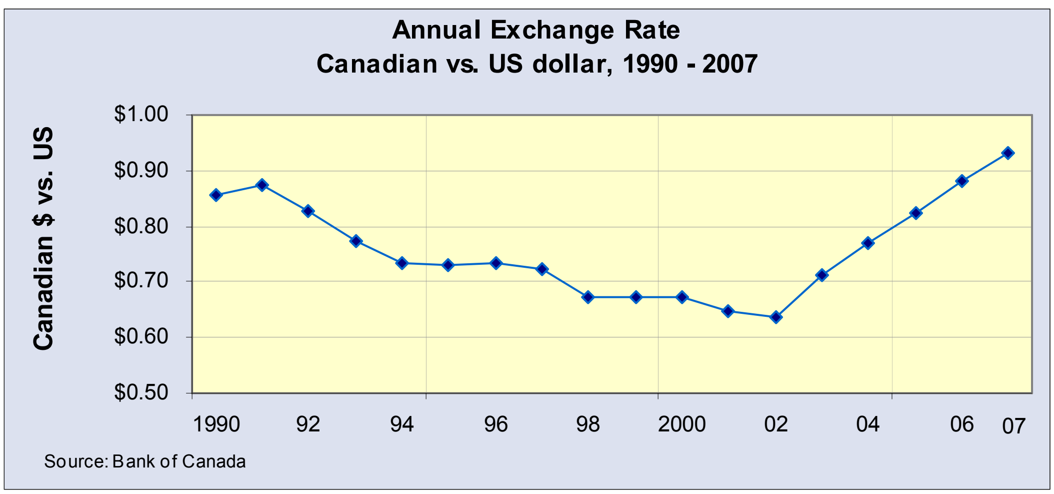
3.1.4 Potential factors contributing to lower electric utility construction price index increases

Several factors have been identified as likely contributing to the relatively low price index trends for electric utility construction. One factor is the specialized nature of the utility-based industrial construction segment. There may be a somewhat limited ability of firms to cross over into other industrial construction market segments, where activity levels have increased significantly, to pursue opportunities in these markets.

Another contributing factor may be the concentrated structure of the Canadian electric utility industry. The limited number of larger utilities may make it easier for these utilities to resist upward price pressures from suppliers.

Another likely 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 electric utility materials (e.g. cables) and equipment (e.g. transformers). As illustrated in Exhibit 3c, the Canadian dollar has strengthened considerably against the US dollar in recent years.

Exhibit 3c – Long-term annual exchange rate: Canadian vs. US dollar

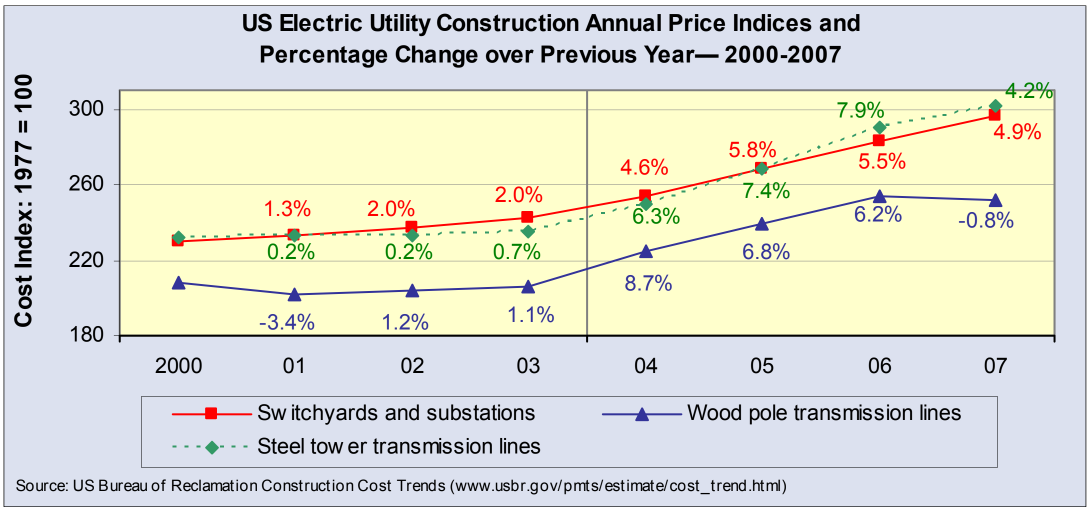


3.2 US electric utility price trends

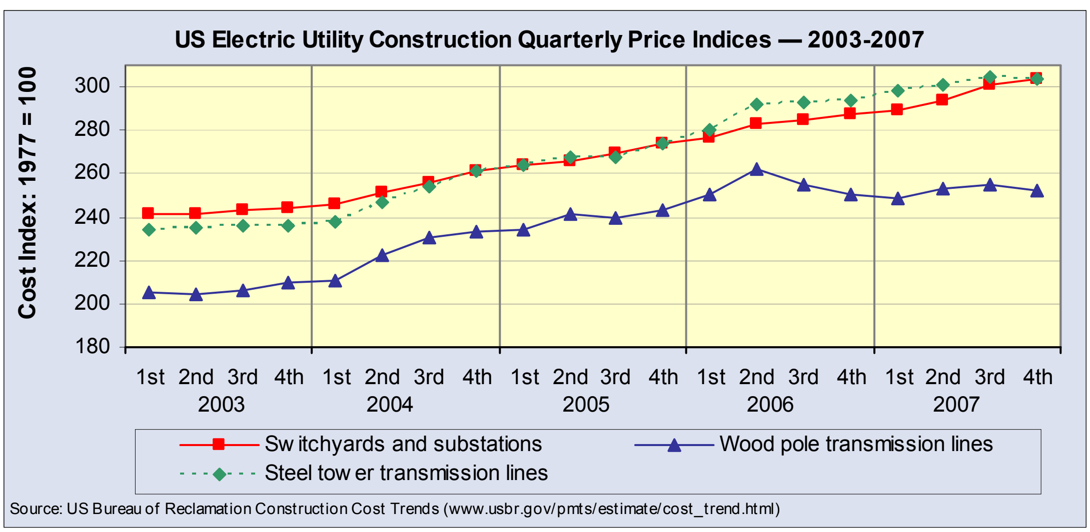
a) US construction price trends

The US Bureau of Reclamation[1] Construction Cost Trends for electric utility construction are illustrated in Exhibit 3d. They illustrate the continuing strong upward price trends for switchyards/substations and steel tower transmission lines, as well as a flattening of the upward trend in wood pole transmission lines.

Exhibit 3d – US electric utility construction price indices
(i) Annual trends, 2000 to 2007



(ii) Quarterly trends, 2003 to 2007

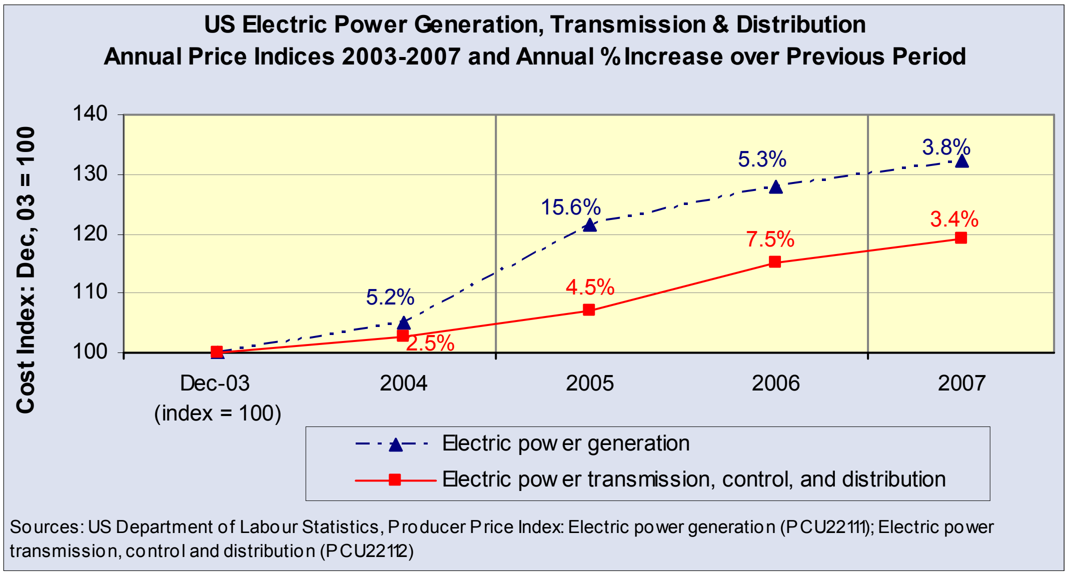


[1] The US Bureau of Reclamation manages, develops, and protects water and related resources. It has developed Construction Cost Trends to track construction relevant to the primary types of projects being constructed by the organization. Cost models consisting of appropriate labor, equipment, and materials types are used as the principal costs reference. Data for the models are primarily extracted from:
- Producer Price Indexes [PPI], US Department of Labor, Bureau of Labor Statistics
- Price Trends for Federal-Aid Highway Construction, US Department of Transportation
- Engineering News-Record, weekly publication of McGraw-Hill.
Actual field data, when available, is used to confirm the reasonableness of the models.

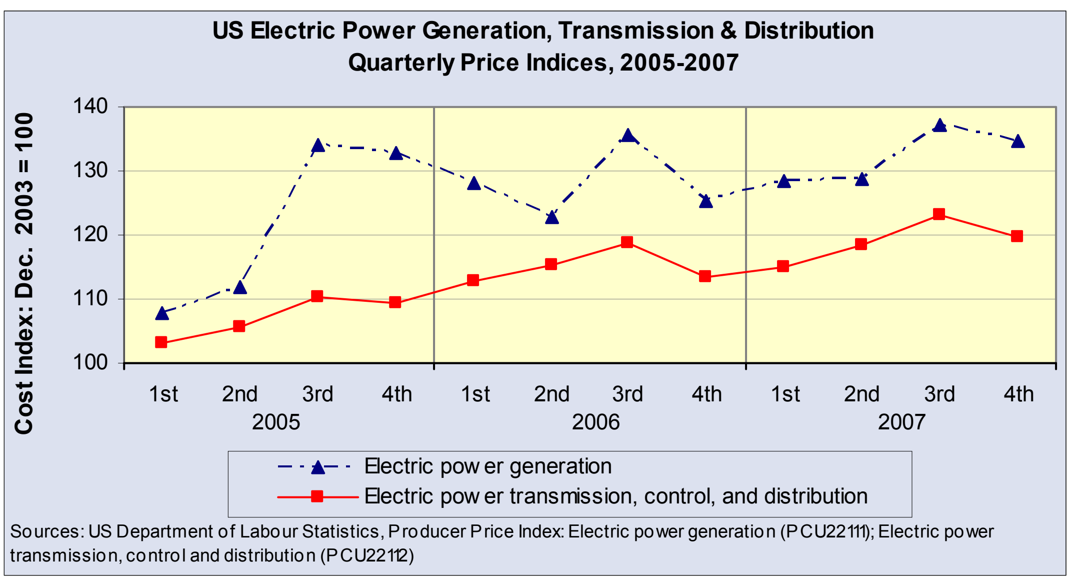
b) US producer price trends

Recent US producer price trends for electric power generation, transmission and distribution are illustrated in Exhibit 3e. Price trends in 2007 were upward, at a lower rate of increase than in 2006.

Exhibit 3e – US electric power generation, transmission & distribution – (i) Annual trends 2003-07



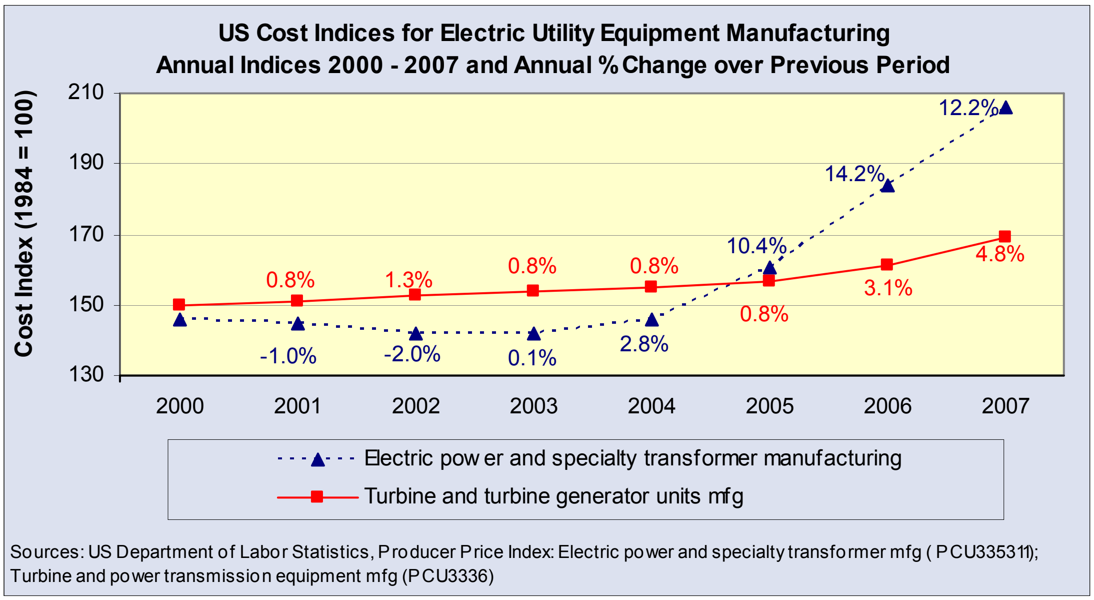
(ii) Quarterly trends 2005-2007



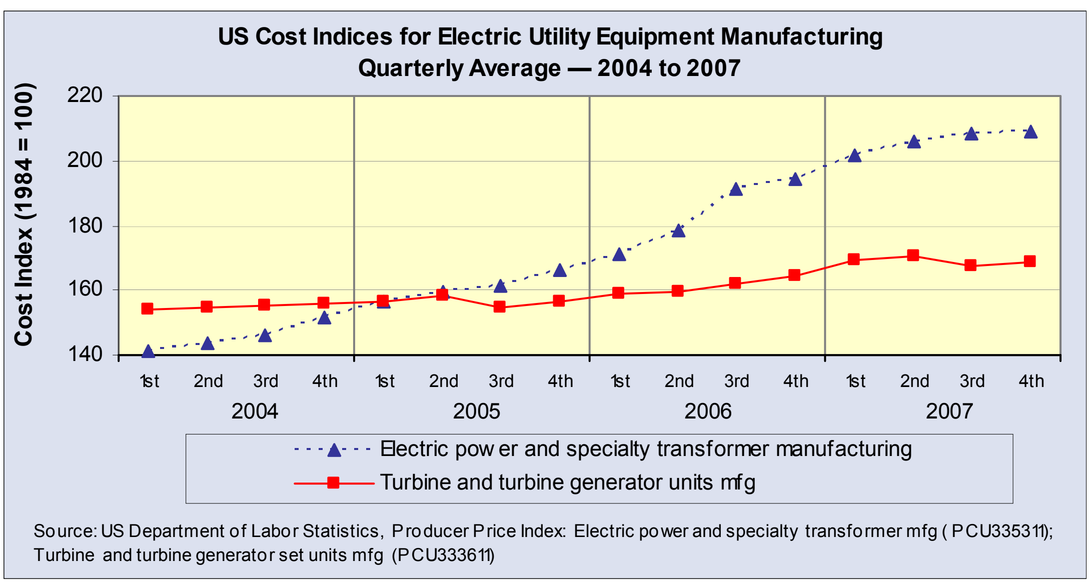
c) *US equipment manufacturing price trends*

As illustrated in Exhibit 3f, US electric power and specialty transformer equipment manufacturing price indices have risen by approximately 40% since 2003. Turbine and power transmission equipment manufacturing has increased at a much lower rate, approximately 8%, over the same period.

Exhibit 3f – US electric utility equipment manufacturing
(i) Annual trends 2000-07



(ii) Quarterly trends 2004 to 2007



d) Construction activity trends — US transmission and delivery

There is also evidence that US electric utility construction activity has been increasing in recent years, and is likely to continue to do so. According to a recent report prepared for the Edison Foundation[1]:

> "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. ...In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid.... From 2006-2009..., the industry is planning to invest $31.5 billion... nearly a 60% increase over the amount invested from 2002-2005."
>
> **"**Utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon. ...Investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030."

The same report also indicated that there is a shortage of spare shop capacity in the electric equipment and machinery manufacturing sector, as a result of increasing activity in electric utilities construction. These constraints may delay the delivery of major components such as turbines and transformers, and add costs to the project through higher manufacturing equipment costs.

These comments help to explain the increasing US manufacturing price index trends illustrated in Exhibit 3f.

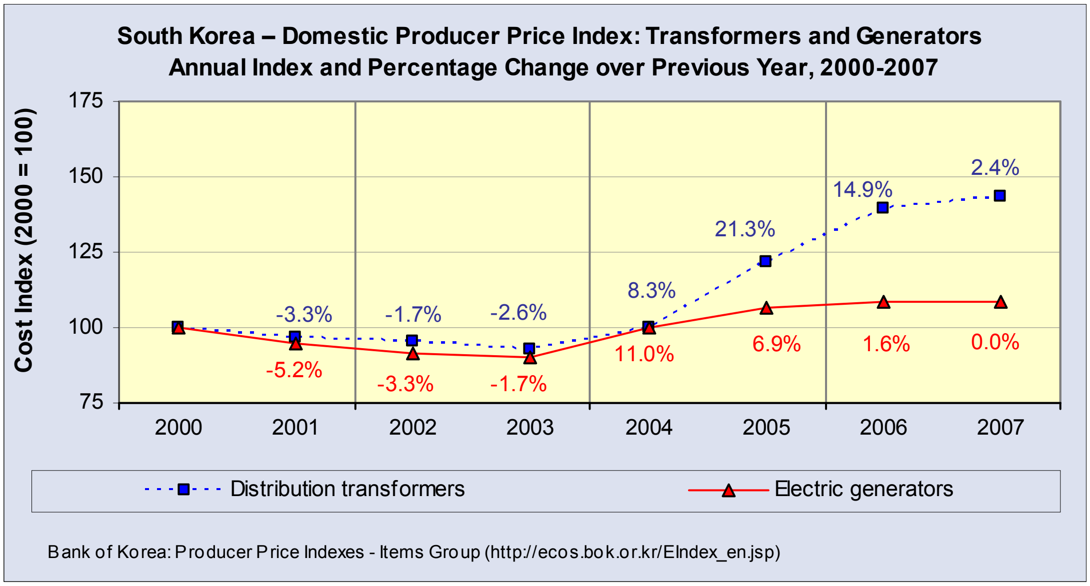
3.3 Equipment price trends — South Korea

3.3.1 Power generation and distribution equipment

As illustrated in Exhibit 3g, South Korea's domestic price index for distribution transformers increased by approximately 50% between 2003 and 2007. Price indices for electric generators have also increased, but much more moderately.

[1] Source: "Rising Utility Construction Costs: Sources and Impacts", The Battle Group, September 2007. Prepared for The Edison Foundation. (p.5 and 6)

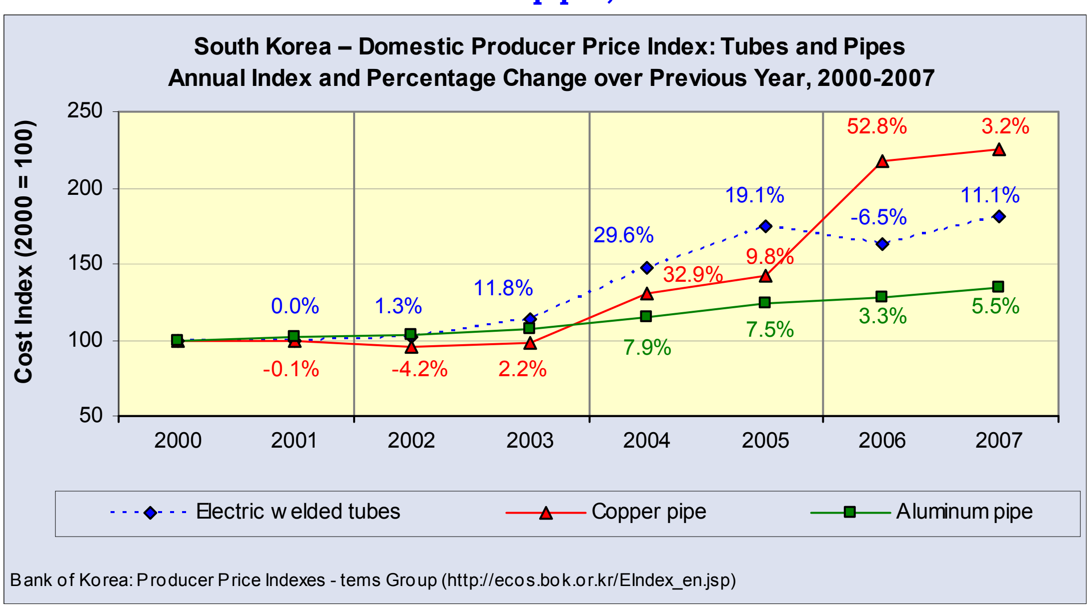
Exhibit 3g – Cost trends power generation equipment, South Korea



3.3.2 Other representative equipment and materials

As illustrated in Exhibit 3h, Korean price index trends for other representative equipment and materials items (such as tubes and pipes) have tended to reflect the significant upward worldwide trend in price indices for metals and other commodities.

Exhibit 3h – Cost trends for tubes and pipes, South Korea

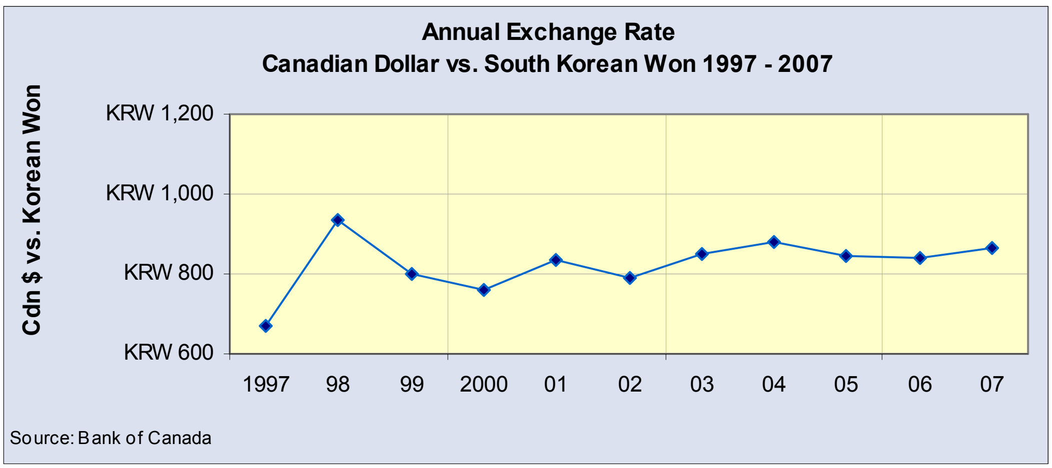


3.3.3 Exchange rate impacts

As illustrated in Exhibit 3i, currency exchange rates between Canada and South Korea have been fairly stable over the past four years. Thus, the Korean domestic trends illustrated in Exhibits 3g and 3h are not significantly impacted by exchange rates.

We caution that the price indices illustrated in Exhibits 3g and 3h are for domestic sales within South Korea, which may limit their relevance to export prices available to BC Hydro and other international customers.

Exhibit 3i – Exchange rates – Canadian dollar versus South Korean won

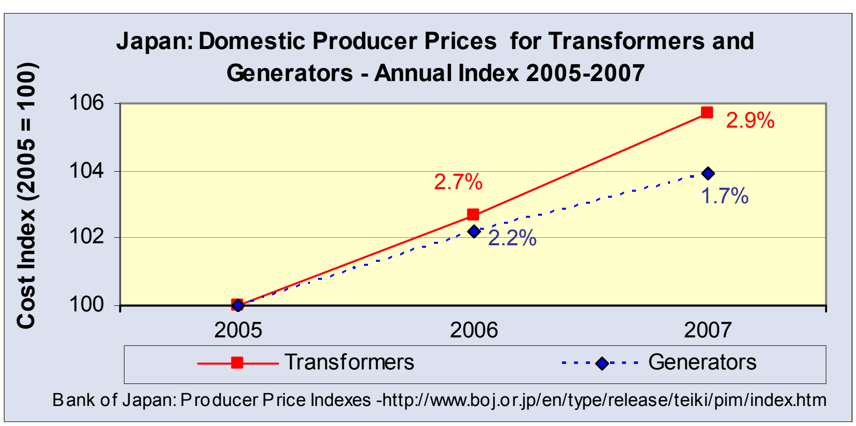


3.4 Equipment price trends – Japan

3.4.1 Power generation and distribution equipment

Domestic price trends for Japanese power generation and transformer equipment, measured in Japanese yen, are presented in Exhibit 3j. Domestic price increases in Japan have been relatively modest since 2005.[1]

Exhibit 3j – Domestic prices for transformers and generators

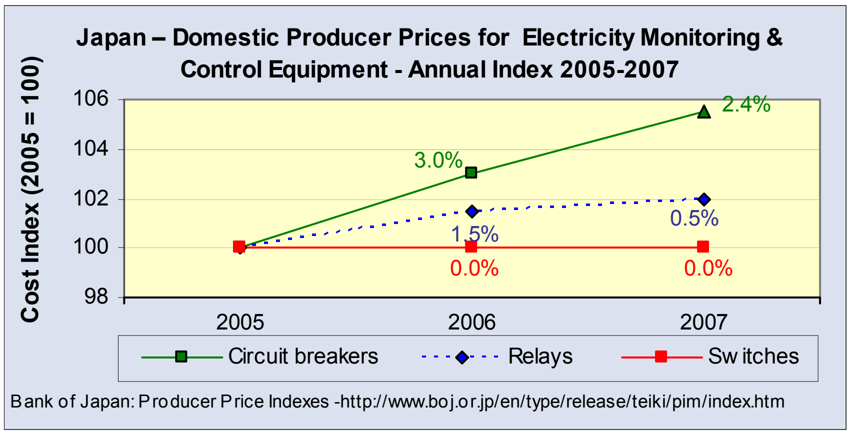


[1] Data is only available from 2005 for the Japanese electric utility subsector. Prior to 2005, producer price data is only available by major industry sectors.

3.4.2 Electricity monitoring and control equipment

Domestic price trends for electricity monitoring and control equipment are illustrated in Exhibit 3k. Domestic price increases for circuit breakers have been in the range of 2.4% to 3.0% annually, while price index trends for relays and switches have been relatively flat.

Exhibit 3k – Domestic prices for electricity monitoring & control equipment

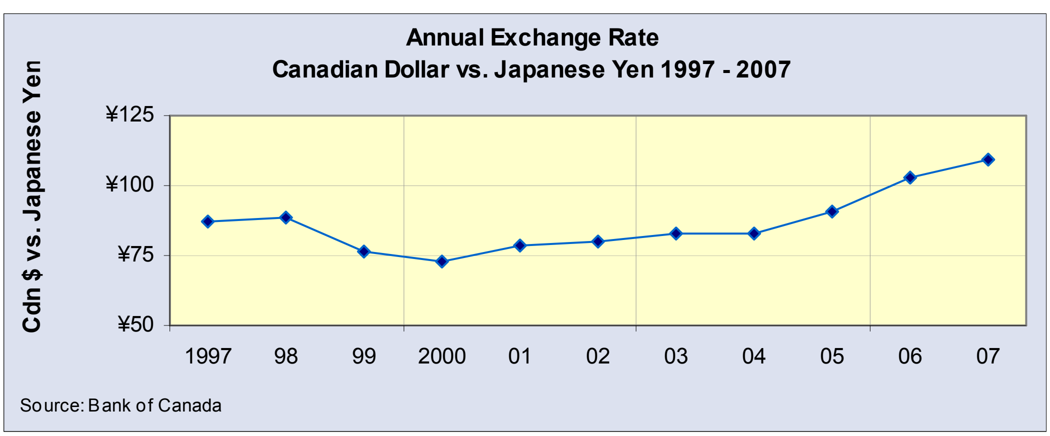


3.4.3 Exchange rate impacts

As illustrated in Exhibit 3l, the Canadian dollar has appreciated against the Japanese yen in recent years. This trend would tend to dampen or offset the domestic price increases noted in Exhibits 3j and 3k.

We caution that the price indices illustrated in Exhibits 3j and 3k are for domestic prices within Japan, which may limit their applicability to export prices available to BC Hydro and other international customers.

Exhibit 3l - Exchange rates – Canadian dollar versus Japanese yen



3.5 Recent BC Hydro purchasing experience

Hydro's purchasing staff also indicate that they have experienced significant increases in international equipment prices over the past few years. Our September 2007 reported noted Hydro staff reporting transmission equipment (e.g. transformer) prices of up to 25%-30% above expectations.

In early 2008, Hydro staff report that these price trends have flattened, but at the higher levels reached during 2007.

3.6 Conclusion — Electric utility construction price and activity trends

For most of the past four years, price index increases have been much lower in Canada for electric utility transmission/distribution than for the broader industrial construction indices. While Statistics Canada's Vancouver price index for industrial construction increased by 30.5% between 2003 and 2007, the Canadian construction price indices for distribution-related electric utility construction (distribution systems, transmission lines and substations) only increased by approximately 12% over the same four years.

With respect to US electric utility construction cost trends, cost indices for switchyards/substations and steel tower transmission lines increased by 4.9% and 4.2% respectively, while declining 0.8% for wood pole transmission lines, between 2006 and 2007.

US equipment price indices for electric power and specialty transformer manufacturing (in US dollars) have continued their upward trends, rising 12% in 2007, following increases of approximately 25% in the prior two years. By contrast, price trends have been relatively flat with respect to turbine and power transmission equipment manufacturing.

In Japan and Korea, domestic price indices for electrical transformers increased by 2.9% (Japan) and 2.4% (Korea) in 2007. Generator price index trends were more modest, increasing by 1.7% in Japan while remaining flat in Korea.

Looking ahead, US industry publications are forecasting high levels of transmission and distribution construction activity over the next few years. BC Hydro purchasing experts also indicate that they have experienced significant increases in international equipment prices over the past few years. In recent interviews, several current industrial construction suppliers to BC Hydro have also indicated that activity levels and market conditions in early 2008 are stronger than they were in early 2007.

4. Price Trends — By Cost Component

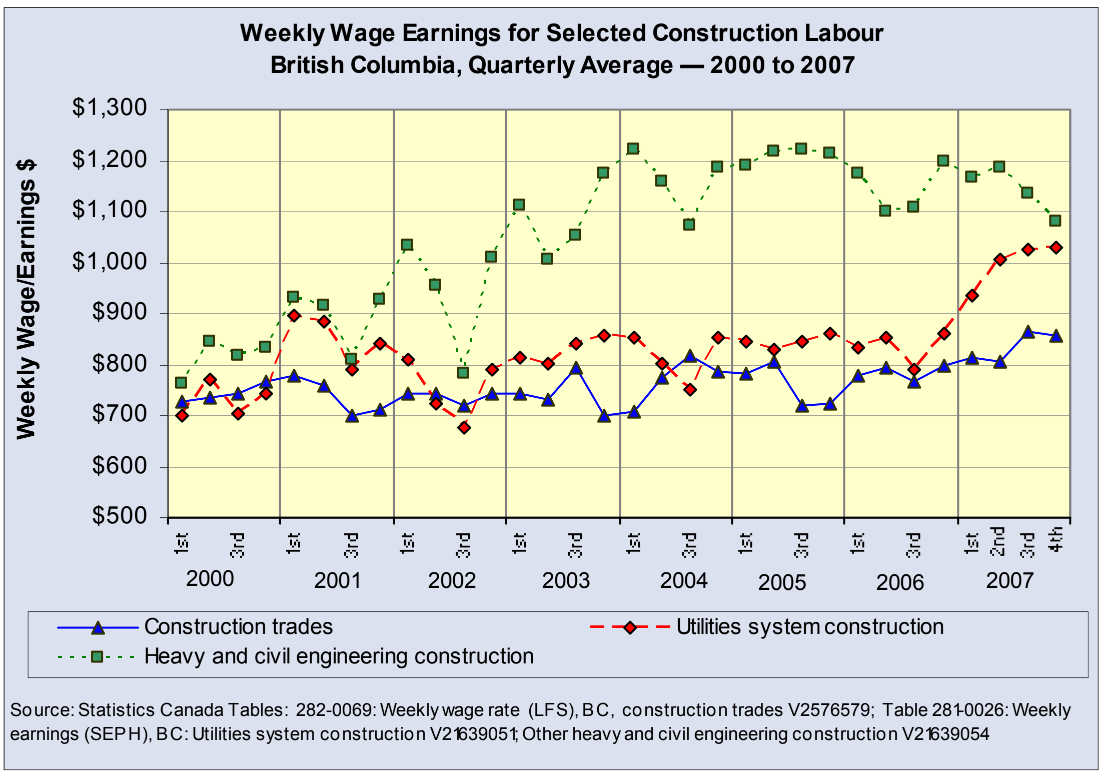
This chapter analyzes price index trends in many of the component cost factors (labour, materials, fuel, etc.) that will typically underlie industrial construction cost estimates and contractor bid prices.

4.1 Construction labour

a) Quarterly trends in wage earnings

As illustrated in Exhibit 4a, the apparent trends in wage earnings vary according to the specific index selected for analysis. Weekly wage earnings in utilities system construction have increased by more than 25% between the third quarter of 2006 and the fourth quarter of 2007. At the same time, reported wage earnings in more broadly-defined construction labour categories have increased at lower rates.

Exhibit 4a — Weekly wage earnings for selected construction labour in British Columbia

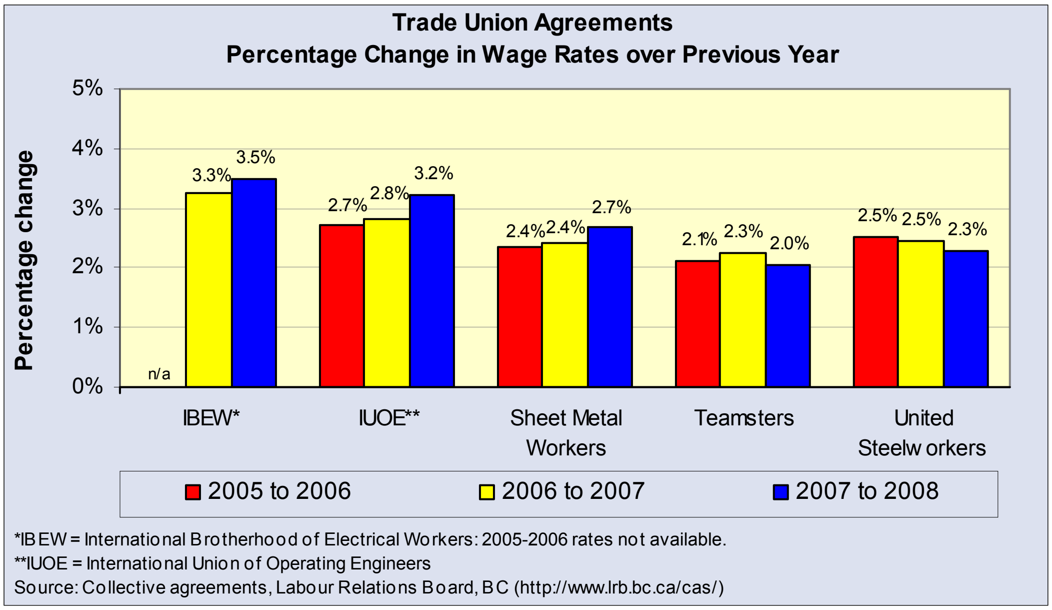


The mixed trends appear at first glance to be somewhat inconsistent with industry sources, who report significant increases in wages paid to similarly qualified labour. One explanation of these results is that the rapid growth of the BC construction industry has resulted in a decline in average experience 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.

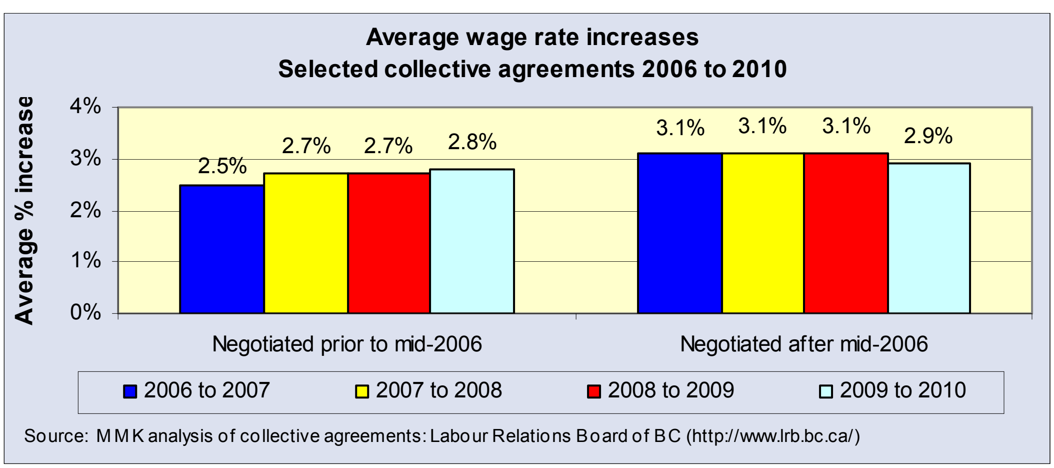
Exhibit 4b — Wage rate increases for sample union trade positions



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

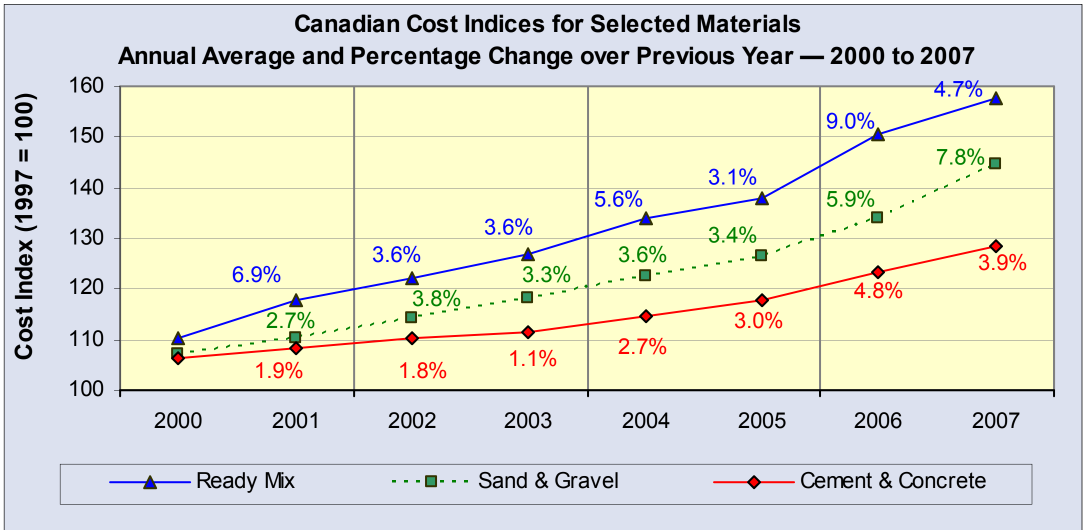


4.2 Concrete materials

Concrete materials price indices have been trending steadily upwards over the past few years. As illustrated in Exhibit 4d(i), the overall price indices in 2007 were up by between 3.9% (cement/concrete) and 7.8% (sand & gravel) over 2006.

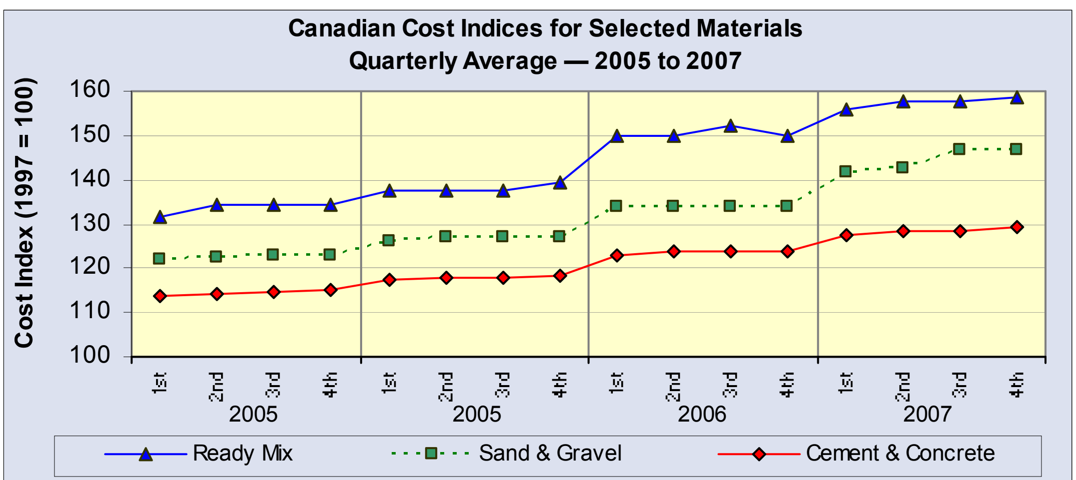
On a quarterly basis, Exhibit 4d(ii) illustrates the tendency for price adjustments to occur between the fourth and first quarter of each year. During the latter half of 2007, increases in ready mix and cement & concrete prices were small, although sand & gravel prices increased between the second and third quarters of 2007.

Exhibit 4d — Cost indices for selected construction materials
(i) Annual trends



Source: Statistics Canada: Table 329-0047 Ready Mix, Canada V1575965; Table 329-0046 Cement and concrete products, Canada V1575794; Table 330-0006 Sand & gravel, Canada V1576515

(ii) Quarterly trends



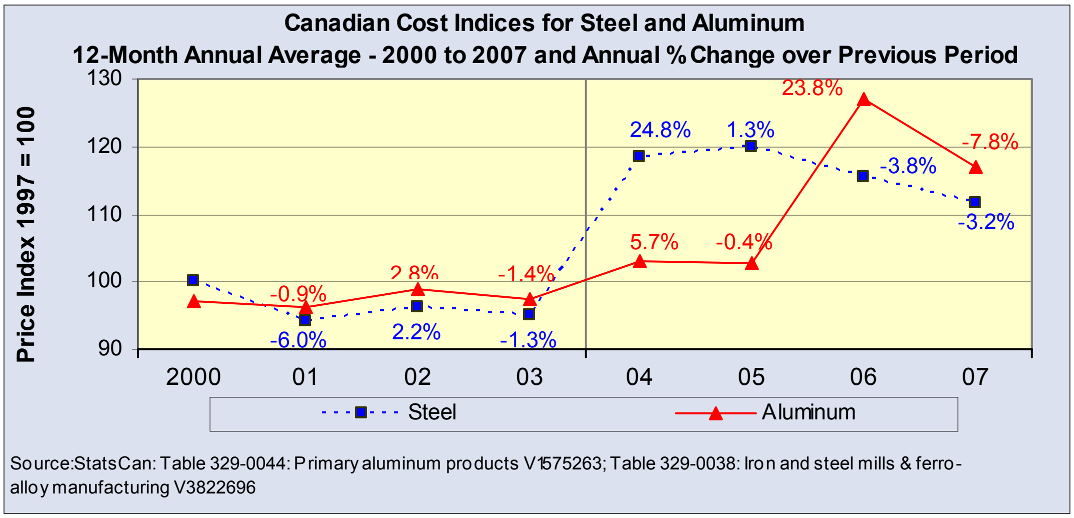
Source: Statistics Canada: Table 329-0047 Ready Mix, Canada V1575965; Table 329-0046 Cement and concrete products, Canada V1575794; Table 330-0006 Sand & gravel, Canada V1576515

4.3 Metal prices[1]

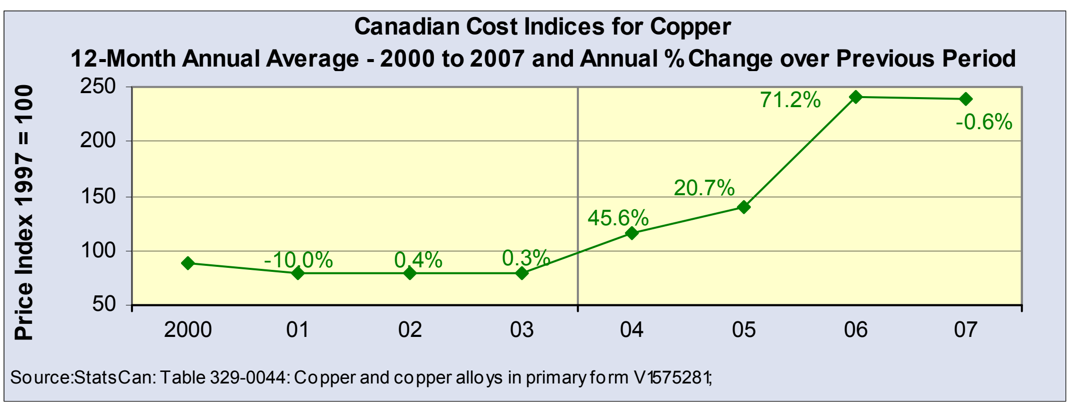
a) Annual trends

Exhibit 4e illustrates annual Canadian trends in steel, copper and aluminum.

Exhibit 4e — Selected metal cost trends – Canada
(i) Steel and aluminum



(ii) Copper



Price volatility in 2007 was generally lower than in the previous few years, albeit at significantly higher price levels:

- **Copper** has experienced the greatest price increase in recent years, roughly tripling in price between 2003 and 2006. In 2007, average copper prices were close to 2006 levels.

[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.

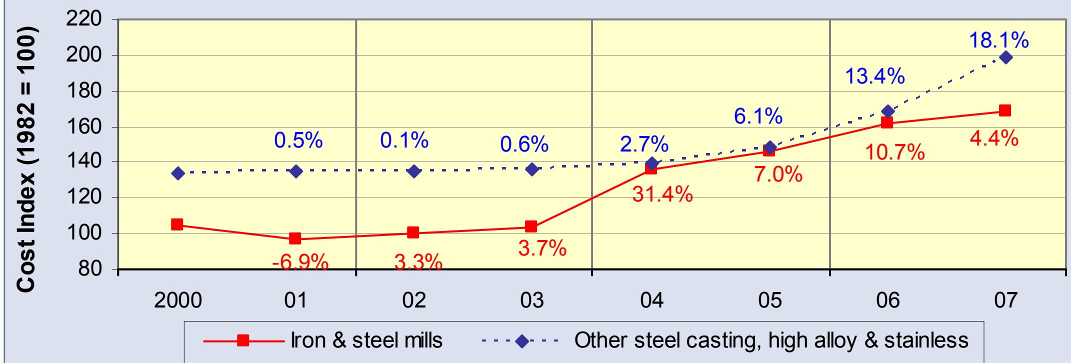
- **Steel** price levels increased by more than 25% between 2003 and 2005, before declining slightly in 2006 and 2007.

- **Aluminum** prices increased by 24% in 2006, before falling back 8% in 2007.

US price index trends, for selected metal products, are illustrated (in US dollars) in Exhibit 4f.

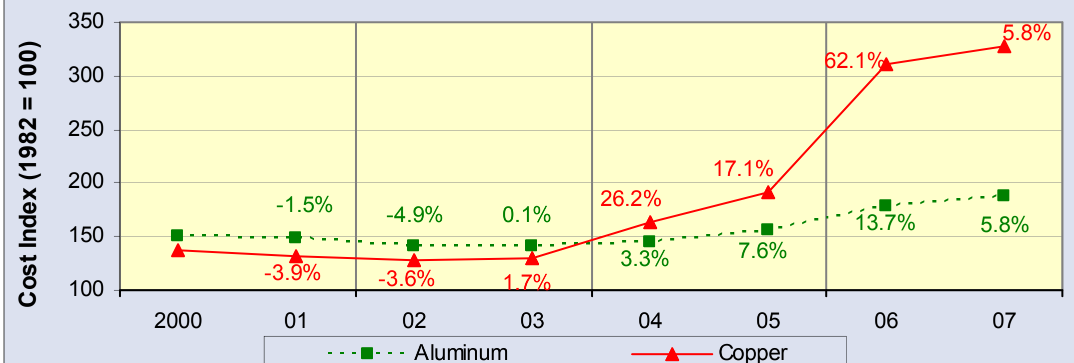
US metal indices for early 2008 continue to show a rising trend. Over the two-month period January to February 2008, steel indices are up 2% (iron steel) and 8% (stainless steel), copper is up 7%, while aluminum is stable.

Exhibit 4f — US producer price index for selected metal products
(i) Steel products



Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Iron and steel mills (PCU331111), Other steel casting, high alloy & stainless (WPU101508).

(ii) Copper and aluminum

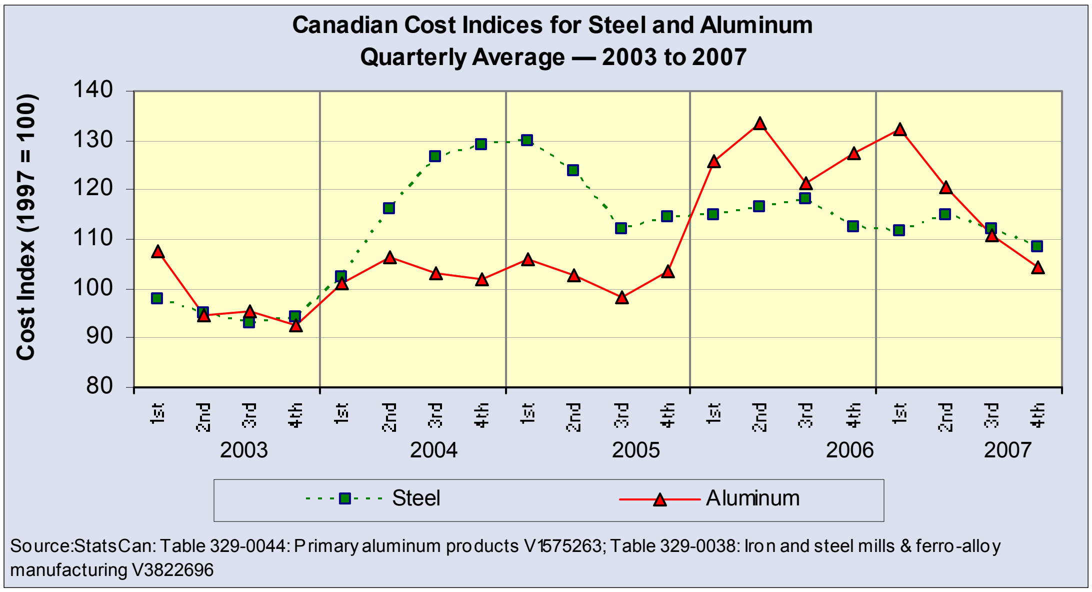


Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Aluminum sheet, plate & foil manufacturing (PCU331315). Copper rolling, drawing & extruding (PCU331421)

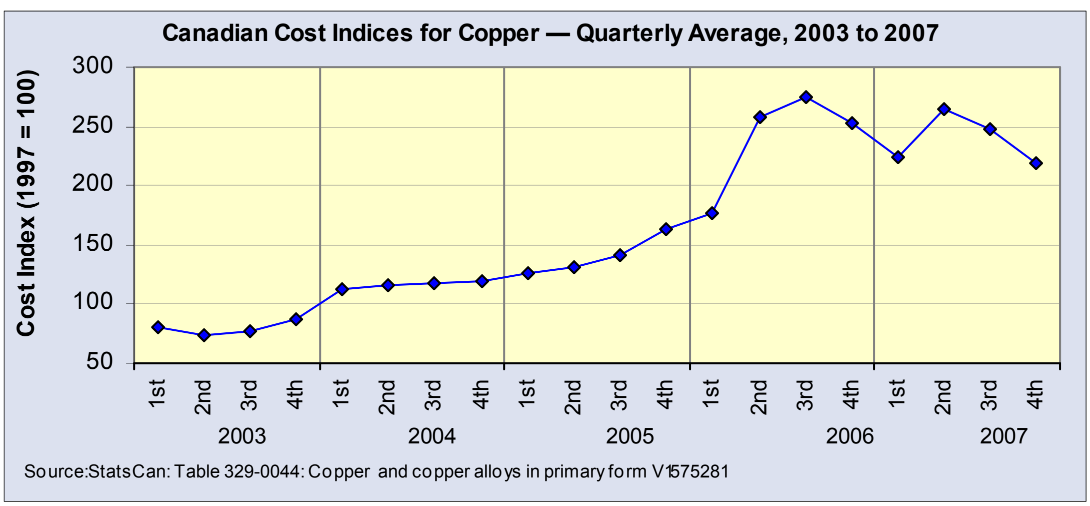
b) *Quarterly trends*

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 declined 17% in the second half of 2007, after rebounding in the second quarter of 2007. Although copper prices peaked in 2006, recent prices remain high in comparison to pre-2006 levels.

Aluminum prices in Canada dropped 13% in the second half of 2007, continuing their decline from the first half of the year, returning to 2004/2005 levels. In the US, aluminum prices reached record highs (in US dollars) during the first half of 2007, but declined in the second half.

Steel prices were steadier, declining 5% in the second half of 2007, after a small increase during the first half of the year.

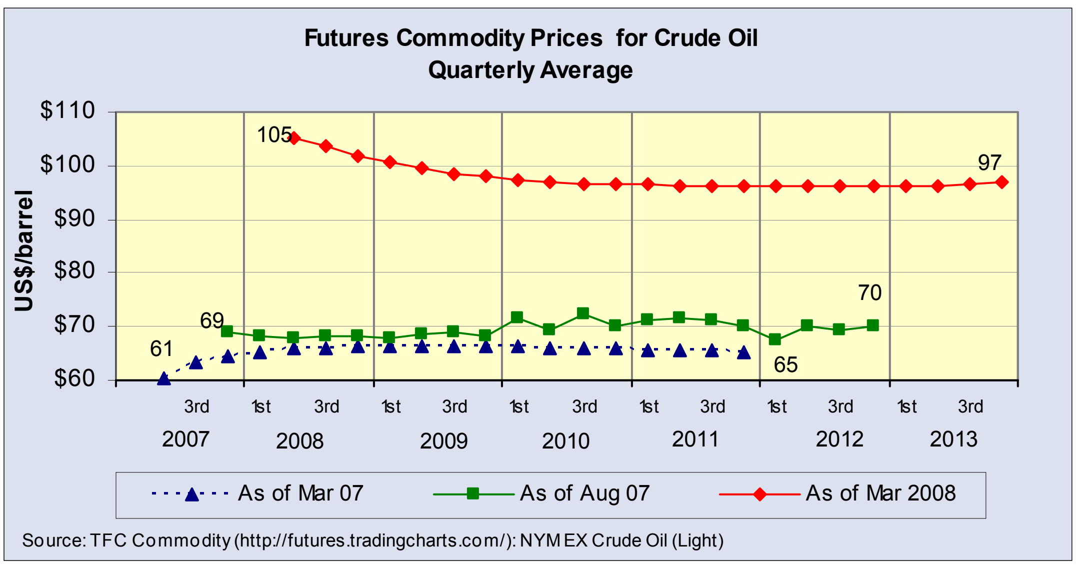
4.3.2 Changes in Futures markets

a) Crude oil

Exhibit 4h illustrates the futures prices for crude oil as recorded by the Futures New York Mercantile Exchange (NYMEX) on March 12, 2007, August 21, 2007 and March 28, 2008.

The futures markets, at all three points in time, were fairly flat in terms of expected future price movements. At the same time, the flat forecasts are based on very different starting points. While the March 2008 futures outlook is for a decline in prices, the projections are still for crude oil prices to be much higher than what was forecast in August 2007.

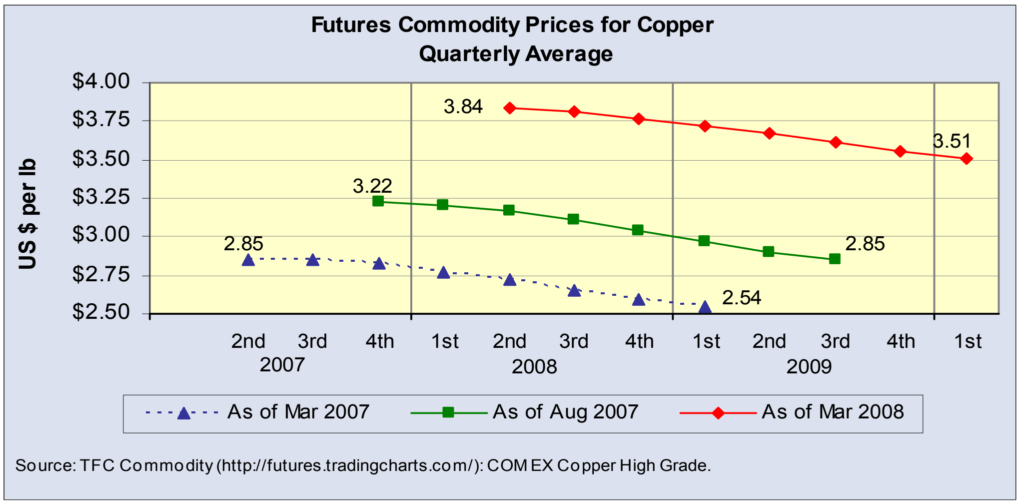
Exhibit 4h - Futures price indices for crude oil, based on the Futures New York Mercantile Exchange



b) Copper

Exhibit 4i illustrates the futures prices for copper as recorded by the Futures New York Mercantile Exchange (NYMEX) on March 12, 2007, August 21, 2007 and March 28, 2008. As in the case of crude oil, the futures expectation in March 2008 is for a declining market, but from a much higher base because of the increase in current prices.

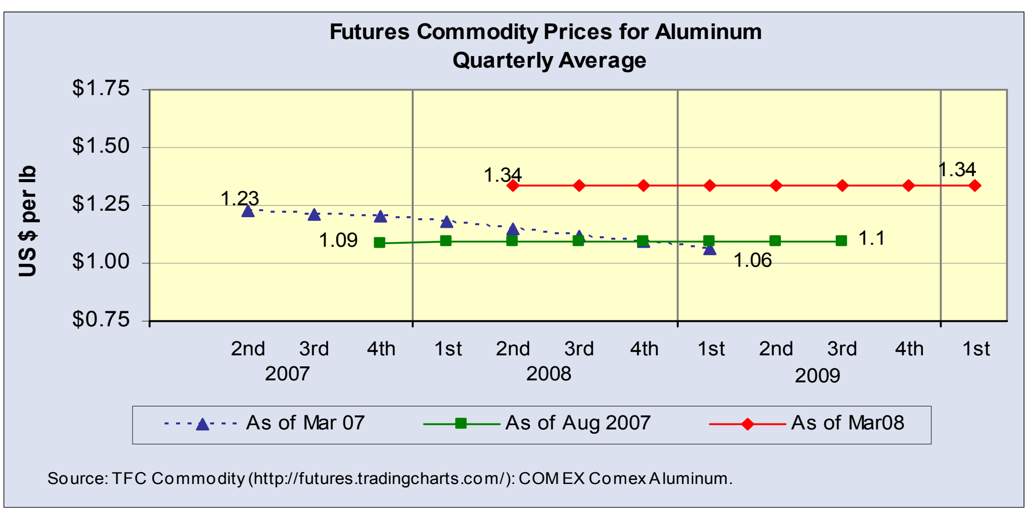
Exhibit 4i - Futures price indices for copper, based on the Futures New York Mercantile Exchange



c) Aluminum

Exhibit 4j illustrates the futures prices for aluminum as recorded by the Futures New York Mercantile Exchange (NYMEX) on March 12, 2007, August 21, 2007 and March 28, 2008. Current price and futures trends have been more stable for aluminum than for crude oil and copper.

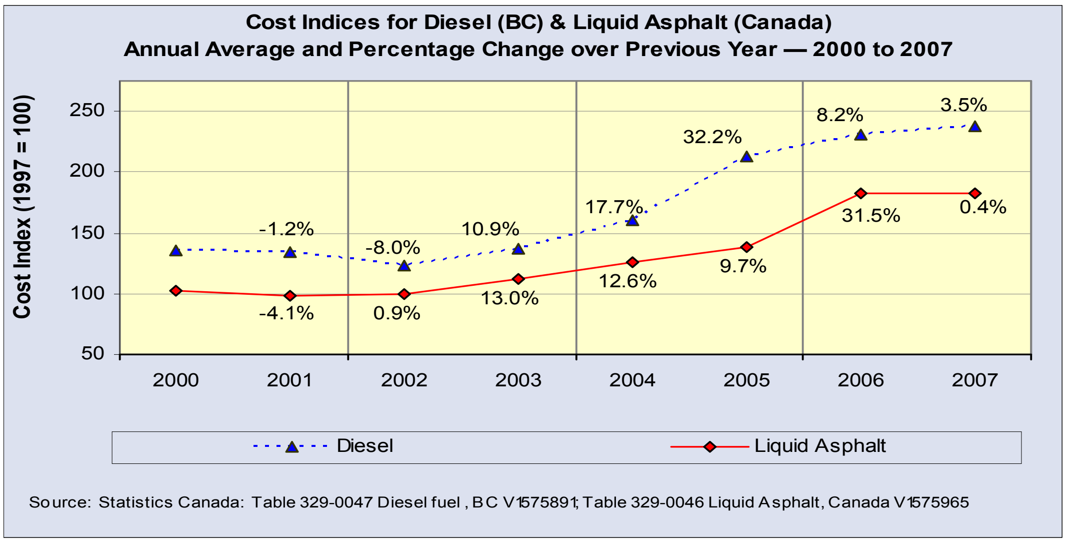
Exhibit 4j - Futures price indices for aluminum, based on the Futures New York Mercantile Exchange



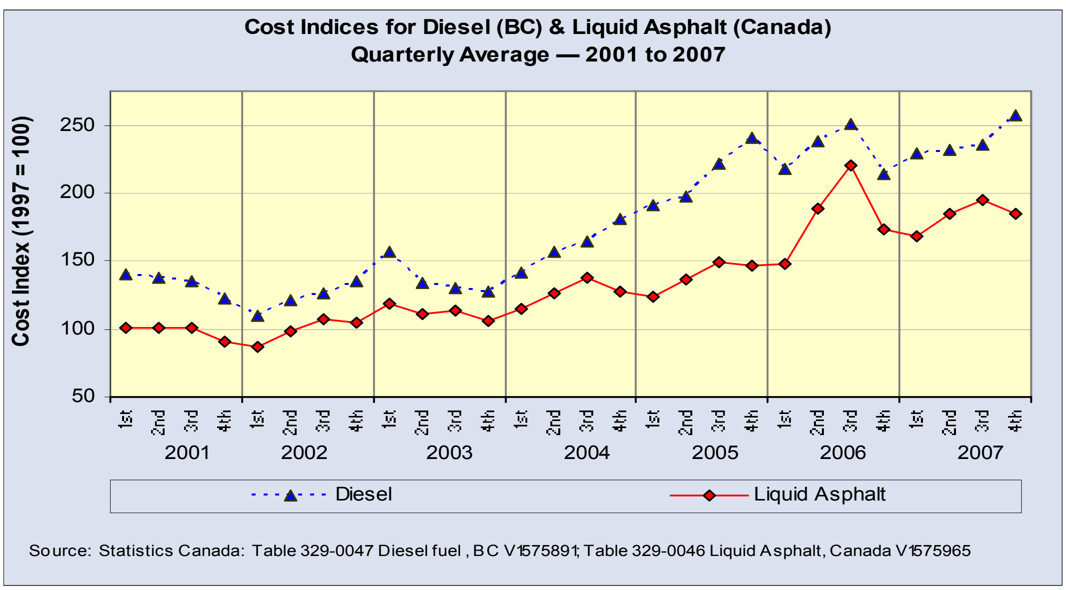
4.4 Diesel fuel and asphalt

Quarterly price index trends for diesel fuel and asphalt are illustrated in Exhibit 4k.

Exhibit 4k — Cost indices for diesel and liquid asphalt
(i) Annual trends



(ii) Quarterly trends



Diesel fuel price trends increased 11% in the second half of 2007, with the largest increase (9%) in the last quarter pushing diesel prices to a new all-time high.

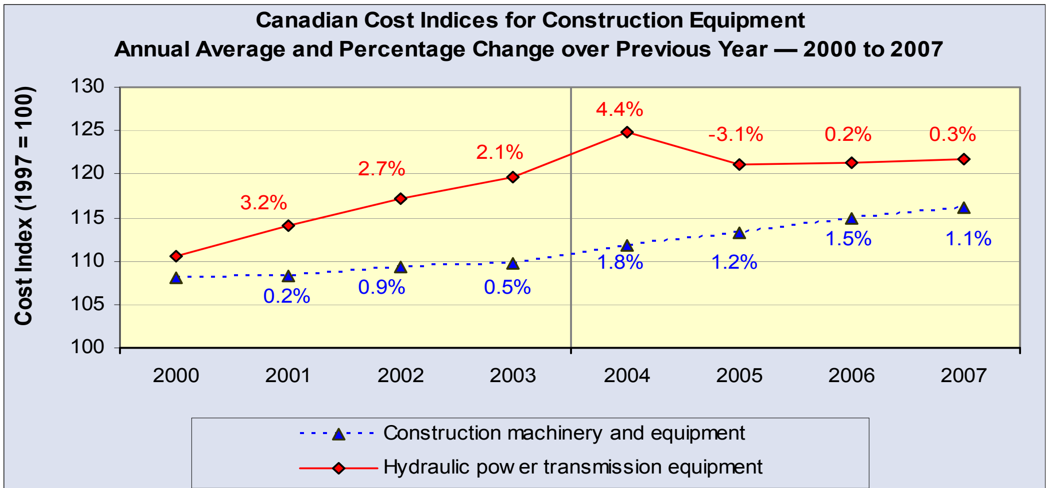
Asphalt prices increased 5% in the third quarter of 2007, before dropping back to second-quarter levels during the fourth quarter. Asphalt prices are still significantly higher than pre-2006 levels.

4.5 Construction machinery & equipment

As illustrated in Exhibit 41(i), Canadian price index trends for construction machinery and equipment, and for hydraulic power and transmission equipment, have been stable in recent years.

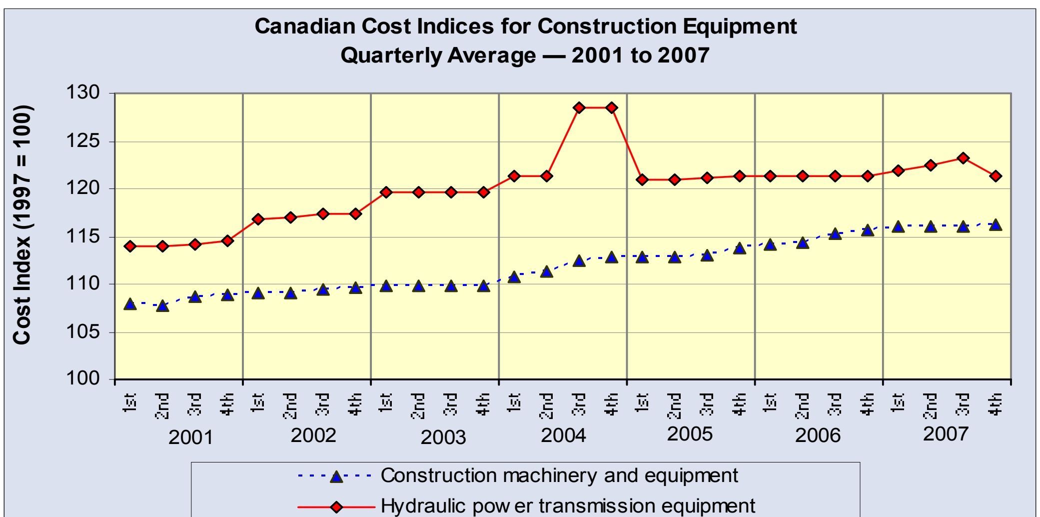
Quarterly results (Exhibit 41(ii) are also generally stable, except for a modest downturn in hydraulic power transmission equipment in the fourth quarter of 2007.

Exhibit 41 — Cost indices for construction equipment
(i) Annual trends



Source: Statistics Canada: Table 329-0045 - Industry price indexes for machinery and equipment, autos, trucks and other transport equipment, Canada: Construction machinery and equipment V1575466; Hydraulic power transmission equipment V1575474

(ii) Quarterly trends



Source: Statistics Canada: Table 329-0045 - Industry price indexes for machinery and equipment, autos, trucks and other transport equipment, Canada: Construction machinery and equipment V1575466; Hydraulic power transmission equipment V1575474

4.6 Oil & gas drilling/extraction and mining costs

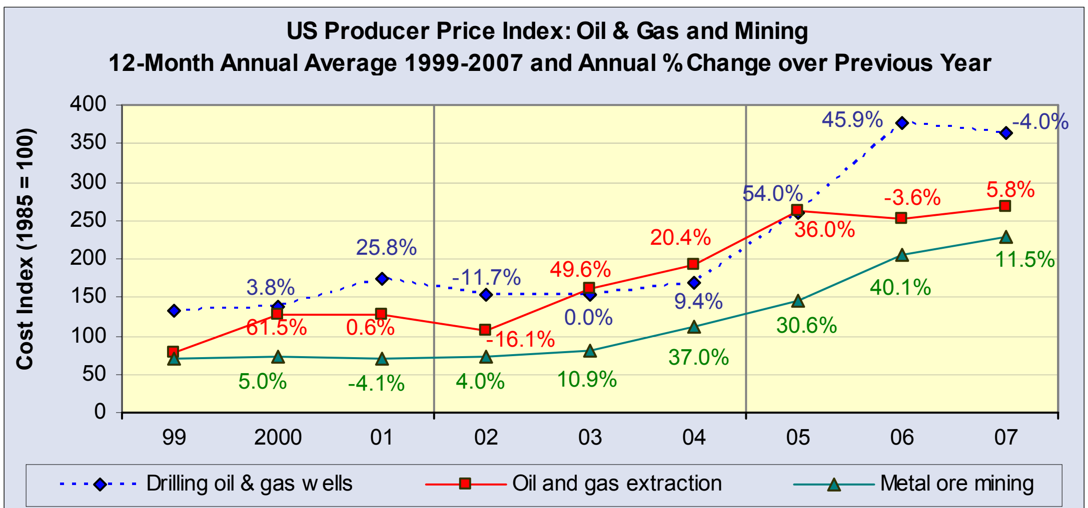
Exhibits 4m and 4n illustrate price trends for selected US oil, gas and mining indices. (These indices relate to the cost of drilling/extracting/mining activity, rather than the value of the product.)

a) Annual trends

Exhibit 4m illustrates US annual price trends in oil and gas drilling/extraction and ore mining activities. In 2007:

- **Oil & gas drilling** prices decreased 4%, after having doubled between 2004 and 2006.
- **Oil and gas extraction** prices increased 5.8%, returning to 2005 trends after a decrease in 2006.
- **Metal ore mining** prices continued their strong upward trend from the previous three years, at a somewhat more moderate rate of 11.5%.

Exhibit 4m — US producer price index for selected mining activities



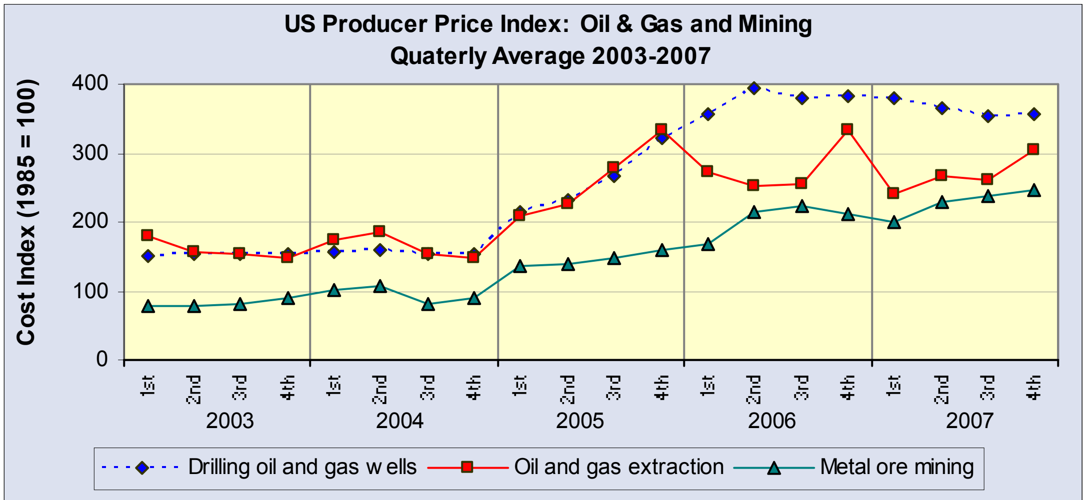
Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Metal ore mining (PCU2122). Oil and gas extraction (PCU211). Drilling oil and gas wells (PCU 213111)

b) Quarterly trends

Quarterly trends are illustrated in Exhibit 4n:

- **Oil and gas drilling** prices dropped by approximately 3% from the second quarter to the fourth quarter, continuing the decline of the first half of 2007,.
- **Oil and gas extraction** prices increased particularly in the fourth quarter.
- **Metal ore mining** prices rose moderately in the last half of 2007.

Exhibit 4n — 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 (PCU 213111)

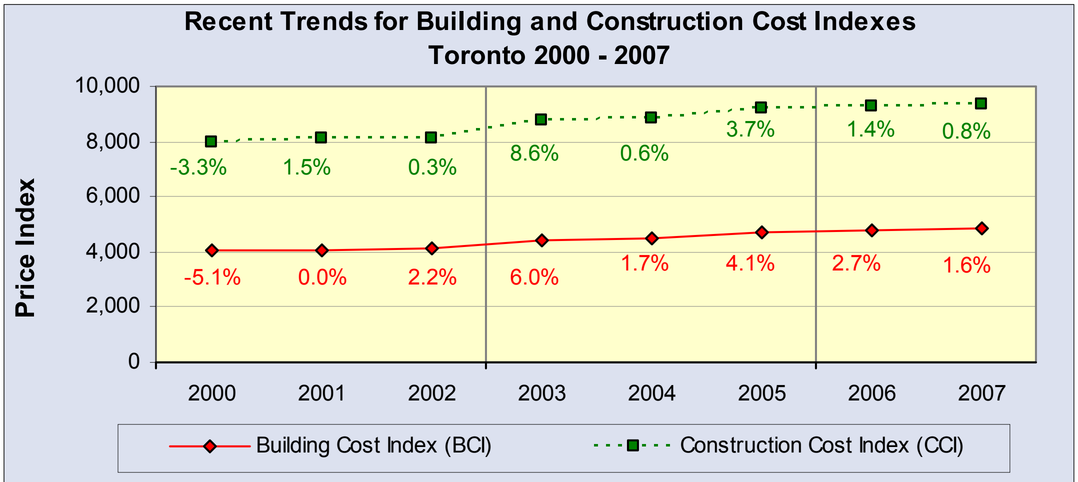
4.7 ENR composite measure of construction cost components

Engineering News Record (ENR) publishes two composite indices of construction cost components, for a number of North American cities (including Toronto): the Building Cost Index (BCI), and the Construction Cost Index (CCI) [1].

As illustrated in Exhibit 4o, ENR construction cost component indices for Toronto show moderate increases in recent years, and less than 1% over the past six months.

These indices are of specific component costs only, and do not take into account cost factors such as profit margins, insurance costs, employee bonuses and incentives, and employee productivity. They are therefore only partial indicators of cost trends faced by contractors.

Exhibit 4o – ENR construction cost component indices for Toronto 2000-2007



Source:Engineering News-Record (ENR). 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 towards skilled trade labour, and the CCI is weighted towards common laborers.

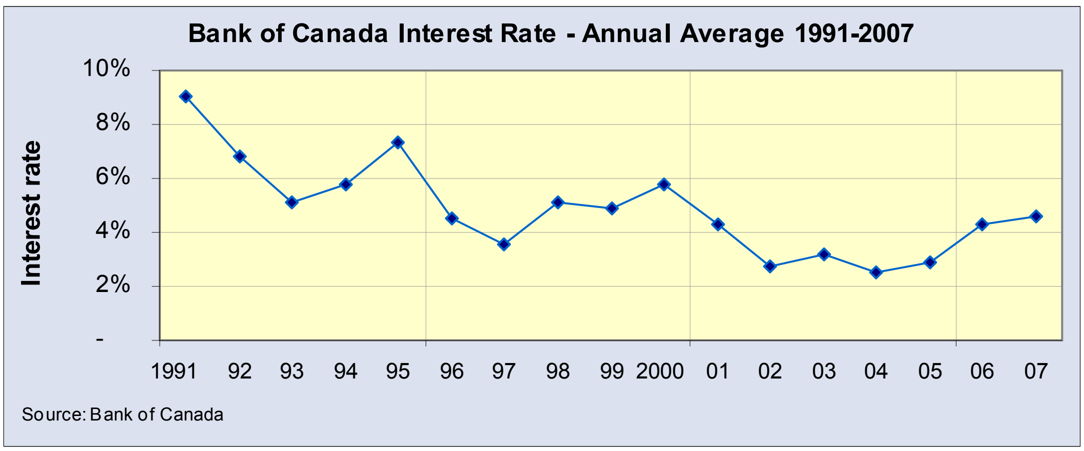
[1] ENR indices are weighted aggregate indices of the prices of constant quantities of structural steel, portland cement, lumber and labor. The BCI index is weighted more towards skilled trade labour, and the CCI is weighted more towards entry-level laborers.

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 4p. They demonstrate the historically low interest rates that have prevailed during the past few years. Rates increased in 2006 and 2007, 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 4p — Long-term Bank of Canada interest rates



b) Quarterly trends

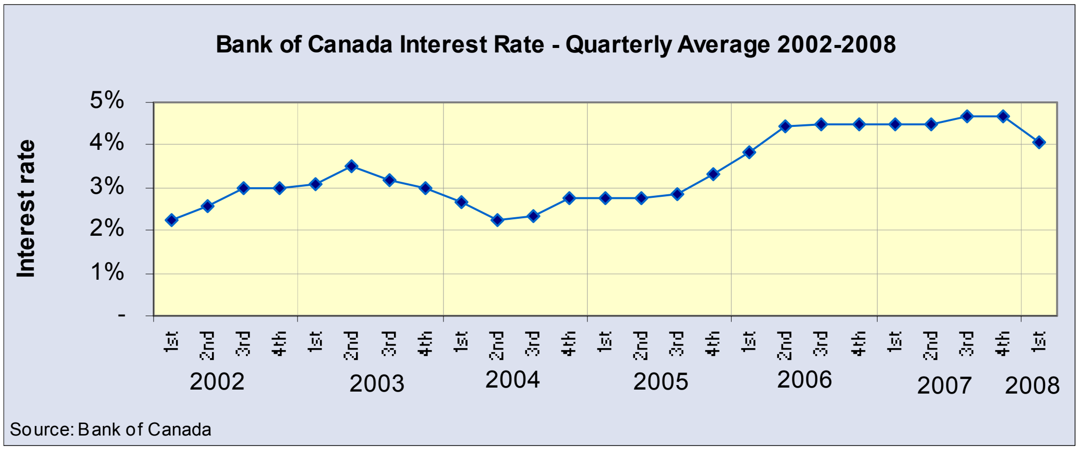
Quarterly interest rate trends, shown in Exhibit 4p, illustrate the upturn in interest rates in late 2005, early 2006, and a more modest increase in late 2007. These increases affect non-residential construction prices in two ways:

- **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 the current low interest rate environment.

Exhibit 4p — Quarterly Bank of Canada interest rates



In 2008, the Bank of Canada has reduced its interest rates in accordance with reductions in US interest rates. As of April 4, 2008, the Bank of Canada's prime rate was 3.75%.

4.9 Conclusion — Component cost trends

While component cost trends have been mixed during the second half of 2007, there has been far greater stability than that experienced in 2005 and 2006. Commodity prices (such as fuel and metal), while less volatile in recent months, are still high compared to pre-2006 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 (construction supply and demand) factors.

5. BC Regional Trends

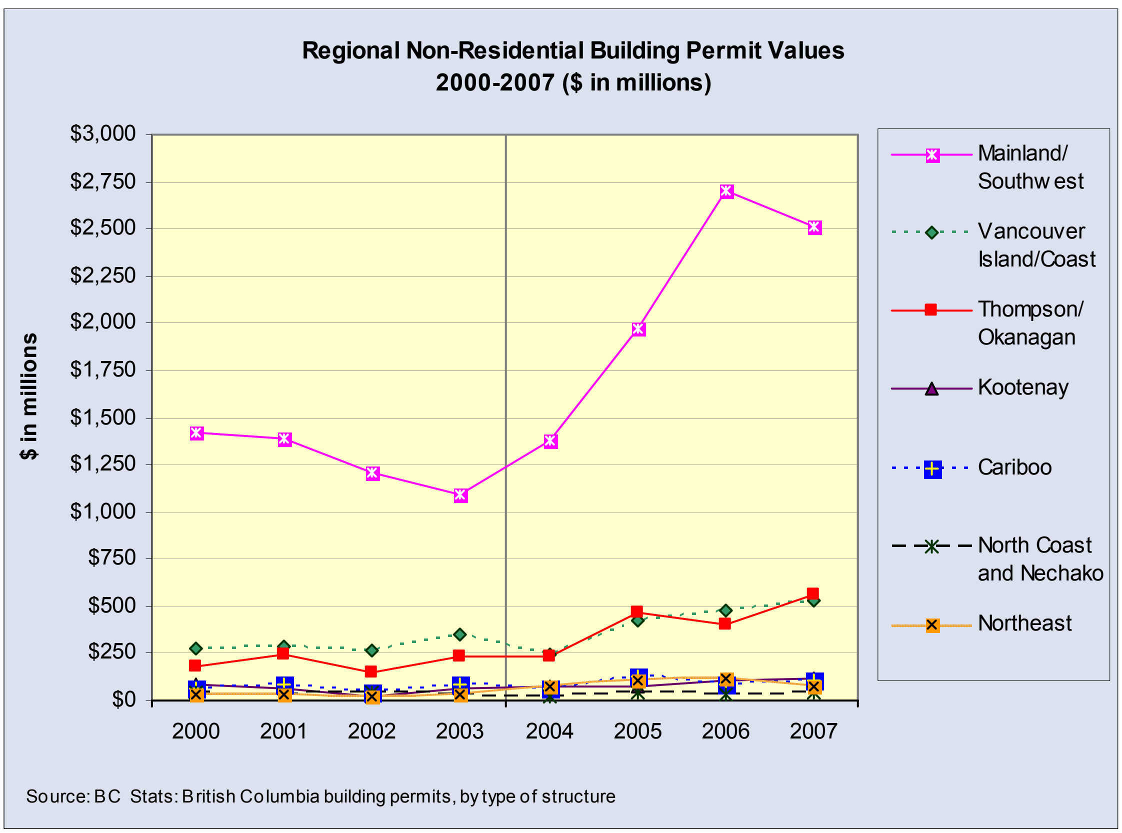
Within British Columbia, construction price indices are not tracked on a regional basis. However, two regional activity level indicators – building permit values and construction employment -- provide indirect measures of the regions in which constructions activity levels are highest, and where cost inflation pressures may be expected to be more significant.

5.1 Regional trends in construction activity

a) Annual trends

Regional trends in non-residential construction levels are illustrated in Exhibit 5a, based on the detailed data contained in Exhibit 5b.

Exhibit 5a — Regional annual trends in non-residential building permit values



The Mainland/Southwest region, which accounts for 64% of residential construction activity in BC, experienced a decrease in building permit values of (7% for non-residential, 24% for industrial buildings) between 2006 and 2007. Northeast non-residential building permit values also decreased in 2007 by 40% over 2006 levels, but were still more than double pre-2004 levels. All other regions experienced significant increases in the values of building permits, ranging from 10.5% (Vancouver Island-Coast to 39.8% (Thompson-Okanagan).

Exhibit 5b — BC value of building permits, by region

	2000	2001	2002	2003	2004	2005	2006	2007	Annual Change 07 vs 06	Jul-Dec 2006	Jul-Dec 2007	6-mth Change 07 vs 06
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	8,541.3	-26.0%	4,228.2	3,961.1	-6.3%
Non-residential												
Industrial	296.0	221.0	230.0	244.0	328.0	346.2	358.2	323.9	-9.6%	193.4	175.7	-9.1%
Commercial	1,297.0	1,171.0	1,117.0	1,130.0	1,228.0	1,886.4	2,491.4	2,647.9	6.3%	1,431.5	1,103.6	-22.9%
Institutional/Govnt	496.0	732.0	424.0	506.0	514.0	979.5	1,067.4	961.2	-10.0%	461.4	466.6	1.1%
Total non-residential	2,089.0	2,124.0	1,771.0	1,880.0	2,070.0	3,212.1	3,917.0	3,933.0	0.4%	2,086.3	1,745.9	-16.3%
Residential	2,403.0	2,830.7	3,888.4	4,514.2	5,868.7	6,979.0	7,624.1	4,608.4	-39.6%	2,137.9	2,215.2	3.6%
Vancouver Island/Coast												
Total value	581.5	632.0	769.2	993.4	1,098.4	1,459.9	1,705.7	1,841.2	7.9%	945.5	786.5	-16.8%
Non-residential												
Industrial	29.7	34.8	16.5	33.6	18.5	20.7	31.4	30.1	-4.2%	16.5	12.5	-24.3%
Commercial	147.6	145.1	155.2	202.5	139.1	257.4	281.9	229.4	-18.6%	174.3	116.5	-33.2%
Institutional/Govnt	99.3	102.6	93.5	113.6	81.0	148.3	161.8	265.4	64.0%	101.0	71.8	-28.9%
Total non-residential	276.6	282.5	265.2	349.7	238.6	426.4	475.2	525.0	10.5%	291.8	200.7	-31.2%
Residential	304.9	349.5	504.0	643.7	859.8	1,033.5	1,230.5	1,316.2	7.0%	649.7	585.8	-9.8%
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	3,825.9	-48.6%	2,082.7	1,613.2	-22.5%
Non-residential												
Industrial	194.9	150.5	162.7	129.8	198.4	187.7	227.9	173.6	-23.8%	137.5	94.4	-31.3%
Commercial	953.0	799.3	787.7	697.4	861.5	1,204.7	1,802.8	1,898.2	5.3%	1,039.4	706.7	-32.0%
Institutional/Govnt	269.2	433.9	257.7	262.7	315.1	582.9	672.1	437.9	-34.8%	256.1	226.4	-11.6%
Total non-residential	1,417.1	1,383.7	1,208.1	1,089.9	1,375.0	1,975.3	2,702.7	2,509.7	-7.1%	1,433.0	1,027.4	-28.3%
Residential	1,662.7	2,012.9	2,820.2	3,075.1	3,996.6	4,412.0	4,740.4	1,316.2	-72.2%	649.7	585.8	-9.8%
Thompson/ Okanagan												
Total value	397.01	531.256	515.998	774.3	963.7	1,560.7	1,551.7	1,881.8	21.3%	763.3	986.4	29.2%
Non-residential												
Industrial	30.2	17.4	23.4	49.2	30.5	48.3	69.1	65.0	-5.9%	22.5	39.7	76.4%
Commercial	96.2	159.4	94.2	116.2	135.3	293.6	209.8	369.0	75.9%	102.9	194.7	89.3%
Institutional/Govnt	54.6	70.2	35.6	70.1	70.0	122.0	125.8	131.8	4.8%	66.4	68.0	2.4%
Total non-residential	181.0	247.0	153.2	235.5	235.8	464.0	404.6	565.7	39.8%	191.7	302.4	57.7%
Residential	216.0	284.3	362.8	538.8	727.9	1,096.8	1,147.0	1,316.1	14.7%	571.6	684.0	19.7%
Kootenay												
Total value	219.001	174.291	164.2	239.4	244.6	369.7	402.4	493.3	22.6%	209.0	305.1	46.0%
Non-residential												
Industrial	27.8	8.8	6.5	6.7	13.9	8.9	13.4	14.2	5.9%	4.5	11.6	154.9%
Commercial	44.0	18.3	13.5	28.6	33.4	22.9	33.0	47.1	42.5%	18.4	37.3	102.5%
Institutional/Govnt	15.3	34.7	5.0	23.5	23.8	38.6	55.7	55.5	-0.3%	26.3	40.7	54.8%
Total non-residential	87.1	61.8	25.0	58.8	71.1	70.4	102.1	116.7	14.3%	49.2	89.5	81.9%
Residential	131.9	112.5	139.2	180.6	173.5	299.3	300.3	376.6	25.4%	159.8	215.6	34.9%
Cariboo												
Total value	101.8	115.2	88.5	125.4	121.2	203.0	174.0	257.4	47.9%	80.7	136.2	68.6%
Non-residential												
Industrial	7.5	4.0	10.2	6.5	16.2	38.0	7.2	10.4	44.8%	4.6	6.3	36.9%
Commercial	22.4	21.3	25.7	52.0	32.3	30.3	39.8	53.3	34.0%	25.4	20.7	-18.7%
Institutional/Govnt	29.9	55.9	9.8	31.2	11.1	62.0	33.4	39.9	19.3%	2.8	36.9	1238.5%
Total non-residential	59.8	81.2	45.7	89.7	59.6	130.4	80.4	103.6	28.9%	32.8	63.9	94.8%
Residential	42.0	34.0	42.8	35.7	61.6	72.6	93.7	153.8	64.3%	47.9	72.2	50.7%
North Coast and Nechako												
Total value	57.7	45.9	46.4	41.2	33.3	61.5	63.1	78.0	23.7%	34.0	43.0	26.5%
Non-residential												
Industrial	2.2	4.1	5.9	11.4	1.5	11.8	4.5	3.8	-13.8%	3.2	2.9	-10.9%
Commercial	13.5	11.8	10.9	13.1	7.7	10.8	21.9	19.5	-11.2%	14.8	6.5	-55.8%
Institutional/Govnt	24.3	18.3	21.3	4.0	10.9	18.8	5.2	16.2	209.2%	1.6	14.3	795.0%
Total non-residential	39.9	34.2	38.1	28.5	20.1	41.3	31.6	39.5	24.9%	19.6	23.7	20.8%
Residential	17.7	11.7	8.3	12.6	13.2	20.1	31.5	38.5	22.5%	14.4	19.3	34.4%
Northeast												
Total value	55.2	59.5	46.7	55.6	105.9	149.1	201.2	163.7	-18.6%	113.0	90.7	-19.7%
Non-residential												
Industrial	3.3	1.7	5.0	6.8	49.0	30.8	4.8	26.8	455.2%	4.5	8.4	87.1%
Commercial	20.7	16.0	19.5	19.9	18.7	66.7	102.2	31.5	-69.2%	56.3	21.2	-62.4%
Institutional/Govnt	3.5	16.6	1.5	1.3	1.9	6.9	13.4	14.5	8.2%	7.3	8.6	18.0%
Total non-residential	27.5	34.3	26.0	28.0	69.5	104.4	120.5	72.8	-39.5%	68.1	38.2	-43.9%
Residential	27.7	25.2	20.7	27.6	36.4	44.6	80.7	90.9	12.6%	44.9	52.5	17.0%

Source: BC Stats – British Columbia building permits, by type.

b) Six-month trends

Exhibit 5c illustrates building permit trends by region, over the past two six-month periods.

Caution is advised in interpreting the significance of these figures, given the relatively small values in some regions. However, the results indicate that, during the second half of 2007, non-residential building permit values declined in Vancouver Island/Coast and Mainland/Southwest, while increasing in all other regions of the province.

Exhibit 5c — Value of building permits, by region

	Value of non-residential building permits ($ M)					
	Jul-Dec 2006	Jan-Jun 2007	Six-month change	Jan-Jun 2007	Jul-Dec 2007	Six-month change
Total non-residential						
■ Vancouver Island/Coast	292	324	11.1%	324	201	-38.1%
■ Mainland/Southwest	1,433	1,482	3.4%	1,482	1,027	-30.7%
■ Thompson/Okanagan	192	263	37.3%	263	302	14.8%
■ Kootenay	49	27	-44.8%	27	89	229.6%
■ Cariboo	26	40	53.7%	40	64	61.3%
■ North Coast & Nechako	20	16	-21.3%	16	24	50.0%
■ Northeast	45	35	-22.4%	35	38	10.3%
Industrial construction						
■ Vancouver Island/Coast	17	18	6.4%	18	13	-28.9%
■ Mainland/Southwest	137	79	-42.4%	79	94	19.1%
■ Thompson/Okanagan	22	25	12.6%	25	40	56.7%
■ Kootenay	5	3	-43.2%	3	12	348.9%
■ Cariboo	5	4	-12.7%	4	6	56.7%
■ North Coast & Nechako	3	1	-70.5%	1	3	201.8%
■ Northeast	3	18	545.9%	18	8	-54.7%

Due to rounding numbers may not add up exactly.

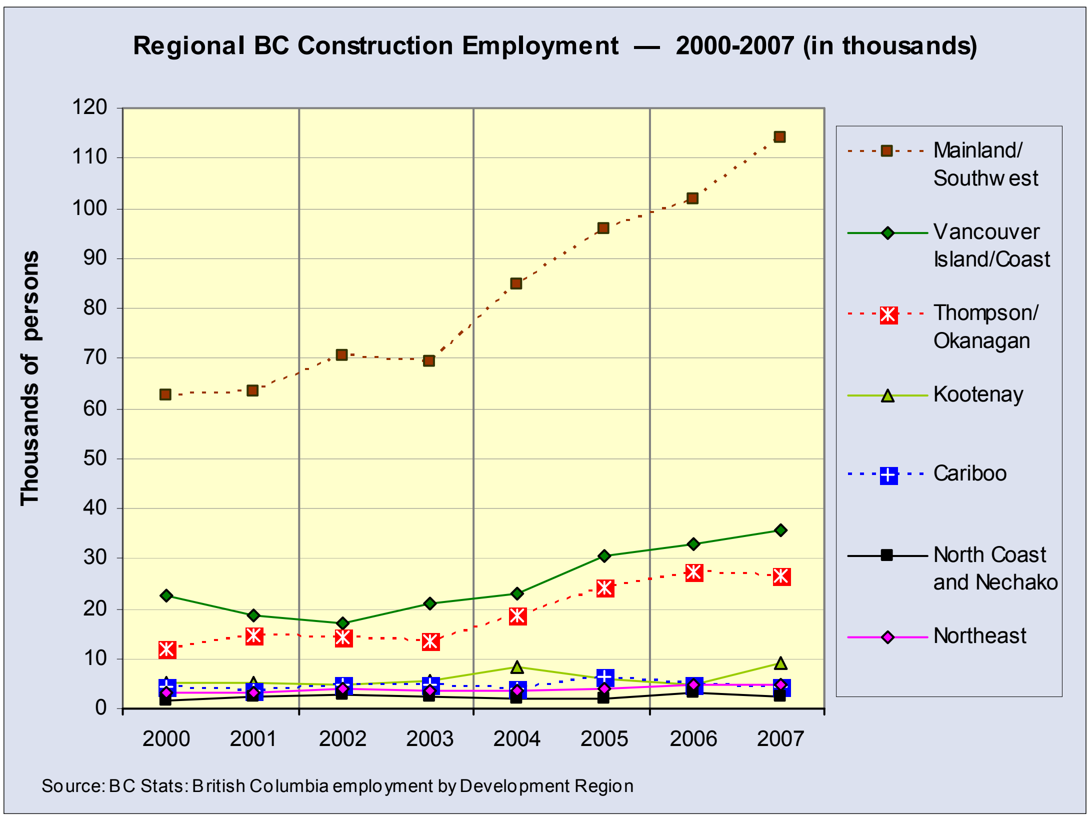
5.2 Regional trends in construction employment

a) Annual trends

Annual regional trends in construction employment are illustrated in Exhibit 5d, in both graph and tabular form.

The highest growth in construction employment between 2006 and 2007, in absolute terms, was in the BC Mainland/Southwest. Strong construction employment growth was also recorded in Vancouver Island/Coast and Kootenay, while Northeast and Thompson/Okanagan were flat. Reported construction employment in Cariboo and North Coast/Nechako declined in 2007 from 2006 levels.

Exhibit 5d — Regional construction employment trends 1999-2007 (000s)[1]



1. See also table overleaf.

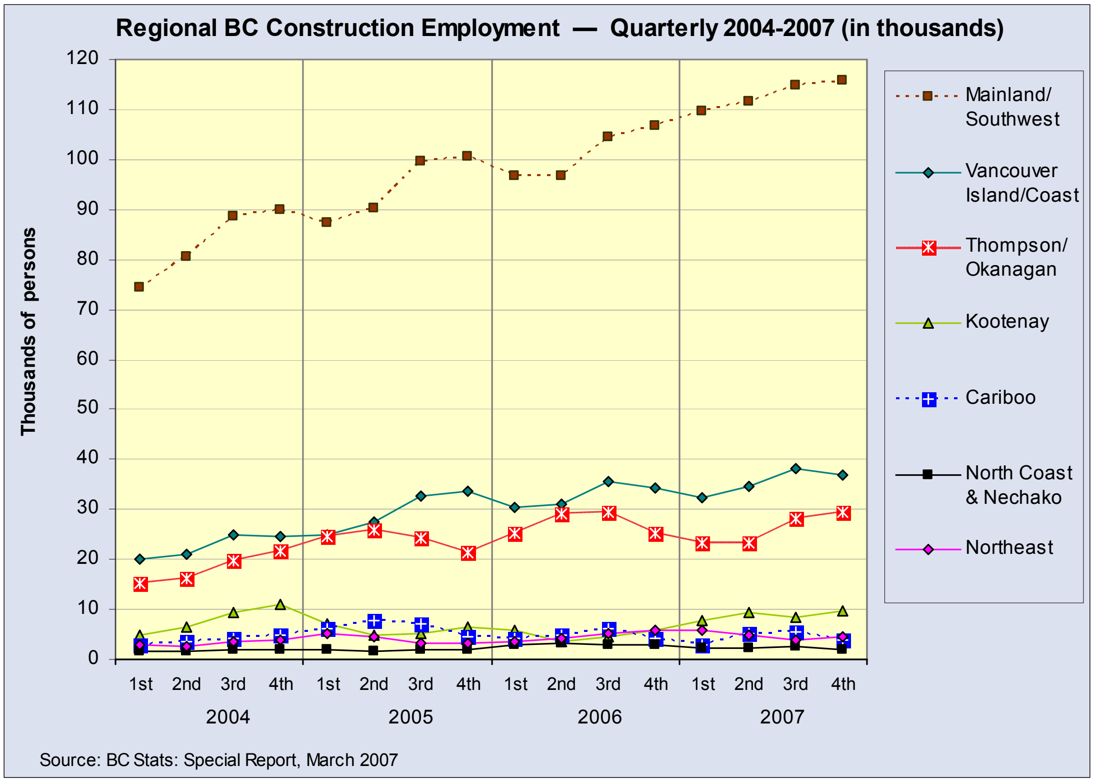
Exhibit 5d (cont'd) — Regional construction employment trends 2001-2007 (000s)

	2001	2002	2003	2004	2005	2006	2007	% change 06 vs 07	Jan 07-Jun 07	Jul 07-Dec-07	6-mth % Change
British Columbia											
Construction employment	110.7	118.1	119.8	144.0	168.0	179.3	196.9	9.8%	187.5	202.1	7.8%
- % of total employment	5.8%	6.0%	5.9%	7.0%	7.9%	8.2%	8.7%				
Vancouver Island/Coast											
Construction employment	18.5	17.1	20.9	23.0	30.3	32.8	35.8	9.1%	33.4	37.6	12.6%
- % of total employment	6.0%	5.4%	6.5%	6.9%	8.7%	8.9%	9.5%				
Mainland/Southwest											
Construction employment	63.4	70.4	69.2	84.6	95.8	101.7	114.1	12.2%	110.7	115.3	4.2%
- % of total employment	5.4%	5.8%	5.5%	6.6%	7.3%	7.6%	8.2%				
Thompson/Okanagan											
Construction employment	14.6	14.3	13.6	18.8	24.1	27.3	26.4	-3.3%	23.3	28.8	23.8%
- % of total employment	6.9%	6.9%	6.2%	8.2%	9.9%	10.8%	10.3%				
Kootenay											
Construction employment	5.1	4.6	5.5	8.3	5.8	4.9	9.2	87.8%	8.6	9.1	6.8%
- % of total employment	7.2%	6.9%	8.2%	12.4%	8.4%	7.1%	11.9%				
Cariboo											
Construction employment	3.7	4.9	4.9	4.1	6.2	4.8	4.4	-8.3%	4.0	4.8	21.5%
- % of total employment	4.7%	6.3%	6.3%	5.1%	7.7%	5.8%	5.3%				
North Coast and Nechako											
Construction employment	2.3	2.6	2.2	1.9	1.8	3.0	2.2	-26.7%	2.2	2.3	0.7%
- % of total employment	4.9%	5.8%	4.9%	4.5%	3.9%	7.0%	5.3%				
Northeast											
Construction employment	3.1	4.0	3.4	3.4	3.9	4.7	4.8	2.1%	5.4	4.2	-22.8%
- % of total employment	9.5%	12.0%	9.7%	10.2%	11.4%	13.8%	13.1%				

b) *Quarterly trends*

Quarterly construction employment trends for 2004-07 are illustrated in Exhibit 5e.

Exhibit 5e – Regional BC construction employment



In Mainland/Southwest, construction employment levels have increased steadily over the past year, without the seasonal downturn reported in previous years.

Vancouver Island/Coast experienced normal seasonal trends, at higher overall construction employment levels than in previous years. In Thompson/ Okanagan, construction employment increased in the third quarter of 2007 after dropping in the first half of the year.

5.3 Conclusions — Regional trends

While the regional data on construction activity levels (building permit values, construction employment trends) provide sometimes contrary indicators, it is apparent that activity-level-driven cost pressures were felt in all parts of the Province during 2007.

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-	2012-2015
BTY	BC Lower Mainland construction							
	• December 2005	11%	10%	10%	9%	8%		
	• December 2006	11%	5-7%	5%	3%	3%		
	• December 2007	-	-	7%	6%	5%	3%	
ENR (US)	Component cost Index							
	• Building Cost Index (BCI)	3.9%	3.5%[1]	1.8%				
	• Construction Cost Index (CCI)	4.1%	3.7%[1]	3.2%				
RLB (US)	Selling price index							
	• US	10.4%	9.0%					
	• Seattle	n/a	8.2%					
BC MoT	Construction cost allowances							
	• Property		10%	n/a[2]				
	• Major projects			n/a[2]				
	• Other projects		5.2%	5%	5%	3%	3%	3%
BC AVED	Construction cost allowances	15%	15%	12%	9%	8%		
YVR	Construction cost allowances		8%	6%	5%	3.5%	2.5%	2.5%
StatsCan	Industrial construction							
	• Seven CMAs	7.8%	8.7%					
	• Vancouver	10.3%	12.6%					
	Electric utility construction							
	• Distribution systems	4.1%	3.2%					
	• Transmission lines	6.6%	3.6%					
	• Substations	3.8%	5.7%					

1 Actual for 2007 = 2.6% (same for BCI and CCI indices)
2 As of 2008, property and major projects are estimated individually on a project-by-project basis.

6.1 BTY Group

BTY Group is a Canadian-based construction project management consulting firm that periodically issues construction cost inflation forecasts. BTY's forecasts in the past three years are illustrated in Exhibit 6a. In its most recent December 2007 forecast, BTY is projecting BC Lower Mainland construction costs to increase by 7% in 2008, 6% in 2009, 5% in 2010, and 3% in 2011.

BTY is also forecasting that construction cost inflation in Alberta will be approximately double that in the BC Lower Mainland — 18% in 2008, 15% in 2009, 10% in 2010, and 7% in 2011.

6.2 ENR composite cost index

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, in December 2006 ENR was forecasting a 0.7% increase in its Building Cost Index for 2007. The actual increase in 2007 was 2.6%. In December 2007, ENR projected a BCI index increase of 1.8% for 2008.

- ENR's US **Construction Cost Index** (CCI) is more heavily (79%) weighted towards labour costs. In late 2006, ENR was forecasting a 2.7% increase in this index for 2007. The actual increase, for 2007, as measured by ENR, was also 2.6%. For 2008, ENR is expecting increasing labor costs to put pressure on construction costs in 2008, and as of December 2007 was projecting a CCI increase of 3.2% for 2008.

It should be emphasized that these indices are only partial measures of construction cost inflation, since they do not take into account factors 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 overall US construction cost index (based on bid prices) increased by 9.0% in 2007.

- That its Seattle construction cost index increased by 8.2% 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 reports

Two recent Conference Board of Canada reports contain forecasts for the Canadian construction industry (including residential):

- 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 projected 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 reductions in profit margins is expected to be the rising cost of labour, resulting from labour shortage, combined with a less skilled workforce.

- In a recent Winter 2008 report, the Conference Board of Canada reported that Canada's residential construction industry saw a significant drop in profit in 2007, and can expect profitability to decline by 3.3% in 2008 and 4% in 2009. However, profit margins are still higher than historical norms.

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.

MoT's strategies for mitigating construction 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 different 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.

As of April 2008, the Ministry's cost inflation policies are as follows:

- Property acquisition – as recommended by regional property group.

- Major construction projects – individually estimated on a project-by-project basis.

- Other projects – 5% annually for first two years, 3% annually thereafter.

[1] Conference Board of Canada: Canadian Industrial Outlook: Canada's Non-Residential Construction Industry — Summer 2007 and Winter 2008.

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 detailed in earlier chapters, Statistics Canada price indices indicate that industrial construction cost inflation in Vancouver has been in the range of 10% to 12% over the past two years.

On the other hand, Statistics Canada's price index increases for electric utility transmission and distribution were in the range of 4% to 7% for 2006, and 4% to 6% for 2007.

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 reflects different approaches to measuring cost inflation, different expectations about the duration of the current construction boom, and different approaches in determining how conservatively 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 two previous reports are illustrated in Exhibit 7a. In our March 2007 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…".

Our subsequent September 2007 report noted that 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." We also noted that "… 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."

Since our last report, the weakening of upward trends in component costs has now been reflected in construction price indices. The 3.7% increase in the Metro Vancouver industrial construction price index in the last half of 2007 is significantly down from the 6.3% recorded in the first half of the year, and is the lowest increase in the past two years. At the same time, it is important to note that 3.7% in six months is still a significant rate of increase – approximately 7.5% on an annual basis.

7.2 Recommended cost inflation allowances for BC Hydro

Looking ahead, our assessment is that rates of industrial construction cost inflation will continue at late-2007 rates in 2008. While US demand will put price pressure on transmission and distribution equipment, international competition and the strong Canadian dollar will assist in mitigating price impacts.

On balance, our recommended cost inflation allowances are illustrated in Exhibit 7a. As actual six-month trends since our previous report have been generally as expected, our recommended cost inflation allowances are unchanged.

Exhibit 7a — Recommended construction cost inflation allowances

Previous reports vs. this update		2007 to 2010	2011 to 2015
Mar. 2007	• Generation (heavy construct.)	4% to 6%	2.5% to 4%
	• Utility transmission/distribut.	2% to 4%	2% to 4%
Sep. 2007	• All construction projects	4% to 6%	3% to 4%
Apr. 2008	• All construction projects	4% to 6%	3% to 4%

7.3 Interpretation of results

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.

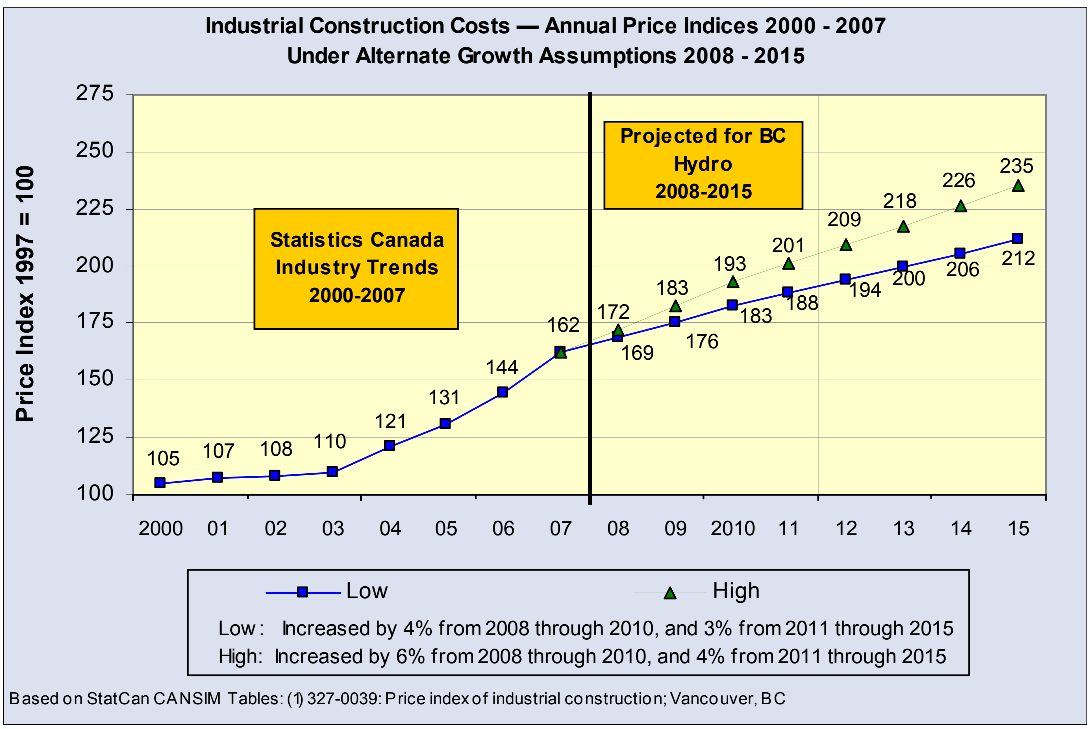
The recommended allowances also assume that the strong construction market in BC between 2003 and early 2008 will continue through 2010, and that the market will have a "soft landing" in 2010 and 2011 as market demand and supply forces come more into balance.

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.

7.4 Future price indices

This recommended range, applied to the Vancouver industrial construction price index, is illustrated in Exhibit 7b.

Exhibit 7b — Future industrial construction price index projections, for recommended range of cost inflation allowances



7.5 Disclaimer

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.