FORTISBC

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Via Email
Original via Courier

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

Dear Ms. Hamilton:

Re: An Application for a CPCN for the 2009-2010 Capital Expenditure Plan Project No. 3698519

Please find enclosed FortisBC Inc.'s responses to Information Request No. 2 from the BC Utilities Commission, and responses to Information Request No. 1 from the BCOAPO et al., IMEU, OEIA, Alan Wait, and Norman Gabana. Twenty copies will be couriered to the Commission.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

Q100.0 Tables & Spreadsheets

Q100.1 Provide all tables and spreadsheets as fully functioning, unprotected Excel spreadsheets.

A100.1 The Excel spreadsheets have been attached to the electronic document as requested.

Q101.0 150 Mvar SVC

Reference: Exhibit B-1, p. 54

Reliability

Q101.1 The 2009/10 CEP at page 54 states a 150 Mvar SVC is required at the DG Bell Terminal in 2011 to provide reliable service, and includes an expenditure of $400,000 in 2010 for preliminary work on the project. For the 2009/10 CEP and the 2009 SDP Update, please describe fully how FortisBC defines "reliable service".

A101.1 In general, FortisBC defines "reliable service" as that which would be delivered by an electric service provider which follows "good utility practice" and complies with accepted industry standards and regulatory requirements.

Q101.2 If the definition of reliable service requires better than N-1 reliability for any part of its system (e.g., N-1-1 or N-2), please justify fully the need for such higher reliability, and clarify if FortisBC believes the Commission has supported such higher reliability planning criteria in the past.

A101.2 FortisBC considers "reliable" transmission service for the Kelowna area to meet the industry accepted N-1 planning criterion as well as the more stringent N-2 / N-1-1 criterion (primarily due to the historical record of latter type of outages causing city-wide blackouts). It was on this basis that the Company submitted a CPCN Application in 2007 for the Okanagan Transmission Reinforcement (OTR) Project. Commission support for this level of reliability was explicitly stated in Order G-52-05: "The Commission Panel accepts that an N-1-1 contingency level for Kelowna is appropriate at this time". Letter L-48-05 clarified that the proposed 230 kV line "would be a prudent investment. This would have the result of increasing the level of reliability for Kelowna beyond what is commonly referred to as an N-1 contingency level". Letter L-48-05 further stated that "each case involving facilities which improve reliability levels must be evaluated on its own merits. In doing so the Commission Panel is guided by good Utility practice, public safety and the economics of providing service." The Company understands that each case must be evaluated on its own merits and is prepared to do so.

Q101.3 Further to page 54 of the 2009/10 CEP, please explain fully and specifically if the Provincial Government's energy objectives and Energy Plan requires better than N-1 reliability with respect to the FortisBC system.

A101.3 The relevant provincial Energy Plan Policy Actions are #14: *Ensure that the province remains consistent with North American transmission reliability standards*, and #12; *The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.*

In general, Policy Action 14 relates to the Reliability Standards established by the North American Electric Reliability Corporation (NERC). These Standards are implemented by the Western Electricity Coordinating Council (WECC) – of which FortisBC is a member – and require a minimum N-1 level of reliability for the bulk electric system. The latter Energy Plan Policy Action is not restrictive to any specific level of reliability. As discussed in the OTR Application, the Kelowna area has had a substandard level of reliability with one to two black-outs per year for the last ten years. These blackouts have been caused by outages within the bulk electrical system at the 230 kV level. The proposed improvements are consistent with the objectives of the BC Energy Plan.

Q101.4 If FortisBC believes Government policy supports better than N-1 reliability even if it does not require it, please outline the reasons why FortisBC believes this, and explain how the cost of providing such better reliability should be taken into consideration.

A101.4 FortisBC believes that the discussion of transmission system reliability provided in response to BCUC Q101.2 above is consistent with the BC Government's policy as it relates to transmission reliability.

Q101.5 The 2009/10 CEP indicates that the SVC will be needed to meet a N-1 reliability criterion in 2013/14, when the load is approximately 562 MW. Please confirm that the $400,000 expenditure is not needed in 2010 to meet a 2013/14 in-service date.

A101.5 Even with the completion of the OTR project, as the load in the Okanagan area continues to grow the level of reliability will once again begin to erode. Based on current load projections, the OTR Project will not be able to provide N-2 reliability for all hours of the year even at the in-service date of the project.

If the Commission determines that compliance with this level of reliability is no longer necessary in the Kelowna area, then the SVC would not be required until 2013/14.

Q101.6 In the OTR proceeding, in response to BCUC IR 96.4 in Exhibit B-11, FortisBC stated the SVC would be needed when the Okanagan load is

approximately 562 MW, and that this level is forecast to be exceeded in 2018/19. Please explain in detail why FortisBC now believes that to meet the N-1 criterion; the SVC will be needed five years earlier in 2013/14. The response should include a full discussion of forecast Okanagan load, relative to the load forecast presented in the OTR proceeding.

A101.6 The advancement of the SVC in-service date by five years is driven by the revision of the load forecast based on recent historical information. The load forecast used in the OTR Project was based on the 2007 System Development Plan Update. The current load forecast shows that the load has grown faster than expected which in turns advances the need for the SVC.

Q101.7 In the 2009/10 CEP, please identify each and every expenditure where the expenditure is required or the timing of the expenditure is advanced in order to provide better than N-1 reliability, and show the corresponding proposed expenditure amounts in 2009 and 2010.

A101.7 Other than the OTR project, none of the projects are either proposed or advanced in order to provide better than N-1 reliability.

Q101.8 For each expenditure identified in response to the previous question, please provide the corresponding amounts of expenditure that would be needed in 2009 and 2010 if FortisBC was striving to meet, at best, a N-1 reliability criterion.

A101.8 Other than the OTR Project, none of the projects are either proposed or advanced in order to provide better than N-1 reliability.

Q102.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit B-1, Transmission Line Urgent Repairs, p. 56
Plant Failures

Q102.1 Please provide the actual cost associated with plant failures that are contained within the Transmission Line Urgent Repairs, resulting in a requirement for additional funds for urgent repairs from 2005 to 2007.

A102.1 The requested information is provided in Table A102.1 below. Note that the 2009 unloaded-escalated by 5 percent figure reflects a reduction of $50,000 for work to be done with in the Copper Conductor Replacement Project.

Table A102.1
Transmission Line Urgent Repairs ($000s)

	Year				3 year loaded running average (2006 - 2008F)	3 year average unloaded	2009 unloaded - escalated by 5% ($2008 to $2009)	**Estimated 2009 number loaded at 17%**	3 year average unloaded (2007 - 2009F)	3 year average unloaded	2010 unloaded value escalated by 5% over 2009 values	**2010 value with 17% loadings**
	2005	**2006**	**2007**	**2008F**								
Transmission Line Urgent Repairs	268	347	351	312	337	281	246	**287**	277	237	248	**291**

Q102.2 Please provide the forecast cost associated with plant failures that are contained within the Transmission Line Urgent Repairs, resulting in a requirement for additional funds for urgent repairs for 2008.

A102.2 Please refer to Table A102.1 above and attached electronic Excel sheet in response to BCUC IR No. 2 Q102.3 for a full calculation.

Q102.3 Please provide the plan cost associated with plant failures that are contained within the Transmission Line Urgent Repairs, resulting in a requirement for additional funds for urgent repairs for 2009 and 2010.

A102.3 Funds requested for Transmission Line Urgent Repairs are based on a three year historical rolling average. The 2009 budget is based on the actual costs reported in 2006 and 2007, along with the Year End Forecast for 2008. These numbers are averaged for the three year period and reduced by 20 percent to account for corporate overheads and loadings (an estimated value). The unloaded number is then escalated by 5 percent to account for market increases and inflation, and then escalated by 17 percent to account for future corporate loadings and overheads. The process is then repeated for 2010 using 2007 actuals, 2008 Year End Forecast and 2009 Budget numbers.

Please refer to the Table A102.1 provided in response to Q102.1 above and the attached Excel spreadsheet titled BCUC IR2 A102.3 for a full calculation.

Q103.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit B-1, Right of Way Reclamation, pp. 57-58
Expenditures for Plan 2009 and Plan 2010

The CEP provided the Right of Way Reclamation expenditures in the following table:

Right-of-Way Reclamation

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

Q103.1 Please explain why this budget is increasing in 2009 and 2010 in comparison to the 2008 forecast.

A103.1 The Transmission Right-of-Way Reclamation expenditures for 2009 and 2010 are based on three year historical rolling averages. It was noted during the review of this undertaking that in calculating the three year rolling average, FortisBC included the full costs of Transmission Right-of-Way Reclamation in the calculation for 2009 and 2010. As noted in the response to BCOAPO IR No. 1 Q10.1, the Company transferred $0.23 million out of the Transmission Right-of-Way Reclamation into the Mountain Pine Beetle Hazard Project. This reduction in 2007 expenditures was overlooked in calculating the three year historical average spending.

Table A103.1 showing the correct values is shown below. In addition, an Excel spreadsheet titled Table A102.3 attached in response to detailing the corrections

Table A103.1
Right of Way Reclamation (Revised)

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	443	421	591[1]	359	**468**	**496**

[1] reflects 2007 spending minus $0.23 million.

Q104.0 Reference: 7. General Plant, Furniture and Fixtures
Exhibit B-1, Furniture and Fixtures, p. 130
Furniture Condition Assessment

Q104.1 Please provide the most recent inventory assessment records of furniture at all sites.

A104.1 Please see BCUC Appendix A104.1 for a detailed inventory of furniture completed in 2003. As FortisBC performed upgrades at Warfield, Benvoulin and added Springfield and Enterprise as part of the transition process, the new furniture purchased at these sites has been identified by number of stations. All furniture purchased since 2003 is the same product which allows re-utilization of components when reconfiguring work spaces and moving from area to area as required.

Q104.1.1 Please reconcile the inventory assessment records to the planned additions or replacements in 2009 and 2010.

A104.1.1 Please see Table A104.1.1 below. Areas where replacements are proposed contain furniture 10 to 15 years old. This furniture is in very poor condition and is not conducive to current work processes.

Table A104.1.1

Location	No. of Units	Existing No. of Units	Description of Units	Cost
				($000s)
Benvoulin	4	N/A	Additional Stations Required	28.0
Castlegar	4	4	Replace Workstations & Chairs	28.0
	12	12	Replace Lockers(1)	3.6
Creston	3(2)	5	Replace Workstations & Chairs	21.6
		1	Crewroom - lunch table & Chairs	1.8
Grand Forks	3	3	Replace Workstations & Chairs	21.6
Oliver	5(2)	6	Replace Workstations & Chairs	36.0
	12	12	Replace Lockers(1)	3.8
Trail Office	16	14	Replace & Add Workstations & Chairs	115.0
	30	30	Replace approx. 30 chairs	21.6
Warfield Complex	4	N/A	Additional Stations	28.8
Warfield Fleet	2	2	Replace 2 Workstations & Chairs	14.4

Table A104.1.1 cont'd

System Control	6	4	Replace & Add Operator Consoles	120.0
	10	10	Replace Operator Chairs	8.4
		N/A	Mapboard	2.4
Generation	17[2]	20	Change out existing workstations	122.0
			15 to 20 years old with Global	
			workstations compatible with	
			furniture throughout the organization	
Springfield	15	N/A	Additional stations required in 2009	108.0
All areas		N/A	Additional chairs, breakage	55.0
			misc. items such as whiteboards	
			keyboard trays, any special items	
			that present ergonomic issues for	
			individual employees	
				740.0

(1) The difference in cost for lockers for Castlegar and Oliver is due to installation costs.

(2) The difference between the existing and replacement number is due to efficiencies gained by installing appropriate workstations for current technology.

Q104.2 Please provide the fixed asset continuity schedules for Furniture and Fixtures for the last five years.

A104.2 Please see Table A104.2 below.

Table A104.2
Office Furniture and Equipment Asset Continuity Schedule

	($000s)					
Year	**Opening NBV**	**Additions**	**Adjustments**	**Retirements**	**Depreciation**	**Closing NBV**
2003	2,776	451	(1,159)	(458)	323	1,933
2004	1,933	601	-	(62)	(130)	2,342
2005	2,342	315	-	(9)	(210)	2,438
2006	2,438	243	-	-	(352)	2,329
2006 (PLP)	2,329	54	-	-	(178)	2,205
2007	2,205	247		-	(374)	2,078

Q104.3 Please list what are FortisBC's criteria or guidelines that determine a capital expenditure versus an expense item for furniture and fixtures.

A104.3 Capital expenditure criteria includes new product only as opposed to an expense item which would include repairs to existing units. Furniture and fixture purchases less than $500 are expensed.

Q105.0 Reference: 7. General Plant, Tools and Equipment
Exhibit B-1, Tools and Equipment, pp. 130-131
Exhibit B-2, BCUC IR A96.1, p. 173

Q105.1 Please list what are FortisBC's criteria or guidelines that determine a capital expenditure versus an expense item for tools and equipment.

A105.1 FortisBC capitalizes tools and equipment when they are expected to provide substantial benefits for a period of more than one year. Small tool purchases less than $500 are expensed.

Q105.2 Please provide the number of units for each line item of Table A96.1 provided in the response to BCUC IR 96.1.

A105.2 Please see Table A105.2 below.

Table A105.2

Line No.	Department	Description	Quantity
1	**Kelowna Line Ops**	25 kW multi-tap gen set	1
2		6 ton Stick type Cembre press	1
3		Battery Hydraulic Cable Cutter	1
4		Cable thumper / TDR	1
5		Cembre Hydraulic Guy Steel Cutters	1
6		ERP Room Monitor	1
7		Lighting Stands	5
8		Voltage Analyser	1
9			
10	**Kootenay Line Ops**	25 KV URD Ground Set 1/0 6' (Set)	1
11		25 KV URD Grounds Set	1
12		40' Lineman	3
13		AED	2
14		Batt Drills	6
15		Batt Press	3
16		Batt Press B55-4B-KV	3
17		Cembre Guy Cutters Cat.No.HT-TC026Y	4
18		Chain Jacks B-B Kito#KTOL5B015-10	3
19		Chainsaw Drills	3
20		Chainsaws	4
21		Circle Cutters Greenlee 705	3
22		DC High Pot Phasing Sticks	1
23		Ground Resistance Tester	3
24		Ladders	6
25		Modiewalks	6
26		Recording Volt Meter Power Monitors IVS-2SX+	1
27		Sawzall	3
28		Tools for New Trucks	2
29		URD Locators	2
30		URD Secondary Covers	8
31		Web Jacks	3
32			
33	**Kootenay C&M**	ASE 2000-PCM-RS communication test set	1

Table A105.2 cont'd			
Line No.	**Department**	**Description**	**Quantity**
34		Cat # T403-2261 25kV Phasing kit (AB Chance)	2
35		Cat. #BMM80 1000 volt hand held meggar	1
36		Hi voltage Amprobe Ammeter	2
37		Fluke 43B wattmeters/power analyzers	2
38		Burndy 6 ton In line crimper #PATMD6-14V	2
39		Greenlee Gator model#E12CCX11 c/w accessories	1
40		Micron infrared camera M7640	1
41		Misc unforeseen tool purchase in excess of $500 per unit cost	
42		Powermate 330 power quality test set	1
43			
44	**Okanagan C&M**	Battery impedance tester	1
45		Breaker analyzer	1
46		Kelman portable DGA tester	1
47		Mikron 7600pro IR camera	1
48		SFRA test set	1
49			
50	**Okanagan Construction**	15 ton press	1
51		6 ton Stick type Cembre press	6
52		Digital voltage indicator	1
53		Hydraulic impact tool	1
54		Insulated web jacks	3
55		link sticks	4
56		Misc. rubber products	3
57		Pre-app tools	3
58		Range finders	3
59		Self Dumping Dual Axle Gravel hauling trailer with Gravel Chute	1
60		Splice tent c/w ac	1
61		UEI Rated voltmeter	3

Table A105.2 cont'd

Line No.	Department	Description	Quantity
62			
63	**South Okanagan Line Ops**	Cembre ACSR/Guy Cutters Hydraulic	2
64		Cembre Presses Stick Type B54Y	2
65		Hastings HV-240 Triangle Shape Telepole 40 foot Incl testing	2
66		Hilti Drill	1
67		Sensorlink Amcorder Recording Ammeter Kit 6-920-3	1
68		Single phase PMI unit	3
69		Three phase PMI unit	1
70			
71	**Kootenay Construction**	Grounding sets	1
72		Collapsible Reel for Puller/Tensioner	1
73		Ground Resistance Meter	4
74		Hydraulic cutters for Guy Steel CAT. NO. HT-TC026Y	4
75		Husky Battery Cutters REC-T33	2
76		Chance Ins. Wiresholders M48057	30
77		Salisbury guards	12
78		Cembre Stick Type Presses B54Y-CDD6-8	2
79		Chance Tele pole #C405-1021 40'	3
80		URD Striping Tools	2
81		Modiew Okanagan Salisbury #4744	3
82		Chance 2 ton chain Jacks	2
83		Cembre Pistol Type Press Cat. No. B55-YB-KV	3
84		Kito Chain Jack BB Style Cat. No. KTO5LB15-10	4
85		Salisbury Guards 36.6 KV Cat. No.1686	6
86		Replace Rope Pole Boss. 3/8 Tenex	4
87		Chance Web Hoists Cat No. C309-0451	6
88		Cembre Guy Cutters Cat No. HT-TCO26Y	2
89		URD locator	1
90		Salisbury Pole Guards 6' #2466	5

Table A105.2 cont'd

Line No.	Department	Description	Quantity
91		Cembre ACSR/Guy cutters Hydraulic	4
92			
93	**Fleet**	Upgrade SnapOn Can tool Kelowna	3
94		Headlight Alignment Machine	1
95		Hytorc Hydraulic Tourque Wrench	1
96		Upgrade SnapOn Can tool Oliver	3
97		14,000 lb Hoist	1
98			
99	**Generation Electrical**	Video camera and film equipment - video tape specific job procedures to be used as training videos for safety and inspections	1
100		Bore scope with light and camera - to be used for stator inspections, iso bus inspections, and equipment checks and repairs	1
101		Portable asbestos vacuum (backpack style) X 2 - for asbestos removal	2
102		Battery operated cable cutters - safety and employee ergonomics	1
103		Battery operated crimper - safety and employee ergonomics	1
104		24VDC battery operated 200ft lb impact wrench X 2	2
105		Fluke Multi-meters - update existing meters	10
106		Grounding truck for Raffin switchgear - station service equipment	1
107		Safety ground tester - update and replace existing equipment	1
108		Phase 2 - Generator Protection and Control Training Simulator - Governor, excitation and vibration simulations and stator protection	1
109		Portable air movers - for confined space entry X 4	4
110		24v portable hammer drill - replacement	1
111		Cordless drill kits X 2	2
112		Step ladders and extension ladders for trucks - update required	10

Table A105.2 cont'd

Line No.	Department	Description	Quantity
113		Infrared temperature scanner - old units require updating	1
114		Grounding truck for COR 15Kv switchgear	1
115		Small parts cleaner for electrical equipment	1
116		Test and calibration station for gas detector maintenance	1
117		Wet cell battery tester	1
118		Battery bank load test - Load Cell	1
119		Grounding truck for COR 15Kv switchgear	1
120		Small parts cleaner for electrical equipment	1
121		Test and calibration station for gas detector maintenance	1
122		Wet cell battery tester	1
123		Battery bank load test - Load Cell	1
124			
125	**Generation Mechanical**	Submersible camera with attachments	1
126		Portable kidney loop filtration system	1
127		Drumlifter and tilter	1
128		Poly-dolly mobile dispensing stations	2
129		Hydraulic test/troubleshoot kit	1
130		Plasma cutting machine	1

Q106.0 Reference: General Plant;
Exhibit B-1, Application, p. 131
Tools and Equipment

Q106.1 Provide the year in which the budget that "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" was established.

A106.1 The 2009/10 Capital Plan budget for tools and equipment was established in 2008.

Q106.1.1 Provide the value of $500 in year that the budget threshold was established in 2008 dollars.

A106.1.1 FortisBC's policy in this regard conforms to the "The British Columbia Energy Commission Province Of British Columbia Uniform System Of Accounts Prescribed For Electric Utilities" as prescribed in Commission Order G-28-80, which states that

"<u>The Minimum rule</u> is intended for accounting convencience to provide a dollar limit on the charging of costs of minor items of plant to the plant accounts. When costs of items are less than $500.00, or such other amount as the Commission may approve, such costs shall be charged to the expense accounts."

Q106.2 Tools and Equipment is an expense and should not be in a capital expenditure plan. Provide an explanation as to why this cost is in the

capital expenditure plan and not an expense item in the Operation and Maintenance budget.

A106.2 According to “The British Columbia Energy Commission Province Of British Columbia Uniform System Of Accounts Prescribed For Electric Utilities” tools and work equipment are classified in plant account 394. The definition of the account is as follows:

“This account shall include the cost of tools and other items of equipment used in construction or maintenance of the system and not includible in account No. 396, “Heavy Work Equipment”. It shall also include the cost of garage equipment and large equipment of a non-movable nature”

The Uniform System of Accounts lists the following examples for plant account 394:

- Air drill
- Alcohol injector
- Anvil
- Barometer
- Battery Charger
- Bevelling machine
- Lawn mower
- Lifting magnet
- Manometer
- Milling machine
- Motor

- Pipe cleaning machine

Q107.0 Reference: 7. General Plant, Information Systems
Exhibit B-1, Information Systems, pp. 120-127
2009 and 2010 Project Detail

Q107.1 For each of the projects, please identify the measures that will be used to evaluate the success or failure of the project. Please identify quantitative measures whenever possible, and include a discussion of the benefits that will accrue to, and be noticeable by, FortisBC customers.

A107.1 System enhancement projects can have a number of different measures of success based on the type of enhancement required. A legislated change to accounting or billing or changes required for compliance will be measured on its ability to meet the requirements of the legislation or compliance criteria.

Other enhancements or interfaces are based on a benefit analysis that is primarily affected by productivity gains and data integrity improvements. All requests are evaluated by appropriate business managers to ensure their value. A review of the benefits of the enhancement is undertaken within 3 months of it being implemented as part of a quarterly review. Success is measured on the ability of the enhancement to meet or exceed its estimated benefit.

The success of infrastructure upgrades is based on system availability and overall performance. An availability of 99.8 percent is the target for production systems due to the 24 hour reliance on these systems for safety and customer service.

The success of desktop infrastructure upgrades is based on system failures and productivity losses. The total amount of productivity loss is not measured exactly, but generally tracked by the technical support team. Escalation in productivity losses due to system or peripheral failures are recognized primarily through the increase in the number of support calls.

The success of the Design Software implementation is based on the information in Appendix 3 of the 2009/10 Capital Plan application and meeting the benefits identified there.

Q107.2 For each of the Information Systems projects, briefly describe the implications of a delay or cancellation.

A107.2 The primary risk in delaying or cancelling any of the enhancement or upgrade projects is loss of productivity and reliability. Enhancements and interfaces are undertaken to improve productivity and data integrity by minimizing input into multiple systems, thus reducing the chances of human error. Upgrades are done to maintain support and compatibility of systems with the rest of the business world as vendor support is discontinued on outdated technology.

The risk of cancelling the Design software project is loss of productivity gains that the project will deliver. The project is intended to improve the efficiency in which FortisBC delivers design packages to customers, and delaying or cancelling the project would adversely affect this.

Q107.3 Please list the Information Systems projects and costs during the two previous years, and identify the qualitative and/or quantitative measures that indicate the success or failure of the project.

A107.3 Please see Table A107.3 below.

Table A107.3

Project Name	Total Cost Estimated to end of 2008	Measure of Success
AM/FM Intergraph Upgrade	2,700,000	Successful implementation meeting all project requirements on time and on budget. Replaced Intergraph system hosted by Fortis Alberta with matching functionality and improved supportability.
AP Document Imaging	351,000	Completion scheduled for December 2008. Success implementation will see a near complete replacement of paper filing for invoices and a streamlining of the invoice approval process and reducing physical filing space requirements.
SAP Security Upgrade	290,594	Final phase of the security upgrade deemed a success by an independent audit indicated the system was secure from a user access level.
Infrastructure Upgrades	612,323	System availability at 98.8%, slightly lower than target due to some aging infrastructure. System availability is the primary measure of success for this project.
Desktop Infrastructure Upgrades	891,221	Only failed systems and peripherals were replaced. There was a higher level of support calls due to equipment failures causing poorer performance than normal. The measure of success is based on the number of calls due to system downtime.
IT Disaster Recovery Phase 2	502,048	Critical systems have been successfully replicated in the disaster recovery site.
SAP Netweaver Portal	561,367	Successful implementation of SAP Portal completed on time 10% over budget. The project delivered a platform that will allow the continued consolidation of application interfaces. This consolidation will allow FortisBC to work toward a simplified more efficient user environment.
SAP Business Warehouse	521,000	Successful implementation of SAP Warehouse completed on time and on budget. The SAP Warehouse infrastructure enables the consolidation and reporting of data from all systems improving efficiency and accuracy.

Table A107.3 cont'd

Project Name	Total Cost Estimated to end of 2008	Measure of Success
MVRS Handheld Upgrade	226,653	MVRS upgrade successfully completed on time and on budget. This upgrade replaced all aging handheld equipment and supporting software decreasing downtime for meter readers. The upgrade also allowed FortisBC to accurately and efficiently, as possible, read meters while new AMI technology is explored and deployed over the following years.
Intranet Enhancements	245,000	Several enhancements successfully implemented on budget. Some enhancements included improved forms for employee and departmental use, improved organizational information including pictures and more efficient access to policy and safety information.
Internet Enhancements	245,000	Several enhancements successfully implemented on budget. Major enhancements included a complete rebuild of the web site improving customer access to information available. There were also significant additions to the PowerSense component of the site.
SAP Business Consolidation	147,827	Several areas of consolidation and data cleanup were completed on budget. These consolidations, in conjunction with process reviews, have improved efficiencies in the finance and material modules.
SAP Contract Management	116,892	Improvements to SAP Contract Management were completed on budget. These improvements positively affected the connection between the system and associated contract.
Dispatch Software Consolidation	411,000	Project estimated to be completed by the end of the year on budget. The measure of success for this project is the consolidation of our desperate systems used for dispatch. The results of this consolidation will be improved and simplified communication to the field staff and the minimizing of data entry for the dispatchers.
CIS+ Integration with SAP	219,000	Improvements to the GL integration were completed on budget. Considered a success by decreasing manual processes required to

Table A107.3 cont'd

Project Name	Total Cost Estimated to end of 2008	Measure of Success
		exchange data between CIS+ and SAP.
HR Training & Events	250,538	Successfully implemented meeting all requirements on time and on budget. The success of this project was measured by the applications ability to meet WCB compliance requirements for employee training and certification information. It was also successful because it is an efficient and convenient application that is used across the organization.
SCC SCADA Upgrade	316,345	Project completed on time but over budget due to added requirements for compliance and safety. The project successfully upgraded the System Control software and servers to a Microsoft environment improving performance and ease of support.
CIS+ Enhancements	354,073	Several enhancements completed with good productivity and efficiency gains on time and on budget. Some of the enhancements were required to meet new legislation requirements, such as the Innovative Clean Energy fund levy.
CIS+ Web Interface Upgrade	331,000	First phases completed improvements to client interface continuing to end of the year. On budget. The success of this project will be determined by the efficiency gains realized by the CIS users using the new interface. There will also be improvements to the coding language that are intended to improve change control and coding efficiency.
Records Management	106,000	Solution implemented on time and on budget. The project was considered a success when all FortisBC hard copy file information was loaded into the system and accessible to all stakeholders in a convenient and efficient manner.
Procard Software Upgrade to Centersuite	7,445	Required upgrade to continue support on the system. Successfully completed. The project was successful because it allowed for the continued use of an efficient and effective application for entering VISA expense information.
SAP Enhancement Project	564,000	Several enhancements completed with good productivity and efficiency gains on time and on

Table A107.3 cont'd

Project Name	Total Cost Estimated to end of 2008	Measure of Success
		budget. Some of these enhancements included HR and payroll which decreased manual intervention on payroll exceptions for all employee time and improved access and management of organizational information. Finance system enhancements streamlined month end and year end procedures. Materials Management enhancements improved material handling and streamlined the material procurement process both internally and externally.
Microsoft Office & Windows Upgrade	535,000	Successfully upgrade of the Microsoft environment scheduled to be completed by the end of the year on budget. The success of this project will see upgrade of the Microsoft environment on FortisBC desktops and notebooks. This will ensure compatibility of information and documents that are exchanged between FortisBC and the organizations that we do business with.

Q108.0 Reference: 7. General Plant, Information Systems
Exhibit B-1, Infrastructure Upgrade, pp. 121-122
Increased Infrastructure

"The life expectancy of the hardware infrastructure components is five years… The budget is predicated on a 20 percent replacement of the asset based on this five year life cycle."

Infrastructure Upgrade

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

Q108.1 Please elaborate on the increased infrastructure upgrade to justify the expenditures in 2009 and 2010 to more than tripling the amount forecasted for 2008.

A108.1 Large implementation projects have been occurring over the past 5 years and the supporting infrastructure has been implemented to support them. Some of that infrastructure has now reached its end of life from a vendor support and reliability perspective and needs to be upgraded or replaced. Alternatives are always being explored and implemented wherever possible to minimize infrastructure requirements, such as Virtual Servers, and these costs are based on minimum requirements.

Q109.0 Reference: 7. General Plant, Information Systems
Exhibit B-1, Desktop Infrastructure Upgrade, pp. 122-123
Increased Desktop Infrastructure

Q109.1 How often is Microsoft Office Suite being updated?

A109.1 The Microsoft Office Suite is upgraded approximately every 4 years.

Q109.1.1 Please explain why this regular upgrade expenditure is necessary.

A109.1.1 A majority of the companies that FortisBC does business with are Microsoft Office users. The main requirement to upgrade is driven by these businesses upgrading their systems making ours incompatible with new file formats. There are also functionality improvements in the new versions that can be taken advantage of to improve productivity and data handling capabilities.

Q109.1.2 Can FortisBC skip an upgrade and sustain the existing information applications?

A109.1.2 FortisBC skips many upgrades to systems, applications and databases. Upgrades are only undertaken when support is no longer available and systems and/or data are considered to be at significant risk. If upgrades were done every time a new version of a system or database was released it would be unmanageable. For example operating systems on our IBM servers are generally upgraded to versions three to four higher than their existing one allowing us to skip all the incremental steps that are generally not worth the effort or cost.

Q109.2 Will FortisBC be actually spending 20% on replacement assets or just setting aside a 20% provision for asset replacement?

A109.2 FortisBC will actually be spending approximately 20 percent of asset cost on replacement. In our experience this practice has provided a good balance between cost and reliability.

Q110.0 Reference: General Plant;
Exhibit B-2, p. 163
Information Systems

Q110.1 Provide an explanation as to why it would be necessary to upgrade the monitor attached to a notebook docking station as the notebook screens are no longer the smaller 13” screens.

A110.1 No monitors are upgraded unless they fail, or have degraded to the point that they are no longer suitable to view. Monitors that are replaced with larger units for specific applications, such as mapping or CAD, are redeployed to other stations if they are still suitable for viewing.

Q111.0 Reference: SDP, p. 3

1. Executive Summary

Exhibit B-2, BCUC IR A98.1, p. 180

2007/08 Capital Expenditure Plan and 2007 System Development Plan, Exhibit B-2, BCUC IR A49.1, p. 100

Cost increases by categories

FortisBC provided the following Tables A98.1 and 49.1 that allocate the overall cost increase of $100.8 million and $71.3 million for the 2009-10 CEP and 2007-08 CEP, respectively:

Table A98.1
Cost Increase Allocation

Category	($million)
Inflation	30.1
AFUDC	4.9
Project Scope Changes	32.1
More Accurate Estimates	11.8
Schedule changes	(4.2)
Added Projects	33.1
Cancelled Projects	(7.0)
Total	**100.8**

Table 49.1

Category	($million)
Inflation	12.9
Project Scope Changes	12.0
Refined Estimates	29.2
Schedule changes	9.6
Added Projects	12.4
Cancelled Projects	-4.8
Total	**71.3**

Q111.1 Please explain why the Inflation component is higher in the 2009-10 CEP than in the 2007-08 CEP.

A111.1 The increase in inflation is primarily associated with the OTR Project. The OTR Project was included in the 2007/08 Capital Plan in $2005.

Q112.0 Reference: Business Cases

Q112.1 Please provide the complete business cases for each project listed in the CEP.

A112.1 Documents prepared prior to filing are contained in BCUC Appendix A112.1 to this filing. In most cases, the projects included in the 2009/10 Capital Plan were the subject of Project Justification documents or Appropriations that were required in order to obtain Executive approval for inclusion in the Plan. Once such approval was obtained, further updates to most documents were not undertaken. For this reason, the documents may vary slightly from the text cost totals contained in the 2009/10 Capital Plan as a result of either scope or timing changes from the original. BCUC Appendix A112.1 contains documents for all projects listed in the 2009/10 Capital Plan with the exception of those projects that are approved or for those for which will be subject to the CPCN process.

Q112.2 For each business case, please calculate the following Benefit-Cost tests:

Q112.2.1 Utility Cost (UC): the difference between FortisBC's avoided cost and the cost of program implementation to FortisBC.

A112.2.1 As outlined in detail in the Application, the majority of projects included in the 2009/10 Capital Plan are necessary to provide service; to ensure public and employee safety; and to provide a reliable supply to the Company's growing customer base. As such, there is little if any discretion available to the Company with respect to options available that would meet the project deliverables. For this reason, FortisBC does not calculate the UC, the TRC or the RIM for the majority of projects included in the Capital Plan since by the nature of the projects, those tests are not valid measures of the benefits, costs or avoided costs of this non-discretionary work. For the majority of projects, the need is driven by system reliability, load growth or safety related issues. Benefits, costs or avoided costs are not necessarily quantifiable, nor would they change the decision to proceed along the recommended course of action. Generally, the decision criteria are more focused on the best value solution, based on various options to meet the particular load, reliability or safety issue.

Further, fully $236.9 million of the $359.9 million or two-thirds of the proposed projects are the subject of existing or future CPCN applications and will be tested in separate regulatory processes. Approximately $123.2 million or over one-half of the CPCN expenditures relate to the OTR project and a further $36.7 million relate to the AMI project.

The remaining $123.0 million of expenditures are necessary to sustain the life of existing assets (as outlined in the 2005 SDP and upgrade life programs); or are expenditures on DSM or General Plant.

The Company's DSM program is designed to ensure that the program benefits customers by ensuring that the avoided cost is greater than the program costs. The DSM program has been approved by the Commission.

Q112.2.2 Total Resource Cost (TRC): the difference between the

benefits and costs of the program, expressed as a net present value.

A112.2.2 Please refer to the response to Q112.2.1 above.

Q112.2.3 Rate Impact Measure (RIM): the avoided supply cost minus (lost revenues + utility costs), expressed as a net present value.

A112.2.3 Please refer to the response to Q112.2.1 above.

Q112.3 For each business case, please provide the benefit-cost ratios (BCR) to be added to the Table requested in Appendix A.

A112.3 Please refer to the response to Q148.1.2 below.

Q113.0 Reference: Physical Inventory

Q113.1 Please provide the results of the last physical inventory performed.

A113.1 In 2007, the Company wrote off approximately $55,000 of inventory on an average inventory balance of approximately $13.2 million.

For the period January 1, 2008 – August 31, 2008 the Company has written back into inventory approximately $57,000 worth of stock items on an average inventory in the period of approximately $14.3 million.

Q113.2 When and how often is the physical inventory?

A113.2 The Company employs a cyclical inventory count process for its two warehouse locations. For the balance of the inventory located in the Company's generation and the district stores, annual physical inventory counts are normally performed in the fourth quarter.

Q113.3 Will the differences in physical and perpetual inventory be reconciled and recorded accordingly in the accounting records?

A113.3 Yes, the account reconciliation and adjustments are done when the counts are posted (real-time in SAP).

Q113.4 Provide the value of the difference between the physical and perpetual inventory.

A113.4 Please refer to the response to Q113.1 above.

Q114.0 Reference: Accounting Procedures & Policies

Q114.1 Please provide copy of FortisBC's most up to date accounting procedures. Also include the dollar threshold limits ranging from building improvements to tool purchases.

A114.1 Except as provided for by Commission accounting variance Orders, the Company follows the accounting procedures in the BCUC "Uniform System of Accounts Prescribed for Electric Utilities".

Q115.0 Reference: Salvage Value

Q115.1 Please provide the salvage value of the capital that is being replaced.

A115.1 Except for the Copper Conductor Replacement Project which has an estimated salvage value of $0.163 million, the salvage value of the capital that is being replaced is generally offset by the cost of removal.

Q115.2 Where is the salvage value being recorded in the accounting records?

A115.2 Salvage value is credited to accumulated depreciation.

Q116.0 Reference: Exhibit No. B-1, Capital Plan, p. 7

Beginning on page 7 of its Capital Plan, FortisBC lists a number of projects (e.g., Naramata, Black Mountain, Benvoulin) that were subject to "unanticipated delays."

Q116.1 Please discuss the unanticipated delays that were encountered. This may be done by type of delay or by project.

A116.1 Naramata Substation: This project was delayed as a result of the difficulties associated with the acquisition of a suitable site for the substation and resulting stakeholder concerns.

Black Mountain Substation: This project has been delayed as a result of the timing associated with rezoning the property and the acquisition of permits to acquire the substation site.

Benvoulin Substation: This project was delayed as a result of an extensive public consultation process involved in locating a site that satisfied most stakeholders.

OTR: As stated in FortisBC's response to BCUC IR No.1 Q3.1, the 2007 SDP Update anticipated that the OTR CPCN would be filed in the first quarter of 2007 with construction taking place between the 2007 and 2011 timeframe. Internal delays associated with completion of the detailed design and CPCN application filing has deferred approximately $5.0 million of the anticipated 2007 and 2008 expenditures to 2009 and 2010. Examples of these delays include a longer than anticipated time to confirm and finalize FortisBC's contract with BC Hydro, as well as additional engineering time to assess alternative transmission line corridors and structure types.

Q116.2 Please indicate what, if anything, FortisBC might do differently in the future to reduce the number of unanticipated delays and/or to account for potential delays in its planning process.

A116.2 In future, as with the 2009/10 Capital Plan Application, FortisBC plans to reduce the number of unanticipated delays by seeking approval of expenditures for project planning purposes when appropriate. Examples in the 2009/10 Capital Plan include the Kelowna Distribution Capacity Requirements and the Static var Compensators.

Q117.0 Reference: Exhibit No. B-1, Capital Plan, p. 28

FortisBC states that an all-plants spare unit transformer would mitigate the risks associated with the failure of a generator step-up transformer. In 2006, the Lower Bonnington Unit 2 generator step-up transformer failed, resulting in unit outage costs estimated at approximately $1.5 million.

Q117.1 Please provide a detailed breakdown of the outage costs including, if applicable, the cost of replacement energy.

A117.1 The outage costs were as follows:

- August $156,436
- September $320,751
- October $333,352
- November $365,709
- December $405,017

- January $333,957
- Total $1,915,221

Q117.2 Please describe the actions that were taken in response to the failure.

A117.2 In response to the transformer failure three major transformer manufacturers were contacted for repair proposals. The vendor was selected, taking into account the delivery time in order to minimize the outage cost. The transformer was removed and shipped to the vendor site where it was dismantled and repaired. Once the repairs were completed it was returned and reinstalled, with cost recovery pursued through the Company's insurers.

Q117.3 Please describe the actions that would be taken in response to another failure, if different than the actions that were previously taken, in cases with and without a spare transformer.

A117.3 The action that would be taken in response to another failure would not be different than previously taken, assuming FortisBC did not have a spare transformer available. If FortisBC did have a spare transformer available, the failed transformer would be removed and replaced with the spare. The failed transformer would then either be repaired or replaced depending on the extent of damage. Once the failed transformer was repaired or replaced, it would be then reinstalled at an appropriate time.

Q117.4 Please provide a table showing the age of each generator step-up transformer that would be backed up by the proposed spare. Please indicate the condition of each of the transformers based on the most recent condition assessment, the year of the assessment, and the date of the last major repair/refurbishment.

A117.4 Please see Table A117.4 below.

Table A117.4

Unit Transformer	Age of Transformer	Condition of Transformer	Year of Recent Condition Assessment	Date of Last Major Repair/Refurbishment
Lower Bonnington Unit 1	2005	Dissolved gas analysis and oil quality and Doble indicates transformer in good condition.	Dissolved gas analysis - 06/08/2007 Oil Quality- 09/18/2006 Doble 05/31/2006	
Lower Bonnington Unit 2	1998	Dissolved gas analysis indicates high CO (1095ppm) and CO2 (4282ppm) 04/21-2008, Oil Quality indicates OK 05/01/2007	Dissolved gas analysis- 04/21/2008 Oil Quality- 05/01/2007	Transformer rewound fall of 2006 by GE due to winding failure.
Lower Bonnington Unit 3	2006	Dissolved gas analysis indicates high CO (737ppm) No Oil Quality or Doble results.	Dissolved gas analysis - 02/27/2008	
Upper Bonnington Unit 5	2000	Dissolved gas analysis indicates high CO (941ppm) & CO2 (5699ppm) Oil Quality OK. & Doble OK	Dissolved gas analysis - 02/27/2008 Oil Quality - 09/27/2007 Doble 4/19/2005	
Upper Bonnington Unit 6	2004	Dissolved gas analysis indicates high CO (1290ppm) & CO2 (5588ppm) Oil Quality OK. & Doble OK	Dissolved gas analysis - 01/14/2008 Oil Quality - 09/27/2007 Doble 4/5/2006	
South Slocan Unit 1	2005	Dissolved gas analysis and oil quality and Doble indicates transformer in good condition.	Dissolved gas analysis - 08/14/2007 Oil Quality - 10/17/2006 Doble 3/1/2006	

Table A114.4 cont'd

Unit Transformer	Age of Transformer	Condition of Transformer	Year of Recent Condition Assessment	Date of Last Major Repair/Refurbishment
South Slocan Unit 2	2000	Dissolved gas analysis and oil quality and Doble indicates transformer in good condition.	Dissolved gas analysis - 08/14/2007 Oil Quality - 03/15/2006 Doble 04/25/2005	
South Slocan Unit 3 A	1927	Dissolved gas analysis OK and oil quality interfacial tension is below normal limits and Doble indicates transformer in bad condition.	Dissolved gas analysis - 09/10/2007 Oil Quality - 09/10/2007 Doble 04/13/2004	transformer oil processing 04/15/2005
South Slocan Unit 3 B	1927	Dissolved gas analysis OK and oil quality OK and Doble indicates transformer investigate condition.	Dissolved gas analysis - 09/10/2007 Oil Quality - 09/10/2007 Doble 04/22/2003	transformer oil processing 04/15/2005
South Slocan Unit 3 C	1927	Dissolved gas analysis OK and oil quality OK and Doble indicates transformer investigate condition.	Dissolved gas analysis - 09/10/2007 Oil Quality - 09/10/2007 Doble 04/22/2003	transformer oil processing 04/15/2005
Corra Linn Unit 1 A	1931	Dissolved gas analysis OK and oil quality OK and Doble indicates transformer investigate condition.	Dissolved gas analysis - 09/26/2007 & Oil Quality - 10/18/2006 & Doble 06/07/2004	transformer oil processing 03/31/2005

Table A114.4 cont'd

Unit Transformer	Age of Transformer	Condition of Transformer	Year of Recent Condition Assessment	Date of Last Major Repair/Refurbishment
Corra Linn Unit 1 B	1931	Dissolved gas analysis OK and oil quality OK and Doble indicates transformer investigate condition.	Dissolved gas analysis - 09/26/2007 & Oil Quality - 10/18/2006 & Doble 06/07/2004	transformer oil processing 03/31/2005
Corra Linn Unit 1 C	1931	Dissolved gas analysis high CO2 (4298ppm) and oil quality OK and Doble indicates transformer investigate condition.	Dissolved gas analysis - 09/26/2007 & Oil Quality - 10/18/2006 & Doble 06/07/2004	transformer oil processing 03/31/2005
Corra Linn Unit 2 A	1931	Dissolved gas analysis high CO2 (6810ppm) and oil quality OK and Doble indicates transformer deteriorate condition.	Dissolved gas analysis - 09/26/2007 & Oil Quality - 10/12/2006 & Doble 09/09/2002	transformer oil processing 03/31/2005
Corra Linn Unit 2 B	1931	Dissolved gas analysis high CO2 (6281ppm) and oil quality OK and Doble indicates transformer good condition.	Dissolved gas analysis - 09/26/2007 & Oil Quality - 10/12/2006 & Doble 09/09/2002	transformer oil processing 03/31/2005
Corra Linn Unit 2 C	1931	Dissolved gas analysis high CO2 (8664ppm) and oil quality OK and Doble indicates transformer deteriorate condition.	Dissolved gas analysis - 02/27/2008 & Oil Quality - 10/12/2006 & Doble 09/09/2002	transformer oil processing 03/31/2005
Corra Linn Unit 3	1999	Dissolved gas analysis high CO (1445ppm) & CO2 (4180ppm) and oil quality OK and Doble indicates transformer good condition.	Dissolved gas analysis - 02/27/2008 & Oil Quality - 02/27/2006 & Doble 10/21/2003	

Q117.5 Please provide a calculation of the “expected value” of the costs of the “with” and “without” spare transformer scenarios. Please explain the calculations and state the assumptions used.

A117.5 Please see Table A117.5a and Table A117.5b below.

Table A117.5a

	Repair on site, no spare transformer (if type of damage allows)	**Ship to manufacture, no spare transformer**	**Replace transformer, no spare**	**Replace with spare transformer**
Outage Time	8 weeks	12 weeks	60 weeks [1]	2 weeks
	($000s)			
Outage Costs [3]	500-800	750-1250	3,750-6,250	125-200
Removal Costs	0	25	25	25
Transportation	0	50	50	50
Repair / Replace	400	400	1,600	1,850
Re-install	0	25	25	25
Commissioning	10	10	10	10
Total	910-1,210	1,260-1,760	5,460-7,960	2,085-2,160

Table A117.5b

	Yearly Deductable	**Business Interruption – Waiting Period**	**Business Interruption – Waiting Period Costs**	**Premium Increase**
	($000s)		**($000s)**	
Insurance Costs without spare transformer	500	90 days	750-1,250	[2]
Insurance Costs with spare transformer	300	30 days	250-400	[2]
Insurance cost savings with spare transformer	200	60 days	500-850	

[1] Normal transformer delivery is 90 weeks but with a 30 percent cost premium the delivery time can be reduced to 60 weeks.
[2] Boiler and Machinery insurance premiums for FortisBC have increased by 21 percent from 2007 to 2008.
[3] The outage costs are contingent on the entitlement calculations.

Q117.6 What is the expected change in reliability associated with FortisBC's plan?

A117.6 The spare transformer addresses failure situations, it does not address the reliability of the existing equipment. By having a spare transformer on site, FortisBC expects to reduce the risk of outage time in the event of a failure down from a period of eight to sixty weeks, depending on the extent of damage, to approximately two weeks.

Q117.7 Do any of FortisBC's neighbouring utilities hold transformers of the type needed in their inventories? If so, and assuming a spares-sharing arrangement could be made, what would be the cost and timing differences for service restoration compared to FortisBC maintaining its own spare?

A117.7 FortisBC understands that none of the neighbouring utilities hold transformers of the required voltage and size configuration.

Q117.8 What steps have or will be taken with respect to transformer repair or replacement during the ULE program at each station?

A117.8 In the yet to be completed ULE projects, FortisBC has included the replacement of the Generator Step-up Transformer in the project scopes, except at South Slocan Unit 1, which was replaced in 2005 due to a failure.

Q118.0 Reference: Exhibit No. B-1, Capital Plan, pp. 30-39

Q118.1 Please clarify what approval FortisBC is seeking from the Commission now for those projects FortisBC expects to submit for approval as part of a subsequent Capital Plan.

A118.1 FortisBC is seeking Commission approval for those expenditures listed in Table 2.2 of the Application (Exhibit B-1). Five of the projects, All Plants Fire Safety Upgrade Phase 1, All Plants Public Safety and Security Phase 1, South Slocan Water Supply Phase 3, Lower Bonnington and Upper Bonnington Upgrade Spillway Gate Control Phase 1, and Corra Linn Spillway Gate Isolation Study, are expected to yield results that will form the basis for the inclusion of further projects in subsequent capital plans.

Q118.2 Please clarify whether the expenditure estimates associated with those projects are solely for work to take place *prior to* approval in a later capital plan.

A118.2 All of the expenditures are to take place in 2009 and 2010. Further expenditures will be included in a later capital plan.

Q119.0 Reference: Exhibit No. B-1, Capital Plan, p. 103

FortisBC states that completing the transition to having all transmission and distribution protected by microprocessor-based relays is a significant achievement that will continue to show benefits such as improved reliability and safety well into the future.

Q119.1 Please provide any data that FortisBC has that quantifies the reliability and safety benefits of the conversion to microprocessor-based protection.

A119.1 No data is available that directly quantifies the reliability and safety benefits. However, there has been reduced maintenance effort since periodic testing of electromechanical relays is no longer required. In terms of the safety, there have been a number of instances where one of a redundant pair of microprocessor relays have detected an internal failure and disabled itself (accompanied by an immediate alarm to the FortisBC System Control Centre). Due to the redundant installation at no time was the protection compromised. While difficult to quantify, these events clearly demonstrate an improved level of overall reliability and safety compared to the older devices which had no self-diagnostic capability.

Q120.0 Reference: Exhibit No. B-1, Capital Plan, pp. 106-107

FortisBC notes that DSM expenditures in 2009 and 2010 will exceed those in 2008, reflecting the major shift in provincial policy that places DSM as the priority resource to meet growing electricity demand in BC.

Q120.1 What impact does FortisBC expect the provincial energy plan to have on the load forecasts presented as part of its Capital Plan?

A120.1 Based on current DSM initiatives, which are focused primarily on energy consumption and not on capacity demand growth, FortisBC expects the impact on the load forecast to be a reduction of 10 percent on annual capacity demand growth.

Q120.2 Are those effects incorporated into the forecasts presented with the Capital Plan? If not, when will those effects be incorporated?

A120.2 FortisBC now incorporates a 10 percent annual reduction in capacity demand growth which takes into account reductions based on existing and planned DSM initiatives.

Q121.0 Reference: Exhibit No. B-2, BCUC IR1 A2.1

Q121.1 Please provide versions of Table A2.1.1a, Table A2.1.1b, and Figures A2.1.2a with the OTR expenditures removed.

A121.1 Please see Tables A121.1a and A121.1b, as well as Figure A121.1 below.

Table A121.1a
Capital Plan Expenditures with Copper Conductor Replacement Costs and without OTR Project Expenditures

		Pre-2008	2008	2009	2010	2011	2012
		($millions)					
1	Generation	9.9	16.1	21.9	22.6	15.7	9.0
2	Transmission and Stations	1.3	36.5	30.8	30.8	3.0	
3	Distribution		0.3	28.2	33.8	15.6	10.2
4	Telecom, SCADA, Protection and Control	0.05	1.9	2.2	2.2	1.6	
5	Demand Side Management			2.5	2.7		
6	General Plant			27.8	31.2		
7	**TOTAL Capital**	**11.3**	**54.8**	**113.4**	**123.3**	**35.9**	**19.2**
8	Annual Operating Savings			0.20	0.72		

Note: Differences due to rounding.

Table A121.1b
Capital Plan Expenditures without Copper Conductor Replacement Costs and without OTR Project Expenditures

		Pre-2008	2008	2009	2010	2011	2012
		($millions)					
1	Generation	9.9	16.1	21.9	22.6	15.7	9.0
2	Transmission and Stations	1.3	36.5	30.8	30.8	3.0	
3	Distribution		0.0	23.4	27.2		
4	Telecom, SCADA, Protection and Control	0.05	1.9	2.2	2.2	1.6	
5	Demand Side Management			2.5	2.7		
6	General Plant			27.8	31.2		
7	**TOTAL Capital**	**11.3**	**54.5**	**108.6**	**116.7**	**20.3**	**9.0**
8	Annual Operating Savings			0.20	0.72		

Note: Differences due to rounding.

Figure A121.1a

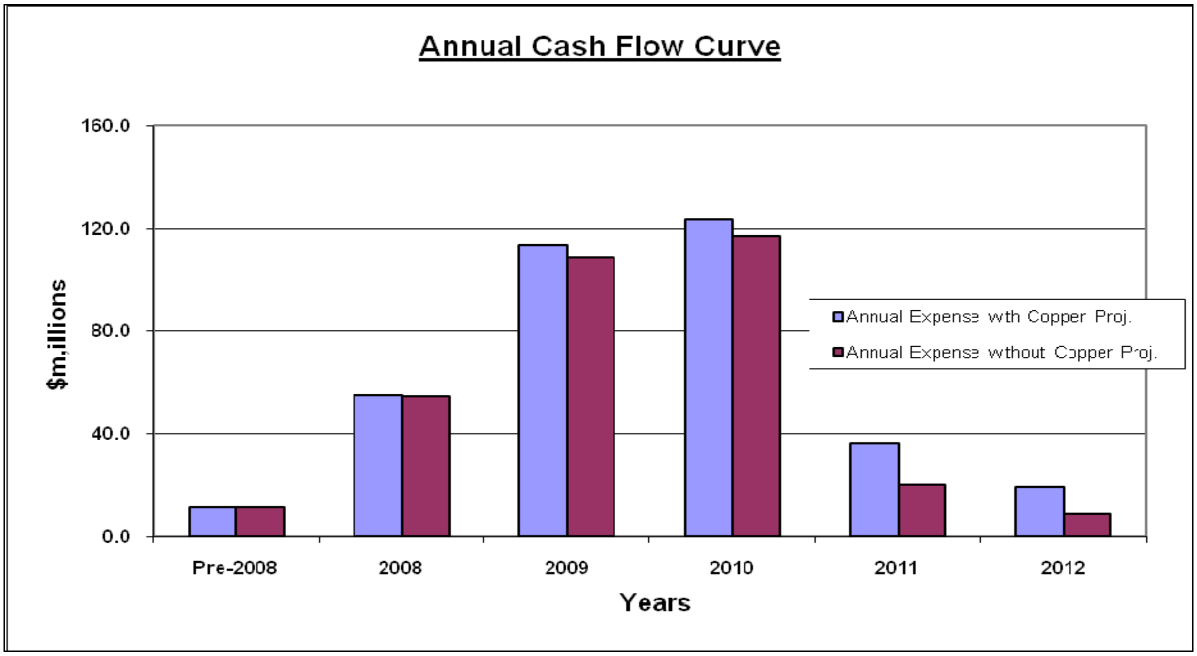
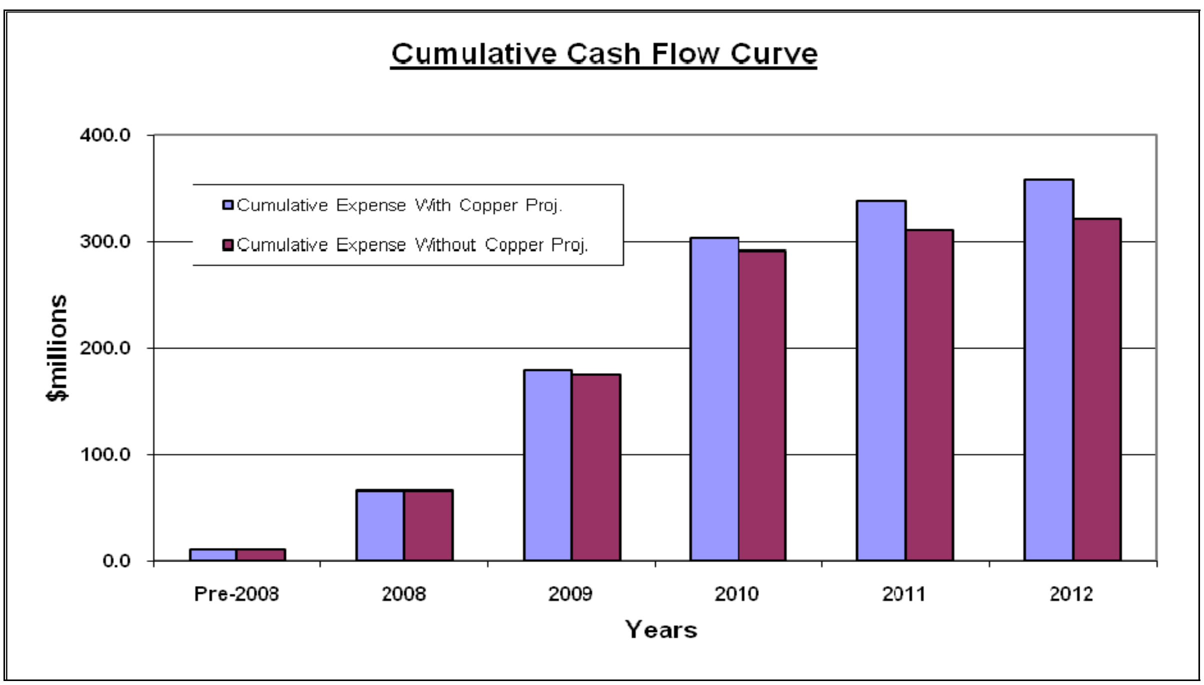


Figure A121.1b



Q121.2 What actions has FortisBC taken, if any, to levelize its annual capital expenditures for the next five years? Please explain.

A121.2 The projects in the 2009/10 Capital Plan have been scheduled to meet customer needs taking into consideration the availability of resources and the impact on rates. FortisBC recognized the need to manage the impact of the capital program when the 2004 System Development Plan was created. The 2004 integrated plan did levelize the work, over the five years of the plan, while continuing to meet growing customer needs. Projects such as the 25 kV conversion of the Boundary area, rather than rebuilding and replacing the existing 63 kV system, resulted in about a $30 million overall reduction in the long term capital spending. The acceptance of the long term plan for the OTR Project resulted in cancellation of about $5 million of station upgrades at Oliver. The 2004 plan recognized similar overall savings by converting 30 Line from 161 kV to 63 kV eliminating the need to replace or replace or refurbish six old 161 kV transformers. This project was scheduled to coordinate with the shutdown of the Teck Cominco Kimberley loads and the transformer replacements were cancelled. FortisBC has considered the reliability risks and scheduled much of its capital plan to ensure the overall rate impacts are managed. FortisBC has continued to manage and update the capital plan to levelize expenditures. One example of FortisBC continuing to assess the risks and manage the overall rate impacts would be the decision to delay the completion of the transmission loop in the Ellison Project. FortisBC felt with the good historical reliability of the transmission lines and Duck Lake Substation it was acceptable to delay this portion of the project.

In the 2006 SDP Update an alternate plan was filed indicating the impacts of delaying projects and not following the original plan. The outcome was confirmation that FortisBC should continue to follow the original plan.

For the next five years FortisBC will ensure the impacts of the capital expenditures are managed to meet our customer needs and minimize rate impacts. One of the outcomes of developing an overall Integrated Capital Plan, incorporating the long term System Development Plan (SDP), long term Resource Plan and long term DSM plan, will be to manage the overall impacts of all capital spending from 2011 - 2015. The updated Integrated Plan will be one of the ways FortisBC plans to manage the overall impact of the capital plan. The stakeholder consultation and regulatory process approving this plan will ensure our customers and stakeholders have input into the capital expenditures in future years.

Q122.0 Reference: Exhibit No. B-2, BCUC IR1 A3.1;
Exhibit No. B-1, Capital Plan, p. 8

On page 8 of its Capital Plan, FortisBC states that expenditure increases in the Transmission Growth category total $75.2 million, of which $71.6 million is related to the OTR project. In BCUC IR1 A3.1, FortisBC states that internal delays associated with completion of the detailed design and CPCN application filing has deferred approximately $5.0 million of the anticipated 2007 and 2008 expenditures to 2009 and 2010.

Q122.1 Please explain the source(s) of the rest of the $71.6 million associated with the OTR project.

A122.1 The balance of the increase in the OTR estimate is composed of scope additions and changes, inflationary pressures, and market escalations in both materials and labour. Details with respect to the change in the OTR estimate from the 2007 SDP update to the CPCN estimate were discussed in the Okanagan Transmission Reinforcement (OTR) CPCN Application process, which is currently under review with the Commission. Details regarding changes in the OTR estimate can be found under OTR Project BCUC IR No. 1 Q29.1 - Q29.5, BCUC IR No. 2 Q68.1 – Q68.7, and BCUC IR No. 1 Q29.4 updated under Errata No. 2. The above documents are attached as Appendix A122.1.

Q123.0 Reference: Exhibit No. B-2, BCUC IR1 A7.1

FortisBC notes that the factors causing extended delivery times for major generating unit upgrade components include increased worldwide demand and the availability of raw materials.

Q123.1 Have these factors, and the cost increases that are often associated with increased demand and constraints on the availability of raw materials, been accounted for in the most recent capital cost estimates for unit life extensions? Please explain, and identify the cost estimates that have been affected.

A123.1 Yes, FortisBC has accounted for the cost increases that are often associated with increased demand and constraints on the availability of raw materials. These increases are detailed in the 2009/10 Capital Plan (Exhibit B-1) as follows: South Slocan Unit 1 increases are referenced on page 21; South Slocan Unit 3 increases are referenced on page 21-22; and Corra Linn Unit 1 increases are referenced on pages 22-23.

Q124.0 Reference: Exhibit No. B-2, BCUC IR1 A12.1

Q124.1 Please discuss the features of the Canal Plant Entitlement Adjustment Agreement that required turbine re-engineering, and describe the physical features of the turbine itself that required alteration.

A124.1 According to Section 2.8 of the Canal Plant Agreement, if FortisBC undertakes any "upgrades", it must optimize the runner design for modeled actual generation. Taking this requirement into consideration a new blade design had to be engineered for this turbine that would produce the appropriate performance curve.

Q125.0 Reference: Exhibit No. B-2, BCUC IR1 A33.5

Q125.1 Please provide a breakdown of the $4.5 million estimated cost of the preferred option.

A125.1 The $4.5 million estimate is broken down into Station Equipment, Station Labour and Station Miscellaneous in Table A125.1 below for each substation affected by the Project.

Table A125.1

Station	Station Equipment	Station Misc	Station Labour	Overheads	AFUDC	Totals
	($000s)					
Kaslo	172	102	198	80	4	556
Crawford Bay	355	371	616	226	25	1,593
Coffee Creek	695	418	866	334	37	2,350
Totals	1,222	892	1,680	640	66	4,500

Q126.0 Reference: Exhibit No. B-2, BCUC IR1 A34.2

FortisBC states that the $400,000 for the engineering work associated with the Kelowna SVC is not meant to cover the costs of detailed design, but to cover the planning and preliminary engineering stages of the project.

Q126.1 Please comment on the accounting treatment of funds that are allocated in a capital budget for an investigative project that ultimately does not result in used and useful assets because the project does not proceed. (Please note that this question is not meant to imply that the project either will or will not proceed, but merely to examine a hypothetical situation in which it does not.)

A126.1 Preliminary and Investigative charges that do not result in a capital project are expensed once there is a determination to not proceed with the project.

Q127.0 Reference: Exhibit No. B-2, BCUC IR1 A35.2; BCUC IR1 A35.3

The annual total costs of both the Transmission Line and Station Sustaining Projects (Line 11 in Table A35.2 and Line 12 in Revised Table 3.3) have increased substantially from their 2005-2007 averages.

Q127.1 Please describe the impact this increase has had on FortisBC's human resource requirements. If the effect has been limited or non-existent, please explain the trade-offs that were made in order to accommodate the increased activity level.

A127.1 FortisBC maintains a full resource schedule for engineering and construction resources related to the execution of the yearly Capital Plan. Although the budgets for Transmission and Substation sustaining projects has increased over previous years, growth projects excluding the Okanagan Transmission Reinforcement project have reduced from previous years. The majority of the OTR Project will be externally resourced permitting the remaining work to be executed with a mix of contractor and internal resources

Q127.2 Please indicate whether FortisBC expects the new expenditure levels to return to their previous levels or continue at their new levels beyond 2010. Please explain and, in doing so, address the impact that recent system upgrades are likely to have.

A127.2 The 2009/10 Capital Plan completes the majority of the medium-term (5 year) System Development Plan components of the 2005 SDP. The Company intends to complete a full planning review of its system in 2009 and will submit a new long-term System Development Plan in 2010. It is anticipated that spending levels will remain at or around 2005 – 2010 levels for the foreseeable future, however this is highly dependent on the future load growth and sustainability requirements of the plant in the service territory.

FortisBC expects future expenditures for Transmission Line Sustaining Projects to be lower relative to 2009/10 expenditures largely due to the completion of such projects as the Transmission Pine Beetle Hazard, 20 Line Rebuild and 27 Line Rebuild projects. The recent system upgrades are expected to have a positive impact on system reliability.

The completion of these system upgrades will have an impact on rates, however, the impacts of load growth, including the impacts of DSM and aging infrastructure, will determine the capital spending required to serve FortisBC customers' electrical needs. FortisBC believes that the current process of prudent planning coupled with Commission review and oversight is the appropriate means to ensure that expenditures are reasonable and in the public interest.

Q127.3 Please explain whether FortisBC tracks sustaining costs on a per-unit basis (e.g., dollars per customer, dollars per MWh of energy delivered, dollars per MW of peak load, etc.). If no such measures are tracked, please explain how FortisBC monitors the effectiveness of its sustaining programs.

A127.3 Currently, FortisBC does not have a quantitative measure to monitor the effectiveness of the sustaining programs. The level of expenditures present in the sustaining program is intended to provide for preventative maintenance and required improvements to the system to maintain reliable service.

Q128.0 Reference: Exhibit No. B-2, BCUC IR1 A41.1

Please explain why transmission-line condition assessments should be classified as capital expenditures as opposed to operating expenditures.

A128.0 Transmission line condition assessment costs are capitalized and the costs enable definition of the scope of capital work required to remedy the deficiencies in the same manner as Preliminary and Investigative charges are collected and charged to the capital projects they relate to.

Q129.0 Reference: Exhibit No. B-2, BCUC IR1 A44.1; BCUC IR1 A45.1

FortisBC is proposing rebuilds on 20 Line and 27 Line, necessitated in part by "clearance issues."

Q129.1 Please elaborate on the clearance issues.

A129.1 The clearance issues are mainly related to the circuit to circuit spacing between the transmission and distribution circuits. For a large portion of both 20 Line and 27 Line the main distribution circuit for the area is on the same structures as the 63 kV transmission circuit. These clearance issues have led to outages and damage claims related to the transmission lines contacting the distribution lines, especially due to tree related outages.

Q129.2 Please explain how the issues arose and whether such issues affect other transmission circuits in FortisBC's territory.

A129.2 These issues arose in part due to the following factors:

- Past standards which did not adequately account for having transmission and distribution circuits on the same structures, both with spacing between the circuits and with the horizontal alignment of the circuits;
- The heavy snow loading along areas of the line corridors; and
- Urgent repairs to the structures that in some cases have reduced the circuit to circuit spacing that was originally provided.

These are issues for other transmission circuits in the FortisBC territory, however, due to the fact that 20 Line and 27 Line have extensive distribution underbuild and are located in areas with heavy snow loading and tightly treed right-of-way, these lines are affected by the clearance issue more directly.

Q129.3 Do any of the clearance issues pose a hazard to the public?

A129.3 There is a potential hazard to the public anytime the distribution system is contacted by the transmission system. Distribution system components are not designed to withstand the transmission level voltages and can fail sometimes resulting in fire and other safety issues.

Q130.0 Reference: Exhibit No. B-2, BCUC IR1 A50.2

FortisBC states that the new breaker will be a vacuum design to avoid the leakage issues that may arise with an SF_6 design.

Q130.1 Please describe FortisBC's experience with respect to gas leakage from SF_6 equipment generally.

A130.1 FortisBC has a good performance record with SF6 insulated equipment. Minor leaks have occurred and have been repaired as part of the normal course of action. A vacuum breaker has been proposed in this instance because installation of a breaker in a mobile substation may make it more susceptible to SF6 leakage due to the frequent movement and vibration associated with road transportation. As well, in this 25 kV installation a vacuum breaker is a suitable alternative (vacuum breakers are not commonly available at 63 kV and above).

Q130.2 Are there any existing or proposed standards that govern leakage from such equipment?

A130.2 FortisBC tracks the usage of SF6 gas within the company and reports this information to the Canadian Electrical Association. The Association is responsible for reporting aggregated usage and leakage information to Environment Canada. This practice was established to demonstrate the commitment of the electricity industry to manage SF6 in an environmentally responsible manner and to report annual releases. Since SF6 is non-toxic there are no legislative standards regarding permissible releases of SF6 into the environment. To FortisBC's knowledge there are no new standards in development. With regards to the equipment itself, there are no specific gas leakage standards.

Q130.3 Are there any environmental liabilities associated with existing SF_6 equipment?

A130.3 While SF6 gas is non-toxic, it has the disadvantage that it is a greenhouse gas and thus any atmospheric leakage must be minimized. FortisBC uses procedures to ensure that inadvertent leakage is minimized and all used gas is reclaimed rather than vented into the atmosphere. These practices do increase maintenance costs somewhat due to their complexity. However, there is no replacement substance that has all of the beneficial qualities (high dielectric value, low reactivity and toxicity, and relatively low cost) of SF6 gas. Virtually all high-voltage (above 63 kV) circuit breakers manufactured today use SF6 gas as the interrupting and insulating medium. The only practical alternative to SF6 is insulating mineral oil which has many more negative qualities associated with it.

Q131.0 Reference: Exhibit No. B-2, BCUC IR 79.1

The following is the abstract for a recently published article:

"Are compact fluorescent lamps bright green or grayish green? Although energy savings can be obtained by using them under certain conditions, those savings largely disappear in cold climates. Those lamps also present a number of shortcomings, including their containing mercury—raising the question of their safe disposal—and the undesirable harmonics they feed back to the grid. Manufacturers and governments are called on to tackle those problems."

G. Olivier and R. Benhaddadi, "How Green are Compact Fluorescent Lamps?" ***IEEE Canadian Review,*** **No. 56, December 2007.**

Q131.1 Please comment on the findings presented in this article in the context of FortisBC's own CFL programs.

A131.1 FortisBC believes that compact fluorescent lamps are the best energy efficient lighting choice that is currently widely available. The moderate climate of FortisBC's service territory coupled with the fact that 66 percent of our customers use non-electric heating methods maintains the expected energy savings of compact fluorescent lamps. The incandescent light bulb is an effective generator of heat, but light fixtures are located to provide light, and are not optimally located to provide space heating.

FortisBC recognizes the fact that compact fluorescent lamps contain mercury and trusts that the appropriate municipal, regional and provincial authorities will provide acceptable waste management policies for compact fluorescent lamps. FortisBC carefully monitors the power quality of its distribution network for Total

Harmonic Distortion. The proliferation of non-linear loads such as computers, televisions, compact fluorescent lamps and variable frequency drives has increased the harmonic content of the distribution network, but the contribution of compact fluorescent lamps to the Total Harmonic Distortion of the network is not significant enough to outweigh the energy savings.

Q132.0 Reference: Exhibit No. B-2, BCUC IR 82.1

FortisBC estimates energy savings of approximately 700 MWh per year from the Enabling Workshops initiative.

Q132.1 How was this value estimated?

A132.1 This is a new offering for industrial customers, the results of which are dependent on customer participation and reporting. A conservative savings estimate was used as a proxy until actual results are known.

Q133.0 Reference: Exhibit No. B-2, BCUC IR 86.2

FortisBC notes that a vehicle's age and odometer reading trigger a review for continued service versus replacement.

Q133.1 Please describe the review and analysis that takes place once a vehicle's trigger criteria are met and provide a quantitative example.

A133.1 Updating the 15 year Fleet Capital Plan is an ongoing process on a vehicle by vehicle basis. Please also see Exhibit B-1, page 117, lines 6 through 12.

The following is an example of the review and analysis of a vehicle for continued service versus replacement once the trigger criteria have been met. This particular unit was removed from service after extending beyond the trigger criteria. This unit was replaced as part of the approved 2008 Capital Plan.

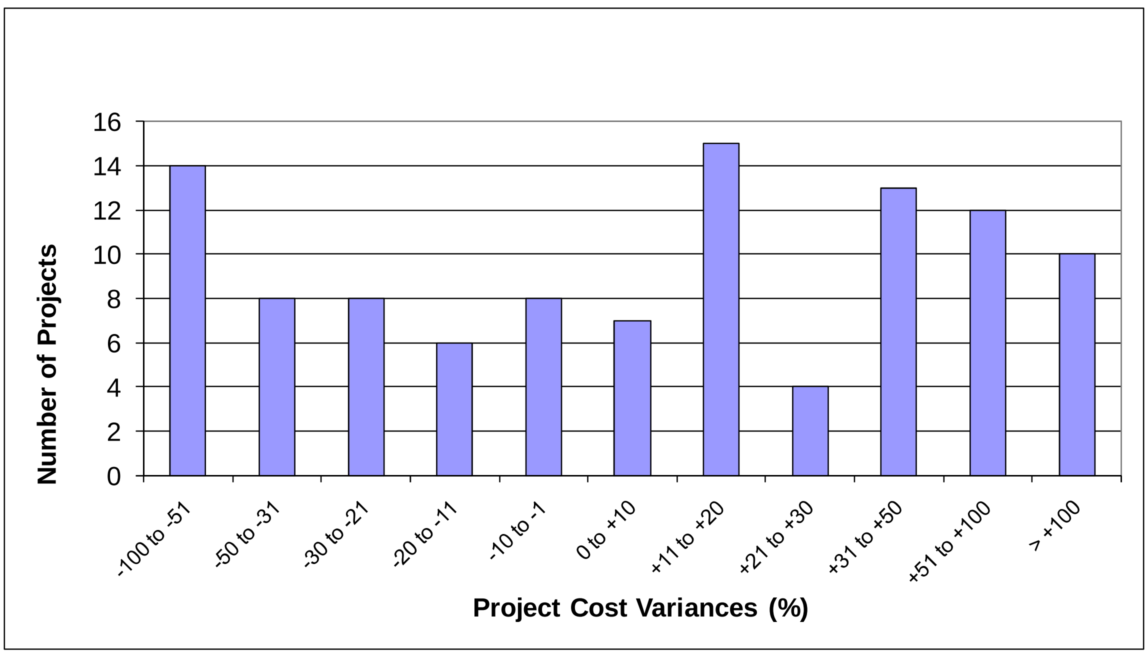
At the time of review in 2006, potentially $4,000 worth of repairs was imminent on this 8 year old ¾ ton 4X4 pickup with 164,000 kilometres on the odometer. The time criteria had passed in 2006, but not the odometer criteria and after due consideration it was decided to forgo the repairs and keep it in service until 2008. After reviewing this vehicle again in May 2008 the replacement was accelerated slightly (scheduled for fall replacement but actually replaced in late spring) to avoid investing in repairs with no chance of recovering the repair cost through the disposal proceeds later.

Q134.0 Reference: Exhibit No. B-2, BCUC IR 97 (Appendix A97.0)

Q134.1 Please prepare a histogram that shows, for the <u>completed</u> projects listed in Table A97.0, the distribution of cost variances. The categories in the histogram should be something like: -100 to -50, -50 to -30, -30 to -20, -20 to -10, -10 to 0, 0 to +10, +10 to +20, +30 to +50, +50 to +100, greater than +100, though FortisBC is free to use different categories if desired. FortisBC may wish to prepare separate histograms for different classes of projects, though a histogram for all projects should be prepared.

A134.1 Please see Figure A134.1 below.

Figure A134.1



Q134.2 Please calculate the mean and the standard deviation of the project cost variances.

A134.2 The mean is 20 percent and the standard deviation is 0.82.

Q135.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.1, p. 7

FortisBC states that the current load forecast, developed in the first quarter of 2008, continues to show a high level of load growth in the north and south Okanagan areas with average winter growth rates exceeding 5% and 3%, respectively, over the next five years.

Q135.1 Based on more recent economic data showing further slowdown in the US economy and declines in Canadian GDP, does FortisBC continue to believe the stated growth rates will be achieved? Please explain.

A135.1 The load forecasts are based on known and proposed residential and commercial growth at this time. While it is a possibility that growth rates may slow down, it should be noted that financial indicators suggest British Columbia to be less affected than other parts of Canada (source BC Stats).

Q136.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.1.4, p. 9

FortisBC states that the Vaseux Lake Terminal Station Transformer 3 is not a component of the proposed OTR Project, and that the future work is discussed in a project CPCN application.

Q136.1 Please provide a statement regarding how Fortis wishes the Commission to treat this project in respect of the 2009 System Development Plan and Capital Expenditure Plan. Specifically, is FortisBC seeking approval of this project at this time?

A136.1 FortisBC has provided the information as an update only. There is no work scheduled for this project in 2009/10 and thus no approval is being requested.

Q137.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.2.1(d), pp. 11-12

FortisBC states that a solution to high fault levels has been implemented at Glenmore Station and that no other substations require attention in the foreseeable future.

Q137.1 Please explain the changes in FortisBC's assumptions or in the physical system that obviated the need for fault-level-related upgrades at the other stations.

A137.1 As per the FortisBC Distribution Substation Fault Level Control Guidelines which was included as Appendix 8 of the FortisBC 2007/08 Capital Plan, feeder reactors are not generally required in single transformer stations. In the case of double-transformer stations, reactors are not required if the two transformers are operated with the low voltage bus tie open (as this is essentially the same as two single transformers at one location). The operational disadvantages of operating the transformers separated (increased losses and uneven load sharing) are outweighed by the greatly reduced costs from not having to install reactors and acquire additional property at these legacy substation.

Q138.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.2.1(e), p. 12

FortisBC states that the transmission loop for the Sexsmith, Ellison, and Duck Lake Substations will be further assessed as part of the 2011 long-range plan.

Q138.1 Please explain the changes in FortisBC's assumptions or in the physical system that allowed FortisBC to defer consideration of this project.

A138.1 As part of the 2009 and 2010 capital planning process, the Company assessed projects that could be deferred to mitigate customer rate impacts. The high reliability of the transmission line at Duck Lake was a deciding factor in the decision to defer this project.

Q139.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.2.2(a), p. 15

FortisBC states that unanticipated delays have deferred the completion of the project to 2009 from the originally scheduled 2005/06 timeframe.

Q139.1 Please describe the impact, if any, that the delay in this project has had on reliability.

A139.1 To date, the delay has not created any reliability issues in the Naramata area.

Q139.2 Please review the original justification for the project and make an assessment as to whether the original project might have been scheduled too early, whether FortisBC got "lucky" that reliability did not suffer, or whether specific actions were taken to mitigate the impact of project delays.

A139.2 The timing of the application for approval of the Naramata substation project was appropriate. The project was delayed due to an extended regulatory process that was initiated following BCUC approval of the project. The Company remains concerned that the peak load for the Naramata area will exceed the capability of the transformer leading to unacceptable interruptions in service to the customers in this area. FortisBC has monitored the condition of the Naramata transformer closely to proactively respond to any potential issues.

Q139.3 Please indicate FortisBC's level of confidence that the expected completion date of 2009 will actually be achieved. Please explain.

A139.3 The Company is confident the completion date of 2009 will be achieved. The project schedule remains:

- Land purchase and rezoning complete October 2008;
- Construction Contract Award January 2009;
- Construction Start February 2009;
- Retaining Wall March 2009;
- Footings poured mid April 2009;
- Erect structures and bus work May 2009;
- Transformer delivery and setup July 2009;
- Control Room and site wiring June-August 2009;
- Transmission and Distribution lines September 2009;
- Construction end September 2009; and
- Commissioning complete October 2009.

The land rezoning process will formally start with the first reading at the Regional District of Okanagan-Similkameen (RDOS) on September 4, 2008. The associated public hearing is scheduled for October 20, 2008 in Naramata. The land acquisition process is well in hand with both Integrated Land Management Bureau (ILMB) and Ministry of Transportation and Infrastructure (MoTI). A formal offer to purchase has been presented to MoTI and the ILMB application is complete including the surveying and posting of the property. FortisBC expects to have title to an appropriately zoned property by late October or early November. The General Arrangement and Site Plan have been finalized and drawings approved. Detailed engineering to complete the site/civil construction package is well underway and it is expected that the work will be tendered this fall. The critical major equipment, notably the transformer and breaker, are in the FortisBC warehouse in Penticton.

All the key milestones are being met, particularly those that represent a risk to the project schedule including the land process, major equipment acquisition and finalizing the General Arrangement and Site Plan. The balance of the project milestones have a limited risk in terms of schedule.

Q140.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.3.6(a), p. 23

FortisBC states that the Slocan City to New Denver transmission line has been deferred indefinitely due to the high cost.

Q140.1 Please identify the original justification for this project and identify what has changed to make it no longer necessary for system reliability.

A140.1 The justification for this project is based on the historical reliability for this area. In general, 19 Line between South Slocan and Slocan City is one of the worst performers within the FortisBC transmission system. There is little that can be done to improve the line corridor itself given the constraints of the narrow valley bottom and the large number of trees in the vicinity. Thus, the only way to substantially improve the area reliability would be to establish a new transmission source from BCTC at New Denver south to Slocan City. This project would require significant new transmission right-of-way (approximately 30 kilometres) and potential environmental disruption.

It has not been deemed that this tie it is no longer necessary; rather the very high costs of proceeding with this interconnection at this time are felt to outweigh the improved reliability that would result. There is some potential that interconnection requests from independent power producers could occur in the future. Any required transmission upgrades could be partially funded by the proponent at time. This would have the advantage of both improving the area reliability while at the same time reducing the impact to the ratepayer.

Q141.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.1.1(l), p. 26

FortisBC has identified the Creston Substation Protection Upgrade as a new project for 2009 to eliminate nuisance trips to the station's customers.

Q141.1 Please provide the reliability statistics for the station and/or the connected customers, and compare them with the system-wide averages.

A141.1 Please see Table A141.1 below.

Table A141.1
Creston Substation Reliability

	2003		2004		2005		2006		2007	
	No. of Cust.	Cust. Hours	No. of Cust.	Cust. Hours	No. of Cust.	Cust. Hours	No. of Cust.	Cust. Hours	No. of Cust.	Cust. Hours
Creston T1	12,708	20,637	0	0	2,621	604	0	0	2,237	57
Creston T2	13,888	22,586	0	0	2,510	579	0	0	2,160	55

In 2008 the number of customers connected to the Creston Substation is about 4,500.

Since 2003 there have been few outages at the Creston Substation, and the reliability numbers would be relatively comparable to similar sized communities such as Castlegar and Trail.

Q141.2 Discuss the impact on system reliability.

A141.2 This project is addressing the protection coordination issues with the transmission line and transformer protection. Currently, a transformer fault with either of the Creston Substation transformers will cause an outage to all of the Creston Substation customers due to the fact that the transmission supply will respond before the transformer protection operates. This project will eliminate this issue and ensure that only the faulted transformer is involved in any outage. Since the customer counts are relatively the same on both transformers, this project would improve the Creston Substation reliability by about 50 percent for transformer faults.

Q142.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.2.2(e), p. 28

The Company has developed a contingency plan to address the possible failure of the Trout Creek transformer.

Q142.1 Please discuss the contingency plan.

A142.1 A contingency plan has been developed that would utilize the 63/8.0 kV transformer which was salvaged by the Waterford Capacity Increase project in 2006. The ex-Waterford transformer has been refurbished and placed in storage. If the transformer at Trout Creek was to fail, then the immediate FortisBC response would be to install the mobile substation transformer to restore the customer load. This would then allow the “temporary” installation of the ex-Waterford transformer. This installation would take possibly two to three weeks. Once the temporary transformer was installed, the mobile could be removed (thus ensuring that the mobile is not unavailable for an extended period). The temporary installation would be safe, but would likely have operating constraints which would not be acceptable in the long term. However, since this situation will only occur if the existing transformer fails, it is felt to be an acceptable risk.

Q142.2 Will a run-to-failure scenario for the Trout Creek substation materially affect the salvage value of the substation’s assets or present any risk to employees or the public? Please explain.

A142.2 No. There are no significant employee or public safety risks associated with the station as it exists today. Very few of the substation components would be suitable for re-use; hence, no material impact on the salvage value is expected.

Q143.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.2.2(l), p. 30

Q143.1 Please describe the safety hazards associated with the Pine Street Substation distribution breakers.

A143.1 These breakers use obsolete arc-chute interrupters and are inferior to newer breakers which use vacuum or SF6 interruption technology. There have been cases in other installations when these breakers have jammed mechanically and then accidentally closed while being extracted from the breaker cubicle. Extracting the breaker while closed and energized may result in a violent arc fault. Serious injuries have occurred as a result of this type of failure. FortisBC currently mitigates these risks by the use of personal protective equipment, however even this may not eliminate the risk of injury.

Q144.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.2.2(m), p. 30

Fortis states that, as a result of a capacity addition at the substation, the existing reclosers are no longer adequate to interrupt the available fault current.

Q144.1 Please describe the capacity additions.

A144.1 The capacity addition is related to the replacement of the Princeton T2/T3 step-down arrangement (equivalent to a 10 MVA 138/13 kV unit) with a new single 32 MVA 138/13 kV transformer. This upgrade resulted in a doubling of the fault level at the station 13 kV bus.

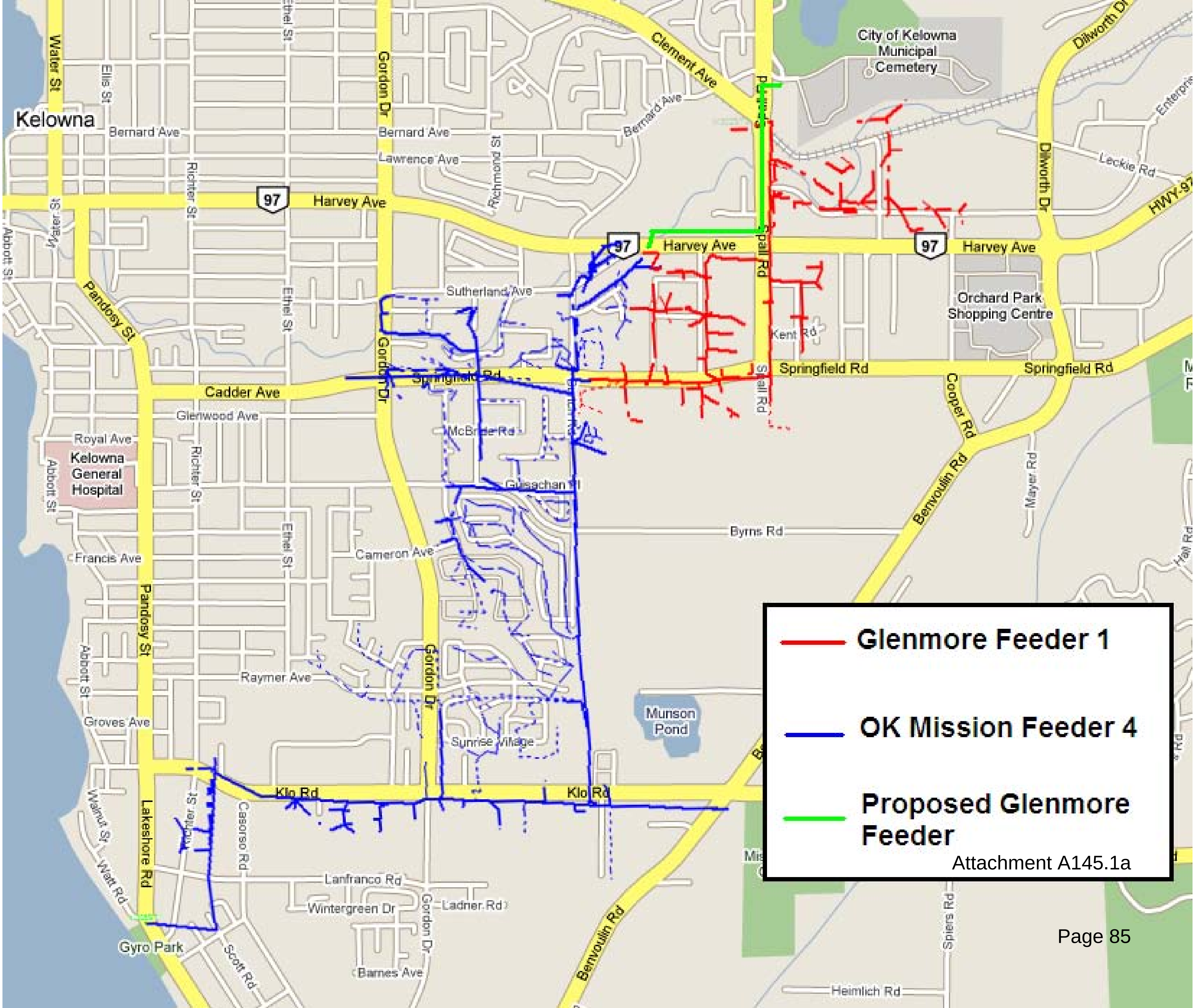
Q144.2 Why was the necessity of replacing the reclosers with circuit breakers not identified at the time of the capacity additions?

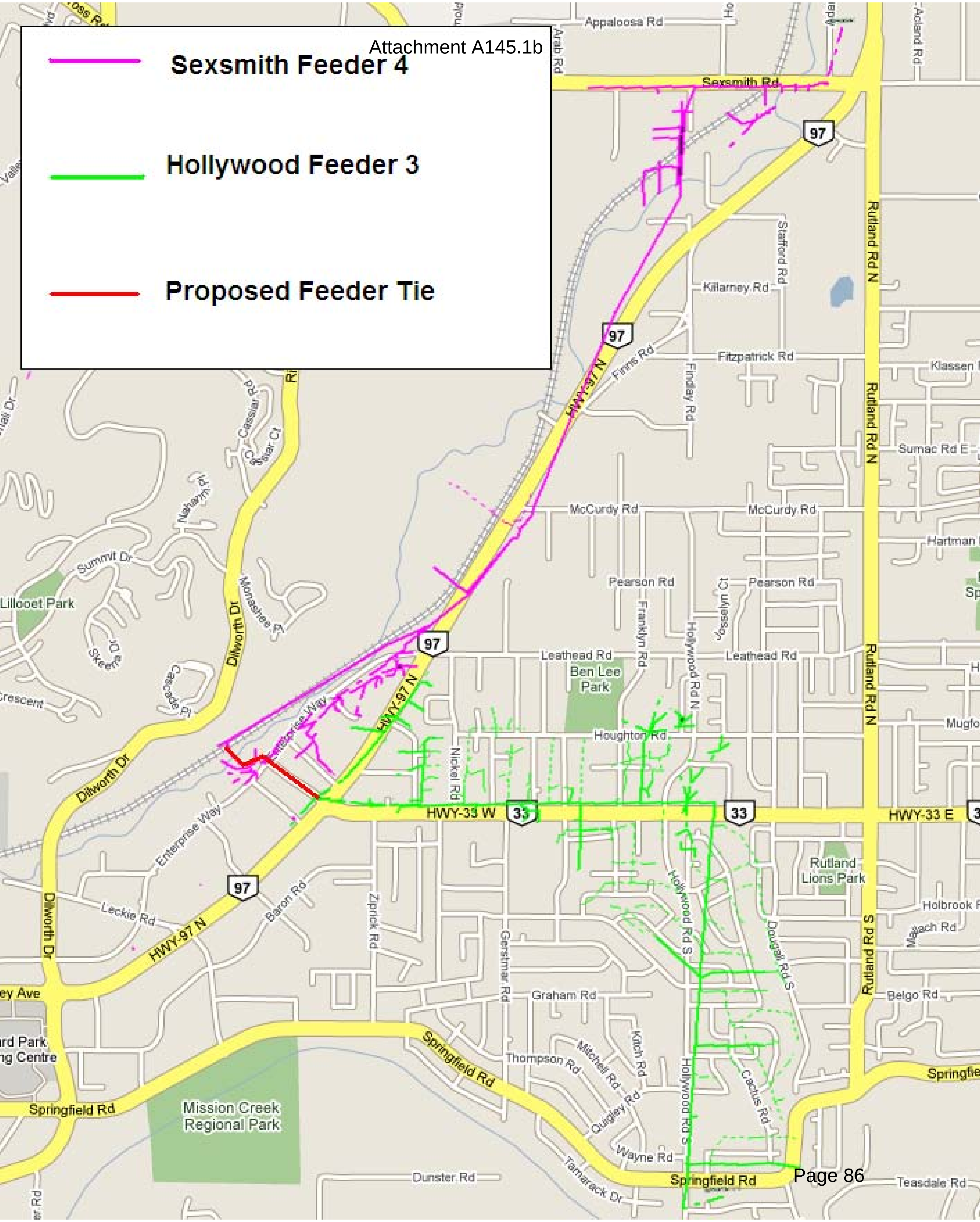
A144.2 Any affected equipment owned by FortisBC at the time was replaced as part of the capacity increase project. The distribution recloser assets at that time were owned and maintained by Princeton Light and Power and that company would have been responsible for funding and carrying out any necessary upgrades.

Q145.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.3.3.1, pp. 31-35

Q145.1 Please provide conceptual circuit maps showing the Kelowna-area distribution upgrades.

A145.1 Please see Attachments A145.1a and A145.1b.


Glenmore Feeder 1
OK Mission Feeder 4
Proposed Glenmore Feeder
Attachment A145.1a
Kelowna
City of Kelowna Municipal Cemetery
Orchard Park Shopping Centre
Kelowna General Hospital
Munson Pond
Sunrise Village
Gyro Park
Harvey Ave
Springfield Rd
Cadder Ave
Klo Rd
Gordon Dr
Pandosy St
Lakeshore Rd
Spall Rd
Clement Ave
Bernard Ave
Lawrence Ave
Sutherland Ave
Glenwood Ave
Royal Ave
McBride Rd
Guisachan Pl
Cameron Ave
Francis Ave
Raymer Ave
Groves Ave
Byrns Rd
Benvoulin Rd
Cooper Rd
Dilworth Dr
Leckie Rd
Kent Rd
Mayer Rd
Lanfranco Rd
Wintergreen Dr
Ladner Rd
Barnes Ave
Heimlich Rd
Spiers Rd
Casorso Rd
Scott Rd
Watt Rd
Walnut St
Abbott St
Water St
Ellis St
Richter St
Ethel St
Richmond St
HWY 97


Sexsmith Feeder 4
Hollywood Feeder 3
Proposed Feeder Tie
Appaloosa Rd
Sexsmith Rd
Killarney Rd
Stafford Rd
Fitzpatrick Rd
Finns Rd
Findlay Rd
Klassen
Rutland Rd N
Sumac Rd E
McCurdy Rd
McCurdy Rd
Hartman
Pearson Rd
Pearson Rd
Josselyn Ct
Franklyn Rd
Hollywood Rd N
Leathead Rd
Leathead Rd
Ben Lee Park
Houghton Rd
Nickel Rd
HWY-97 N
HWY-33 W
HWY-33 E
97
33
Enterprise Way
Dilworth Dr
Monashee Pl
Summit Dr
Lillooet Park
Skeena Dr
Cascade Pl
Cassiar Rd
Nahanni Pl
Crescent
Leckie Rd
Baron Rd
Ziprick Rd
Gerstmar Rd
Graham Rd
Rutland Lions Park
Holbrook
Dougall Rd S
Hollywood Rd S
Rutland Rd S
Belgo Rd
Springfield Rd
Mission Creek Regional Park
Thompson Rd
Mitchell Rd
Kitch Rd
Cactus Rd
Quigley Rd
Wayne Rd
Tamarack Dr
Dunster Rd
Teasdale Rd

Q146.0 Reference: Exhibit No. B-1, 2009 SDP Update, Section 2.3.3.2, p. 36

The Christina Lake feeder is experiencing below-standard end-of-line voltages.

Q146.1 Were solutions other than reconductoring, such as a capacitor bank, considered? Please explain.

A146.1 The addition of voltage regulation was considered as an option on this project. This option would resolve the voltage issues, however it would also involve considerable capital cost in 2009 that would not be required and would be salvaged when the copper conductor is replaced as a part of the Copper Conductor Replacement program.

Q147.0 Reference: Capital Expenditures;
Exhibit B-2, Application, pp. 1-131
Capital Expenditure Ratio

Q147.1 Provide the Capital Expenditure to Property, Plant and Equipment balance ratios for the years 2005 through 2010.

A147.1 Please see Table A147.1 below.

Table A147.1

			Actual			Forecast		
		Note	2005	2006	2007	2008	2009	2010
			($millions)					
Capital Expenditures ("CE")		1	115.7	111.6	146.2	122.9	179.3	197.9
Gross Property Plant & Equimpment ("PPE")		2	832.3	940.2	1,074.0	1,188.9	1,329.5	1,529.8
Ratio (CE / PPE)			13.90%	11.87%	13.61%	10.34%	13.49%	12.94%
Notes:								
1	Gross Capital Expenditures and DSM addtions							
2	Defined as Gross Plant in Service plus the Utility Plant Acquisition Adjustment account balance.							
	Capital Expenditures		113.3	109.3	143.7	120.6	177.1	195.3
	DSM		2.4	2.3	2.5	2.3	2.2	2.6
	Total		115.7	111.6	146.2	122.9	179.3	197.9

Q148.0 Reference: Capital Expenditures;
Exhibit B-2, Application, pp. 1-131
Growth & Sustaining $/year

Q148.1 Complete the table in Appendix A.

A148.1 Please see BCUC Appendix A148.1.

Q148.1.1 Add any missing capital expenditures to the table.

A148.1.1 The missing capital expenditures have been added to the table.

Q148.1.2 Provide the Benefit Cost Ratio ("BCR").

A148.1.2 The majority of projects do not lend themselves to a Benefit Cost Ratio. In general, these projects undertaken by the public utility are required to provide service or part of the utility's obligation to serve, or to maintain employee or public safety. Please also refer to the response to Q112.2.1 above.

Q148.1.3 Provide the Status – identified, definition, underway, started, complete.

A148.1.3 Please see BCUC Appendix A148.1.

Q148.1.4 Provide the CPCN Order or the future date of Application for approval.

A148.1.4 Please see BCUC Appendix A148.1.

Q148.1.5 Using 10 as the highest and 1 as the lowest,

A148.1.5 Please see BCUC Appendix A148.1.

Q148.1.5.1 Provide the ranking for increasing the electrical system reliability with 10 being the highest.

A148.1.5.1 Please see BCUC Appendix A148.1.

Q148.1.5.2 Provide the ranking for increasing the electrical system safety with 10 being the highest.

A148.1.5.2 Please see BCUC Appendix A148.1.

Q148.2 Provide detailed cost estimates for all the capital expenditures showing direct costs, indirect costs, undistributed costs, and other non-project related costs.

A148.2 As noted in the Application (Exhibit B-1) page 12, lines 6-12, FortisBC has prepared estimates for the projects in the 2009/10 Capital Plan to a level of accuracy of +/- 20 percent generally, and +/- 10 percent for those subject to a separate CPCN application process. Detailed engineering has not been performed in many cases. This is the level of accuracy that FortisBC would normally pursue for planning estimates of this type. The level of detail sought by the Information Request does not exist at this time and cannot be produced without incurring significant cost and the extensive use of both internal and external resources. On a best-efforts attempt to further refine the estimate for all capital expenditures, FortisBC provides Table A148.2 below, separating direct project costs from land cost, AFUDC and overheads.

Table A148.2

	2009	2010
	($millions)	
Direct project cost	155.51	154.73
Land Cost	0.88	0.15
AFUDC	5.69	8.97
Capital Overheads	16.68	17.24
Total	178.76	181.09

Q148.3 Complete the following rows in the following tables provided.

TABLE 1 GROWTH AND SUSTAINING $/YEAR

			2005	2006	2007	F2008	F2009	F2010
					$/ year			
Generation	Growth	Forecasted						
		Actual						
		Backlog						
Transmission and Stations	Growth	Forecasted						
		Actual						
		Backlog						
Distribution	Growth	Forecasted						
		Actual						
		Backlog						
Telecom, SCADA, Protection and Control	Growth	Forecasted						
		Actual						
		Backlog						
Transmission	Sustaining	Forecasted						

			2005	2006	2007	F2008	F2009	F2010
			$/ year					
		Actual					-	-
		Backlog						
Generation	Sustaining	Forecasted						
		Actual					-	-
		Backlog						
Distribution	Sustaining	Forecasted						
		Actual					-	-
		Backlog						
Telecom, SCADA, Protection and Control	Sustaining	Forecasted						
		Actual					-	-
		Backlog						
Demand Side Management		Forecasted						
		Actual					-	-
		Backlog						
General Plant		Forecasted						

			2005	2006	2007	F2008	F2009	F2010
			$/ year					
		Actual						
		Backlog						

TABLE 2 GROWTH AND SUSTAINING $/KWH/YEAR (KWH IS ENERGY DELIVERED TO CUSTOMERS FROM ALL SOURCES)

			2005	2006	2007	F2008	F2009	F2010
			$/ year					
Generation	Growth	Forecasted						
		Actual						
		Backlog						
Transmission and Stations	Growth	Forecasted						
		Actual						
		Backlog						
Distribution	Growth	Forecasted						
		Actual						
		Backlog						
Telecom, SCADA, Protection and Control	Growth	Forecasted						
		Actual						
		Backlog						
Transmission	Sustaining	Forecasted						
		Actual						

		Backlog						
Generation	Sustaining	Forecasted						
		Actual						
		Backlog						
Distribution	Sustaining	Forecasted						
		Actual						
		Backlog						
Telecom, SCADA, Protection and Control	Sustaining	Forecasted						
		Actual						
		Backlog						
Demand Side Management		Forecasted						
		Actual						
		Backlog						
General Plant		Forecasted						
		Actual						
		Backlog						

TABLE 3 KEY PARAMETERS

		2005	2006	2007	F2008	F2009	F2010
Number of New Connections	Forecasted						
	Actual					-	-
Number of FTE's	Forecasted						
	Actual					-	-
Escalation /Inflation (%)	Forecasted						
	Actual					-	-
Average Growth in Demand (MW)	Forecasted						
	Actual					-	-
Energy Supplied or Delivered to Customers (GWh)	Forecasted						
	Actual					-	-
Cost of Capital (%)	Forecasted						
	Actual					-	-

Cost of Energy ($/kWh)	Forecasted						
	Actual					-	-
SAIDI	Forecasted						
	Actual					-	-
SAIFI	Forecasted						
	Actual					-	-
RATE IMPACTS	Forecasted						
	Actual						

A148.3 Please see Tables A148.3a, A148.3b, and A148.3c below.

Table A148.3
Growth and Sustaining $/Year

			2005	2006	2007	F2008	F2009	F2010
			($000s)					
Generation	Growth	Forecasted	-	-	-	-	-	-
		Actual	-	-	-	-	-	-
		Backlog	-	-	-	-	-	-
Transmission & Stations	Growth	Forecasted	60,302	30,705	56,926	42,513	84,396	76,178
		Actual	49,335	28,958	62,084	-	-	-
		Backlog	10,967	1,747	(5,158)	-	-	-
Distribution	Growth	Forecasted	17,142	16,724	18,990	26,709	12,158	15,433
		Actual	24,079	26,310	28,069	-	-	-
		Backlog	(6,937)	(9,586)	(9,079)	-	-	-
Telecom, SCADA, Protection & Control	Growth	Forecasted	651	3,565	3,458	1,223	1,338	1,438
		Actual	28	36	162	-	-	-
		Backlog	623	3,529	3,296	-	-	-
Transmission	Sustaining	Forecasted	15,915	13,071	7,479	10,431	11,727	12,497
		Actual	8,936	16,133	6,984	-	-	-
		Backlog	6,979	(3,062)	495	-	-	-
Generation	Sustaining	Forecasted	17,772	15,804	21,659	18,400	21,935	22,557
		Actual	13,856	13,672	20,404	-	-	-
		Backlog	3,916	2,132	1,255	-	-	-
Distribution	Sustaining	Forecasted	8,476	9,096	8,016	9,597	16,049	18,317
		Actual	8,756	12,328	10,417	-	-	-
		Backlog	(280)	(3,232)	(2,401)	-	-	-
Telecom, SCADA, Protection & Control	Sustaining	Forecasted	1,701	1,173	1,657	177	864	738
		Actual	882	1,308	1,243	-	-	-
		Backlog	819	(135)	414	-	-	-
Demand Side Management		Forecasted	1,201	1,498	1,657	1,634	2,513	2,707
		Actual	1,607	1,514	1,623	-	-	-
		Backlog	(406)	(16)	34	-	-	-
General Plant		Forecasted	6,040	14,775	15,475	11,590	27,783	31,221
		Actual	7,437	10,603	14,377	-	-	-
		Backlog	(1,397)	4,172	1,098	-	-	-
Total Forecasted (exc. DSM)			127,999	104,913	133,660	120,640	176,250	178,379
Total Actual (exc. DSM)			113,309	109,348	143,740	-	-	-
Total Backlog (exc. DSM)			14,690	(4,435)	(10,080)	-	-	-
Total Forecasted (inc. DSM)			129,200	106,411	135,317	122,274	178,763	181,086
Total Actual (inc. DSM)			114,916	110,862	145,363	-	-	-
Total Backlog (inc. DSM)			14,284	(4,451)	(10,046)	-	-	-

Source:	2005	2006	2007	2008	2009	2010
	2005 Period Annual Report	2006 Period Annual Report	2007 Period Annual Report	CEP 2007/2008	CEP 2009/2010	CEP 2009/2011

Table A148.3b
Growth and Sustaining $/kWh/Year
(kWh is Energy Delivered to All Customers from all Sources)

			2005	2006	2007	F2008	F2009	F2010
			2,971 Gwh (N)*	3,054 Gwh (N)*	3,084 Gwh (N)*	3,090 Gwh	3,125 Gwh	3,173 Gwh
			($/kWh)					
Generation	Growth	Forecasted	-	-	-	-	-	-
		Actual	-	-	-	-	-	-
		Backlog	-	-	-	-	-	-
Transmission & Stations	Growth	Forecasted	0.02030	0.01005	0.01846	0.01376	0.02701	0.02401
		Actual	0.01661	0.00948	0.02013	-	-	-
		Backlog	0.00369	0.00057	(0.00167)	-	-	-
Distribution	Growth	Forecasted	0.00577	0.00548	0.00616	0.00864	0.00389	0.00486
		Actual	0.00810	0.00861	0.00910	-	-	-
		Backlog	(0.00233)	(0.00314)	(0.00294)	-	-	-
Telecom, SCADA, Protection & Control	Growth	Forecasted	0.00022	0.00117	0.00112	0.00040	0.00043	0.00045
		Actual	0.00001	0.00001	0.00005	-	-	-
		Backlog	0.00021	0.00116	0.00107	-	-	-
Transmission	Sustaining	Forecasted	0.00536	0.00428	0.00243	0.00338	0.00375	0.00394
		Actual	0.00301	0.00528	0.00226	-	-	-
		Backlog	0.00235	(0.00100)	0.00016	-	-	-
Generation	Sustaining	Forecasted	0.00598	0.00517	0.00702	0.00595	0.00702	0.00711
		Actual	0.00466	0.00448	0.00662	-	-	-
		Backlog	0.00132	0.00070	0.00041	-	-	-
Distribution	Sustaining	Forecasted	0.00285	0.00298	0.00260	0.00311	0.00514	0.00577
		Actual	0.00295	0.00404	0.00338	-	-	-
		Backlog	(0.00009)	(0.00106)	(0.00078)	-	-	-
Telecom, SCADA, Protection & Control	Sustaining	Forecasted	0.00057	0.00038	0.00054	0.00006	0.00028	0.00023
		Actual	0.00030	0.00043	0.00040	-	-	-
		Backlog	0.00028	(0.00004)	0.00013	-	-	-
Demand Side Management		Forecasted	0.00040	0.00049	0.00054	0.00053	0.00080	0.00085
		Actual	0.00054	0.00050	0.00053	-	-	-
		Backlog	(0.00014)	(0.00001)	0.00001	-	-	-
General Plant		Forecasted	0.00203	0.00484	0.00502	0.00375	0.00889	0.00984
		Actual	0.00250	0.00347	0.00466	-	-	-
		Backlog	(0.00047)	0.00137	0.00036	-	-	-
Total Forecasted (exc. DSM)			0.04308	0.03435	0.04334	0.03957	0.05720	0.05707
Total Actual (exc. DSM)			0.03814	0.03580	0.04661	-	-	-
Total Backlog (exc. DSM)			0.00494	(0.00145)	(0.00327)	-	-	-
Total Forecasted (inc. DSM)			0.04349	0.03484	0.04388	0.04010	0.05801	0.05792
Total Actual (inc. DSM)			0.03868	0.03630	0.04713	-	-	-
Total Backlog (inc. DSM)			0.00481	(0.00146)	(0.00326)	-	-	-

* (N) Normalized

Source:	2005	2006	2007	2008	2009	2010
	$'s 2005 Period Annual Report, Gwh Normalized	$'s 2006 Period Annual Report, Gwh Normalized	$'s 2007 Period Annual Report, Gwh Normalized	$'s CEP 2007/2008, Gwh Pre-final Revenue Requirements	$'s CEP 2009/2010, Gwh Pre-final Revenue Requirements	$'s CEP 2009/2010, Gwh Pre-final Revenue Requirements

Table A148.3c
Key Parameters

		2005	2006	2007	F2008	F2009	F2010
Number of New Connections (000's)	Forecasted	-	-	-	4,195	4,365	4,176
	Actual	3,970	3,999	3,766	-	-	-
Number of FTE's	Forecasted	-	-	-	-	-	-
	Actual	495.7	496.3	524.2	571.1	-	-
Escalation/Inflation (%)	Forecasted	N/A	N/A	2.0%	-	-	-
	Actual	2.0%	1.7%	1.8%	-	-	-
Average Growth in Demand (MW)	Forecasted	712	706	711	-	-	-
	Actual	708	718	683	-	-	-
Energy Supplied or Delivered to Customers (GWh)	Forecasted	2,999	3,031	3,077	-	-	-
	Actual	2,969	3,040	3,090	-	-	-
Cost of Capital (%)	Forecasted	7.69%	7.60%	7.44%	-	-	-
	Actual	7.91%	7.91%	7.53%	-	-	-
Cost of Energy ($/kWh)	Forecasted (Decision)	0.06	0.06	0.06	-	-	-
	Actual	0.06	0.06	0.06	-	-	-
SAIDI	Forecasted	2.50	2.61	2.37	-	-	-
	Actual	2.09	2.93	2.38	-	-	-
SAIFI	Forecasted	2.09	4.18	2.41	-	-	-
	Actual	3.07	2.48	2.95	-	-	-
Rate Impacts	Forecasted	3.4%	5.9%	2.1%	3.4%	-	-
	Actual	3.4%	5.9%	2.1%	3.4%	-	-

Q149.0 Reference: Capital Expenditures;
Exhibit B-2, Application, pp. 1-131
Growth & Sustaining $/year
Generators

Q149.1 Explain the Canal Flat Agreement, the FortisBC Entitlement Adjustment Agreement, the impact of minimum level of flow required as a condition of the water license for the Kootnay Canal Plant, the number of generating units at each plant that are required to efficiently process this level of flow and the interaction with the Power Purchase Agreement with BC Hydro.

A149.1 The Canal Plant Agreement is an agreement between the FortisBC, BC Hydro and other generating entities that provides for the coordination and integrated operation of the parties' Kootenay River generating plants in order to obtain optimum output.

This is done through the management by BC Hydro of the storage in Kootenay Lake and the flow of water on the Kootenay River through BC Hydro's Kootenay Canal Plant and the other generating plants. In return, the Company receives a monthly energy and capacity entitlement as long as the generating units are available to be dispatched (FortisBC continues to own the water rights on the Kootenay River).

The Canal Plant Entitlement Adjustment Agreement defines the additional entitlement that FortisBC receives for generator upgrades, including certain design principles to be applied during an upgrade.

Following the Entitlement Adjustment Agreement, upgrades are designed to generate the maximum amount of power from the actual expected flows in the

Kootenay River, with the Company receiving the entitlement increase as per the as built design.

The BC Hydro Kootenay Canal Plant water license includes a requirement that the minimum allowable flow in the Kootenay River is 5,000 cubic feet per second (cfs). BC Hydro is free to divert the balance of the flow through the Kootenay Canal Plant if they so choose to do so under the Canal Plant Agreement.

The Canal Plant Agreement Operating Procedure No. 2 contains unit dispatch tables for various Kootenay River flows. At 5,000 cfs the following units are required to run:

- Lower Bonnington: Unit 1, 3
- Upper Bonnington: Unit 6, City of Nelson generation
- South Slocan: Unit 1, 3
- Corra Linn: Unit 1, 2

The Power Purchase Agreement with BC Hydro has no operational links to the Canal Plant Agreement.

Q149.2 Describe the age and conditions of these units.

A149.2 Please see Table A149.2 below.

Table A149.2

Unit	Year Built	Age	Year Upgraded	Condition
Lower Bonnington Unit 1	1924	84	2006	Completed Water to Wire Refurbishment
Lower Bonnington Unit 2	1924	84	1998	Completed Water to Wire Refurbishment
Lower Bonnington Unit 3	1924	84	2007	Completed Water to Wire Refurbishment
Upper Bonnington Unit 1	1907	101	-	Original Equipment
Upper Bonnington Unit 2	1916	92	-	Original Equipment
Upper Bonnington Unit 3	1916	92	-	Original Equipment
Upper Bonnington Unit 4	1907	101	-	Original Equipment
Upper Bonnington Unit 5	1940	68	2003	Completed Water to Wire Refurbishment
Upper Bonnington Unit 6	1940	68	2004	Completed Water to Wire Refurbishment
South Slocan Unit 1	1928	80	-	Original Equipment
South Slocan Unit 2	1928	80	2000	Completed Water to Wire Refurbishment
South Slocan Unit 3	1928	80	-	Original Equipment
Corra Linn Unit 1	1932	76	-	Original Equipment
Corra Linn Unit 2	1932	76	-	Original Equipment
Corra Linn Unit 3	1932	76	1999	Completed Water to Wire Refurbishment
Note: "Water to Wire Refurbishment" includes the following activities as well as other related work: New Step-up Transformer, Generator Rewind, Turbine Replacement or Refurbishment and Control Protection Upgrade.				

Q149.3 Explain the reduced maintenance costs for FortisBC in regards to the Canal Flat Agreement.

A149.3 As per section 2.7 of the FortisBC Entitlement Adjustment Agreement, if maintenance outages are planned with 30 days notice, the capacity loss remains the same, however, the energy loss is based on the actual flow regime rather than the natural flows that existed pre-Canal Plant. In general these energy costs go to zero for the non-freshet months.

Q149.4 Explain the need to repair the generators in regards to the Canal Flat Agreement with BC Hydro.

A149.4 The Canal Plant Agreement states that FortisBC will receive fixed energy and capacity entitlement as long as the generating units are available to be dispatched. If a generating unit is incapable for any reason, this entitlement is forfeited. Therefore the repair of this equipment is required to avoid unplanned outages and maintain this entitlement.

Q149.5 Explain the need repair the generators and provide the annual output of each generator in MWh.

A149.5 Please see Table A149.5 below. Refer also to the response to Q149.4 above.

Table A149.5
2007 Annual Generator Output

Unit	Output
Lower Bonnington	**(MWh)**
Unit 1	107,464.70
Unit 2	93,857.00
Unit 3	62,484.60
Upper Bonnington	
Unit 1	9,912.70
Unit 2	10,620.80
Unit 3	10,642.10
Unit 4	8,939.30
Unit 5	104,031.50
Unit 6	97,879.60
South Slocan	
Unit 1	107,325.50
Unit 2	71,617.60
Unit 3	86,607.50
Corra Linn	
Unit 1	61,282.20
Unit 2	109,803.40
Unit 3	51,644.30
Note: Based on actual output not entitlement values	

Q149.6 Provide the annual generator capacity factor by unit and dam.

A149.6 Please see Table A149.6 below.

Table A149.6
2007 Annual Generator Capacity Factors

Unit	**Capacity Factor**
Lower Bonnington	**(%)**
Unit 1	68.2%
Unit 2	59.5%
Unit 3	39.6%
Plant Total	**55.8%**
Upper Bonnington	
Unit 1	18.9%
Unit 2	21.7%
Unit 3	21.7%
Unit 4	17.0%
Unit 5	52.8%
Unit 6	49.7%
Plant Total	**30.3%**
South Slocan	
Unit 1	77.8%
Unit 2	37.8%
Unit 3	62.8%
Plant Total	**59.5%**
Corra Linn	
Unit 1	51.8%
Unit 2	92.8%
Unit 3	32.8%
Plant Total	**59.1%**

Q149.7 Will the upgrades to the generators result in an increase in energy capacity produced and would there be a benefit to FortisBC? Explain the benefit.

A149.7 Yes the upgrades would result in an increase in energy capacity. There would be an entitlement increase for this increased capacity in accordance with section 2.4 of the Canal Plant Agreement/FortisBC Entitlement Adjustment Agreement.

Q149.8 Provide and explain the impact of the limit of the Water License as compared to the capacity of the turbine units in cubic feet per second by dam.

A149.8 The water licenses are granted on a plant basis. The water license for FortisBC plants are as follows:

- Lower Bonnington: 10,400 cfs
- Upper Bonnington: 12,800 cfs
- South Slocan: 10,800 cfs
- Corra Linn: 12,600 cfs

The maximum turbine capacity is as follows:

- Lower Bonnington: 11,372 cfs
- Upper Bonnington: 13,926 cfs
- South Slocan: 11,425 cfs
- Corra Linn: 12,681 cfs

If the turbine capability of the plant equals or exceeds the water license then an increase in water license will potentially generate additional power. If the turbine capability of the plant is lower than the water license, then an upgrade to make use of the full water license is possible.

Q149.9 Does the installed capacity at the four Kootenay River dam sites exceed the Expected Actual Streamflows and if so for how many months of the year?

A149.9 The excess capacity of the Kootenay River Plants is not relevant in light of the Canal Plant Agreement as discussed in response to Q149.1 above. Any incremental water license FortisBC obtains on the Kootenay River will be secondary to the BC Hydro Kootenay Canal Plant license. As a result, the increased generation could only be expected for a few weeks a year during the spring freshet, when generated energy is typically plentiful.

Q149.10 Provide the cost of purchased power required to defer the repair of the generators for F2009/F2010.

A149.10 The FortisBC Entitlement Adjustment Agreement provides for the energy loss from planned outages to reflect actual average generation losses rather than the normal entitlement energy losses as calculated as part of the Canal Plant Agreement outage methodology. This results in both the 2009 South Slocan Unit 1 and the 2010 Corra Linn Unit 1 upgrades being completed with no energy loss due to the timing of the outages. Capacity costs are incurred by the projects in November and a portion of December at a current estimated cost of approximately $0.1 million. These costs are relatively constant independent of year providing the same outage window (August to early December) is maintained.

Q149.11 Provide the value of generated power assuming the generators were operational for F2009/F2010.

A149.11 Please see the response to Q149.10 above.

Q149.12 Provide the repair cost plus the operating and maintenance cost of the generators for F2009/F2010.

A149.12 The operating and maintenance budgets for the Generating Stations in 2008 were as follows (2009/2010 is yet to be developed):

- Lower Bonnington: $305,000
- Upper Bonnington: $420,000
- South Slocan: $371,000
- Corra Linn: $339,000

Q150.0 Reference: Capital Expenditure Plan ("CAPEX") Plan;
Exhibit B-2, Table1.1, p. 6
Ratio to O&M

Q150.1 Provide pie charts showing CAPEX, O&M and Other percentage cost for the years 2005 through 2010. State the Total Revenue Requirement on the chart.

A150.1 Please find pie charts for the years 2005 – 2008 illustrating the ratio of approved revenue requirements components and total approved revenue requirements. The Company is unable to supply forecast 2009 – 2013 revenue requirements broken down in this detail at this time.

Figure 150.1a ($000s)

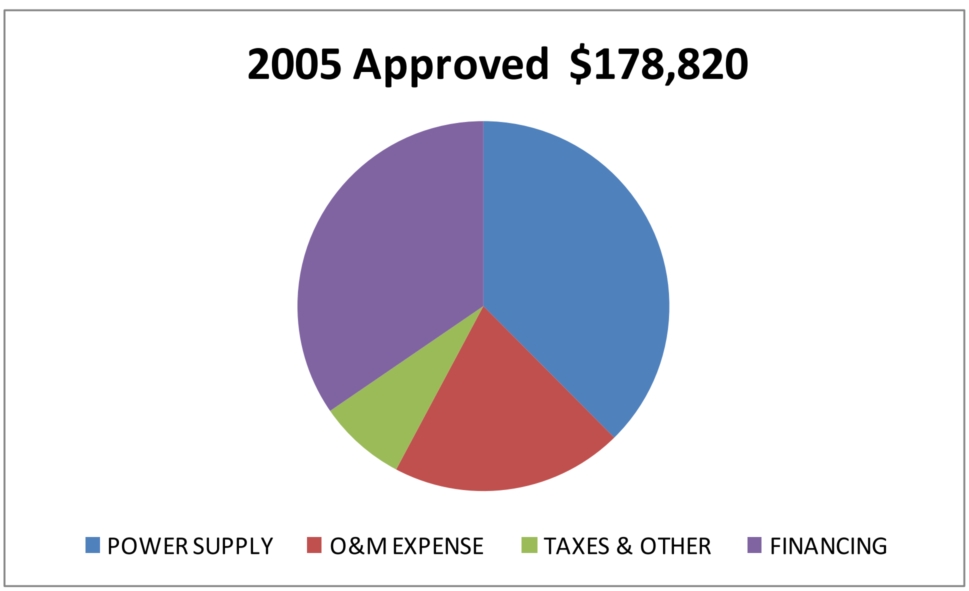


Figure 150.1b ($000s)

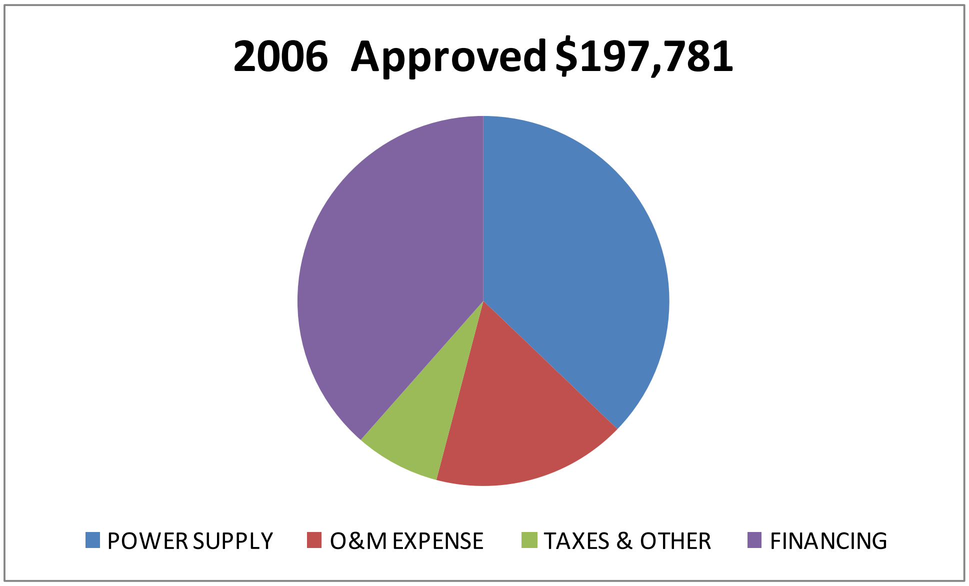


Figure 150.1c ($000s)

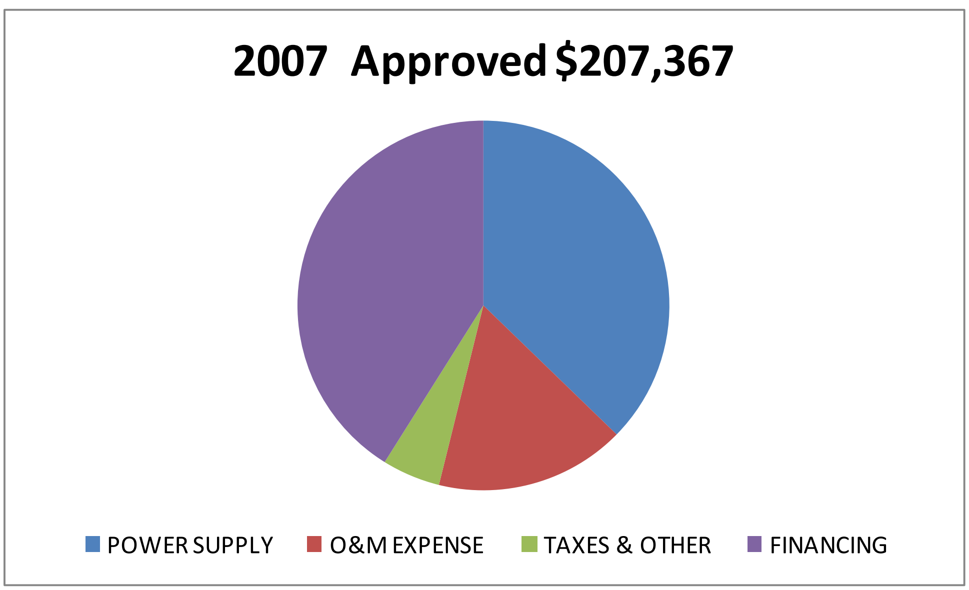
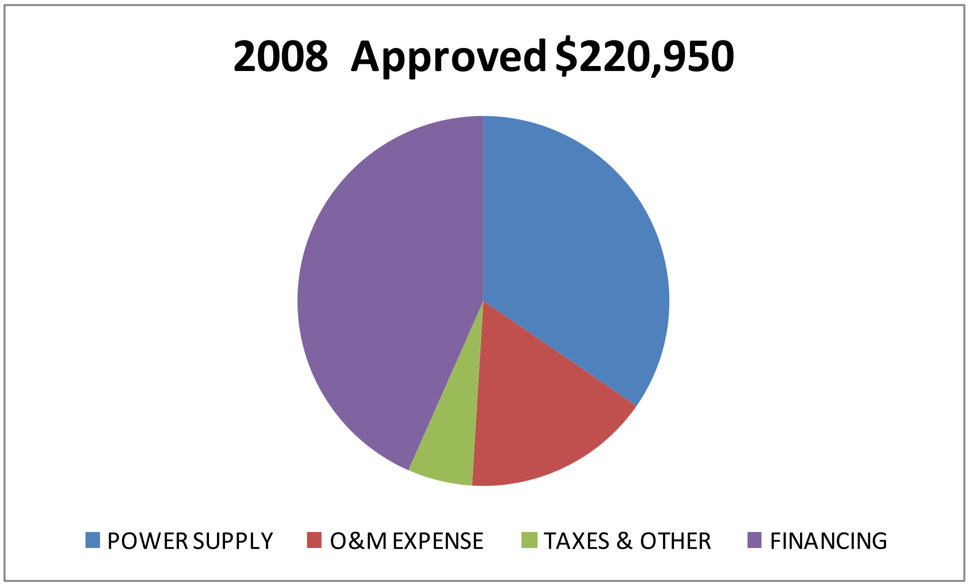


Figure 150.1d ($000s)



Q151.0 Reference: Generic Rate Impact;
Exhibit B-2, Table A1.3, pp. 11-14
Magnitude of Rate Impact

Q151.1 As the total Generic Rate Impact in Table A1.3 is about 16%, would FortisBC please identify the projects that are solely necessary to proceed to maintain system reliability and system safety only.

A151.1 The 2009/10 Capital Plan projects are intended to maintain a secure, safe and properly functioning electric utility system. Although some of the projects contained in the Capital Plan do not serve to "keep the lights on" they provide support for, or create the conditions conducive to the continued viable operation of the system. As such, all are necessary to ensure FortisBC's ability to provide service, public and employee safety and reliability of supply to the Company's growing customer base. Where an individual project may be foregone or deferred in the interest of rate mitigation, there exists a risk that the system or the safety of Company employees or customers may be compromised at some point in the future. FortisBC believes that the approval of the capital projects as presented is the most prudent approach that will not introduce these potential pitfalls. As an example, although the Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade in isolation may not contribute to system reliability or safety, the accuracy of metering is a basic requirement for a utility system and in the opinion of the Company should be maintained. It should also be noted that during the development of the 2009/10 Capital Plan, the Company reduced the number of included Projects through an internal review process several times to arrive at the version submitted for approval. The remaining projects 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. A discussion of projects that the Company has identified as potential deferral candidates can be found in the response to BCUC IR No. 2 Q151.7 below. For rankings with respect to reliability and safety please see BCUC Appendix A148.1.

Q151.2 As the total Generic Rate Impact in Table A1.3 is about 16%, would FortisBC please identify the projects that they wish to defer that will not compromise system reliability and system safety only.

A151.2 FortisBC considers that all the projects are necessary to ensure FortisBC's ability to provide service, public and employee safety and reliability of supply to the Company's growing customer base and as such have not identified any projects that the Company wishes to defer.

Q151.3 As the total Generic Rate Impact in Table A1.3 is about 16%, would FortisBC please identify the projects that they wish to abandon at this time that will not compromise system reliability and system safety only.

A151.3 FortisBC considers that all the projects are necessary to ensure FortisBC's ability to provide service, public and employee safety and reliability of supply to the Company's growing customer base and as such have not identified any projects that the Company wishes to abandon.

Q151.4 As the total Generic Rate Impact in Table A1.3 is about 16%, would FortisBC please comment on the possibility of removal of the following from the 2009-2010 Capital Expenditure Plan:

Q151.4.1 Beaver Park Feeder-2 to Fruitvale Feeder-1 Distribution Tie Upgrade (CCR CPCN?)

A151.4.1 Removal of this project from the 2009/10 Capital Plan would limit the distribution system capability for supporting the Fruitvale area customers in the event of a transformer failure. The existing Fruitvale transformer is nearing nameplate capacity during peak periods and a transformer failure would result in an extended outage to a large portion of the customers served until a mobile transformer could be placed into service.

Q151.4.2 Christina Lake Feeder-1 Capacity Upgrade (CCR CPCN?)

A151.4.2 Removal of this project from the 2009/10 Capital Plan would mean that during peak periods of the year customers on the Christina Lake Feeder 1 would experience unacceptable voltage levels.

Q151.4.3 Construction Projects Requirements

A151.4.3 The dollars budgeted are required to facilitate material yard set ups (fencing, covered storage, paved pads for off-loading) and any temporary office requirements resulting from increased material handling and warehousing associated with Capital Projects. Removal would result in increased transportation costs and possible increased material loss through vandalism and theft.

Q151.4.4 Facility Upgrades

A151.4.4 The dollars budgeted are for projects identified and prioritized as having impact on employee and public safety issues, FortisBC emergency response plan, replacement of aging infrastructure, accommodate changes in work processes resulting in increased efficiencies. Removal would result in possible safety issues and foregone efficiency gains.

Q151.4.5 Furniture & Fixtures

A151.4.5 The dollars budgeted are required for replacement of existing furniture and additional new furniture. These needs have been identified and prioritized based on impact on employee health and safety, additional staff requirements, age and use of existing furniture & fixtures. Removal could result in an increased negative impact on employee health and safety.

Q151.4.6 Desktop Infrastructure Upgrades

A151.4.6 As identified by the response to Q107.2 above, the removal of this upgrade project presents a risk to supportability, reliability and ultimately productivity. FortisBC makes every effort to balance expenditures with productivity using minimum standards.

Q151.4.7 Harmonic Remediation

A151.4.7 This is an ongoing program-type project (since the 2005 SDP) that covers unforeseen expenditures related to identifying and analyzing power system harmonics issues. If removed from the Plan it could potentially cause harmonic issues to go unresolved for a longer period of time until they were found and resolved through some other project. This could result in unnecessary damage to both customer and utility equipment.

Q151.4.8 Joe Rich Breaker Addition

A151.4.8 The project resolves the non-standard installation of HV fuses on the Joe Rich transformer. These fuses do not coordinate with the incoming 57 Line protection and provide less than optimal protection for the Joe Rich transformer. Removal of this project from the Plan will increase the potential damage to the Joe Rich Transformer 1 for fault at Joe Rich and decrease the reliability of the Big White Substation supply (refer also to the responses to BCUC IR No. 1 Q56.1 through Q56.4).

Q151.4.9 Corra Linn Spillway Gate Isolation Study

A151.4.9 This project must be completed in order to meet Canadian Dam Association Dam Safety Guidelines. Failure to carry out this project will put FortisBC in violation of these regulations.

Q151.4.10 All Plants Lighting Upgrade

A151.4.10 The current plant lighting is inadequate for general plant and emergency lighting based on industry standards. Failure to correct this situation could contribute to worker safety and result in a WorkSafeBC violation.

Q151.5 As the total Generic Rate Impact in Table A1.3 is about 16%, would FortisBC please comment on the possibility of deferral of the following from the 2009-2010 Capital Expenditure Plan:

Q151.5.1 Protection Upgrades

A151.5.1 This is an ongoing program since the 1998 Capital Plan. Virtually all electromechanical relays have been retired from the FortisBC system. The only remaining relays to be addressed are transformer differential relays at a number of distribution substations. These devices can fail “silently”, have no spare parts and are not routinely tested. Failure of these devices can place a much more valuable asset (a substation transformer) at risk of failure. Deferral of this program will extend the period of time that this equipment is at risk.

Q151.5.2 Creston Substation Transformer T1&T2 Circuit Switchers

A151.5.2 The Creston substation has already experienced complete outages due to a fault on the secondary of one of the station transformers. Installation of independent protection for each transformer would prevent a complete station outage from occurring from a fault in only one of the transformers (or downstream equipment). As well, the station high voltage bus arrangement is inflexible and requires unnecessary outage to complete station maintenance. Deferral of this project will decrease the overall reliability of the substation. Please also see the responses to Q141.1 and Q141.2 above.

Q151.5.3 Joe Rich Breaker Addition

A151.5.3 Refer also to the response to Q151.4.8 above. Deferral of this project would potentially decrease supply reliability for the Big White Substation and continue to place the Joe Rich transformer at risk of damage for a longer period of time.

Q151.5.4 Pine Street Replacement of Distribution Breakers (F-1, F-2, F-3 Breaker Replacement & Protection upgrade)

A151.5.4 As described in the response to Q143.1 above, these breakers use obsolete arc-chute interrupters. The installation is 1960s vintage and spare parts are no longer available. By replacing the Pine Street breakers with vacuum units the existing breakers can be salvaged for spare parts until the other units are replaced in the next Capital Plan. Deferral of this project will extend the period during which a breaker may fail violently or a breaker failure may occur with no practical way to repair it.

Q151.5.5 Slocan City – Valhalla

A151.5.5 The aging Slocan City Transformer is located on the flood-plain of Springer Creek which feeds into Slocan Lake. Deferral of this project would extend the period of time that potential environmental issues caused by a major transformer leak at this location are unmitigated. There is no remote monitoring of this substation and thus a transformer leak could persist for an extended period of time until detected during a routine month-end check.

Q151.5.6 Kootenay 12 MVA Mobile Breaker Replacement

A151.5.6 Deferral of this project would extend the period of time that potential environmental and condition issues posed by the mobile substation oil circuit breaker are unmitigated. Due to its use for many years in a mobile application, this breaker is in poor condition and requires replacement. Since mobile substations are critical units that provide backup for the failure of other substations, failure of the mobile breaker could result in an extended customer outage with no other supply source readily available.

Q151.5.7 Replace Gap-Type Silicon Carbide Arrestors

A151.5.7 This is a new ongoing program to address the safety issues posed by the uncontained failure of this type of surge arrestor. It should be noted that BCTC already has a similar program underway to replace these devices. The FortisBC program is already staged out over a number of years to reduce the rate impact. Removal of this project would leave identified safety issues unmitigated.

Q151.5.8 Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade

A151.5.8 This project is required to ensure the revenue metering capability is maintained at all plants. Current equipment is aging and no longer supported by the original manufacturer. Removal of this project would result in incorrect metering which can result in incorrect power purchase decisions.

Q151.5.9 Queen's Bay Level Gauge Building Ph. 1

A151.5.9 This project is required in order to maintain employee and public safety and to meet BC Building and Canadian Electrical Codes. Failure to complete this project will put FortisBC in violation of these codes.

Q151.5.10 All Plants Spare Exciter Transformer

A151.5.10 The requirements for this spare are identical to that of the Spare Unit Transformer. Currently there are seven units that utilize this type of transformer. Having a spare on site is meant to mitigate the consequences of a failure. As outlined on page 32 of the 2009/10 Capital Plan (Exhibit B-1), the outage costs could range from $1.5 - $2.5 million depending on the extent of damage. Removal of this project would increase this risk of increased future costs.

Q151.5.11 All Plants Spare Unit Transformer

A151.5.11 The deferral of this project would result in FortisBC continuing to bear the risk of a transformer failure and the resulting outage costs as outlined in the response to Q117.5 above.

Q151.5.12 Lower Bonnington & Upper Bonnington Comm. Network Comp.

A151.5.12 Failure to complete this project would result in FortisBC continuing to run the risk of a failure of the obsolete SCADA Remote Terminal

Units which would result in increased operational costs.

Q151.5.13 SCADA Systems Enhancements

A151.5.13 This project, as well as those IT related projects that are the subject of Q151.5.14 to Q151.5.20 below have all been identified and carefully considered by FortisBC. The deferral of any of them will result in limitations in our ability to improve productivity, meet legislated requirements, improve customer service and improve data quality. With the ever increasing reliance on technology to meet goals, such as those set out in the BC Energy Plan, these projects are critical. Long term planning and decision making is based on the timely gathering of quality information from Company systems, and these projects are required to ensure that these needs are met.

Q151.5.14 Castlegar Substation Switch CAS-6 & CAS-26 Upgrade

A151.5.14 Deferral of this switch installation will extend the outage duration for Castlegar customers following a permanent fault on the normal 63 kV supply line. At that present time switching must be carried out manually to transfer the station to the alternate supply line. This switching typically extends the duration of an outage by 1 to 2 hours.

Q151.5.15 Static VAR Compensators (SVC) Kelowna

A151.5.15 Deferral of this project will continue to expose the Kelowna area to outages due to N-1-1 / N-2 contingency events (even following the completion of the OTR project). Deferral of this project beyond one year will result in the Kelowna area then becoming exposed to outages due to N-1 transmission contingencies. This violates industry standard planning criteria. As well, deferral of this installation will potentially increase system losses due to the inability for final control the var supply dispatch in the Okanagan area.

Q151.5.16 Infrastructure Upgrades

A151.5.16 Please see the response to Q151.5.13 above.

Q151.5.17 SAP Operations Systems Enhancements

A151.5.17 Please see the response to Q151.5.13 above.

Q151.5.18 Distribution Design Software

A151.5.18 Please see the response to Q151.5.13 above.

Q151.5.19 AM/FM Systems Enhancements

A151.5.19 Please see the response to Q151.5.13 above.

Q151.5.20 Customer Systems Enhancements

A151.5.20 Please see the response to Q151.5.13 above.

Q151.5.21 Advanced Metering Infrastructure

A151.5.21 This project has been the subject of a CPCN Application and written public hearing and is awaiting a Commission decision.

Q151.5.22 Aesthetic & Environmental Upgrades

A151.5.22 The annual budget for this item is $100,000 per year. There is little risk in deferring this item

Q151.6 As the total Generic Rate Impact in Table A1.3 is about 16%, would FortisBC please comment on the possibility of continuing of the following without an increase from the prior years average in the 2009-2010 Capital Expenditure Plan:

Q151.6.1 Distribution Right-of-Way Reclamation

A151.6.1 Expenditures for this budget category are based on a three year historical average. Increases in the budget are requested to cover anticipated inflation and material and labor price escalations from 2008 to 2010. If no increase in budget were to be approved, FortisBC would continue on the program with a reduced scope. This could result in larger expenditures in future years.

Q151.6.2 Distribution Line Rehabilitation (Hot Tap Replacement)

A151.6.2 The Company has experienced a number of failures of Hot Tap Connectors, resulting in conductors falling to the ground and causing employee and public safety concerns. Failure to increase expenditures to remove Hot Tap Connectors will continue the risk of exposing the public and employees to these safety concerns.

Q151.6.3 Small Planned Capital (F2008)

A151.6.3 Expenditures for this budget category are based on a three year historical average. Increases in the budget are requested to cover anticipated inflation and material and labor price escalations from 2008 to 2010. If no increase in budget were to be approved, FortisBC would continue on the program with a reduced scope. This will result in larger expenditures in future years.

Q151.6.4 2008 FortisBC Forced Upgrades (F2008)

A151.6.4 Forced upgrades are based on a three year historical average, but are highly dependent on the type of construction activity present in the service territory in a given year. Large capital expenditures by municipalities and MOTI (primarily on road widening and realignment projects) result in higher activity in this category. It is difficult to predict actual spending patterns as a result of this dependence on third party construction activity.

Q151.6.5 Demand Side Management (F2008)

A151.6.5 The 2007 Energy Plan and the 2008 Utilities Act amendments, both of which push DSM to the forefront, indicate that the Company must scale up its existing DSM initiative in response.

The Company has undertaken a number of contractual obligations such as Destination Conservation, LiveSmart BC and Public Sector Energy Conservation Agreement (PSECA) which include (co)funding obligations. The 2009/10 DSM budgets also contain funding for a number of pilot projects, such as Cool Shops and low-income residential housing retrofits, both of which operate in traditionally under-served market segments. Finally the 2009/10 DSM uplift includes funding for staffing necessary to deliver and properly manage the Company's DSM program offerings, new and existing.

Continuing with the status quo budget in light of increased expectations, from government and customers is not desirable.

Q151.6.6 Vehicles ($2M)

A151.6.6 There is no material increase to Fleet average capital expenditures relative to the prior years.

Q151.6.7 PCB Testing Program – Distribution (F2008 or $700,000/yr)

A151.6.7 FortisBC is in the final two years of its program to test transformers in its service territory for PCBs. Reductions in this budget category would extend the time required to complete this program.

Q151.6.8 Distribution Urgent Repairs (F2008)

A151.6.8 Expenditures in this category are based on a three year historical average. Items completed under this budget category are urgent in nature and therefore unplanned.

Q151.6.9 Small Planned Capital

A151.6.9 Please refer to the response to Q151.6.3 above.

Q151.6.10 Distribution Line Condition Assessment

A151.6.10 Expenditures for this budget category are based on a three year historical average. Increases in the budget are requested to cover anticipated inflation and material and labor price escalations from 2008 to 2010. If no increase in budget were to be approved, FortisBC would continue on the program with a reduced scope. This would result in a reduced frequency of pole testing and treatment, which could result in higher capital costs in future years.

Q151.6.11 Distribution Line Rehabilitation

A151.6.11 A reduction in the budget for Distribution Line Rehabilitation will result in less corrective maintenance work. This could ultimately result in higher capital costs and reduce reliability if existing issues on the lines are not dealt with in a timely fashion.

Q151.6.12 Distribution Right-of-Way Reclamation (F2008)

A151.6.12 Expenditures for this budget category are based on a three year historical average. Increases in the budget are requested to cover anticipated inflation and material and labor price escalations from 2008 to 2010. If no increase in budget were to be approved, FortisBC would continue on the program with a reduced scope. This could result in larger expenditures in future years.

Q151.6.13 Transmission Line Rehabilitation

A151.6.13 A reduction in the budget for Transmission Line Rehabilitation will result in less corrective maintenance work. This could ultimately result in higher capital costs and reduce reliability if existing issues on the lines are not dealt with in a timely fashion.

Q151.6.14 Transmission Line Condition Assessment (F2006)

A151.6.14 Expenditures for this budget category are based on a three year historical average. Increases in the budget are requested to cover anticipated inflation and material and labor price escalations from 2008 to 2010. If no increase in budget were to be approved, FortisBC would continue on the program with a reduced scope. This would result in a reduced frequency of inspection, which could result in higher capital costs in future years.

Q151.7 Would FortisBC please submit revised tables to reflect their comments on the above?

A151.7 FortisBC believes, for the reasons stated in the responses to Q151.1 - Q151.6 above, that the 2009/10 Capital Plan should be approved as proposed.

However, the Company has considered the possible deferral of two projects.

The first is the Static var Compensators (SVC) Kelowna (see Q101.5 above and Q151.5.15 below). FortisBC believes that double contingency reliability is the appropriate planning criteria for evaluation of this project, however the exposure to N-2 events is, subject to actual load growth, limited in the near term and for that reason is prepared to defer the initial $400,000 expenditure planned for 2010. The timing of the SVC Project will be determined as part of FortisBC's next System Development Plan.

The second is the Aesthetic and Environmental Upgrade Program (see Q151.5.22) at a cost of $100,000 annually. The program has had limited uptake, and in this instance, FortisBC proposes to remove the estimate from the Capital Plan, but does not believe that the program should be cancelled and therefore requests that actual expenditures under the program to the level of $100,000 annually be approved for inclusion in rate base.

Tables A151.7a through A151.7d corresponding to Tables 1.1 and 1.4, 3.1 and 3.4 of the Application (Exhibit B-1) show the potential modified 2009/10 Capital Plan based on these changes. The reduced values are highlighted for identification.

Table A151.7a

		2009 Expenditures	2010 Expenditures	Future Expenditures
		($millions)		
1	Generation	21.9	22.6	24.7
2	Transmission and Stations	96.1	88.3	3.0
3	Distribution	28.1	33.7	
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**	**178.7**	**180.6**	**29.3**
8	Annual Operating Savings	0.2	0.72	

(Reference: Table 1.1 Exhibit B-1)

Table A151.7b

		2009 Expenditures	2010 Expenditures	Total
		($millions)		
1	Previously Approved	30.9	18.0	48.9
2	CPCN Submitted	81.8	78.1	159.9
3	CPCN to be Submitted	7.7	20.1	27.9
4	**Subtotal**	**120.4**	**116.3**	**236.7**
5	Remainder	58.3	64.3	122.6
6	**Total**	**178.7**	**180.6**	**359.3**

(Reference: Table 1.4 Exhibit B-1)

Table A151.7c
Transmissions 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					-		-
14	**SUBTOTAL GROWTH**			**56,061**	**84,396**	**75,778**	**3,000**	**219,235**

Table A157.1c cont'd

		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**	**88,275**	**3,000**	**243,459**

(Reference: Table 3.1 Exhibit B-1)

Table A151.7d
Distribution Projects Expenditure

		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	-	-
25	Copper Conductor Replacement Program	CPCN to be filed	4,798	6,586
26	**TOTAL SUSTAINING**		**15,949**	**18,217**
27	**TOTAL**		**28,107**	**33,650**

(Reference: Table 4.1 Exhibit B-1)

Q152.0 Reference: Copper Conductor Replacement;
Exhibit B-1, Application, p. 83
Christina Lake Feeder 1 Capacity Upgrade

BCTC states "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".

Q152.1 Provide an explanation as to whether or not this is included in the CCR CPCN and if not why not?

A152.1 The scope of the Christina Lake Feeder 1 Capacity Upgrade is not included in the CCR CPCN Application. The scope of the Capacity Upgrade Project is related to the unacceptable voltage levels on the feeder during peak periods of the year.

Q153.0 Reference: Copper Conductor Replacement;
Exhibit B-1, Application, p. 83
Beaver Park Feeder 1 - Fruitvale Feeder 2 Tie Upgrade

BCTC states "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".

Q153.1 Provide an explanation as to whether or not this is included in the CCR CPCN and if not why not?

A153.1 This is not included in the CCR CPCN Application. The Beaver Park to Fruitvale feeder tie upgrade is required due to the load growth in the Beaver Park and Fruitvale areas and to defer a substation upgrade project.

Q154.0 Reference: Distribution Line Rehabilitation;
Exhibit B-1, Application, p. 90
Hot Tap Connector Replacement

Q154.1 Provide the total number of Hot Tap connectors to be replaced.

A154.1 The Company estimates that there are approximately 44,000 Hot Tap Connectors that need to be replaced.

Q154.2 Would FortisBC consider a reduction in expenditures going forward?

A154.2 FortisBC's considers the 2009/10 Capital Plan to be reasonable taking into account the safety and reliability issues associated with in service deteriorated plant.

Q154.3 Complete the following rows in the table provided.

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	569	1,961	1,231	2,582	3,124	3,470
No. of Hot Tap Connectors - Replaced						
Average Unit Cost/Connector Replaced						
Cost of Outage and Repair of Existing						

A154.3 Please see Table A154.3 below.

Table A154.3

	2005	2006	2007	2008F	2009	2010
Cost ($000s)	569	1,961	1,231	2,582	3,124	3,470
No. of Hot Tap Connectors - Replaced	(1)	(1)	(1)	(1)	3,200	3,200
Average Unit Cost/Connector Replaced	(1)	(1)	(1)	(1)	$235	$240
Cost of Outage and Repair of Existing (2)				$850		

(1) The Company has not tracked the number of Hot Tap Connectors that it has replaced or the cost per unit.

(2) As outlined in response to Copper Conductor Replacement Project BCUC IR No. 1 Q1.1, the estimated cost to undertake a simple emergency repair is approximately $850.

Q155.0 Reference: Distribution Line Rehabilitation;
Exhibit B-1, Application, p. 90
Rights-of-Way Vegetation Management Plan

Q155.1 As this is maintaining an existing right of way, the Distribution Line Rehabilitation is an expense and should not be in a capital expenditure plan. Provide an explanation as to why this cost is in the capital expenditure plan and not an expense item in the Operation and Maintenance budget.

A155.1 FortisBC is unsure if the question refers to the Distribution Line Rehabilitation work or to the Distribution Right-of-Way Reclamation. With respect to Distribution Line Rehabilitation work, the Company charges the cost of the replacement or plant units to the appropriate plant account as provided for in the BCUC Uniform System of Accounts Prescribed for Electric Utilities. With respect to rights-of-way, the Company capitalizes the initial cost of establishing rights- of-way and expenses the maintenance thereafter. In this case, the Company is increasing the tree-free zone around the distribution system, effectively establishing a new right-of-way.

Q156.0 Reference: Distribution Rights of Way Reclamation;
Exhibit B-1, Application, p. 90
Rights-of-Way Vegetation Management Plan

Q156.1 As this is maintaining an existing right of way, the Distribution Rights of Way Reclamation is an expense and should not be in a capital expenditure plan. Provide an explanation as to why this cost is in the capital expenditure plan and not an expense item in the Operation and Maintenance budget.

A156.1 FortisBC capitalizes the costs associated with establishing or re-establishing a right-of-way and expenses the cost of trimming and brushing in order to maintain rights-of-way. The Distribution Line Rehabilitation Project completely removes trees from the right-of-way. There is a long term benefit of these tree removals and therefore these costs have always been treated as capital and have previously been approved by the Commission as such.

Q157.0 Reference: Rights of Way Reclamation – Pine Beetle Kill Hazard Trees; Exhibit B-1, Application, p. 90 Rights-of-Way Vegetation Management Plan

Q157.1 As this is maintaining an existing right of way, the Distribution Rights of Way Reclamation is an expense and should not be in a capital expenditure plan. Provide an explanation as to why this cost is in the capital expenditure plan and not an expense item in the Operation and Maintenance budget.

A157.1 FortisBC capitalizes the costs associated with establishing or re-establishing a right-of way and expenses the cost of trimming and brushing in order to maintain rights-of-way. The Pine Beetle Kill Hazard Trees Project completely removes the trees from the right-of-way. There is a long term benefit of these tree removals and therefore these costs have always been treated as capital and have previously been approved by the Commission as such.

Q158.0 Reference: PCB Program;
Exhibit B-1, Application, pp. 97-98
Costs

Q158.1 As this project is 70% complete, the funds spent to date are $3,451,000 and the estimate at completion is $4,906,000, then both the F2009 and F2010 should be about $700,000 each. Provide justification for the amount shown in the Application.

A158.1 The amounts shown in the tables are as spent dollars. When these are inflated to 2009 dollars with annual escalation rates of 5 percent the funds spent total in excess of $4.0 million. Assuming 70 percent complete, the estimated total cost would be $5.7 million. The remaining $1.7 million together with a contingency of 15 percent and 5 percent inflation in 2010 and the possibility that less than 70 percent of the work is complete, justifies the amount shown in the Application.

Q159.0 Reference: Transmission Condition Assessment;
Exhibit B-2, Table A35.2, p. 82
Costs

Q159.1 Provide tables for the F2006 and F2007 similar to Tables 3.2 (a) and 3.2 (b) in the Application.

A159.1 Please see Table A159.1a and Table A159.1b below. The total length of each line as well as the average cost per pole is included in the table below. The cost is determined by dividing the funds expended in each year by the number of poles assessed.

Table A159.1a
2006 Transmission Condition Line Assessment Projects

	Line	Location	Poles	Length (km)	Cost per pole ($)
1	26L	Brilliant to Castlegar to Celgar	372	9.85	
2	20L	Warfield Terminal Station (W261S) to Salmo	523	46.35	
3	10BL	Tap from 10 Line to Baldy	81	6.13	
4	**Total**		**976**	**62.33**	**254.10**

Table A159.1b
2007 Transmission Condition Line Assessment Projects

	Line	Location	Poles	Length (km)	Cost per pole ($)
1	52L	RG Anderson to Huth Penticton	41	3.78	
2	53L	RG Anderson to Huth Penticton	36	3.76	
3	21L, 22L, 23L, 24L	Slocan/Brilliant/Generation river lines	285	15.22	
4	27L	South Slocan/ Nelson and Salmo	443	79.00	
5	77L	Warfield Terminal to Brilliant Terminal	196	28.20	
6	79L	Brilliant Terminal to Kootenay Canal	83	22.10	
7	**Total**		**1,084**	**152.06**	**459.00**

Q159.1.1 Add the length of line and the average cost per pole.

A159.1.1 Please refer to the response to Q159.1 above.

Q159.2 Provide updated tables for the F2009 and F2010 similar to Tables 3.2 (a) and 3.2 (b) in the Application.

A159.2 Please see Table A159.2a and Table A159.2b below. The total length of each line as well as the average cost per pole is included in the table below. The cost is determined by dividing the funds expended in each year by the number of poles assessed.

Table A159.2a
2009 Transmission Condition Line Assessment Projects

	Line	**Location**	**Poles**	**Length (km)**	**Cost per pole ($)**
1	1L	Warfield to Stoney Creek	15	1.73	
2	25L	Slocan to Playmor to Tarrys to Brilliant	299	17.20	
3	29L	Slocan Valley	140	13.50	
4	31L	Lambert to Creston	105	7.90	
5	30L	Coffee Creek to Crawford Bay	26	7.60	
6	50L	FA Lee to Sexsmith to Glenmore to Recreation to Saucier	320	15.60	
7	49L	Huth to West Bench to Trout Creek to Summerland	310	16.50	
8	**Total**		**1,215**	**80.03**	**351.44**

Table A159.2b
2010 Transmission Condition Line Assessment Projects

	Line	**Location**	**Poles**	**Length (km)**	**Cost per pole ($)**
1	41L	Huth to Waterford to Kaleden to OK Falls to Oliver	580	35.30	
2	42L	Huth to Waterford to Kaleden to OK Falls to Oliver	420	36.50	
3	45L	RG Anderson to Westminster to Naramata	290	14.60	
4	45A L	45L to downtown Penticton	48	2.13	
5	46L	FA Lee to Duck Lake	87	12.50	
6	47L	Huth to Waterford	50	3.50	
7	**Total**		**1,475**	**104.53**	**336.27**

Q159.2.1 Add the length of line and the average cost per pole.

A159.2.1 Please refer to the response to Q159.2 above.

Q160.0 Reference: DSM;

Exhibit B-1, Application, pp. 106-114

DSM Data

Q160.1 Complete the table provided below.

TABLE 4 DSM PARAMETERS

		2005	2006	2007	F2008	F2009	F2010
Total GWh delivered	Forecasted						
	Actual					-	
DSM GWh saved	Forecasted						
	Actual					-	
DSM Program Cost ($/GWh)	Forecasted						
	Actual					-	
DSM Cost per Total GWh delivered (GWh)	Forecasted						
	Actual					-	
DSM Cost per GWh saved ($/GWh)	Forecasted						
	Actual					-	
Value of the DSM Energy Saved ($/GWh)	Forecasted						
	Actual					-	

A160.1 Please see Table A160.1 below.

Table A160.1
DSM Parameters

	Year	2005	2006	2007	F2008	F2009	F2010
Total GWh delivered	Forecast	2,999	3,031	3,077	3,087	3,149	3,227
	Actual	2,969	3,040	3,090	-	-	-
DSM GWh saved	Forecast	19.0	20.4	21.8	19.5	25.3	27.5
	Actual	23.9	23.1	27.9	-	-	-
DSM Program Cost ($/GWh*)	Forecast	$78	$92	$96	$101	$120	$119
	Actual	$83	$83	$80	-	-	-
DSM Cost per Total GWh delivered ($)	Forecast	$0.60	$0.70	$0.80	$0.80	$1.20	$1.20
	Actual	$0.80	$0.70	$0.80	-	-	-
DSM Cost per GWh saved ($/GWh*)	Forecast	$97	$110	$113	$121	$145	$144
	Actual	$98	$97	$91	-	-	-
Value of the DSM Energy Saved ($/GWh*)	Forecast	$330	$315	$375	$385	$375	$382
	Actual	$298	$348	$288	-	-	-

* Note: $/GWh are nominal dollars divided by first year savings, and are not levelized costs.

Q161.0 Reference: DSM;

Exhibit B-1, Application, pp. 106-114

DSM Data

Q161.1 Complete the table provided below.

TABLE 5 DSM COST PER PROGRAM IDENTIFIED

Program			2005	2006	2007	F2008	F2009	F2010
Co-Funded Engineering Studies	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Incentives (Grant & Loans)	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Residential Financial Incentives	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
General Service Financial Incentives	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Industrial Customer Financial Incentives	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
New - Conservation Culture Communications Plan	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program	Forecasted						
		Actual					-	-

	Cost							
New – Bright Ideas Messaging.	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Residential - CFL /LED Rebate Program	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Residential – Heat Pump Program Incentive	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
New Residential – LiveSmart BC Program	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
New Residential – Solar BC Thermal Program	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
New Residential – envelope technologies	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
New General Service Program – Cool Shops	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
New General Service Program – Public Sector Energy Conservation Matching	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-

Incentives								
New General Service Program – Destination Conservation Program	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Industrial – Industrial Efficiency Program	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Industrial – New Process Design Program	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Industrial – Sustainable Energy Plan Workshops	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Conservation Culture – advertising and promotion of DSM – one new FTE	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-
Planning and Evaluation	DSM GWh saved	Forecasted						
		Actual					-	-
	DSM Program Cost	Forecasted						
		Actual					-	-

A161.1 Please see Table A161.1 below.

Table A161.1
DSM Cost per Program Identified

Program (Note 1 &2)			**2005**	**2006**	**2007**	**F2008**	**F2009**	**F2010**
Incentives (Grant & Loans)	DSM GWh saved	Forecast	19.0	19.0	21.8	19.5	25.3	27.5
		Actual	23.9	23.1	27.9	-	-	-
	DSM Program Cost ($000s)	Forecast	730	732	1,276	1,174	1,840	2,047
		Actual	1,079	1,070	1,332	-	-	-
Residential Financial Incentives	DSM GWh saved	Forecast	8.2	8.2	10.6	8.4	10.7	12.1
		Actual	9.5	10.9	15.3	-	-	-
	DSM Program Cost ($000s)	Forecast	357	359	813	634	869	968
		Actual	603	643	936	-	-	-
General Service Financial Incentives	DSM GWh saved	Forecast	9.2	9.2	9.2	9.1	11.6	12.1
		Actual	12.4	9.7	10.4	-	-	-
	DSM Program Cost ($000s)	Forecasted	263	263	372	413	735	806
		Actual	425	361	294	-	-	-
Industrial Customer Financial Incentives	DSM GWh saved	Forecast	1.7	1.7	2.1	2.0	3.0	3.4
		Actual	2.0	2.4	2.3	-	-	-
	DSM Program Cost ($000s)	Forecast	110	110	91	127	236	274
		Actual	51	73	102	-	-	-
Residential - CFL /LED Rebate Program	DSM GWh saved	Forecast	3.1	3.1	2.25	1.8	-	-
		Actual	2.0	2.5	2.7	-	-	-
	DSM Program Cost ($000s)	Forecast	169	194	170	156	-	-
		Actual	38	58	59	-	-	-
Residential – Heat Pump Program Incentive	DSM GWh saved	Forecast	4.5	4.5	6.2	4.9	-	-
		Actual	293	6.6	9.5	-	-	-
	DSM Program Cost ($000s)	Forecast	353	366	513	446	-	-
		Actual	6.2	303	436	-	-	-
New Residential – LiveSmart BC Program	DSM GWh saved	Forecast	-	-	-	-	0.3	0.4
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	30	40
		Actual	-	-	-	-	-	-

Table A161.1 cont'd

Program (Note 1 &2)			2005	2006	2007	F2008	F2009	F2010
New Residential – Solar BC Thermal Program	DSM GWh saved	Forecast	-	-	-	-	0.03	0.04
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	9	13
		Actual	-	-	-	-	-	-
New Residential – envelope technologies	DSM GWh saved	Forecast	-	-	-	-	0.3	0.3
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	63	63
		Actual	-	-	-	-	-	-
New General Service Program – Cool Shops	DSM GWh saved	Forecast	-	-	-	-	0.5	0.5
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	150	150
		Actual	-	-	-	-	-	-
New General Service Program – Public Sector Energy Conservation Matching Incentives	DSM GWh saved	Forecast	-	-	-	-	1.0	1.25
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	50	70
		Actual	-	-	-	-	-	-
New General Service Program – Destination Conservation Program	DSM GWh saved	Forecast	-	-	-	-	1.0	1.1
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	81	61
		Actual	-	-	-	-	-	-
Industrial – Industrial Efficiency Program	DSM GWh saved	Forecast	0.7	0.7	0.5	0.5	-	-
		Actual	0.4	2.0	1.7	-	-	-
	DSM Program Cost ($000s)	Forecast	70	68	55	62	-	-
		Actual	22	46	75	-	-	-
Industrial – New Process Design Program	DSM GWh saved	Forecast	0.25	0.25	0.35	0.3		
		Actual	0	0	0.1	-	-	-
	DSM Program Cost ($000s)	Forecast	22	21	26	22	-	-
		Actual	0	0	5	-	-	-
Industrial – Sustainable Energy Plan Workshops	DSM GWh saved	Forecast	-	-	-	-	0.7	0.7
		Actual	-	-	-	-	-	-
	DSM Program Cost ($000s)	Forecast	-	-	-	-	75	75
		Actual	-	-	-	-	-	-

Notes

1) The following programs are not shown because:

    - Co-funded Engineering Studies are bundled into General Service financial incentives;
    - Conservation Culture communication plan incl. FTE staff have no energy savings attributed; and
    - Bright Ideas Messaging have no energy savings attributed

2) Existing programs are forecast by sector, and individual program figures are not available.

FortisBC																						
British Columbia Office Furniture																						
Detailed Inventory List																						
Kaslo																						
									Seating						**Filing cabinets**						**Value**	
		Vacant/	**Desk**		**Credenza**		**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Miscellaneous**		**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**		**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**					
			see legend below		**(size)**		**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**											
1	Front	Occupied					2' x 2'	P			Brown/Cole	P									$100	$0
2	Front	Occupied	70's Laminate DP	P																	$200	$0
3	Front	Occupied	70's Laminate DP	P																	$200	$0
4	Front	Occupied							5 Global	G	2 brown	P			2 x 3 hi artofex	F					$800	$50
5	Front	Occupied	80's Laminate DP	F					5 Gobal Steno	F					3 hi Cole	F	4 h Johl	F			$800	$50
6	Front	Occupied	90's Laminate No Ped	F																	$100	$0
7	Side	Occupied	80's Laminate DP	F					5 Global	P											$200	$0
8	Side	Occupied			5 1/2' 5 drawer	P															$300	$0
9	Side	Occupied									Brown	P	5 Laminate	F							$250	$0
10	Meeting	Occupied					3 x 6 Laminate	F	4 Black	P	6 brown	P							Stool - w - cracked	P	$325	$0
11	Warehouse	Occupied	50's Oak	P																	$100	$0
	Total																				$3,375	$100
DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood																						
G = Good F = Fair P = Poor																						

FortisBC																
British Columbia Office Furniture																
Detailed Inventory List																
SALMO																
								Seating				**Filing cabinets**			**Value**	
		Vacant/	**Desk**		**Credenza**	**Table**		**Task**	**Guest**		**Bookcase**	**2 High**	**4 High**	**Miscellaneous**	**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**	**(describe)**		**(color, manuf.**	**(color, manuf.**		**(describe)**	**(inc. manu)**	**(inc. manu)**			
			see legend below		**(size)**	**(size,base)**		**4 or 5 prong)**	**4 or 5 prong)**							
38	Front	Vacant	SP Metal/Laminate	P					2 Orange	P					$100	$0
39	Front	Vacant							3 Orange	P					$100	$0
40	Front	Vacant				3x5 white Laminate	P								$100	$0
41	Side	Vacant				3x5 Laminate/Metal	P		3 Orange	P					$100	$0
	Total														$400	$0
DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood																
G = Good F = Fair P = Poor																

FortisBC																					
British Columbia Office Furniture																					
Detailed Inventory List																					
Creston																					
									Seating						**Filing cabinets**					**Value**	
		Vacant/	**Desk**		**Credenza**		**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Misc.**	**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**		**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**				
			see legend below		**(size)**		**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**										
12	Front	Occupied					Grey	P			2 Brown	P								$200	$0
13	Front	Occupied	DP - Work Station-Grey	G					5 Gray	P										$1,125	$333
14	Front	Vacant	DP - Work Station-Grey	G					5 old brown	P	brown old chairs	P								$1,125	$333
15	Front	Occupied											3 - white	P						$75	$0
16	Front	Occupied					Printer Stand - brown L & steel	F							brown 3 H	F	2 - Beige G&T	G		$200	$0
17	Rear	Occupied											4 white/oak	G						$400	$0
18	Rear	Occupied	Old style	P					5 Brown old	P										$225	$0
19	Rear	Occupied	DP Laminate/wood 80's	F					5 Brown old	P										$1,125	$0
20	Rear	Occupied			4D L - w 80's	F														$250	$0
21	Side #1	Occupied					1.5'x2" Oak 50's	P			2 black	P								$150	$0
22	Side #1	Occupied	DP - u workstn Lam	G																$1,000	$0
23	Side #1	Occupied							5 Gray	P										$125	$0
24	Side #1	Occupied													3 H Cole - black	F				$100	$0
25	Side #1	Occupied											2 5Hi	P						$100	$0
26	Side #2	Occupied					Lam/Metal - cheap	P			Brown vinyl	P								$100	$0
27	Side #2	Occupied	DP 80's Lam/Steel	F					5 ped blue	G										$1,000	$0
28	Side #2	Occupied					Drafting	G												$2,000	$500
29	Side #2	Occupied											3 hi W	F			4H Lat Steelcase/	G		$600	$0
30	Side #2	Occupied															4H Commerce	G		$600	$0
31	Side #2	Occupied															5H tan steelcase	G		$750	$0
32	Side #2	Occupied													3H brown-cole	G				$200	$0
33	Lunchroom	Occupied									9 vinyl-mixed colors	P								$180	$0
34	Lunchroom	Occupied					Door & legs	P												$0	$0
35	Lunchroom	Occupied					2x3x6 Lam/metal	P												$50	$0
36	Lunchroom	Occupied											4 white w/doors	P						$100	$0
37	Crew Room	Occupied							(2-4 leg)(1x5 leg)	P	3 vinyl	P	3 - white	P						$225	$0
	DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood																				
	G = Good F = Fair P = Poor																				

FortisBC
British Columbia Office Furniture
Detailed Inventory List

CASTLEGAR

									Seating						Filing cabinets						Value	
		Vacant/	**Desk**		**Credenza**		**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Miscellaneous**		**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**		**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**					
			see legend below		**(size)**		**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**											
42	Front	Occupied	L - DP 6 x 6	G					5 Brown HOM	G									Custom shelving	G	$3,000	$750
43	Front	Occupied	L - DP 6 x 6	G					5 Brown Global	G									Upper shelving	G	$3,000	$750
44	Front	Occupied	L - DP 9.5 x 6	G					5 Gray Global	F											$3,000	$750
45	Front	Occupied	L & M DP 3 x 5	F					5 brown steno	P					2 commander	G					$2,200	$550
46	Front	Occupied															5H Lat G&T	G			$1,000	$250
47	First Office	Occupied													2 & 3 drawers-b	F					$200	$0
48	First Office	Occupied	L SP 9.5 x 6	G					5 Blue global	G											$3,250	$813
49									5 steno	F											$2,000	$500
50	First Office	Occupied					Drafting - M - L	G									4H commodore	G			$2,000	$500
51	Meter Read	Occupied	L-W DP	G																	$300	$0
52	Meter Read	Occupied	W - SP	P					5 Brown global	P											$2,500	$625
53	2nd Office	Occupied	L - DP 9.5 x 6	G					5 Tan unknown	P											$2,000	$500
54	2nd Office	Occupied			L-brown 4 x 2.5	G															$100	$25
55	2nd Office	Occupied									1 Brown	F									$50	$0
56	Lunchroom	Occupied					2 - 5'x 2.5' Folding	F	5 global	P	8 black vinyl	F									$525	$131
57	Lunchroom	Occupied									3 Mixed	F	4 Black Laminated	G							$475	$119
58	Lunchroom	Occupied											3 Fake Wood	P					Fridge	G	$600	$150
59	3rd Office	Occupied	L - SP 9 x 6	G					2 Global	P									Upper shelving	G	$2,500	$625
60	3rd Office	Occupied											4 storage cabs	F							$200	$0
	Total																				$28,900	$7,038

DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood
G = Good F = Fair P = Poor

FortisBC
British Columbia Office Furniture
Detailed Inventory List

GRAND FORKS

								Seating						Filing cabinets						Value	
		Vacant/	**Desk**		**Credenza**	**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Miscellaneous**		**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**	**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**					
			see legend below		**(size)**	**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**											
61	Front	Occupied	Gray L 51/2 x 51/2	G		3x3 2 shelves	G	gray - unknown	G											$1,200	$300
62	Front	Occupied	Fake W 2 x 4	G				gray Global	G											$600	$150
63	Front	Occupied	Gray L 'U shape" 6'6'x6x'6'	G				burgundy Global	F											$600	$150
64	Front	Occupied						Steno Tan	F			3 W-L cheap	F	2 steel case	G			5x2 microwave stand	F	$700	$175
65	Office #1-Ralph	Occupied	Gray L 'U shape" 6'6'x6x'6'	G				Gray Unknown	F											$1,100	$275
66	Office #1-Ralph	Occupied								Brown	P									$100	$0
67	Office #1-Ralph	Occupied														Gray HON Lat-damaged	P			$500	$0
68	Office #2-Len	Occupied	Gray - L - 11 1/2'x6' SP	G				Blue Global	G											$1,100	$275
69	Office #2-Len	Occupied				Drafting 3 x 3	F	Steno Tan-Vinyl	P							4L Tan Global	G			$850	$213
70	Office #2-Len	Occupied										5H brown-cheap	P							$200	$0
71	Vest	Occupied														2x4H Fire Safe	G			$500	$125
72	Vest	Occupied														2-2x4H L Global & G&T Tan	G			$1,000	$250
73	Back Office	Occupied	W - L - 80's DP	P				black global	G											$1,300	$325
74	Back Office	Occupied	W - L - 80's DP	P		1 1/2'x3' metal	P	blue global	G											$1,600	$400
75	Back Office	Occupied				wood drafting 3x6	P					4 brown-cheap	P							$200	$50
76	Meeting	Occupied				Black-6 pieces	G			10 black	G									$3,000	$750
77	Meeting	Occupied								8 black vinyl	P										
78	Meeting	Occupied						brown	F											$160	$0
79	Meeting	Occupied				Tan-Metal & Lam	P													$50	$0
80	Meeting	Occupied	M - L - 80's comp. desk	P																$300	$0
81	Shop	Occupied	2 - M-L 70's	P																$1,000	$0
82	Lunchroom	Occupied						4 yellow Vinyl	P											$100	$0
83	Lunchroom	Occupied			8 x 3 Folding	F		3 black Vinyl	P											$200	$0
84	Lunchroom	Occupied			50's Metal & Wood	P														$100	$0
85	Lunchroom	Occupied										4 Shelf-W-home made	F							$0	$0
86	Lunchroom	Occupied																Fridge	G	$400	$0
	Total																			$16,860	$3,438

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FortisBC																				
British Columbia Office Furniture																				
Detailed Inventory List																				
GREENWOOD																				
								Seating						**Filing cabinets**					**Value**	
		Vacant/	**Desk**		**Credenza**	**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Miscellaneous**	**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**	**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**				
			see legend below		**(size)**	**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**										
87	Lunchroom	Occupied								8 blue&grey Vinyl	F								$160	$0
88	Lunchroom	Occupied				6 x 2 1/2 folding	P												$150	$0
89	Lunchroom	Occupied	3x2 M-L	P															$500	$0
90	Lunchroom	Occupied										2 shelf - white	P						$100	$0
91	Back Office	Occupied										5 shelf -white-homemade	P						$0	$0
92												& 4 shelf brown								
93	Back Office	Occupied												2H L Steel Tan	G	3H Green	P		$350	$88
94	Back Office	Occupied	DP M & Lam 70's	P				4 prong	P										$500	$0
95	Back Office	Occupied	DP M & Lam 70's	P		DP M - 2x2	P			Global	G			3H JOHL	P				$600	$150
96	Back Office	Occupied										5 Shelf-home made	P						$0	$0
	Total																		$2,360	$238
DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood																				
G = Good F = Fair P = Poor																				

FortisBC																						
British Columbia Office Furniture																						
Detailed Inventory List																						
OLIVER																						
									Seating						**Filing cabinets**						**Value**	
		Vacant/	**Desk**		**Credenza**		**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Miscellaneous**		**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**		**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**					
			see legend below		**(size)**		**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**											
97	Front	Vacant	3 - DP white L	G					1 grey	G					1 beige	G	1 beige	G	6 high - grey 78"	G	$3,400	$850
98	Front	Vacant							2 red	G	1 - red visitor	G									$1,600	$400
99	Lunchroom	Occupied							1 grey	G	12 fabric	P									$700	$175
100	Lunchroom	Occupied	1 - DP wood	G			3 folding tables	G			24-multi colored	G									$3,500	$875
101	Lunchroom	Occupied	L - used for TV	P			1 - round - coffee table	G					W - 4 shelf	G					small Kelvinator fridge	G	$950	$238
102	Lunchroom	Occupied																	Whirlpool microwave	G	$300	$75
103	Lunchroom	Occupied	DP-L 70" x 36"	G															Roper dishwasher	G	$500	$125
104	Spare in back	Vacant	DP - Heartwood	G									5 Shelf-L-wdgrain	G							$2,500	$625
105	Spare in back	Vacant					1-35"x71" W	P			2 red	G									$700	$175
106	Spare in back	Vacant									4 fabric	G							1 grey map storage	F	$400	$100
107	Vic Macor	Occupied							1 red	G	multicolored	G									$875	$219
108	Vic Macor	Occupied	DP - small grey	G					1 Global-grey	G							2 grey	P			$1,550	$388
109									old style executive	P							1 black	G			$200	$0
110																						$0
111	Meter readers	Occupied	DP-small grey	G					1 red	G									Desk on blocks	P	$2,125	$531
112	Meter readers	Occupied	SP - L - old	P					1 global - Grey	G							5 various types&colors	F			$1,300	$325
113																						$0
114	M. MacFadden	Occupied	DP - L - white	G									1-L-oak	G	1-L-Oak	G	1-G&T-beige	G	1-36x49h-fliptop OH	G	$4,200	$1,050
115									1 red	G											$625	$156
116																						$0
117	Barry Radies	Occupied	DP - L - white	G					1-red	G			1-5 shelf-L-white	G			1 - grey - HON	G	1-60x49h-fliptop OH	G	$4,625	$1,156
118									1-grey hi back-personna	G											$500	$125
119											1-red (visitors)	G							1 Printer table-W	F	$545	$136
120											1 multi-color	F									$300	$75
121	Harold Piche	Occupied	SP-L- "U shaped" oak	F					1 red	G	1 red visitor	G									$1,970	$493
122			with static keyboard tray																			
123	Hallway																		1-storage-grey metal	F	$200	$50
124																						
125	R. Royer (Todd R)	Occupied	1-small DP-grey 68x30 & 42x30	G					1 red	G	1 red visitor	G	4 shelf-L-light oak	G							$3,670	$918
126			with pull out keyboard										5 shelf-oak veneer	G	1-L-light grey						$500	$125
127																						
128	Upstairs	Vacant	DP-White-L-pull out keyboard tray	G	4 door-wh-L	G											1 beige HON	G	1 printer table-wh-L	F	$3,500	$875
129																			Oh-4 door-wh-L 71"x14"	G		
130	Upstairs	Vacant	no photos - various items for disposal	P																		
131			1 - computer hutch	P													1 - black	P			$300	$0
132			1 - large desk	P													1 - beige lateral	P			$300	$0
133																			1 - wooden shelf	P	$100	$0
134																			1 - corner cabinet	P	$100	$0
135															1 lateral	P					$200	$0
136																	1 lateral	P			$300	$0
137							2 - printer tables	P													$200	$0
	Total																				**$42,735**	**$10,259**
DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood																						
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FortisBC																				
British Columbia Office Furniture																				
Detailed Inventory List																				
PENTICTON																				
									Seating						**Filing cabinets**						**Value**	
		Vacant/	**Desk**		**Credenza**		**Table**		**Task**		**Guest**		**Bookcase**		**2 High**		**4 High**		**Miscellaneous**		**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**		**(describe)**		**(color, manuf.**		**(color, manuf.**		**(describe)**		**(inc. manu)**		**(inc. manu)**		**(include manufacturer)**			
			see legend below		**(size)**		**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**											
138	Front	Vacant							Global-moveable arms	P											$300	$75
139	Front	Vacant													unusual 3 sm				small table - 2 doors	G	$300	$75
141	Front	Vacant	SP-A top-L-light grey	G															OH-cubby holes & 2 fliptops	G	$3,500	$875
142	Front	Vacant	DP-A top-L-light grey	G					br-non-moveable arms	F									OH-cubby holes & 2 fliptops	G	$3,800	$950
143	Front	Vacant													1 grey lateral	G					$300	$75
144																			(2 door small table & 2 OH	G	$300	$75
145	Front	Vacant					7' x 30" w 1 shelf	G									2 black metal	G	(bought 5 yrs ago @ Winter's)		$500	$125
146	Reception Area						1 sm sq 17" high	F			2 dark blue	G									$300	$75
147											with metal legs								Kelvinator fridge	G	$500	$125
148	Lunch area																		Danby microwave	G	$300	$75
150	Todd Romano	Occupied	30"x24" with keyboard tray	G																	$2,500	$625
151					2 Lat & 2 door				grey-Global	P											$1,000	$250
152	Linda Fleming	Occupied	DP-wh-L-arborite top	G	30" high with OH																$3,500	$875
153					72"x20" deep												3 beige metal	G			$600	$150
154									grey-Global		1 light brown	F					2 grey	G			$650	$163
155	Perry Feser	Occupied	DP - wh - L - curved end	G							1-red	G	5 shelf L-grey	G			1 beige-metal	G			$4,625	$1,156
156	spare (K.Jones)	Vacant	DP- 72" x 36" oak	G					hi-back charcoal	G			1-29" H-2 door with	G							$650	$163
157									non-moveable arms	G			bookcase on top								$2,700	$675
158			DP-8'x20" oak with keyboard tray	G									1-oak veneer L-72"h	G							$2,300	$575
159																			70" x 20"-2 doors	G	$500	$125
160											grey wi black M legs	G							& 2 L drawers		$150	$38
161	Pam Ouelette	Occupied	DP 4 with 4 drawers - L - wh	G					1 grey Global 200	P			1-wh-L-4h	G	1 beige G&T M	G	1 beige G&T M	G	3 shelf OH w flip top	G	$3,750	$938
162											2-multi colored blue										$600	$150
163	Old Crew Room	Vacant	SP - W - oak	P					2 old steno type chairs	P											$200	$0
164			1 old style comp station wi pull out tray	P																	$500	$0
165			2 metal DP	P					1 grey Global	G											$250	$0
166	Back Storage	Vacant													2-3 drawer SUNAC	G					$400	$100
167															brown M		2 G&T beige M	G			$600	$150
168															2 G&T beige M storage cabinets	G					$400	$100
169	Back Office	Vacant	DP - wh - L - 3 drawers	G					1 grey Global 200	G	lt brwn w chrome legs	G							OH 2 open shelves	G	$3,400	$850
170											grey w black M legs	G									$100	$25
171											3 black armless chair	G									$300	$75
172	Bob Gibney's	Occupied			3 drwrs- oak	G							5 shelves - oak	G							$500	$125
173	(8 years old)		DP - oak - good	G	w 2 shelves		round - oak	G													$1,500	$375
174											2 grey Global	G									$400	$100
175									1 - red	G	w chrome legs										$625	$156
176			comp stand w static pull out tray	G																	$500	$125
	Total																				$43,300	$10,588

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FortisBC
British Columbia Office Furniture
Detailed Inventory List

TRAIL 1

								Seating				**Value**	
		Vacant/	**Desk**		**Credenza**	**Table**		**Task**		**Guest**		**New**	**Now**
Item #	**Office**	**Occupied**	**(describe)**		**(describe)**	**(describe)**		**(color, manuf.**		**(color, manuf.**			
			see legend below		**(size)**	**(size,base)**		**4 or 5 prong)**		**4 or 5 prong)**			
177										76 Blue with grey arms & legs	G	$5,700	$1,425
178										3 blue with grey arms & legs & castors	G	$225	$56
179	Lunchroom							23 blue armless chairs (chrome legs)	G			$690	$173
180										3 blue patterned armchairs with oak arms & solid patterned sides	G	$225	$56
181			11 Blue Wkstns. (9.5'x10'8" and 5'x10'8")	G								$44,000	$11,000
182			4 Burgundy Wkstns.	G								$16,000	$4,000
183	Boardroom									16 blue/purple patterned adjustable chairs with wheels	G	$3,200	$800
184	Exec area									25 blue/purple patterned armchairs (Kruge)	G	$1,875	$469
185										8 dark blue armchairs w black arms & legs	G	$600	$150
186	Mailroom									2 dark blue patterned armchair	G	$60	$15
187	Trng. Lab									1 dark grey elevated steno chair	G	$45	$11
188	Trng. Lab							6 dark grey steno	G			$210	$53
189										2 dark purple armchairs w bl arms & legs	G	$150	$38
190	IT							5 elevated stools	G			$200	$50
191	Video room							20 green w grey plastic arms & legs	G			$800	$200
192	Video room							3 green w green plastic arms & legs	G			$120	$30
193	Video room							24 green armless with grey legs	G			$960	$240
194								10 grey with bl arms & solid chrome legs	G			$400	$100
195	4th floor mtg. Rooms							20 light blue w bl plastic arms & legs	G			$800	$200
196								2 tan w brown plastic arms & legs	G			$80	$20
197		Occupied								3 light blue w grey arms & legs	G	$120	$30
198		Occupied								1 light purple armless w grey legs	G	$30	$8
199		Occupied								4 purple with cherry wood legs	G	$300	$75
200		Occupied								4 purple with oak arms & legs	G	$300	$75
201		Occupied								1 purple armless with bl legs	G	$40	$10
202		Occupied								2 purple armless with chrome legs	G	$80	$20
203		Occupied								2 purple patterned with square dark oak arms	G	$150	$38
204	Reception	Occupied								9 blue comfy armchairs	G	$900	$225
205	Exec area	Occupied								2 Purple striped comfy chairs	G	$200	$50
206										1 purple striped comfy couch	G	$400	$100
207	3rd flr mtg.	Occupied				10' l x 41.5" wide	G					$1,000	$250
208	4th flr mtg	Occupied				8' x 4' boat shape	G					$2,000	$500
209	4th flr mtg.	Occupied				48" x 10' racetrack	G					$5,000	$1,250
210		Occupied				2 round cherry wood w bl trim & sm base	G					$600	$150
211		Occupied				4 round cherry wood Lam with solid base	G					$1,200	$300
212		Occupied				2 round dark oak w solid base	G					$600	$150
213		Occupied				2 round light oak w bl trim	G					$500	$125
214		Occupied				5 round light oak (no trim)	G					$1,250	$313
215	Video room	Occupied				11 polygon shaped grey	G			`		$3,300	$825
216	Video room	Occupied				6 rectangular grey	G					$1,800	$450
	Total											$96,110	$24,028

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FortisBC
British Columbia Office Furniture
Detailed Inventory List
TRAIL 2

			Seating						Filing cabinets						Value	
		Vacant/	Task		Guest		Bookcase		2 High		4 High		Misc.		New	Now
Item #	Office	Occupied	(color, manuf.		(color, manuf.		(describe)		(inc. manu)		(inc. manu)					
			4 or 5 prong)		4 or 5 prong)											
217		Occupied			2 tan w wood sq. arms	G									$150	$38
218		Occupied			2 very light tan w plastic grey solid legs	G									$100	$25
219		Occupied	4 brown	F											$200	$50
220		Occupied	1 dark green	G											$50	$13
221		Occupied	2 purple patterned	G											$100	$25
222		Occupied	15 red	G											$9,375	$2,344
223		Occupied	37 grey global	G											$3,700	$925
224		Occupied	7 dark blue	G											$700	$175
225		Occupied	4 dark grey	G											$400	$100
226		Occupied	2 hi back dark purple	G											$200	$50
227		Occupied	6 hi back blue/grey w cherry arms	G											$1,200	$300
228		Occupied	3 hi back dark blue	G											$600	$150
229		Occupied	2 black leather	G											$600	$150
230		Occupied					1-6 shelf L dark wood	G							$200	$50
231		Occupied					5-5 shelf light oak L	G							$1,000	$250
232		Occupied					1 sm grey 4 shelf L	G							$250	$63
233		Occupied					2-3 shelf L dark wood	G							$500	$125
234		Occupied					1-2 shelf dark wood	G							$250	$63
235		Occupied					1-4 shelf metal COLE	G							$75	$19
236															$19,650	$4,913
237	3rd floor	Occupied							1 dark wood lat	G					$300	$75
238	3rd floor	Occupied							4 light oak lat	G					$1,000	$250
239	4th floor	Occupied							8 dark cherry lat	G					$2,400	$600
240	3rd floor	Occupied							9 beige metal lat	G					$2,700	$675
241	2nd floor	Vacant									11 beige lateral	G			$5,500	$1,375
242	2nd floor	Vacant									10 blue lateral	P			$500	$125
243	2nd floor	Vacant									6 black lateral	G			$3,000	$750
244													2-3 drawer beige lat	G	$500	$125
245													2-2 door metal storage	F	$500	$125
246													2 beige map storage	F	$500	$125
247	3rd floor	Occupied											HH microwave	F	$300	$75
248	4th floor	Occupied											Samsung microwave	F	$300	$75
249																
250	2nd floor	Vacant											small Kenmore fridge	F	$300	$75
251	2nd floor	Vacant											mini Citizen fridge	F	$500	$125
252	3rd floor	Occupied											Hotpoint fridge	F	$500	$125
253	4th floor	Occupied											Whirlpool fridge	F	$500	$125
254	4th floor	Occupied											Kenmore dishwasher	F	$500	$125
	Total														$59,100	$14,775

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FortisBC

British Columbia Office Furniture

Detailed Inventory List

TRAIL 3

							Filing cabinets						Value	
		Vacant/	Desk		Bookcase		2 High		4 High		Miscellaneous		New	Now
Item #	Office	Occupied	(describe)		(describe)		(inc. manu)		(inc. manu)		(inc manufacturer)			
			see legend below											
61	3rd floor	Occupied					1 dark wood lat	G					$300	$75
62	3rd floor	Occupied					4 light oak lat	G					$1,000	$250
63	4th floor	Occupied					8 dark cherry lat	G					$2,400	$600
64	3rd floor	Occupied					9 beige metal lat	G					$2,700	$675
65	2nd floor	Vacant							11 beige lateral	G			$5,500	$1,375
66	2nd floor	Vacant							10 blue lateral	P			$500	$125
67	2nd floor	Vacant							6 black lateral	G			$3,000	$750
68											2-3 drawer beige lat	G	$500	$125
69											2-2 door metal storage	F	$500	$125
70											2 beige map storage	F	$500	$125
71	3rd floor	Occupied									HH microwave	F	$300	$75
72	4th floor	Occupied									Samsung microwave	F	$300	$75
74	2nd floor	Vacant									small Kenmore fridge	F	$300	$75
75	2nd floor	Vacant									mini Citizen fridge	F	$500	$125
76	3rd floor	Occupied									Hotpoint fridge	F	$500	$125
77	4th floor	Occupied									Whirlpool fridge	F	$500	$125
78	4th floor	Occupied									Kenmore dishwasher	F	$500	$125
81	3rd floor	Occupied	3 DP-dark cherry w bl trim, curved end		hutch w 2 upper doors								$15,000	$3,750
82	3rd floor	Occupied	DP-light oak w bl trim		hutch, 4 upper doors								$3,000	$750
83	3rd floor	Occupied	DP-light oak w bl trim		hutch w 2 upper doors								$3,000	$750
84	3rd floor	Occupied	DP-light oak		hutch w 4 upper doors								$3,000	$750
85	3rd floor	Occupied	DP-light oak w bl trim		2 hutches w 4 small and 4 large upper doors								$3,000	$750
86	3rd floor	Occupied	4 DP-light oak veneer		4 metal hutches								$14,800	$3,700
87	3rd floor	Occupied	DP-light oak veneer		hutch w 2 open shelves								$3,000	$750
88	3rd floor	Occupied	2 DP-dark cherry		1-hutch with 4 upper long files								$10,000	$2,500
89	3rd floor	Occupied	3 DP-light oak veneer, curved end		3-hutch w 2 upper doors								$11,100	$2,775
90	3rd floor	Occupied	4-DP-light oak veneer		hutch with upper file								$14,800	$3,700
91	3rd floor	Occupied	3-DP light oak veneer		1 w 2 open shelves; 1 w 4 upper shelves								$11,100	$2,775
92	3rd floor	Occupied	2-DP light oak veneer w bl trim curved end		hutch with 2 upper shelves								$7,400	$1,850
93	3rd floor	Occupied	3-DP light oak veneer w bl trim		2 hutches with 4 long upper shelves								$11,100	$2,775
94	3rd floor	Occupied	2-DP-light oak veneer		hutch with 4 upper doors & 2 open shelves								$7,400	$1,850
95	3rd floor	Occupied	2-DP-dark cherry w bl trim		2 hutches with 4 upper shelves								$10,000	$2,500
96	3rd floor	Occupied	DP-dark cherry		hutch with 4 upper cupboards & 2 bottom cupboards & drawers								$5,000	$1,250
97	4th floor	Occupied	SP-dark cherry (no hutch)										$3,000	$750
99	4th floor	Occupied	5-DP-dark cherry w bl trim, curved end		5 hutches with 4 large upper doors & 2 shelves								$25,000	$6,250
100	4th floor	Occupied	2-DP-dark cherry w bl trim		2 hutches with 4 large open upper shelves								$10,000	$2,500
101	4th floor	Occupied	2-DP-light oak veneer		2 uppers with open shelf	G							$7,400	$1,850
102	4th floor	Occupied	5-DP-light oak veneer w bl trim		hutch w 4 large upper doors & 2 shelves	G							$18,500	$4,625
103	4th floor	Occupied	DP-light oak veneer w bl trim, curved end table		hutch 2 4 large upper doors & 2 shelves	G							$3,700	$925
104	4th floor	Occupied	DP-dark cherry w bl trim										$5,000	$1,250
105	4th floor	Occupied	2-SP-dark cherry		1-hutch w 4 large upper cupboards	G							$10,000	$2,500
106	4th floor	Occupied	U-shaped counter wkstn, dark cherry w bl trim		hutch w 4 large upper cupboards & 2 shleves	G							$3,700	$925
107	4th floor	Occupied	3-DP-light oak veneer										$11,100	$2,775
108	4th floor	Occupied	4-SP light color										$12,000	$3,000
109	4th floor	Occupied	SP-dark cherry w bl trim										$3,700	$925
110	4th floor	Occupied	DP-light color w curved end table										$3,700	$925
111	4th floor	Occupied	DP-dark cherry w curved end table		hutch w 4 sm shelves	G							$5,000	$1,250
112	4th floor	Occupied	DP-dark cherry		3 bottom cupboards, 4 top sm shelves & 1 open shelf	G							$5,000	$1,250
113	4th floor	Occupied	2-DP dark cherry		hutch w 4 upper sm shelves	G							$7,400	$1,850
114	4th floor	Occupied	2-DP dark cherry wood										$7,400	$1,850
115	4th floor	Occupied	2-DP dark cherry w bl trim		hutch w 4 sm upper cupboards & 1 shelf	G							$7,400	$1,850
116	4th floor	Occupied	DP-dark cherry		hutch w 4 large upper cupboards	G							$3,700	$925
117	2nd floor	Vacant/	DP-dark cherry		hutch w 4 small upper cupboards	G							$3,700	$925
118	2nd floor	Vacant/	2-DP-light color		1 hutch w 4 upper large cupboards	G							$6,000	$1,500
119	2nd floor	Vacant/	2-SP-light color										$5,000	$1,250
	Total												$319,900	$79,975

DP = double pedestal SP = single pedestal A - arborite L = laminate M = metal W = wood

G = Good F = Fair P = Poor

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Trail Contact Centre								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
120	TCC	Workstation	Global Evolve	2005	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	24	$ 6,000.00	$ 144,000.00
121	TCC	Supervisor's office	Global License	2005	Everything above plus 2 visitor chairs, bookcase, slightly larger work surface	3	$ 10,000.00	$ 30,000.00
122	TCC	Reception area		2005	1 workstation, 1 large storage cabinet, 1 small filing cabinet, 2 lounge chairs, 1 endtable	1	$ 5,000.00	$ 5,000.00
123	TCC	Lunchroom		2005	Lunchrooms with fridges, coffee maker, microwave, lunch table and chairs	2	$ 1,500.00	$ 3,000.00
124	TCC	Training room		2005	Computer stations with chair	11	$ 1,000.00	$ 11,000.00
125	TCC	Training room		2005	Overhead, proxima, screen	1	$ 1,500.00	$ 1,500.00
							Total	$194,500

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Warfield								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
126	Warfield	Workstation	Herman Miller Ethospace	2001/02	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	37	$ 4,500.00	$ 166,500.00
127	Warfield	Lunchroom		2002/03	Fridge, coffee maker, microwave, 9 lunch tables and 35 chairs	1	$ 1,500.00	$ 1,500.00
128	Warfield	Meeting room		2002/03	Table, chairs, overhead, proxima, screen, room for 20 people	1	$ 3,000.00	$ 3,000.00
							Total	$171,000

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Warfield System Control Centre								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
129	SCC	Workstation	Global	2001/02	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	8	$ 6,000.00	$ 48,000.00
130	SCC	Supervisor's office			Everything above plus 2 visitor chairs, bookcase, slightly larger work surface	2	$ 7,000.00	$ 14,000.00
131	TCC	Lunchroom			Lunchroom with fridge, coffee maker, microwave, lunch table and chairs	1	$ 1,500.00	$ 1,500.00
132	SCC	Meeting room			Table, chairs, overhead, proxima	1	$ 1,500.00	$ 1,500.00
133	SCC	Console units			Holds multiple monitors	4	$ 8,000.00	$ 32,000.00
134	SCC	Control room chairs			Chairs	8	$ 600.00	$ 4,800.00
							Total	$101,800

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
South Slocan								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
135	South Slocan	Workstation			Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	19	$ 2,000.00	$ 38,000.00
136	South Slocan	Reception area			1 workstation, 1 large storage cabinet, 1 small filing cabinet, 2 lounge chairs, 1 endtable	1	$ 3,000.00	$ 3,000.00
137	South Slocan	Lunchroom			Lunchrooms with fridges, coffee maker, microwave, lunch table and chairs	1	$ 1,500.00	$ 1,500.00
							Total	$42,500

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Springfield								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
138	Springfield	Workstation	Global Evolve	2005/06	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	55	$ 6,000.00	$ 330,000.00
139	Springfield	Manager's/Supervisor's workst	Global License	2005/06	Includes everything as above plus additional privacy panels, larger footprints and a visitor chai	14	$ 7,000.00	$ 98,000.00
140	Springfield	Office configurations	Global Descor	2005/06	Includes everything above plus 2 visitor chairs, bookcase, small meeting table, slightly larger w	14	$ 8,000.00	$ 112,000.00
141	Springfield	Lunchroom		2005/06	Lunchrooms with fridges, coffee maker, microwave, lunch table and chairs	2	$ 1,500.00	$ 3,000.00
142	Springfield	Training Room		2008	Computer stations with chair	14	$ 1,000.00	$ 14,000.00
143	Springfield	Board Room		2005/06	Table, chairs, overhead, proxima, screen. Room for 16 people	1	$ 10,000.00	$ 10,000.00
144	Springfield	Meeting room		2005/06	Table, chairs, overhead, proxima, screen. Room for 8 people	1	$ 2,500.00	$ 2,500.00
145	Springfield	Meeting room		2005/06	Table, chairs, overhead, proxima, screen. Room for 4 people	1	$ 2,000.00	$ 2,000.00
146	Springfield	Meeting room		2005/06	Table, chairs, overhead, proxima, screen. Room for 4 people	1	$ 1,500.00	$ 1,500.00
								$ -
								$ -
							Total	$573,000

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Enterprise								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
147	Enterprise	Workstation	Global Evolve	2006/07	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	42	$ 6,000.00	$ 252,000.00
148	Enterprise	Lunchroom			Lunchrooms with fridges, coffee maker, microwave, lunch table and chairs	2	$ 1,500.00	$ 3,000.00
149	Enterprise	Meeting room			Table, chairs, overhead, proxima, screen. Room for 4 people	2	$ 2,000.00	$ 4,000.00
							Total	$259,000

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Benvoulin - Purchased 2002								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
150	Benvoulin	Workstation	Herman Miller Ethospace	2001/02	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	36	$ 6,000.00	$ 216,000.00
151	Benvoulin	Manager's/Supervisor's workst	Herman Miller Ethospace		Includes everything as above plus additional privacy panels, larger footprints and a visitor chai	5	$ 7,000.00	$ 35,000.00
152	Benvoulin	Lunchroom			Lunchrooms with fridges, coffee maker, microwave, lunch table and chairs	2	$ 1,500.00	$ 3,000.00
153	Benvoulin	Meeting room			Table, chairs, overhead, proxima, screen. Room for 16 people	1	$ 5,000.00	$ 5,000.00
154	Benvoulin	Meeting room			Table, chairs, overhead, proxima, screen. Room for 8 people	1	$ 2,500.00	$ 2,500.00
155	Benvoulin	Meeting room			Table, chairs, overhead, proxima, screen. Room for 4 people	2	$ 2,000.00	$ 4,000.00
							Total	$265,500

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Princeton								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
156	Princeton	Workstation	Global License	2006/07	Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	7	$ 6,000.00	$ 42,000.00
157	Princeton	Lunchroom			Lunchrooms with fridges, coffee maker, microwave, lunch table and chairs	1	$ 1,500.00	$ 1,500.00
							Total	$43,500

FortisBC								
British Columbia Office Furniture								
Detailed Inventory List								
Keremeos								
	Office	**Unit description**	**Make/model**	**Year purchased**	**Items included in unit**	**# of units**	**Cost per unit**	**Total cost**
158	Keremeos	Workstation			Chair, keyboard trays, drawer pedestals, wardrobes, shelves, lights	4	$ 6,000.00	$ 24,000.00
159	Keremeos	Lunchroom			Table, chairs, fridge, microwave	1	$ 1,500.00	$ 1,500.00
							Total	$25,500

Generation Sustaining Projects

		Previously Approved
	Sustaining	
1	South Slocan Unit 1 Life Extension	G-52-05
2	South Slocan Unit 3 Life Extension	G-147-06
3	Corra Linn Unit 1 Life Extension	G-147-06
4	Corra Linn Unit 2 Life Extension	Exhibit B-1, Appendix 2
5	South Slocan Plant Completion	G-147-06
6	Upper Bonnington Civil \ Structural Upgrade and Old Unit Repowering (Phase 1)	G-147-06
7	South Slocan Unit 1 Headgate Rebuild	G-147-06
8	South Slocan Headgate Hoist, Control, Wire Rope Upgrade	G-147-06
9	Generating Plants Upgrade Station Service Supply	G-147-06
10	Generating Plants Area Lighting	
13	All Plants Spare Unit Transformer	

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants Lighting Upgrades

Generation Planning No.: C091500

Executive Summary:

This project is to upgrade the lighting systems in the basement of the Corra Linn and South Slocan powerhouses and a full plant upgrade at the Lower Bonnington plant.

Background:

The present lighting conditions at these plants is very poor and do not meet WCB regulations. Employee safety and plant equipment are at risk with the lighting at its present levels. Annual inspections, routine maintenance and daily measurements are all performed at these various locations and better lighting would make these jobs safer and easier to accomplish.

Options Considered:

Option 1: Do nothing

Pros:

- Zero capital cost

Cons:

- Unsafe work environment
- Possible damage to plant equipment
- Not meeting with WCB regulations

Option 2: Upgrade lighting systems

Pros:

- Safer working enviroment
- Improved system reliability with some lighting installed to emergency panel fed by diesel generator
- Meets WCB regulations
- Lessens risk of equipment damage

Cons:

- Cost of project

Financial Analysis/Assumptions Used:

Option 2: $478,000 for 2009 and $338,000 for 2010

Rate Impact (0.05% per million $s):

Option 2: 0.0248% for 2009 and 0.0179% for 2010

Option Selected:

Option 2

Implementation Process:

Scheduled for 2009 and 2010. Work to be done by FortisBC personnel.

Other Considerations:

To be coordinated with the Station Service upgrades in order to add some lighting to the essential services panel in the event of a plant outage.
Unit outages may be needed in order to upgrade the lighting in the turbine pit areas.

Risks:

Employee safety

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants Spare Transformer

Generation Planning No.: C091300

Executive Summary:

The scope of this project includes the purchase of a 25MVA Generator Step-up Transformer and the construction of a storage facility.

Background:

The generator unit transformers have been identified as high risk equipment, which if failure occurs can result in loss of generation for up to two years. The Corra Linn Unit 1 and 2 transformers are the highest risk, originally installed in 1932, these transformers are well past their normal life expectancy of 35 years. Two years ago there was a failure of the Lower Bonnington Unit 2 transformer with substantial unit outage costs.

The spare transformer will be a 25 MVA size so that it will be capable of replacing any one of eleven unit transformers at the FortisBC Kootenay River plants, this is 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 storage facility is to be built to house the spare transformer. The possible sharing of a spare transformer with other facilities in the area is not possible due to our unique voltage requirements.

It is considered good utility practice to have a spare unit transformer.

Options Considered:

Option 1: Do nothing

Pros:

- No capital costs

Cons:

- High risk of transformer failure with resulting energy and capacity replacement costs.

Option 2: Purchase new Step-up Transformer and erect storage facility

Pros:

- Decrease in costs at time of tranformer failure due to long repair time.
- Less maintenance of spare due to storage facility
- Bushings, conservator, and coolers need to stored in a dry location and be available for re-assembly at any time.
- It is easier to maintain a dry air blanket in the transformer tank when stored in a building.

Cons:
- High capital costs

Option 3: Purchase new Step-up Transformer and store outdoors
Pros:
- Decrease capital costs (no storage facility).

Cons:
- Bushings, conservator, and coolers need to stored in a dry location and be available for re-assembly at any time.
- It is more difficult to maintain a dry air blanket in the transformer tank when stored outdoors.
- Increased transformer maintenance costs while in storage

Option 4: Purchase new Step-up Transformer to be shared with other facilities
Pros:
- Decrease in costs

Cons:
- Not practical solution, due to difference in transformer sizes and voltages

Financial Analysis/Assumptions Used:

Option 2: $1,380,000 in 2009

Rate Impact (0.05% per million $s)

Option 2: 0.0715% in 2009

Option Selected:

Option 2

Implementation Process:

Procurement will begin in 2008, with delivery and installation planned for 2009.

Other Considerations:

Risks:

Equipment failure with revenue loss.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

Rob Dunsmore
Manager Generation

Generation Small Sustaining Projects

1	All Plants Fire Safety Upgrade Phase 1
2	All Plants Public Safety & Security Phase 1
3	Lower Bonnington Power House Crane Upgrade
4	Corra Linn Power House Crane Upgrade
5	Corra Linn East Wingdam Handrail Upgrade
6	All Plants Portable Headgate Closing Device
7	All Plants Spare Exciter Transformer
8	South Slocan Water Supply Phase 3
9	All Plants 2009 Pump Upgrades
10	Upper Bonnington & Corra Linn Deluge Valves
11	Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm System Upgrade
12	Lower Bonnington & Upper Bonnington Upgrade Spillway Gate Control Phase 1
13	Upper Bonnington & South Slocan Airwash Tank Rehabilitation
14	South Slocan Tailrace Gate Corrosion Control
15	Queen’s Bay Level Gauge Building Phase 1
16	Upper Bonnington Unit 5 & Unit 6 Tailrace Gate Corrosion Control
17	Upper Bonnington Trashrack Gantry Replacement.
18	Lower Bonnington Forebay Access Rd. and Intake Upgrade Phase 1 & 2
19	Corra Linn Spillway Gate Isolation Study
20	South Slocan Dam Rehabilitation Study
21	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade
22	Lower Bonnington & Upper Bonnington Communications Network Completion

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants Fire Safety Upgrades Phase 1

Generation Planning No.: C081500

Executive Summary:

Fire safety standards have changed in the hydro industry. BC Hydro has completed extensive work in this area and has developed personnel that are now the recognized authority in fire safety in Hydro Electric Facilities. FortisBC's Generation group have started working with this individual on a consultant basis in order to identify what changes and improvements in our facilities and equipment are necessary to meet the new industry expectations. The intention is utilize this information to develop a scope of work that will be submitted for approval in 2010 to be executed in 2011 and 2012.

Background:

In 2005 a problems with our generator fire protection system at Corra Linn resulted in recognition that there was a need to investigate the rest of the facility and led to seeking a consultant to assess our present systems. Based on the consultants report we will develop a plan to upgrade our facilities and machinery's fire protection systems.

Options Considered:

Option 1: Do nothing

Pros:

- Eliminate expenitures and stay with exsisting system.

Cons:

- Increased risk of damage and downtime due to a fire.
- Deacreased unit operational reliability.

Option 2: Replace and Upgrade deluge valve and operating system

Pros:

- Reduce the risk of revenue loss.
- Increase operational reliability.

Cons:

- Based on BCHydro's experience the work might cost as much as $1-1.2 million.

Financial Analysis/Assumptions Used:

Option 2: $241,000 in 2009

Rate Impact (0.05% per million $s):

Option 2: 0.013% in 2009

Option Selected:

Option 2

Implementation Process:

Design work to begin in 2009 for implementation in 2011 and 2012.

Other Considerations:

Risks:

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants Public Safety and Security Ph.1

Generation Planning No.: C081100

Executive Summary:

2009 Budget Year:
Engineering services for the security system design at Lower Bonnington, Upper Bonnington, South Slocan and Corra Linn. Detailed drawings with material lists for the security systems will be produced.

2010 Budget Year:
Based on the Engineering drawings produced in the 2009 budget year, equipment vendors and suppliers are to provide bids for the supply and installation of the security equipment. The vendor costs and delivery periods are to be collected in a final cost estimate. A construction schedule for the 2011/2012 budget years is to be developed.

Background:

During the 2008 budget year the Generation Public Safety and Security projects Scope is to be developed. Based on this scope, drawing layouts are to be completed to define the extent of the perimeter fencing. The perimeter fence layout drawings and security equipment criteria will be used by an engineering consultant to prepare a Feasibility costing study. The study report is to be used as the basis for all public safety and security items for the four power generation plants. During the 2011 and 2012, the implementation of the Public safety and security equipment is to be undertaken.

Options Considered:

Option 1: Do nothing
Pros:
- No costs expended

Cons:
- Will not be properly prepared to implement security equipment
- Potential cost and schedule over-runs

Option 2: Public Safety & Security Ph 1
Pros:
- Detailed Engineering drawings takes the guesswork out of the installation process.
- Sound Scope to ensure that the best interests of the general public and the power generation facilities are addressed.
- Vendor bids improves the accuracy of the project costing
- Vendor supplied equipment delivery dates helps to develop a realistic construction schedule.

Cons:

- Minor costs for engineering and project services

Financial Analysis/Assumptions Used:

Option 2: $82,000 in 2009 and $52,000 in 2010

Rate Impact (0.05% per million $s):

Option 2: 0.0024% in 2009 and 0.0027% in 2010

Option Selected:

Option 2

Implementation Process:

- In 2009, Engineering drawings will be completed.
- In 2010, Vendor bids will be obtained, final project Scope will be defined, final project costing will be assembled and a construction schedule is to be developed.
- The implementation of the security system(s) at all plants is to be done in 2011.

Other Considerations:

Risks:

Generation Plants and Assets Security
Public safety
Power production reliability

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Lower Bonnington Power House Crane Upgrade

Generation Planning No.: C080501

Executive Summary:

This project consists of a condition assessment done by a reputable vendor. Perform modifications and installation of new equipment on crane to meet today's regulatory standards.

Background:

The power house crane has received control and drive upgrades in the past, but is deficient on trolley and bridge stops along with upper and lower limits on both hooks. In addition this crane has seen extensive usage throughout the three Unit upgrades at this plant and due diligence would dictate that a thorough inspection of the components should be done.

Options Considered:

Option 1: Do Nothing
Pros:

- Least cost outlay
- Crane is operational

Cons:

- Contrivention of Crane Standards
- Undo risk to workers and equipment

Option 2: Perform assesment and upgrade crane
Pros:

- Compliance with regulatory bodies
- Increased operator and equipment safety

Cons:

- Increased costs

Financial Analysis/Assumptions Used:

Option 2: $174,000 for 2009

Rate Impact (0.05% per million $s):

Option 2: 0.009%

Option Selected:

Option 2

Implementation Process:

In 2009, perform condition assessment and schedule work to commence after materials are procured.

Other Considerations:

Risks:

Employee, equipment safety. Reliability.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FortisBC Business Case

Project Name: Corra Linn Power House Crane Upgrade

Generation Planning No.: C090804

Executive Summary:

This project consists of a condition assessment done by a reputable vendor. Perform modifications and installation of new equipment on crane to meet today's regulatory standards.

Background:

The Power House Crane has received control and drive upgrades in the past, but is deficient on trolley and bridge stops along with upper and lower limits on both hooks.

Options Considered:

Option 1: Do Nothing
Pros:
- Least cost outlay
- Crane is operational

Cons:
- Contrivention of Crane Standards
- Undo risk toworkers and equipment

Option 2: Perform assesment and upgrade Crane
Pros:
- Compliance with regulatory bodies
- Increased operator and equipment safety

Cons:
- Increased costs

Financial Analysis/Assumptions Used:

Option 2: $174,000

Rate Impact (0.05% per million $s):

Option 2: 0.0089%

Option Selected:

Option 2

Implementation Process:

In 2009, perform condition assessment and schedule work to commence after materials are procured.

Other Considerations:

N/A

Risks:

Employee, equipment safety, reliability.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manger Generation

FortisBC Business Case

Project Name: Corra Linn East Wingdam Handrail Upgrade

Generation Planning No.: C080804

Executive Summary:

To replace the three foot tall wingdam fence that runs from the B.C. Hydro Canal entrance gates to the foot of the stairs going up to spill gate fourteen.

Background:

Existing fence was originally installed in 1948 and is of insufficient height to meet WCB regulations. The fence also is in generally poor condition.

Options Considered:

Option 1: Do nothing
Pros:
- No cost

Cons:
- Safety issues and compliance to WCB regulations have not been addressed.

Option 2: Remove old fence & replace with new chain link fencing
Pros:
- The new fence will meet WCB regulations (employee safety) and will be made of all galvanized materials to minimize corrosion issues.

Cons:
- None

Financial Analysis/Assumptions Used:

Option 2: $78,000

Rate Impact (0.05% per million $s):

Option 2: 0.004%

Option Selected:

Option 2

Implementation Process:

Design and install by contractor.

Other Considerations:

N/A

Risks:

FortisBC personnel safety risk. In violation of WCB regulations.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants Portable Headgate Closing Device

Generation Planning No.: C081000

Executive Summary:

A portable headgate closing system is required for the FortisBC plants on the Kootenay River.

Background:

A headgate assessment study was performed on all FortisBC plants in 2000 by Agra Monenco. The results of the study were that the headgates did not have enough 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 speed-no-load.

Options Considered:

Option 1: Do nothing and risk exposing the units to uncontrolled runaway for long periods of time
Pros:
- Cheapest option

Cons:
- Risky

Option 2: Add ballast to existing headgates
Pros:
- none

Cons:
- Expensive and amount of ballast required is not definate

Option 3: Design and build a mobile headgate closing device to be used at all plants
Pros:
- Cheapest solution

Cons:
- Doesn't completely address the problem (band-aid)

Financial Analysis/Assumptions Used:

Option 3: $50,000

Rate Impact (0.05% per million $s):

Option 3: 0.0026%

<u>Option Selected:</u>

Option 3

<u>Implementation Process:</u>

<u>Other Considerations:</u>

<u>Risks:</u>

<u>Approvals Required:</u>

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants Spare Exciter Transformer

Generation Planning No.: C081200

Executive Summary:

The scope of this project is to purchase a spare exciter transformer.

Background:

The exciter transformer has been identified as high risk equipment. All upgraded generating units will have static exciters installed. These units have redundant power electronic and control units for increased reliability but the exciter transformer is not redundant. A failure of the transformer will result in loss of generation for up to six months. This transformer is a dry indoor type which is of a unique voltage and physical size making it difficult to find a replacement.

It is considered good utility practice to have a spare exciter transformer.

Options Considered:

Option 1: Do nothing
Pros:
- No capital costs

Cons:
- High risk of transformer failure with resulting energy and capacity replacement costs

Option 2: Purchase new spare Exciter Transformer
Pros:
- Decrease in costs at time of tranformer failure due to long repair time

Cons:
- High capital costs

Option 3: Purchase new skid mounted Exciter Unit
Pros:
- None, the installation of a complete unit after a failure is very difficult

Cons:
- No reliabilty advantage over purchasing a new transformer only
- Increased costs

Option 4: Modify the old MG Sets for excitation
Pros:
- None

Cons:

- Not a practical solution, if the modification is capable, it will be marginally sized
- Will have limited protection
- Will lose VAR and PSS control.
- High maintenance costs

Financial Analysis/Assumptions Used:

Option 2: $24,000 in 2009 and $116,000 in 2010

Rate Impact (0.05% per million $s)

Option 2: 0.0012% in 2009 and 0.0063% in 2010

Option Selected:

Option 2

Implementation Process:

Procurement will begin in 2009, with delivery and installation planned for 2010.

Other Considerations:

Risks:

Equipment failure with revenue loss.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: South Slocan Domestic Water Supply Upgrades Ph 3

Generation Planning No.: C090600

Executive Summary:

This project consists of upgrading the gravity water supply from Rover Creek to the South Slocan Generation site. A Water Source Options study report prepared by Kerr-Wood-Leidel early in 2008 will form the basis of the work to be done during the 2009/10 budget years. During 2009/10 FortisBC will review the reports' viable options and create a project direction based on the study options, FortisBC organizational changes, regulations requirements and Generations' current and future water needs.

Background:

The present gravity water supply system feeding South Slocan is aging and requires upgrading in numerous areas. The water is collected in a reservoir created behind a concrete structure located on Rover Creek. The concrete dam structure was built in 1975 and is in excellent condition but the reservoir must be frequently dredged to remove settled silt. The water is carried by a 4" steel pipe line about a half mile down the mountain to a pressure reducing station. The present valve reducing station is buried in the ground and excessive condensation is causing valve and moisture related maintenance issues. The pipe line continues for another half mile to the South Slocan power house. The pipe line changes size from 4" to 6" and continues another 1500 feet to a 42000 gallon Aqua-Store tank. The pipeline materials vary from asbestos-cement, to steel, and to PVC.

During the spring of 2006 the water line embedded in the concrete wingdam structure at South Slocan failed and Phase 1 of this project consisted of upgrading this to a permanent PVC bypass line.

The pipe run between Rover Creek and the powerhouse contains a 70+ year old suspension bridge and two 30+ year old wooden trestles. Replacement of the suspension bridge deck, bridge deck supports, pipeline traversing the bridge, new pipe saddles, pipe insulation and pipe covers were included in the Phase 2 upgrade in 2007. The bridge steel structure and cable systems are original. The two wooden trestles are presently in good condition but atmospheric conditions are reducing the life expectancy of the materials.

Options Considered:

Option 1: Do nothing

Pros:

- No additional engineering req'd
- Established Water system
- Water license on Rover Creek
- Gravity water source, electrical energy is not req'd to maintain the water flow

- No water restriction up to the limit of the water permit

Cons:
- Aging system components
- Major pipeline upgrades are necessary to allow the water system to deliver the water reliably.
- Routine system maintenance is escalating annually
- Additional water treatment is necessary to meet the standards for Canadian Guidelines for Drinking Water Quality

Option 2: Review of Generations Water Needs
Pros:
- Develop a sound decision for Generations' current and future water needs as relating to infrastructure changes, organizational changes and regulations requirements

Cons:
- Costs to develop sound decisions
- Costs to maintain existing water supply system during the decision making process.
- Additional water treatment is necessary to meet the standards for Canadian Guidelines for Drinking Water Quality

Financial Analysis/Assumptions Used:

Option 2: $47,000 for 2009 and $50,000 for 2010

Rate Impact (0.05% per million $s):

Option 2: 0.00245% for 2009 and 0.00265% for 2010

Option Selected:

Option 2: Review of Generations Water Needs

Implementation Process:

- In 2009, Review Generations current and future water needs
- In 2010, Prepare detailed Engineering drawings based on the 2009 Review of Generations' water needs.
- In 2010, Project submitted for approval
- In 2011 & 2012, If approved in 2010 South Slocan's water system is to be installed.

Other Considerations:

Risks:

Employee and public safety. Reliability.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: All Plants 2009 Pump Upgrades

Generation Planning No.: C091100

Executive Summary:

Upgrade the dewatering pumps for reliable service and improvements to environment.

Background:

The dewatering Pumps are an integral part of FortisBC safety and isolation procedures. The Pumps and Lines are original vintage and have suffered from corrosion and excessive wear of components. The underwater bearings are oil lubricated which contaminates the water course.

Options Considered:

Option 1: Do Nothing
Pros:
- No capital dollars invested

Cons:
- Possible inability to dewater units.Oil escaping intowater way

Option 2: Upgrade Pumping system
Pros:
- Safe reliable system. No environmental concerns

Cons:
- Increased costs

Financial Analysis/Assumptions Used:

Option 2: $233,000 for 2009

Rate Impact (0.05% per million $s):

Option 2: 0.012%

Option Selected:

Option 2

Implementation Process:

FortisBC employees would remove, upgrade and install Pumps, tees. Vendor will refurbish motor. All work scheduled for 2009

Other Considerations:

Risks:

- Employee safety
- Unit reliability
- Environmental issues

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Upper Bonnington and Corra Linn Deluge Valves

Generation Planning No.: C091400

Executive Summary:

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. Upon the recommendation of a Fire Safety Consultant, it was decided to upgrade these systems to limit damage should a fire occur. The upgrade will also reduce the risk of a false trip wetting down the rotor and stator assemblies.

Background:

In 2005 the failure of a deluge valve at Corra Linn caused a rotor wash. This caused $317,000 in combined labour and outage cost to dry the unit. The follow up investigation recognized the need for an improved valving system to eliminate this risk. These valves have been changed as part or the ULE program since then, but the units that had went through the ULE program prior to this and one that is scheduled for 2012 need to be addressed.

Options Considered:

Option 1: Do nothing

Pros:

- Eliminate expenitures and stay with exsisting system

Cons:

- Risk of reoccurance of what happened at P4 Corra Linn in 2005

Option 2: Replace and Upgrade deluge valve and operating system

Pros:

- Reduce the risk of revenue loss.

Cons:

- Some possibillity that valve system will be reworked in conjuction with Facilities Fire Safety Upgrades

Financial Analysis/Assumptions Used:

Option 2: $50,000 in 2009

Rate Impact (0.05% per million $s):

Option 2: 0.0026% in 2009

Option Selected:

Option 2: $52,000

Implementation Process:

Do this work in 2009 in conjunction with Unit Inspections

Other Considerations:

Risks:

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Lower Bonnington (LBO), Upper Bonnington (UBO) & Corra Linn (COR) Sump Oil Alarm and Level Upgrade

Generation Planning No.: C091800

Executive Summary:

This project is to improve the oil detection capabilities in the plant sump pits in order to avert the possible discharge of oil into the Kootenay River as well as improve the reliability the system for possible call-out situations.

Background:

There have been previous problems in the past with the current oil detection system in that false alarms as well as the pit being pumped too low have locked out the sump pump thus causing the sump pit to overfill. Some instances had the call person respond to a false alarm and other instances, a real alarm went unnoticed.

Options Considered:

Option 1: Do nothing

Pros:

- Zero capital costs

Cons:

- Unreliable equipment which could result in further false alarms
- Possible environmental damage due to oil being discharged into the river

Option 2: Replace oil detector and sump level sensor

Pros:

- Improved reliability
- Less maintenance costs
- Better public image by not polluting the environment

Cons:

- Cost of project

Financial Analysis/Assumptions Used:

Option 2 : $128,000 in 2009

Rate Impact (0.05% per million $s):
0.0067% in 2009

Option Selected: Option 2

Implementation Process:
Installation of the oil detection and sump level sensor will be performed by FortisBC labour force. Installation of equipment will be scheduled for 2009.

Other Considerations:

Risks:
Possible environmental damage from oil being discharged into the river.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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FortisBC Business Case

Project Name: Lower Bonnington (LBO) and Upper Bonnington (UBO) Upgrade Spillway Gate Controls Phase 1

Generation Planning No.: C092000

Executive Summary:

This project is to conduct an engineering study and produce a set of drawings to be used for the upgrade of the spillway gate controls at Lower Bonnington and Upper Bonnington. The study shall include the upgrade of the gate controls, control equipment, gate telemetry for SCC control, load calculations and specifications for the resistor grid replacement (LBO) used for speed acceleration of the gate motor.

Background:

The existing controls are old and unreliable. Due to age and deterioration, the function of the controls has become an issue with regards to worker safety and system reliability. The current gate controls and related equipment contain levels of asbestos deemed unsafe by WCB regulations.

Options Considered:

Option 1: Do nothing

Pros:

- Zero capital costs

Cons:

- Unsafe working conditions for FortisBC employees due to asbestos exposure at levels higher than WCB standards.
- Shock hazard to employees operating outdated equipment.
- Unreliable control of the spillway gates.

Option 2: Perform an engineering study to upgrade spillway controls

Pros:

- Safer working environment for FortisBC personnel.
- Better control of spillway gates which will improve the ability to manage river levels.

Cons:

- Costs associated with the project.

Financial Analysis/Assumptions Used:

Option 2 : $40,000 in 2009

Rate Impact (0.05% per million $s):
0.0021% in 2009

Option Selected: 2

Implementation Process:
Existing drawings and specifications will be sent to engineering to facilitate a better scope to determine costs of the spillway hoist control replacement.

Other Considerations:

Risks:
- Employee safety due to shock hazard and asbestos exposure.
- Unreliable control of river levels.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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FORTISBC

2009/2010 FortisBC Business Case

Project Name: Upper Bonnington (UBO) and South Slocan SLC Airwash Tank Rehabilitation & Corrosion Control

Generation Planning No.: C092100

Executive Summary:

To upgrade the corrosion protection on the air wash fan and housing, the steel portion of the discharge plenum ,the steel doors at the air wash chamber at the South Slocan plant and the sprayers recovery tank, wall and ceiling at both Upper Bonnington and South Slocan.

Background:

The corrosion coating of the mild steel components of the fan housing, discharge plenum, air wash chamber doors, and the sprayers recovery tank, wall and ceiling, has failed in numerous areas and the exposed mild steel is very susceptible to corrosion from the moist air in the equipment environment. If left unchecked the corrosion may affect the equipment structural integrity and the air wash fan and tank system may require to be shut down. The air wash equipment is crucial in maintaining 100% production from the power generating units during the hot summer temperatures. Depending upon exterior temperatures, unavailability of the air wash equipment may result in plant capacity reductions as high as 50%.

Options Considered:

Option 1: Do Nothing
Pros:

- No cost

Cons:

- If left unchecked the corrosion may affect the equipment structural integrity and the air wash fan and tank system may require to be shut down. The air wash equipment is crucial in maintaining 100% production from the power generating units during the hot summer temperatures. Depending upon exterior temperatures, unavailability of the air wash equipment may result in plant capacity reductions as high as 50%.

Option 2: Corrosion control of fan housing and tank.
Pros:

- By doing this project in 2009 we will be able to use pressure washing procedures as there is still not a large rust issue at this time . If the project is not done in 2009 there is a risk that we may have to sandblast all steel components which would increase costs of the project by as much as 100% . This increased cost would be because of the need for containment of dust &grit and the disposal of grit. More equipment would be needed and there would be possible structural repairs needed.

Cons:

- If left unchecked the corrosion may affect the equipment structural integrity and the air wash fan and tank system may require to be shut down. The air wash equipment is crucial in maintaining 100% production from the power generating units during the hot summer temperatures. Depending upon exterior temperatures, unavailability of the air wash equipment may result in plant capacity reductions as high as 50%.

Financial Analysis/Assumptions Used:

Option 2: $108,000 in 2009.

Rate Impact (0.05% per million $s):

0.0056% in 2009.

Option Selected:

Option 2

Implementation Process:

Have Fortisbc personal do corrosion control of fan housing and tank in 2nd quarter of 2009.

Other Considerations:

Risks:

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: South Slocan Tailrace Gate Corrosion Control

Generation Planning No.: C100203

Executive Summary:

Corrosion control of the tailrace gates is to include, sandblasting and removal of all lead paint, containment of lead waste, removal and disposal, application of 2-part epoxy with urethane top coat. This project will increase the life of the 80 year old tailrace gates an additional 50 years. Reliability increases relating to gate operation, preserving gate structural soundness and ensuring operator safety, will be realized.

Background:

The two, tailrace gates were commissioned into service in 1928. The life expectancy of tailrace gates is 50 years. Thus, the gates have exceeded their anticipated operating life by over 50%.

Options Considered:

Option 1: Do Nothing

Pros:

- Failing to repaint the tailrace gates to the extent outlined in the project description will jeopardize the reliability of the tailrace gates operation. The corrosion control has failed in vast areas of the gates and eventually structure components failure is eminent. It is unacceptable practice to operate the tailrace gates to failure since they are a vital component of the generating unit safety. The gates also function as a prime safety barrier for workers performing maintenance on the unit.
- No capital costs

Cons:

- Risk of gate failures

Option 2: Repaint Tailrace Gates

Pros:

- Repainting of the two tailrace gates will prolong the tailrace gate system an additional 50 years. Reliability increases relating to gate operation, preserving gate structural soundness and ensuring operator safety, will be realized.

Financial Analysis/Assumptions Used:

Option 2: $114,000 for 2010

Rate Impact (0.05% per million $s):

Option 2: 0.0061%

Option Selected:

Option 2

Implementation Process:

FortisBC employees would sandblast and paint. The repainting of both gates will be carried out in 2010.

Other Considerations:

Risks:

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Queen's Bay Level Gauge Building

Generation Planning No.: C100204

Executive Summary:

An in-house investigation was conducted to determine the structures basic deficiencies. Based on the deficiencies list developed, an engineering consultant is to provide detail drawings for the new aluminum walkway handrail, aluminum beacon maintenance platform and handrails, and for the aluminum beacon access ladder. FortisBC labour forces will undertake the installation of the items as listed on the Engineering drawings as well as most remaining items from the deficiency list including:

- Install an overhead light and light switch
- Install a new service mast for the incoming power
- Install another wall receptacle
- Install new aluminum hatch door
- Upgrade level gauge mounting plate
- Refinish level gauge numerals
- Corrosion control on the existing walkway and walkway support structure
- Install public safety sign on fence and on structure facing open water

A fencing contractor will provide the services to install a new 7 foot tall security fence and man gate to limit public access to the structure.

Background:

The Queen's Bay level gauge structure is unpainted concrete and was constructed in 1939. 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 FortisBC 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 of inspection. Code deficiencies and a condition forecast of 50 years into the future dictate that the structure be upgraded.

Options Considered:

Option 1: Do nothing

Pros:

- No costs expended

Cons:

- Electrical code violations
- Work Safe BC code violations
- Walkway and support structure may need more extensive corrosion control upgrades in a decade or so.

Option 2: Upgrade Structure

Pros:
- Compliance with current Work Safe BC codes and regulations
- Compliance with current Electrical code
- Extend structure life to about 40 to 50 years

Cons:
- Costs for upgrades

Financial Analysis/Assumptions Used:

Option 2: $67,000

Rate Impact (0.05% per million $s):

Option 2: 0.0035%

Option Selected:

Option 2

Implementation Process:

- In 2009, Engineering drawings will be completed, new aluminum beacon platform and all aluminum handrails are to fabricated.
- In 2010, Procure equipment as per the Consultants Engineering drawings.
- In 2010, Install equipment as per the Consultants Engineering drawings and as per the deficiency list items
- In 2010, Install the Security fence and man gate.
- In 2010, prepare Scope of PH 2 of the project

Other Considerations:

Risks:

Employee and public safety. Reliability.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Upper Bonnington U5/U6 Tailrace Gate Corrosion Control

Generation Planning No.: M020102

Executive Summary:

Corrosion control of tailrace gates to include, sandblasting and removal of all lead paint, containment of lead waste, removal and disposal, application of 2-part epoxy with urethane top coat. This project will increase the life of the 60 year old tailrace gates an additional 50 years. Reliability increases relating to gate operation, preserving gate structural soundness and ensuring operator safety, will be realized.

Background:

Tailrace gates are utilized for unit isolation and dewatering system. They also function as an isolation point for system lockout during maintenance on the unit. Since the tailrace gate does not represent a double block and bleed as is normally required for an isolation point a variance has to be requested from the provincial regulatory body to allow the use of these gates as a Single Device Isolation. In order to receive this variance the company must show that due diligence has been applied to the inspection and maintenance of these gates. The continuing Tailrace and Headgate rebuild program is a significant part of this due diligence. The two, tailrace gates in question were commissioned into service in 1939. The life expectancy of tailrace gates is 50 years. Thus, the gates have exceeded their anticipated operating life by over 25%.

Options Considered:

Option 1: Do Nothing

Pros:

- No capital costs

Cons:

- Risk of gate failures
- Doing nothing is unacceptable as it leaves the gates in a condition whereby the company cannot guarantee their integrity such that they will meet the requirements as a Single Device for isolation.

Option 2: Repaint Tailrace Gates

Pros:

- By undergoing a rehabilitation of these gates the integrity of the gate components can verified and the proper application of a new coating will provide another 50 years of reliable service.

Cons:

- Increased costs

Financial Analysis/Assumptions Used:

Option 2: $139,000 for 2010

Rate Impact (0.05% per million $s):

Option 2: 0.0074%

Option Selected:

Option 2

Implementation Process:

FortisBC employees would sandblast and paint. The repainting of both gates will be carried out in 2010.

Other Considerations:

Risks:

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Upper Bonnington Extension Trash Rack Gantry Replacement

Generation Planning No.: C020502

Executive Summary:

This project consists of a wholesale replacement of the trash rack cleaning gantry for Upper Bonnington Units 5 and 6.

Background:

The Vintage 1939 Gantry is past its expected life span. The wiring and controls are fabricated with asbestos materials. The DC power system is antiquated. Spare parts are non existent. The gantry is not in compliance with crane standards.

Options Considered:

Option 1: Do nothing
Pros:

- Least cost outlay
- Gantry is operational

Cons:

- Contrivention of crane standards
- Undo risk to workers from exposure to asbestos
- Risk to unit reliability
- Excess maintenance

Option 2: Develop specifications and upgrade gantry
Pros:

- Compliance with regulatory bodies
- Increased operator and equipment safety
- Increased reliability
- Less maintenance

Cons:

- Increased costs

Financial Analysis/Assumptions Used:

Option 2: $417,000 in 2009

Rate Impact (0.05% per million $s):

Option 2: 0.022% in 2009

Option Selected:

Option 2

Implementation Process:

- In 2009, develop specifications, develop RFQ and award contract ,vendor to supply and install new gantry
- FortisBC to support vendor through process

Other Considerations:

N/A

Risks:

Employee and equipment safety, reliability.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FortisBC

2009/2010 FortisBC Business Case

Project Name: Lower Bonnington Intake Area Upgrade (Ph.1 & Ph.2)

Generation Planning No.: C090401

Executive Summary:

Phase 1: 2009
Phase1 will consist of the upgrade of the forebay access road

Phase 2: 2010
Engineering recommendations studies and summary of work preparation for future work in 2011

Background:

The road way is narrow and does not allow for two vehicle traffic. It has a gravel surface. There is a large bluff near railway crossing which reduces visibility. No protection is offered from steep shoulders to river. Steep banks to railway are sloughing onto roadway.

Options Considered:

Option 1:

Do Nothing
Pros:

- No capital costs, increased O&M costs

Cons:

- Roadway has visual impairment problems on railway track crossing, bank stability is in question and does not have protection for vehicles on steep banks.

Option 2:

Perform above mentioned scope of work
Pros:

- Increased reliability and safety.

Cons:

- Increased costs.

Financial Analysis/Assumptions Used:

Option 2: 2009 $393,000 & 2010 $102,000

Rate Impact (0.05% per million $s):

Option 2: 2009 0.0204%, 2010 0.0054%

Option Selected:

Option 2, this option achieves the objectives of utmost reliability, increased employee and public safety.

Implementation Process:

Phase 1: 2009
Contractor to perform all road restoration work with FortisBC support.

Phase 2: 2010
Third Party Engineering to supply condition assessment on forebay structures

Project Implementation flow

Other Considerations:

N/A

Risks:

Regulatory non conformance
Employee and public safety
WorksafeBC non compliance
Environmental and fisheries issues

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Corra Linn Spillway Gate Isolation

Generation Planning No.: X110104

Executive Summary:

The Corra Linn Dam was designed and constructed in 1932 with no provisions for spill gate isolation. The mild steel embedded items relating to the spillway gate guides have not received a complete inspection since the original construction. Condition assessments performed on similar spillway gates located downstream from the Corra Linn Dam indicate that formal condition assessments be done. To enable a formal condition assessment a spillway gate and guide system must be completely isolated. FortisBC Generation staff have reviewed viable isolation options based on information received from external engineering consultants. The selected option is a patented Reverse Needle Beam gate isolation system from Dix Corporation. This isolation system for each spillway gate is to be accomplished by notching the top of the piers on the reservoir side of the spill gate and installing a horizontal structural support beam in the notches. Vertical needle beams will be floated into position, attached to the horizontal support beam and then sunk to create a vertical wall across the spillway opening. The spillway gate can then be raised, releasing the trapped water and exposing the embedded items. This gate isolation system offers the quickest most efficient method of isolating a spill gate and the system components are virtually maintenance free. As recommended in the British Columbia Dam Safety Guidelines/Canadian Dam Association Dam Safety Guidelines, complete formal annual inspections can then be conducted on all spill gates embedded items.

Background:

The spillway gates were designed and constructed with no provisions for spill gate isolation. Gate repairs can only be conducted during spring freshet when water spillage is greater than the spill capacity for one spill gate. Embedded items repair is extremely limited and the accessible repair areas can only be conducted with a specialized diving crew. Currently thorough inspections and repairs of embedded parts can not be conducted

A Planning Approval document has been completed comparing viable spillway isolation options. The document highlights the advantages, disadvantages and costs for each viable option.

Canadian Dam Association Dam Safety Guidelines suggest that formal inspections be conducted on spillway gates and related hardware every five years on a rotative basis.

Based on condition assessments performed on similar spill gates downstream from the Corra Linn plant, prudent engineering practice would suggest formal condition assessments be conducted as recommended by the Canadian Dam Association Dam Safety Guidelines.

The sole purpose of this project is to ensure that the spill gates and embedded items are maintained in accordance with BC Dam Safety Guidelines/ Canadian Dam Association Dam Safety Guidelines, to be structurally sound. Presently the embedded items cannot be maintained in accordance with the Guidelines. Emergency repairs may require water spillage resulting in lost revenue.

A spill gate rehabilitation program is in progress at the Waneta dam. The program includes the spill gates, the spill gate guides, and concrete rehabilitation. The Waneta spill gates are about 20 years younger than the spill gates at the Corra Linn dam.

Options Considered:

Option 1: Reverse needle beam

Pros:

- Turn key equipment supply and installation from the Vendor.
- Minimal moving parts are not susceptible to corrosion.
- A Diving crew is not req'd during initial installation.
- A Diving crew is not req'd during needles installation.
- Pier notches to accept the needles support beam will be made in all eight spillway bays.
- Only one needles support beam is req'd for all 8 spillway bays.
- Additional needles support beams can be installed in notches on remaining seven spillway bays to decrease installation time of needles.
- Installation of needles on support beams can be accomplished by using a small boat, a small FortisBC crew and floating them to the appropriate needles support beam.
- Installation of needles is relatively quick and easy is the most cost effective installation option.
- Needles can be pressurized with Nitrogen to prevent internal corrosion.

Cons:

- Total project cost is marginally more expensive than option #2.
- Reverse Needle Beam system is patented by Aubian/Schnabel Engineering.

Option 2: Segmental Floating Bulkhead

Pros:

- Turn key equipment supply and installation from the Vendor.
- Classic proven design.
- Total project cost is marginally less expensive than option

Cons:

- Installation of floating bulkhead system is laborious and equipment intensive.
- Moving parts are susceptible to corrosion.
- A Diving crew is necessary for initial installation of equipment
- A Diving crew is necessary each time the floating bulkhead is used.
- Floating bulkhead seats must be installed on each spillway bay.

Financial Analysis/Assumptions Used:

Option 1: $46,000 for 2009

Rate Impact (0.05% per million $s):

Option 1: 0.0024% for 2009, 0.0002%

Option Selected: Option 1 REVERSE NEEDLE BEAM

Implementation Process:

- Engineering and Planning during 3rd and 4th quarter of 2009.
- Send out for quotes for contractors and marterials .- 2010.
- Prepare contracts and order materials –2010
- Installation spring of 2011

Other Considerations:

- The "Do-Nothing" Option was considered and rejected as being a non-viable option.
- Prudent engineering practice, BC Dam Safety Guidelines, Canadian Dam Association Dam Safety Guidelines and historical spill gate assessments on similar spill gates indicate that it is time to conduct a formal condition assessment.

Risks:

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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FORTISBC

2009/2010 FortisBC Business Case

Project Name: South Slocan Dam Rehabilitation Ph. 1

Generation Planning No.: X010903

Executive Summary:

The scope of the 2009 portion of this project is to perform engineering and produce an estimate that will allow Generation to submit a budget request in 2010 for approval to commence work in 2012. The construction work is proposed to be completed in 2012 and 2013, and will include concrete rehabilitation of the spillway dam.

Background:

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 another layer freezes and is pushed away. As concrete deteriorates rapidly once begun, ongoing monitoring and assessment is necessary so as to repair the concrete in a timely manner as possible so as to minimize repair cost. The portions of concrete most at risk are those adjacent to the water level.

During the early 1990's an Engineering consultant produced a concrete rehabilitation report for the South Slocan dam spillway. Approximately 50% of the spillway concrete surface was rehabilitated in the mid 1990's. The remainder of the concrete surface rehabilitation was not completed.

Concrete spalling at the water line is prevalent and requires attention. Concrete spalling is also being addressed at other FortisBC dam sites.

Options Considered:

Option 1: Do nothing

Pros:

- No capital costs

Cons:

- Will not be properly prepared for budget submittal

Option 2: Complete Engineering and Estimating for Concrete Rehabilitation

Pros:

- Will allow for core sampling as well as the review of options and costs to enable Generation to estimate for budget submittal.

Cons:

- None, minor costs only

Financial Analysis/Assumptions Used:

Option 2: $46,000 in 2009

Rate Impact (0.05% per million $s)

Option 2: 0.0024% in 2009

Option Selected:

Option 2

Implementation Process:

Engineer & Estimate in 2009, installation planned for 2012.

Other Considerations:

Risks:

Dam Failure.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

____
Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Lower Bonnington and Upper Bonnington Plant Totalizer

Generation Planning No.: C030700

Executive Summary:

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.

Background:

This metering is used to accurately measure and totalize the power produced from each generating plant for billing purposes. The existing PSI Quad 4 meters were installed in 1995 and 1996. The repair of these 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.

Options Considered:

Option 1: Do nothing

Pros:

- No capital expenditures

Cons:

- Risk of revenue meter failure with no spare parts available

Option 2: Install new PML-7650 meters

Pros:

- Will be using skills and knowledge obtained in implementing this same project at other FBC substations.
- Will reduce risk of revenue meter failure
- The installation is now occuring on all the remaining ULE progams. So all generating plants will have the same metering

Cons:

- Capital cost.

Option 3: Install different manufacturers Revenue meter

Pros:

- None, no cost saving identified

Cons:

- Cannot standardize on spare parts
- Additional training required to program and maintain new meters

Financial Analysis/Assumptions Used:

Option 2: $212,000 in 2010

Rate Impact (0.05% per million $s):

Option 2: 2010 0.0106%

Option Selected:

Option 2:   Install new PML 7650 meters.

Implementation Process:

In 2010:
Complete Lower Bonnington and Upper Bonnington at the same time. This work is independent of any other project.

Other Considerations:

None

Risks:

Approvals Required:

____
Manager Budgets & Forecasts FortisBC

____
Rob Dunsmore
Manager Generation

FORTISBC

2009/2010 FortisBC Business Case

Project Name: Lower Bonnington and Upper Bonnington Plant Communication Network Completion

Generation Planning No.: C100500

Executive Summary:

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.

Background:

The old SCADA systems at LBO and UBO plants are obsolete. Spare parts are not available to repair failures. This project will complete the installation of a new communication system and allow for the deactivation of the old system. 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.

Options Considered:

Option 1: Do nothing

Pros:

- No capital expenditures

Cons:

- Risk of communications failure which would not allow System Control Center control the generating stations.

Option 2: Communication Network completion

Pros:

- Will be using skills and knowledge obtained in implementing this same project at other FBC substations and the Brilliant Generating Station.
- Will reduce risk of communication failure
- The installation is now occuring on all the remaining ULE progams. So all generating plants will have the same communication system.

Cons:

- Capital cost.

Option 3: Install different manufacturers Communication System

Pros:

- None, no cost saving identified

Cons:

- Cannot standardize on spare parts
- Additional training required to program and maintain new equipment

Financial Analysis/Assumptions Used:

Option 2: $95,000 in 2009 and $297,000 in 2010

Rate Impact (0.05% per million $s):

Option 2: 2009 0.00475% and 2010 0.01485%

Option Selected:

Option 2: Communication Network Completion.

Implementation Process:

In 2009:

Complete engineering for project. Install several components in the system to be coordinated with South Slocan communication system completion being done under the ULE projects

In 2010:

Complete Lower Bonnington and Upper Bonnington at the same time.

Other Considerations:

None

Risks:

Approvals Required:

____
Manager Budgets & Forecasts FortisBC

____
Rob Dunsmore
Manager Generation

Transmission and Stations

		Previously Approved
2	Ellison Distribution Source - Approved	C4-07
3	Black Mountain Source - Approved	C-7-07
4	Naramata Substation - Approved	G-124-07
5	Okanagan Transmission Reinforcement - CPCN filed	
6	Ootischenia Substation - Approved	C-10-07
7	Benvoulin Substation - CPCN to be filed	
8	Recreation Capacity Increase	
9	Kelowna Distribution Capacity Requirements - NA	
10	Tarrys Capacity Increase	
11	Huth Substation Upgrade	
12	30 Line Conversion	
13	Static var Compensators - NA	
16	**Transmission**	
17	Transmission Line Urgent Repairs	
18	Right-of-Way Enhancements	
19	Right-of-Way Reclamation	
20	Transmission Pine Beetle Hazard Allocation	
21	Transmission Line Condition Assessment	
22	Transmission Rehabilitation	
23	Switch Additions	
24	20 Line Rebuild	
25	27 Line Rebuild	
26	30 Line Lake-Crossing Rebuild	
27	**Stations**	
28	Station Condition Assessment & Minor Projects	
29	Ground Grid Upgrades	
30	Station Urgent Repairs	
31	Bulk Oil Breaker Replacement	
32	Transformer Load Tap Changers Oil Filtration Project	
33	Slocan City-Valhalla Substation Upgrade	
34	Passmore Substation Upgrade	
35	Pine Street Substation –Distribution Breaker Replacement	
36	Princeton Substation Distribution Recloser Replacement	
37	Joe Rich Transformer Protection Upgrade	
38	Creston Substation Protection Upgrade	

Capital Expenditure
Justification Document

Project Name: Recreation Station (second transformer addition)

Project Number: SDP-TG4000

Project Cost: $178,000 / $3,401,000

Project Classification:

Project Description:

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.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Capacity, reliability, customer service

Background:

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

<u>Options Considered:</u>

<u>Option:1</u>
Offloading existing feeders.
Pros:

- Least cost option

Cons:

- Places strain on Saucier, Spall and Glenmore Feeders
- Limits flexibility for moving around load

Option:2
New distribution source transformer
Pros:

- Caters for growth in the region
- Allows for flexibility for moving loads
- Provides relief for Saucier, Spall feeders

Cons:

- cost

Financial Analysis/Assumptions Used

Option Selected
Option 2 is the only technical solution because of growth in the region it will be impossible to offload the feeders without incurring capacity additions at other stations.

Implementation Process
Construction required by the winter of 2010/2011 where the capacity of the existing transformer will exceed capacity

Other Considerations

Risks

2009-10 Capital Expenditure Justification Document

Project Name: Tarry's Sub Station Capacity Increase

Project Number: To be assigned

Capital Cost: $403,000

Project Classification: **Transmission Growth**

Project Description:

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.

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Background:

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 200 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.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Land: The Tarrys substation is built on Kaleshnikoff Lumber land, and FortisBC only has a right of way on this property. Part of this project would be to purchase land for the Tarry's substation. No capital will be invested on land that is not owned by FortisBC.

Reliability: The existing transformer at the Tarrys substation is overloaded and nearing the end of its useful life. If it failed, the mobile sub would have to be installed since the neighboring distribution system cannot support the mill load. However, currently there is no mobile bay at Tarry's so the installation of the mobile would require a non-standard configuration which would involve installing temporary grounding and fencing etc,. Therefore if the transformer failed, the Kaleshnikoff Mill would experience an outage for a significant length of time.

Capacity: The power contract currently agreed upon is for 3.4MVA, and the transformer at Tarrys substation only has 2MVA available. FortisBC must upgrade the system to meet contractual agreements, and to meet the current demand of the mill.

Options Considered:

Option 1: Rehabilitate the 5.6 MVA Wynndel transformer, tap changer and switchgear and relocate it to the Tarry's substation.

Pros:

- Resolve capacity issues
- Meet current contract demand at mill
- Lowest station solution capital cost

Cons:

- Unsufficient capacity to meet backup planning criteria for Playmor station.
- Cost $1,288,000.

Option 2: Rehabilatate a 15 MVA system spare and install in the Tarry's substation.

Pros:

- Resolve capacity issues
- Meet current contract demand at mill
- Meet planning criteria for backup to Playmor station

Cons:

- Significant station upgrade required
- Highest capital cost

Option 3: install Fans on the existing transformer to increase the capacity and install 200 A regulators on the Playmor feeder to serve the mill load during emergencies.

Pros:

- Resolve capacity issues
- Lowest capital cost

Cons:
- Possible power quality issues to resolve due to mill load on a customer feeder
- Reduction in reliability to the mill as they will be exposed to feeder outages
- $402,000

Financial Analysis/Assumptions Used:

Option3: 402,000

Rate Impact (0.05% per million $s):

Option 1: 0.02%

Option Selected:

Option 1.

Implementation Process:

2009

Other Considerations:

N/A

Risks:

Capital cost and ability to acquire land at Tarry's.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

____
Barry Smithson
Manager Network Services

2009/10 Capital Expenditure
Justification Document

Project Name: **Huth Substation Upgrade**

Project Number: SDP-TG21

Project Cost: **$$413,000/ $3,000,000**

Project Classification: (G, T & S)

Project Description:

This project is required to provide customer service and to maintain service reliability for the growing customer base in the South Okanagan Lake area.It involves a major upgrade to the 63 kV facilities at Huth Substation in Penticton. . 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.

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**
Capacity, Reliability

Background:

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

Options Considered:
The following options have been considered:

Option 1:

This option involves the installation of 63 kv facilities to form a split bus arrangement to utilize both supply lines (52L and 53L) efficiently.

Pros:
- Low cost
- Resolves supply capacity issue

Cons:
- Not fully meshed thereby making necessary momentary outages for load restoration.
-

Option 2:

This option provides for a complete ring bus arrangement which essentially provides a dual source to each ring bus element (line, transformer, bus segment)
Pros:
- Eliminates momentary outages
- Provides optimal equipment maintenance flexibility

Cons:
- High cost (approximately double the cost of Option 1)
- Utilizes all remaining property

Financial Analysis/Assumptions Used

Option Selected
Option 1

Implementation Process
Option 1 consists of some new switchyard facilities but can be easily accommodated within the existing substation property. Operationally, existing 8 kV load would be

transferred to neighbor stations and 13 kV would be provided by a mobile substation during the 63 kV switchyard re-configuration.

Other Considerations

Risks

Option 1 relies on the assumption that the existing switchyard steel structures are not approaching end of life and are adequate for another 30 years of service. A preliminary structural analysis will be conducted to mitigate this risk.

2009-10 Capital Expenditure Justification Document

Project Name: 161 – 63kV Voltage Conversion

Project Number: To be assigned

Capital Cost: $4,500,000
Project Classification: **TG**

Project Description:

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.

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**

Environmental: By eliminating all of the 161kV breakers and transformers, a significant amount of oil filled components will be removed from the system. None of these transformers currently have proper oil containment and are very near to water sources.

Maintenance: In total 5 transformer banks and 1 OCB breaker will be removed from the current maintenance program.

Reliability: Currently both the 161/63 kV transformers at South Slocan and Crawford Bay have no spares and in the event of a failure of either of these units all the customers in the North Kootenay would be exposed to a high risk of outage as they would be limited to only one source of supply. Currently, both 30L and 32L are available to supply this area.

Background:

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.

Option 1: Remove 161 kV transformers from Coffee Creek, Crawford Bay and South Slocan, install 1 breaker at Coffee Creek, 1 breaker at Crawford Bay, 63 kV capacitors at Coffee Creek and 25 kV capacitors at Kaslo for voltage support.

Pros:

- Removes non standard equipment
- Removes environmental risk associated with equipment
- Improves reliability by reducing risk associated with equipment failure
- Improves the electrcial characteristics of the network
- Lower capital cost than the ring bus option

Cons:

- Capital costs associated with the project.

Option 2: Remove 161 kV transformers from Coffee Creek, Crawford Bay and South Slocan; install 2 breakers and a 63 kV ring bus at Coffee Creek, 1 breaker at Crawford Bay, 63 kV capacitors at Coffee Creek and 25 kV capacitors at Kaslo for voltage support.

Pros:

- Removes non standard equipment
- Removes environmental risk associated with equipment
- Improves reliability by reducing risk associated with equipment failure
- Higher level of reliability due to ring bus arrangement
- Improves the electrcial characteristics of the network

Cons:

- Significant station upgrade required
- Higher capital cost
- Invests high capital into a 63 kV solution that may require upgrade in the future

Option 3: Do Not Convert

Pros:

Cons:

- Requires replacement of transformers at Coffee Creek and Crawford Bay due to deterioration (Initially included in the 2005 SDP)
- Require system spares for non standard equipment at Coffee Creek,South Slocan and Crawford Bay
- Continue to be exposed to environmental risk associated with equipment
- Exposure to reliability impact associated with equipment failure
- Higher maintainance costs associated with additional equipment

Financial Analysis/Assumptions Used:

Option 1:

Rate Impact (0.05% per million $s):

Option 1:

Option Selected:

Option 1.

Implementation Process:

2009

Other Considerations:

N/A

Risks:

None

Approvals Required:

Manager Budgets & Forecasts FortisBC

Barry Smithson
Manager Network Services

2009/10 Capital Expenditure
Justification Document

Project Name: Transmission Urgent Repair

Project Number: STP TS0100

Project Cost: $288,000 / $293,000

Project Classification: G T&S

Project Description:

This Project involves the repair or replacement of equipment that fail in service due to severe weather, vandalism or for other unexpected reasons. The estimate for this project is based on historical information. The following table shows the expenditures for the past four years as well as plan for 2009 and 2010.

Table 3.3
Transmission Line Urgent Repairs

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability, Capacity

Background:

Component failures on the transmission system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained.

Options Considered:

Option 1: Do nothing
Option 2: Repair all failures that cannot be deferred to the upcoming year.

Option:1
Pros: Nil
Cons: Unacceptable due to safety concerns and system reliability issues

Option 2:
Pros: Ensures that safety and reliability issues are addressed in a timely manner
Cons: Nil

Financial Analysis/Assumptions Used

The estimates are based on historical information.

Option Selected

Implementation Process

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Right of Way Easements

Project Number: SDP TS 0200

Project Cost: $311,000/ $345,000

Project Classification: T&D

Project Description:

This project is required for acquiring rights of way and easements for power systems that cross over customer property. This project has historically been used to obtain easements to address existing trespass situations. Easements for new projects are obtained as part of the new project and are not included. Expenditures will 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. The following table shows the expenditures for the past four years and plan for 2009 and 2010.

Table 3.4 Right of Way Easements

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

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**
Safety, Reliability

Background:
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.

Options Considered:

1 Do nothing….
1. Implement program.

Option 1 presents a huge risk in terms of liability and greatly impacts stakeholders.

Option 2 reduces the risk to employees, the public, our lines and therefore our shareholders and improves reliability.

Financial Analysis/Assumptions Used

Option Selected

Option 2 offers the best alternative as it does reduce risk to all stakeholders.

Implementation Process

Sustain and continuous improvement of current programs

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Transmission ROW Reclamation

Project Number: SDP TS 0300

Project Cost: SDP TS 0300 $550,000/ $602,000

Project Classification: G T&D

Project Description:

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

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**
Safety, Reliability

Background:

FortisBC's program for brushing includes the goal of removing trees that are of high risk to fail and hit transmission lines. Trees that meet the criteria as hazard or danger trees have a high probability of failing and hitting the lines. These types of trees are identified during the cyclic patrols performed on lines and are removed on a scheduled basis.

The following points influence the Transmission ROW reclamation program.

- The beetle problem in BC is increasing the number of dead trees that need to be removed.
- Forest fires can result from a failure of one of these trees.
- Removal of these trees would considered due diligence in the industry.

Options Considered:

1 Do nothing….
1. Implement program.

Option 1 presents a huge risk in terms of liability and greatly impacts stakeholders.

Option 2 reduces the risk to employees, the public, our lines and therefore our shareholders and improves reliability.

Financial Analysis/Assumptions Used

Option Selected

Option 2 offers the best alternative as it does reduce risk to all stakeholders.

Implementation Process

Sustain and continuous improvement of current programs

Other Considerations

Risks

2009/10 Capital Expenditure Plan

Project Name: Right-of-Way Reclamation – Pine Beetle Kill Hazard Trees

Project Number - SDP TS0300

Project Cost: $1,218,000/$821,000

Project Classification: T&D Sustaining

Project Description:
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 transmission lines

Key Drivers: Safety, Reliability

Trees that have been attacked by the MPB will deteriorate quickly, losing stem wood strength.

When trees identified within this program fail, they have a high probability of falling directly onto energized lines.

Background:

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

Financial Analysis/Assumptions Used

Estimates of trees attacked and reaching the final grey or dead state were assessed on a line by line basis using known brushing zones from the annual O&M program; the mix of deciduous versus coniferous trees in that area and a mortality rate assessment. These assessments are made by contracted members of the International Society of Arborists (ISA), who in addition have Certified Utility Arborists status.

Cost estimates provided by both of FortisBC's primary brushing contractors on a regional and line basis for the cost per line to down hazard trees are shown on pp 5-10. The costs are based on a prediction of the number of trees that would be considered a hazard in 2009 and 2010. The hazard trees will be addressed on an area priority basis beginning in urban areas where a downed line has a higher probability of human interface versus in more urban areas.

Return on wood value is considered negligible as only trees downed on Crown land may be harvested, if deemed economical, based on wood condition and retrieval cost. Removal of trees downed on private, municipal and Ministry of Transportation property will be up to the individual parties as to whether they are removed, disposed of or left on the ground.

Implementation Process

The probable percentage of grey tree counts within striking distance of all distribution and transmission lines has been estimated. Downing of the trees will be based on actual tree infestation status, location, and economies presented by brushing crews. Beetle Kill hazard tree removal does not necessarily align with the scheduled annual brushing zones. The annual maintenance brushing, capitalized removal in place of brushing, and Beetle Kill- Hazard tree removal will be overseen by FortisBC's Supervisor of Land and Brushing who will manage the program with input from contracted brushing crews who have qualified ISA members and Certified Utility Arborists on staff.

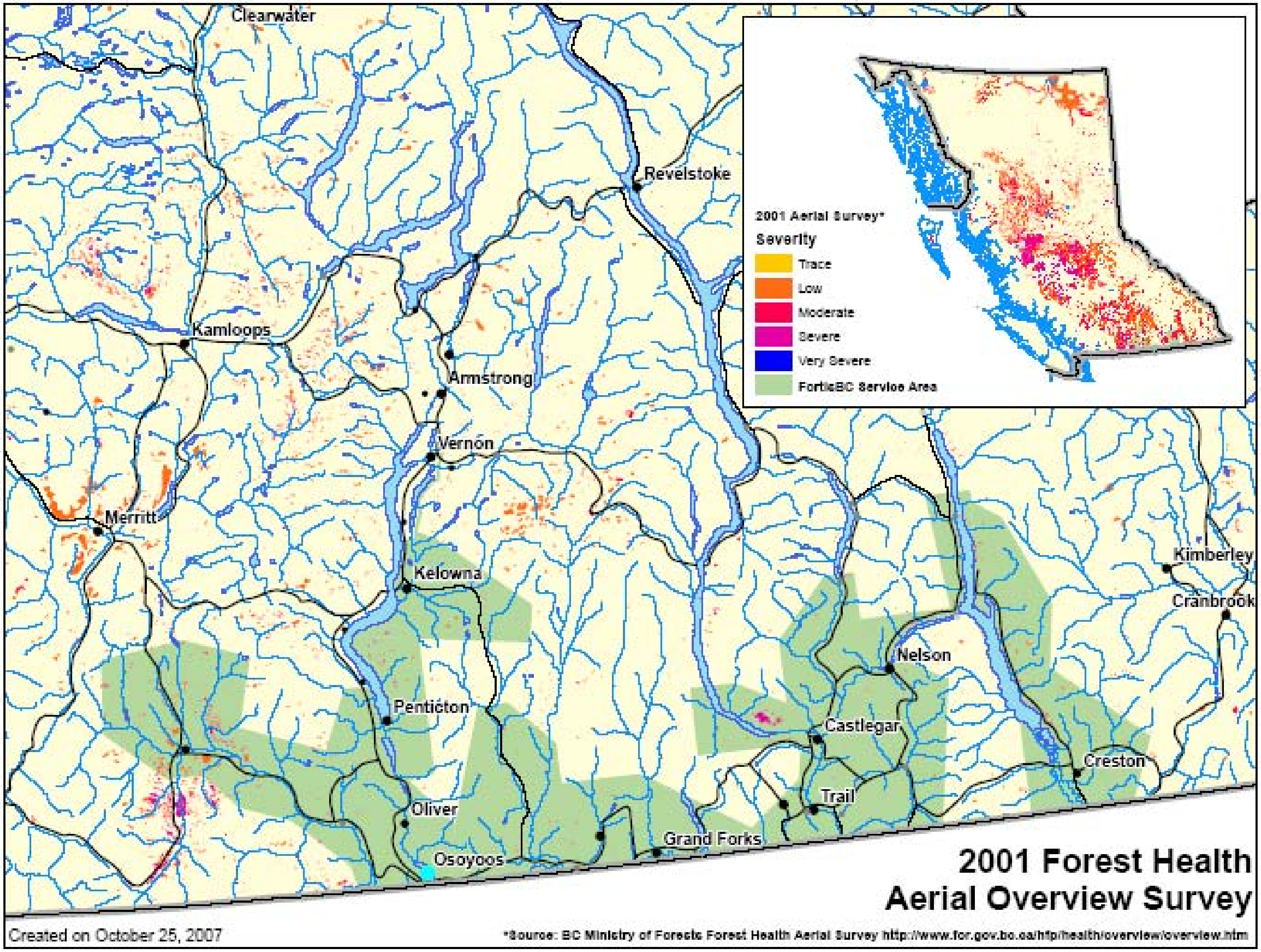
Beetle killed hazard trees in close proximity to lines will be removed in areas with higher population densities first, then the program will spread to rural areas. This approach will mitigate the danger to the general public and potential fire hazards due to downed power lines in order of highest to lowest probability.

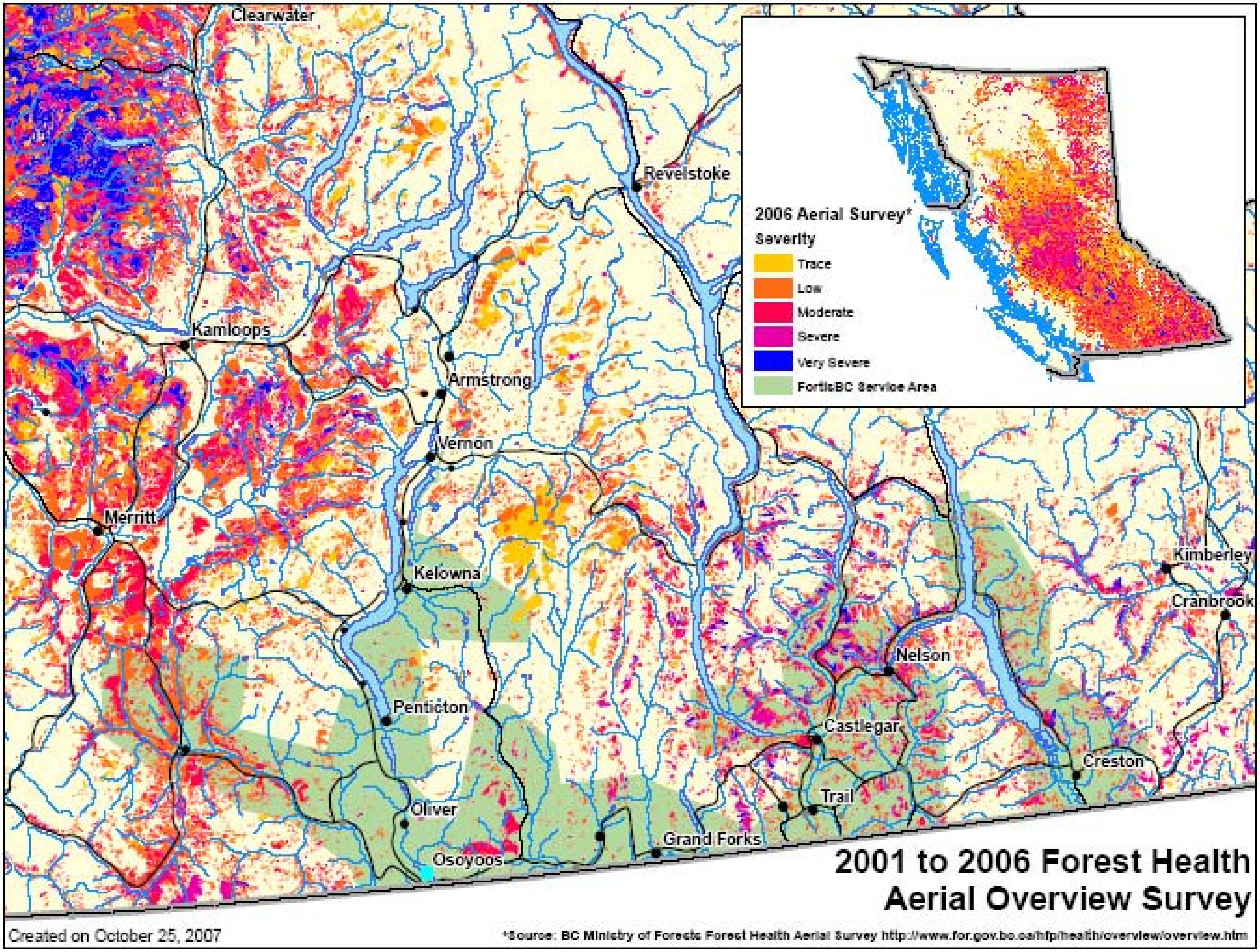
Other Considerations

Having first experienced MPB impacts within their service territory in the western and central interior part of the province, BC Hydro has a very similar program underway at this time. The beetle has moved progressively south and east from the initially affected BC Hydro areas and is expected to impact the entire FortisBC service territory heavily in 2008 through to 2013. FortisBC has approximately 5,300 kilometers of distribution and 1,400 kilometers of transmission line. Due to the location and limited size of the FortisBC system, it is expected that the MPB impact will be intense, but over in a shorter period of time than BC Hydro will experience.

The comparative BC Hydro MPB tree removal program carries an approved budget of $10.4 million for the 2008 fiscal year (end of March) and an approved budget of $11.4 million for the 2009 fiscal year. Subsequent BC Hydro annual expenditure levels are as yet unapproved, but FortisBC understands that they expect to require MPB funding to 2020 given its large service territory (an approximate total of 50,000 kilometers of distribution system, of which 30-40% is expected to suffer some degree of MPB impact).

Both FortisBC and BC Hydro are expending approximately $200/kilometer of distribution circuit annually due to MPB kill.


Clearwater
Revelstoke
Kamloops
Armstrong
Vernon
Merritt
Kelowna
Penticton
Oliver
Osoyoos
Grand Forks
Nelson
Castlegar
Trail
Creston
Kimberley
Cranbrook
2001 Aerial Survey*
Severity
Trace
Low
Moderate
Severe
Very Severe
FortisBC Service Area
2001 Forest Health
Aerial Overview Survey
Created on October 25, 2007
*Source: BC Ministry of Forests Forest Health Aerial Survey http://www.for.gov.bc.ca/hfp/health/overview/overview.htm


Clearwater
Revelstoke
Kamloops
Armstrong
Vernon
Merritt
Kelowna
Kimberley
Cranbrook
Nelson
Penticton
Castlegar
Creston
Trail
Oliver
Grand Forks
Osoyoos
2006 Aerial Survey*
Severity
Trace
Low
Moderate
Severe
Very Severe
FortisBC Service Area
2001 to 2006 Forest Health
Aerial Overview Survey
Created on October 25, 2007
*Source: BC Ministry of Forests Forest Health Aerial Survey http://www.for.gov.bc.ca/hfp/health/overview/overview.htm

2009/10 Capital Expenditure Justification Document

Project Name: Transmission Condition Assessment

Project Number: TS 0400

Project Cost: $427 / $ 496

Project Classification: G T&S

Project Description:
This project involves expenditures for structural stabilization of multiple transmission lines.

Included in the scope of work are pole testing and the application of wood preservatives and pole wraps to extend the life of the structure.

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 3.6(c)
Transmission Line Condition Assessment

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

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**
Safety, Reliability

Background:

The transmission line condition assessment program is based on an eight-year cycle of patrolling and testing all of FortisBC's 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 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.

Options Considered:

The key stakeholders in the present project are customers, property owners and the general public along the route of the subject lines. The customers' interests are related to reliability of service. The property owners' and the general publics' interest relates to the potential for property damage or personal injury in the event that the lines failed mechanically. A proactive preventive maintenance program that minimizes the risk of structural failure best serves their interests.

Available courses of action are as follows:

1. Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

2. Take measures to extend the service life of all structures requiring remediation.

The first course of action is not a legitimate planning option. Since FortisBC would have conducted an assessment of the pole and being aware of certain deficiencies, it would be imprudent not to rectify the deficiencies.

The second course of action involves the application of wood preservatives and pole wraps to extend the life of the pole.

The following table identifies all transmission lines to be tested and treated in 2009 and 2010.

Line	Poles	Kv	Owner	Location	2009	2010
1	15	63	FBC	WTS - STC	X	
25	299	63	FBC	SLC - PLA - TAR - BSS	X	
29	140	63	FBC	SLC	X	
31	105	63	FBC	AAL - CRE	X	
50	320	138	FBC	LEE - SEX - GLE - REC - SAU	X	
30	26	161	FBC	Coffee Creek – Crawford Bay	X	
49	310	63	FBC	HUT - WEB - TRC - SUM	X	
41	580	63	FBC	HUT - WAT - KAL - OKF - OLI		X
42	420	63	FBC	HUT - WAT - KAL - OKF - OLI		X
45	290	63	FBC	RGA - WES - NAR		X
45A	48	63	FBC	45 line to Downtown Penticton		X
46	87	138	FBC	LEE - DUC		X
47	50	63	FBC	HUT - WAT		X

Financial Analysis/Assumptions Used

The estimate for the project was based on historical experience, inflation, and, the number of poles to be tested.
A cost comparison was not completed for this business case because there are no viable alternatives to the proposed project. No attempt has been made to quantify the benefits due to reliability improvements or to quantify the avoided property damage or public injury, although these factors form the strong argument for proceeding with this work.

Option Selected

The second option is selected.

The proposed approach is consistent with FortisBC's strategic plan, in that it focuses on improving reliability, provides improvements in general public and employee safety and reduces the risk of public property damage while conforming to the long-term plan for Kootenay system development.

Implementation Process

Other Considerations

Risks

2009/2010 Capital Expenditure Justification Document

Project Name: Transmission Rehabilitation

Project Number: STP TS 2300

Project Cost:

$1,639,000 / $1,888,000

Project Classification: T, G & S

Project Description:

The project involves expenditures for structural stabilization of multiple transmission lines.

Included in the scope of work is replacement of cross-arms and poles and apparatus replacements on structures according to the needs at each specific pole location. Also, there are some minor requirements in terms of insulator and guy wire changes.

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

Table 3.7 (b)
Transmission Line Rehabilitation

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	3,468	993	336	3443	1639	1888

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**
Safety & Reliability

Background:

Background:

All of the rehabilitation projects will be derived from the 2008 and 2009 detailed Condition assessment and patrol program which is based on an eight year cycle.

Options considered:

The key stakeholders in this project are the property owners and the general public along the route of the subject lines. The interest of property owners and the general public relates to the potential for property damage or personal injury in the event that the lines failed mechanically. A proactive preventive maintenance program that minimizes the risk of structural failure best serves their interests.

Based on the condition assessment reports of the lines, the available courses of action are as follows:

1. Do nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option
2. Take measures to repair or replace all structures requiring remediation, i.e., 8-Year Stabilization Option

The first course of action is not a legitimate planning option. FortisBC has been involved in a condition assessment program for the past eight years, and is in the best position to know the condition of the transmission system. Since- FortisBC is aware of potential failures, the Company could be exposed to liability risk should the transmission line fail and result in damage to the public or to their property.

The second course of action involves repair or replace on a planned basis .The nature of the site-specific fixes is determined based on maximizing the service life of the structures. Specifically, all poles labeled as “reject” in the test data would be replaced, and all poles labeled as “stub” would be stubbed. All fix maintenance items would be completed.

2009 and 2010 rehabilitation will occur on the lines in the table below:

Line	Poles	Kv	Owner	Location	2009	2010
	4385					
1	15	63	FBC	Warfield to Stoney CkC		X
25	299	63	FBC	Slocan to Playmore to Tarry's to Brilliant		X
28	13	63	FBC	Upper Bonnington to Corra Linn	X	
29	140	63	FBC	Slocan Valley		X
31	105	63	FBC	Lambert to Creston		X
34	38	63	FBC	Warfield to Maudsley	X	
37	305	63	FBC	Coffee Ck. to Kaslo	X	
44	315	63	FBC	Oliver to Pine St. to Osoyoos	X	
50	320	138	FBC	Lee to Sexsmith to Glenmore to Recreation to Saucier		X
51	135	138	FBC	DG Bell to Okanagan Mission 50L/55L Junction	X	
54L	160	138	FBC	Lee to Bell, former part of 51L	X	
54AL	43	138	FBC	54L to Joe Riche Sub, former 51AL	X	
74	276	230	FBC	Lee to Vernon	X	
30	26	161	FBC	Coffee Creek-Crawford Bay		X
49	310	63	FBC	Huth-Westbench –Trout Creek-Summerland		X

Financial Analysis/Assumptions Used

The estimates are based historical information and knowledge of the lines being assessed.

Option Selected

Option 2

Implementation Process

Other Considerations

Risks

2009-10 Capital Expenditure Justification Document

Project Name: Switch Additions Castlegar Substation Switch CAS-6 and CAS-26 Upgrade

Project Number: To be assigned

Capital Cost: $132,000

Project Classification: **TS**

Project Description:
Upgrade the CAS 6-1 and 26-1 switches such that they can be operated remotely

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**

Operational Flexibility: The existing switches are manually operated, and result in a call-out anytime switching is needed to be performed. By giving SCC visibility and control of these switches, they can switch between 26L or 6L whenever the need presents itself.

Reliability: If either 6L or 26L trips offline for whatever reason, customers will experience an reduced outage duration if SCC can simply switch the Castlegar station over to the non faulted line.

Background:
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.

Option 1: Install motor operators and remote control from SCC for the Castlegar 63 kV switches

Pros:

- Low capital cost
- Improves transmission system switching and visibility for SCC
- Takes advantage of existing station communications
- Reduces reliability impact of line outages in Castlegar

Cons:

- Capital cost.

Option 2: Do Nothing

Pros:

- No capital cost

Cons:

- Lack of visibility of one of the largest load centers in the Kootenay’s for SCC
- Reliability risk associated with manual operation of the switches and the time required for this.

Financial Analysis/Assumptions Used:

Option 1: $132,000

Rate Impact (0.05% per million $s):

Option 1: 0.01%

Option Selected:

Option 1.

Implementation Process:

2009

Other Considerations:

N/A

Risks:

None

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

2009-10 Capital Expenditure Justification Document

Project Name: 20L Rebuild

Project Number: TS 1800

Capital Cost: $1,943,000 / 1,540,000

Project Classification: TS

Project Description:

This project is required to provide customer service and to maintain service reliability for the customers in the Trail, Waneta, Montrose, Fruitvale and Salmo areas. .The Project involves an extensive rebuild of 20 Line in order to maintain its integrity. The

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

20 Line Rebuild

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)
Safety:

Customer Service/Reliability: An engineering assessment concluded that the circuit is in relatively poor condition with numerous steel stubbed structures and conductor splices in particular within the original copper conductor sections. This leads to reliability issues.

Background:

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.

Option Considered:

Option 1: Upgrade the structures as per the recommendations outlined in the detailed engineered inspection report.

Pros:
- Properly assesses the condition of the line
- Installation of new marker balls for air traffic visability
- Addresses condition based work identified in the report

Cons:
- Capital costs associated with the project.

Option 2: Do Nothing

Pros:

- Lower capital cost

Cons:
- Does not address the condition of the line or the report
- Higher maintainance costs associated with additional equipment

Financial Analysis/Assumptions Used:

Option 1:

Rate Impact (0.05% per million $s):

Option 1:

Option Selected:

Option 1.

Implementation Process:

2009/2010

Other Considerations:

N/A

Risks:
None

Approvals Required:____

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Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

2009-10 Capital Expenditure Justification Document

Project Name: 27L Rebuild

Project Number: TS 2600

Capital Cost: $648,000 / 642,000

Project Classification: TS

Project Description:

This project is required to provide customer service and to maintain service reliability for the customers in the Nelson, Whitewater, and Ymir and Salmo areas. The Project involves an extensive rebuild of 27 Line in order to maintain its integrity. The current cost estimate and schedule for this project is shown below.

27 Line Rebuild

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety:

Customer Service/Reliability: An engineering assessment concluded that the circuit is in relatively poor condition with numerous steel stubbed structures and conductor splices in particular within the original copper conductor sections. This leads to reliability issues.

Background:

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.

Option Considered:

Option 1: Upgrade the structures as per the recommendations outlined in the detailed engineered inspection report.

Pros:

- Properly assesses the condition of the line
- Installation of new marker balls for air traffic visability
- Addresses condition based work identified in the report

Cons:

- Capital costs associated with the project.

Option 2: Do Nothing

Pros:
- Lower capital cost

Cons:
- Does not address the condition of the line or the report
- Higher maintainance costs associated with additional equipment

Financial Analysis/Assumptions Used:

Option 1:

Rate Impact (0.05% per million $s):

Option 1:

Option Selected:

Option 1.

Implementation Process:

2009/2010

Other Considerations:

N/A

Risks:

None

Approvals Required:____

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Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

2009-10 Capital Expenditure Justification Document

Project Name: 30L Kootenay Lake Crossing Upgrade

Project Number: TS-1900

Capital Cost: $350,000

Project Classification: TS

Project Description:

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

It involves upgrading the 30L lake crossing as per the detailed engineering, condition assessment report prepared by a consultant. The condition assessment report investigated the condition of the structures, insulators, anchors and identification marker balls. This project will upgrade the lines structural components as recommended in the report as well as inspect the line and change out the marker balls. This work needs to be completed in order to bring the line up to standard and to ensure the line is structurally sound and safe.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety: Some of the existing marker balls for the line have fallen off and fell into Kootenay Lake. This makes the line less visible to air traffic and creates a potential hazard for water traffic on the lake.

Customer Service/Reliability: The Lake crossing ties the east and west side of Kootenay lake customers together. Losing this link eliminates a redundant source to both of these areas, and therefore Crawford Bay would only have 32L as its source and Coffee Creek and Kaslo would rely solely on 30L. Both of these lines are in excess of 80 km long and travel in tightly treed Row’s and have a long history of reliability issues.

Background:

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

Option Considered:

Option 1: Upgrade the structures supporting the lake crossing as per the recommendations outlined in the detailed engineered inspection report. As part of this upgrade, new marker balls will be installed on the line as needed from a helicopter.

Pros:

- Properly assesses the condition of the line
- Installation of new marker balls for air traffic visability
- Addresses condition based work identified in the report

Cons:

- Capital costs associated with the project.

Option 2: Do Nothing

Pros:

- Lower capital cost

Cons:

- Does not address the condition of the line or the report
- Does not address the condition of the existing marker balls
- Higher maintainance costs associated with additional equipment

Financial Analysis/Assumptions Used:

Option 1:

Rate Impact (0.05% per million $s):

Option 1:

Option Selected:

Option 1.

Implementation Process:

2009

Other Considerations:

N/A

Risks:

None

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

2009/10 Capital Expenditure Justification Document

Project Name: Station Assessments and Minor Planned

Project Number: SDP SS0100

Project Cost: $620,000 / $680,000

Project Classification: G T&S

Project Description:

This Project involves the condition assessment of the Company's substations for safety , environmental and reliability issues on a ten year cycle, and the completion of the work resulting from these assessments in the subsequent year.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability, Capacity

Background

The station assessments and minor planned projects are necessary for the rehabilitation and ongoing upgrades of the substation system. These projects are necessary to ensure continuous service of the substation system which includes all equipment (transformers, breakers, batteries, ground grids, etc.)

The Station condition assessment program reviews the safety and reliability issues at seven to eight stations per year. There are a total of 70 stations that are in need of review. These stations are tracked in a 10-year cycle.

The work resulting from the condition assessments is then planned for the following year in the Station Minor Planned project.

Options Considered

Option 1: Do nothing. Unacceptable due to safety concerns and system reliability issues

Option 2: Conduct a major assessment of the stations on a 10 year cycle, inspect all equipment and recommend upgrades as required. In the following year, complete the upgrades after prioritizing the work for safety, compliance and reliability.

Financial Analysis/Assumptions Used

The estimates are based on historical information and preliminary estimates for the minor projects to be undertaken.

Option Selected

Station Assessments, and Minor Planned Program

Option 2: The station equipment deteriorates with time and operation. FortisBC must keep track of the degradation of its system. Effective assessments ensure that the stations are updated in a planned fashion.

Implementation Process

Assessments are completed year round. The minor planned projects are scheduled to accommodate analysis of priorities for safety compliance and reliability. The highest priority items are completed first.

Risks

Safety – all of the sustaining projects have some level of safety mitigation. The projects are for replacing or rehabilitating equipment or structures that have level of risk of failure.

Reliability – All of these projects are reliability driven. Preventing failures will improve reliability.

Component failures in substations due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained.

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

Replace DC supply 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.

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 system control center 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 to our station alarms, transformer condition and switch/breaker positions. In addition station equipment would not be able to operate, even by crews onsite, until DC power is restored

This project will schedule 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.
- Any battery bank that tests below 70% of capacity or is older than 20 years.

Locations receiving new batteries will also receive an insulated temperature controlled battery room that maintains 17^{o}C to maximize battery life. The following substation DC supply will be updated in 2009 and 2010.

2009	**2010**
Glenmerry	Tarry's
Cascade	Glenmore
Playmor	Hollywood
	OK Mission

<u>Replace Gapped-Silicon-Carbide Arrestors</u>

In 2009, the Company plans to initiate a four year program to replace Gapped Silicon Carbide Arresters with Gapless Metal Oxide MOV Arresters. These arrestors are used to protect electrical equipment and other assets from lightning and switching surges that can damage the equipment. There are two reliability issues involving gapped surge arresters: adequacy of protection and consequential damage resulting from in-service failure. Gapped Silicon Carbide surge arresters have a higher rate of failure than Metal Oxide arresters as well; research has shown Metal-Oxide Arresters provide substantially improved protection over Silicon Carbide Arresters. Replacement of aging and failing gap-type surge arrestors will provide greater protection for existing assets from lightning and switching surges that can damage equipment, and because of the potential for explosive failure of surge arresters, replacing the gapped porcelain arresters will improve work site safety. The Company will replace arrestors in approximately 20 locations in 2010.

Table 3.9
Stations Assessment and Minor Planned Projects

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

2009-10 Capital Expenditure
Justification Document

Project Name: Castlegar Substation Grounding Upgrade

Project Number: To be assigned

Capital Cost: $572,000

Project Classification: **Station Sustaining**

Project Description:

Upgrade the ground grid at the Castlegar Substation to meet current standards. This project includes the installation of a new ground grid, additional ground rods, new ground wells and an upgrade of the insulating gravel to FortisBC standards.

Background:

Preliminary studies have concluded that the existing substation grounding does not provide safe step and touch potential inside the substation, but can upgraded to the required standards. Further studies will provide final details required for upgrading of the station ground grid.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Employee Safety, Public Safety

Options Considered:

Option 1: Upgrade the existing station ground grid.

Pros:
- Resolve step and touch voltages inside the station
- Lowest capital cost

Cons:
- .

Option 2: Do nothing.

Pros:
- No cost

Cons:
- Continue exposure to unsafe step and touch voltages in the station.

Financial Analysis/Assumptions Used:

Option 3: $572,000

Rate Impact (0.05% per million $s):

Option 1: 0.025%

Option Selected:

Option 1.

Implementation Process:

2009

Other Considerations:

N/A

Risks:

None

Approvals Required:

____

Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

2009/2010 Capital Expenditure Justification Document

Project Name: Station Urgent Repair

Project Number: STP SS0200

Project Cost: $473,000 / $448,000

Project Classification: G T&S

Project Description:

This Project involves the repair or replacement of Substation equipment that fail in service due to severe weather, vandalism or for other unexpected reasons.

The estimate for this project is based on historical information. The following table shows the expenditures for the past four years and plan for 2009 and 2010.

Table 3.11
Station Urgent Repairs

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability, Capacity

Background:

Component failures on the Substation system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained.

Options Considered:

Option 1: Do nothing
Option 2: Repair all failures that cannot be deferred to the upcoming year.

Option:1
Pros: Nil
Cons: Unacceptable due to safety concerns and system reliability issues

Option 2:
Pros: Ensures that safety and reliability issues are addressed in a timely manner
Cons: Nil

Financial Analysis/Assumptions Used

The estimates are based on historical information.

Option Selected

Implementation Process

Other Considerations

Risks

BEP - Beaver Park	**KAS - Kaslo**	**TRA - Trail**
BLU - Blue Berry	**KET - Kettle Valley**	**UBO - Upper Bonnington**
BRA - Roxul	**KRA - Kraft**	**VAL - Valhalla**
CAS - Castlgar	**NWD - North Warield**	**WAR - Warfield**
CHR - Christine Lake	**PAS - Passmore**	**WHI - Whitewater**
COT - Cottonwood	**PAT - Paterson**	**WST - Westar**
CRA - Crawford Bay	**PLA - Playmor**	**WYN - Wyndell**
CRE - Creston	**ROS - Rossland**	**YMR - Ymir**
CSC - Cascade	**SAL - Salmo**	**BCG - BC Gas (Terasen)**
FRU - Fruitvale	**SLO - Slocan City**	**HED - Hedley**
GLM - Glenmerry	**STC - Stoney Creek**	**HOL - Hollywood**
GRA - Granite	**TAR - Tarrys**	**HUT - Huth**
GRE - Greenwood	**DUC - Duck Lake**	**JOR - Joe Rich**
HER - Hearns	**GLE - Glenmore**	**KAL - Kaleden**
OKF - OK Falls	**OKM - OK Mission**	**KER - Kermeos**
OSO - Osoyoos	**SAU - Saucier**	**TRC - Trout Creek**

PIN - Pine Street
REC - Recreation
WES - Westminster
SEX - Sexsmith
SUM - Summerland
WAT - Waterford
WEB - Westbench

AAL - (A..A.) Lambert Terminal
ALH - Arrow Lakes Hydro Generating Station
ASM - (A.S.) Mawdsley Terminal
BRD - Brilliant Generation Station
BRX - Brilliant Expansion Generating Station
BSS - Brilliant Switching Station
BTS - Brilliant Terminal Station
COF - Coffee Creek Terminal
COR - Corra Linn Generating Station
DGB - (D.G.) Bell Terminal
ESS - Emerald Switching Station
GFT - Grand Forks Terminal
LBO - Lower Bonnington Generating Station
LEE - (F.A.) Lee Terminal
OLI - Oliver Terminal
PRI - Princeton Terminal
RGA - (R.G.) Anderson Terminal
RSM - Rosemont Switching Station
SLC - South Slocan Generating
TSS - Tadanac Switching Station
USS - Upper Bonnington Switching Station
VAS - Vaseux Lake Terminal
WAL - Walden Generating
WAN - Waneta Switching Station
WAX - Waneta Expansion Generating Station
WDN - Walden North Generating Station
WHS - Waneta Hydro Switching Station
WSS - Warfield Switching Station
WTS - Warfield Terminal Station
BEN - Bentley Terminal

BUSINESS CASE
2009/2010 Capital

Project Name: Bulk Oil Breaker Replacement Mobile M12

Project Number: SDP-SS0700.09.1-2

Project Cost: Estimate $292,000 (Custom to fit Mobile)

Project Classification: (G, T & S)

Project Description:

This Project involves the replacement of the existing 15 KV Bulk Oil Circuit Breaker with an acceptable model which will provide:

1. Greater protection for Transmission Assets
2. Enhanced reliability
3. Reduced maintenance costs
4. Reduced environmental issues

Site:

1. **12 MVA Mobile – T1 Main CB**

Key Driver:

Employee Safety, Public Safety, Reliability, Environmental and Equipment Protection

Background:

Bulk oil circuit breakers of this particular style are not typically designed for a mobile application. Changing to a vacuum type breaker would mitigate excess weight issues and environmental concerns in the event of a leak or spill during transportation to numerous sites.

This breaker is of the 1968 vintage. Component failures on aging Bulk Oil Breakers have become an increased issue due to the availability and cost of primary components. Parts have to be custom built and are not readily available in emergency situations. Repair and technical expertise of these aging assets have also become issues in these emergency situations. These issues have extended maintenance cycles and outage durations.

An oil spill or release during transportation of the mobile could have a major impact on the environment depending on the sensitivity of the area.

2006 Capital Expenditure Justification Document

Project Name: Transformer Load Tap Changers Oil Filtration Project

Project Number: SS1000

Project Cost: $32,000/64,000

Project Classification: T&G

Project Description:

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.

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.

Table 3.12
Oil Filtration Installations

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	119	81	141	303	32	64

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Reliability This project will extend the life of the transformer and increase the cycle time to maintain the tap changer.

Background:

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.

Options Considered:

Option:1 Install filtration System
Pros: Less equipment failure, lower maintenance cost
Cons: capital cost
Option 2: Do Nothing
Pros:
Cons: equipment failures, higher maintenance cost

Financial Analysis/Assumptions Used

Option Selected Option 1

Implementation Process

Other Considerations

Risks

2009-10 Capital Expenditure Justification Document

Project Name: Slocan City – Valhalla Solution

Project Number: To be assigned

Capital Cost: $2.173,000

Project Classification:

Project Description:

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 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 This project is planned for 2009 with forecast expenditures of $2.17 million.

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**

Environmental: The Slocan City sub-station is located approximately 30 meters from Springer Creek which drains into Slocan Lake. A failure or oil leak from the transformer would result in a spill into the lake, which would have a negative impact on the lake and its ecosystems.

Land: The Slocan City sub-station land is not owned by FortisBC.

Reliability and Condition: The existing transformer at the Slocan City substation is old, and maintenance records indicate that it is nearing the end of its useful life. In order to reliably provide power to the mill, the transformer and station would require upgrading.

Background:

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.

Options Considered:

Option 1: Replace existing Valhalla transformer with larger transformer to supply residential and mill load.

Pros:
- Salvage of the existing Slocan City station

Cons:
- High capital cost
- Customer and industrial load supplied by same source

Option 2: Install a second transformer in the Valhalla station.

Pros:
- Salvage of the existing Slocan City station
- Lower capital cost (A spare unit is available)
- Second transformer for backup in remote station

Cons:
- None

Financial Analysis/Assumptions Used

- Work will be done with FortisBC internal work force

Option Selected

Option 2, involving the installation of a spare 10 MVA transformer is selected because it is the most economical and allows for the decommissioning of the Slocan City Substation.

Implementation Process

This project will be completed prior to the end of 2010.

Other Considerations

N/A

Risks

Environmental risks are still present until this project is implemented.

2009-10 Capital Expenditure Justification Document

Project Name: Passmore Sub Station Upgrade and HT Breaker Installation

Project Number: To be assigned

Capital Cost: $1,987,000

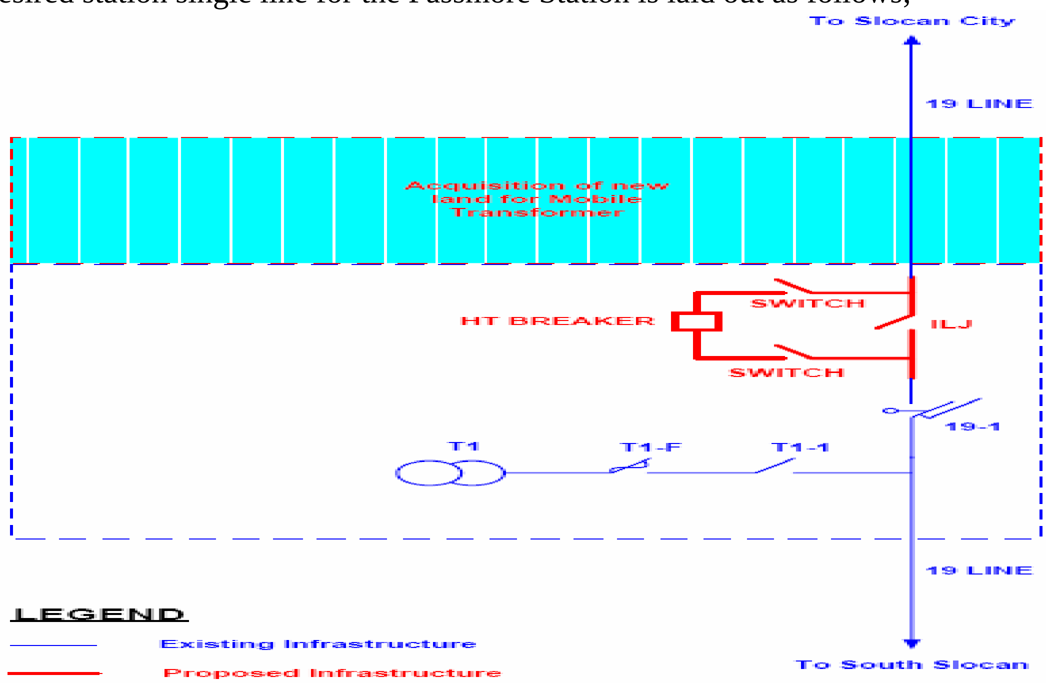
Project Classification: Transmission Growth

Project Description:

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 desired station single line for the Passmore Station is laid out as follows;



Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**
Operational Flexibility: The ability to sectionalize 19L will reduce unnecessary outages to the Passmore customers in the event of a fault on the line anywhere north of Passmore,
Reliability: The installation of the breaker will improve the reliability of 19L which is a radial 63 kV transmission line that has historically been the largest SAIDI contributors in the FortisBC transmission system.
In addition, currently there is no room to safely park the portable mobile sub station trailer within the Passmore station and the distribution system in the area has very little backup capability. Therefore in the event of the transformer failing at Passmore, customers would experience a lengthy outage with the duration being dependant upon the time of year the failure occurred.

Background:

.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.

The table below shows the 19L customer hours of outage and SAIDI in comparison to the entire FortisBC transmission system:

	19L Supplying Slocan Valley		FortisBC Transmission Total			
Year	Cust Hours	SAIDI	Cust Hours	SAIDI	19L as % of Total Tx SAIDI	19L SAIDI Rank (1 is highest)
2004	23209	0.25	53283	0.58	44%	1
2005	4868	0.05	56680	0.61	9%	4
2006	29643	0.32	182293	1.95	16%	2
2007	11287	0.12	80534	0.86	14%	2

NOTE: Non normalized FortisBC Data

The other major component of this project is the expansion of the station to safely and effectively allow for the installation of a mobile station. Currently, in the event of a transformer failure, the customers served by Passmore would experience a long outage as there is very little distribution back up available.

Options Considered:

Option 1: Acquire new land and install breaker and mobile bay
Pros:
- Improve reliability on historically one of FortisBC's worst radial lines (19L)
- Allow for the safe installation of a mobile when required

Cons:
- Up front capital costs

Option 2: Do nothing (status quo)
Pros:
- No upfront capital costs

Cons:
- Continue to face reliability issues
- Continued risk for a transformer failure and reliability impact at Passmore

Financial Analysis/Assumptions Used:

Option 1: 1,987,000

Rate Impact (0.05% per million $s):

Option 1: 0.1%

Option Selected:

Option 1.

Implementation Process:

2010

Other Considerations:

N/A

Risks:

Until this project is implemented we continue to face 19L historical reliability issues and the reliability impact of a transformer failure at Passmore.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

2009/2010 Capital Expenditure Justification Document

Project Name: Pine Street Breaker Replacement
Project Number: SDP-SS1400

Project Cost: $345,000

Project Classification: (G, T & S)

Project Description:

The project involves the replacement of the DH-P air-blast "arc chute" breakers at the Pine Street substation. This project is required to provide customer service and to maintain service reliability for the customers in the town of Oliver.

Background

The Pine Street substation 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 DH-P 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.

Key Driver:
Employee Safety, Public Safety, Reliability and Equipment Protection

Options considered:
No practical alternatives are available for this project. These units are at end-of-life and should be replaced.

2009/2010 Capital Expenditure
Justification Document

Project Name: Princeton Breaker Installation
Project Number: SDP-SS2200

Project Cost: $1,510,000

Project Classification: (G, T & S)

Project Description:

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 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.

Background:

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

Key Driver:
Employee Safety, Public Safety, Reliability and Equipment Protection

Options evaluated:

No practical alternatives are available for this project. The reclosers are at end-of-life and/or are not able to withstand the fault currents at the Princeton yard.

BUSINESS CASE

Project Name: Transformer Protection Project - JOR

Project Number: SDP-TS1790

Project Cost: $404,000

Project Classification: (G, T & S)

Project Description:

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. The Project involves upgrading the protection on the 20 MVA Joe Rich Transformer 1 which is currently equipped with high side fuses

Key Driver:
Employee Safety, Public Safety, Reliability and Equipment Protection

Background

The Transformer at Joe Rich Substation is the only 138 kV transformer in the FortisBC system protected by high side fuses. The upgrade 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.

Options:

In 2010 the high side fuse T1-F on the Joe Riche Transformer will be replaced with a Breaker. No practical alternatives exist for this project. To bring the station up to industry accepted standards this work is required.

2009-10 Capital Expenditure Justification Document

Project Name: Creston Substation Transformer Circuit Switchers

Project Number: To be assigned

Capital Cost: $488,000

Project Classification: **TS**

Project Description:

Creston Substation Protection Upgrade
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.

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**

Reliability: Currently a fault anywhere on the 69kV side off or internal to T1 or T2 at Creston Central will trip 31L (Transmission line) because the relay at Lambert senses the fault and clears it before the fuses have time to melt and isolate the system. This results in a complete station outage at Creston, even though the other non faulted transformer is healthy. By putting in the Circuit switchers they will operate much quicker than the fuses and proper coordination is achievable.

Customer Service: T2 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 the customers served in the Creston area. Replacing the fuses with circuit switchers will allow the T2 transformer to be energized / deenergized whenever the need presents itself, without interfering with T1.

Safety: The 69kV fuses are currently mounted on a horizontal plane, and are very difficult to operate due to their physical location and how close they are to the grounded transformer tank during switching. By installing Circuit switchers, they operate automatically/remotely and will be mounted in more appropriate location.

Background:

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.

Option 1: Replace the existing T1 and T2 fuse protection with circuit switchers and associated protection and modifications to the 63 kV bus.

Pros:

- Improves protection and coordination of the T1 and T2 transformers
- Improves Creston Central reliability impact due to transformer faults
- Improvements to operational flexibility in the station for switching and maintenance

Cons:

- Capital costs associated with the project.

Option 3: Do Nothing

Pros:

- Lower capital cost

Cons:

- Exposure to reliability impact associated with equipment failure
- Operational constraints are not addressed

Financial Analysis/Assumptions Used:

Option 1: $488,000

Rate Impact (0.05% per million $s):

Option 1: 0.05%

Option Selected:

Option 1.

Implementation Process:

2009

Other Considerations:

N/A

Risks:

None

Approvals Required:

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Manager Budgets & Forecasts FortisBC

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Barry Smithson
Manager Network Services

Distribution

1	**GROWTH**	
2	New Connects - System-wide	
3	**Distribution Growth Projects**	
4	Glenmore -New Feeder	
5	Airport Way Upgrade Feeder	
6	Hollywood Feeder 3- Sexsmith Feeder 4 Tie	
7	Christina Lake Feeder 1 Upgrade	
8	Beaver Park-Fruitvale Tie	
9	Small Growth Projects	
10	Unplanned Growth Projects	
11	**TOTAL GROWTH**	
12	**SUSTAINING**	
13	**Distribution Sustaining Programs and Projects**	
14	Distribution Line Condition Assessment	
15	Distribution Line Rehabilitation	
16	Distribution Right-of-Way Reclamation	
18	Distribution Pine Beetle Hazard Allocation	
19	Distribution Line Rebuilds	
20	Small Planned Capital	
21	Forced Upgrades and Line Moves	
22	Distribution Urgent Repair	
23	PCB Program	G-52-05
24	Aesthetic and Environment Upgrades	G-58-06
25	Copper Conductor Replacement Program	CPCN to be filed

FortisBC Business Case

Project Name: DG-2900 New Connects

Cost ($9,788,000 / $10,670,000)

Executive Summary

This project accumulates customer and company expenditures associated with new connects and / or line extensions that are driven by third parties. System upgrade work necessitated by a new extension but not directly attributable to a customer will also be charged to this budget.

Background

FortisBC must respond to requests from customers wishing to connect to the company's electrical system. The manner in which the company charges to build necessary infrastructure to connect customers is governed by the Electric Tariff which is approved by the British Columbia Utilities Commission. The FortisBC Electric Tariff lays out the rules for how costs for a new connection / line extension are to be borne by a customer and / or FortisBC.

Options Considered

Option 1: Continue to handle New Connect requests as per rules in the FortisBC Electric Tariff.

Pros:

- Allows FortisBC to be able to respond to customer connect requests.

Cons:

- None

Option 2: Do nothing

Pros:

- None

Cons:

- Prohibits FortisBC from responding to customer connect requests.

Financial Analysis/Assumptions Used

Option 1:

Rate Impact (0.05% per million $s)

.45%

Option Selected

Option 1

Implementation Process

As per FortisBC Electric Tariff

Other Considerations

Risks

None Identified

Approvals Required

Manager Budgets & Forecasts FortisBC

Capital Expenditure
Justification Document

Project Name: New Glenmore Feeder to Landmark

Project Number: STP DG3200

Project Cost: $788,000

Project Classification:

Project Description:
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 estimated cost of this project is $788,000.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Reliability, capacity, customer service

Background:

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 additional feeder will allow for capacity offloading and backup to OKM4 and GLE1 feeders.

Options Considered:
A new feeder to supply capacity to this area is the only viable option

Option:1
Run a new feeder from Glenmore (using the spare breaker which currently serves the capacitor bank)
Pros:

- Close to load
- By offloading GLE1 some load can be moved off GLE2 as a consequence allowing for Glenmore to provide more road in the Enterprise commercial corridor

Cons:

- Glenmore fast approaching capacity
- Underground cable is required

Option 2:
Run a new feeder from OKM station
Pros:

- Overhead construction possible for most of the length

Cons:

- Very far away from the load (feeder would be an express with a length greater than 6km before any load is delivered)
- Underground would be required

Financial Analysis/Assumptions Used
Cost of the project assumes the existing corridor is within the highway corridor. No major ROW shall be required as the line is being built along an existing distribution line ROW.

Option Selected
Option 1 (least cost and most flexible for long term growth)

Implementation Process
Construction in 2009

Other Considerations

Risks

Capital Expenditure
Justification Document

Project Name: Airport Way Upgrade (Ellison Feeder 3)

Project Number: STP DG3300

Project Cost: $1,551,000

Project Classification:

Project Description:

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.

The estimated cost of this project, scheduled for 2010, is $1.55 million.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Reliability, capacity, customer service

Background:

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.

Options Considered:

Option:1

Upgrade existing 200A cable to a 600A underground cable.

Pros:

- Allows for future expansion and flexibility in this commercial corridor

Cons:

- Will require retrench along entire circuit length as current ducts are insufficient.

Option:2

Build a second line along HWY 97 south of the substation on the east side of the highway and cross Airport owned land on a ROW to connect to Airport way.

Pros:

- Reduced amount of underground line required.

Cons:

- Requires the purchase of ROW on Airport land which is not available based upon conversations with the Airport Manager. The land is being held back for the purposes of developing the airport for the next 50 years.
- Does not create future capacity and flexibility for the areas that are growing to the north of the substation.

Financial Analysis/Assumptions Used

All proposed works are within federal crown land and require statutory rights of way.

Option Selected

Option 1 – Future capacity and the risk to land for option 2 makes option 1 the preferred option.

Implementation Process

Construction in 2009

Other Considerations

Risks

Capital Expenditure
Justification Document

Project Name: HOL3 – SEX4 Tie

Project Number: STP DG3500

Project Cost: $365,000

Project Classification:

Project Description:

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.

The estimated cost of this project scheduled for 2010 is $365,000.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Reliability, capacity, customer service

Background:

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

Options Considered:

Option:1

Run an underground circuit from HOL3 in HWY97 along HWY33 to Enterprise Way install circuit switch and continue with circuit to SEX3 which is an underbuild of the transmission line.

Pros:

- Simple construction.
- Existing Duct.

Cons:

- Uncertainty surrounding the proposed Central Okanagan Bypass and the planned interchange with HWY33.

Financial Analysis/Assumptions Used

Option Selected

Option 1 (cost)

Implementation Process

Construction in 2010

Other Considerations

Risks

2009-10 Capital Expenditure Justification Document

Project Name: Christina Lake Feeder-1 Capacity Upgrade

Project Number: To be assigned

Capital Cost: $608,000/$489,000

Project Classification:

Project Description:

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.

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.

Key Drivers: **(Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)**

Customer Service, Reliability, Capacity:

Customers being fed from the FortisBC distribution system are expected to be served at a voltage between 115V and 125V, as per internal guidelines and CSA standards. Anything outside of this needs immediate attention because electronic equipment within peoples homes are becoming more and more sensitive to these conditions, and in turn are failing more often.

Background:

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.

Options Considered:

There are two Options to meet the project objectives:

Option 1: Reconductor #6 Copper with #3/0 Aluminum

This option will swap the #6 Copper wire with #3/0 from OBID 123180 to OBID 124551. The #6 wire creates a higher impedance and in turn causes a larger voltage drop on the line. By putting in #3/0, we will reduce the losses on the feeder/system, and in turn supply the customers with the appropriate voltage at their utilization point.

Pros:

- Address voltage issues
- Eliminate copper conductor

Cons:

- Higher costs

Option 2: Install 200 A regulators to support voltage

By installing a set of regulators the current voltage issues can be addressed. This option would install a set of 200A regulators and is estimated at about $250,000.

Pros:

- Address voltage issues
- Lower costs

Cons:

- Does not address the copper conductor
- Additional Option 1 costs will be reqiured as a part of the Copper Replacement Program.

Financial Analysis/Assumptions Used

- Estimate based on 2008 information.
- Work will be performed with internal labor forces.

Option Selected

Option 1 is selected to address both the customer voltage issues and reliability issues associated with the copper conductor.

Implementation Process

This project will be completed before the end of 2010.

Other Considerations

N/A

Risks

Damaging sensitive electronic equipment.

2009-10 Capital Expenditure Justification Document

Project Name: BEP2 – FRU1 Distribution Tie Upgrade

Project Number: To be assigned

Capital Cost: $1,230,000

Project Classification: **DG**

Project Description:

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.

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.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Reliability, Capacity, Operation Flexibility, Capital deferral:

This project will increase the capacity and flexibility of the distribution tie between Fruitvale and Beaver Park to allow for load transfer and backup between the stations. The intent of this project is to provide distribution system flexibility to allow for the deferral of a station upgrade project in the Fruitvale/Beaver Park area.

This project will also eliminate copper conductor that has been identified in the Copper Replacement Program.

Background:

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 neighboring 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

Options Considered

OPTION #1 – Highway 3B rebuild/ reconductor. The following descriptions outlines the necessary work needed for each area/maps.

- Tie existing .477on Old Salmo Road (near Fruitvale Substation) into existing .266 conductor at Kootenay Ave and Beaver Street. This project involves the over build of Telus and the clean-up of some sub-standard three phase on Columbia Gardens Road (not included in this ball park estimate).

- 1.5 Km of three phase line upgrade. Re-string .477 on existing poles, (existing #6 copper conductor primary, some of the neutral is 2/0 aluminum) from Fruitvale to approximately Bluebird Corner. Will be about a 25% to 50 % pole replacement rate to resolve and outstanding issues with communications and long spans of triplex. These substandard areas may need to be upgraded from 45 foot to 50 foot poles. Guying/anchoring will definitely need to be vastly improved to accommodate the new conductor.

- 2.7 Km of three phase line upgrade. Re-string .477 on existing poles (exisiting #4 copper conductor) around Montrose. Will be about at least a 75% pole replacement rate to resolve and outstanding issues with communications and long spans of triplex as well as required existing 40 foot 1960 existing pole replacements.. These substandard areas will need to be upgraded to 50 foot poles. Guying/anchoring will definitely need to be vastly improved to accommodate the new conductor.

- 0.5 Km of three phase line upgrade. Re-string .477 on existing poles (existing .90 copper primary and 2/0 aluminum neutral) around Montrose. Will be about at least a 25% pole replacement rate to resolve and outstanding issues with communications and long spans of triplex as well as required existing 40 foot 1960 existing pole replacements. These substandard areas will need to be upgraded to 50 foot poles. Guying/anchoring will definitely need to be vastly improved to accommodate the new conductor.

- 0.6 Km of three phase line upgrade. Re-string .477 on existing poles (existing .90 copper primary and 2/0 aluminum neutral). Will be 100% pole replacement to minimum 50 foot pole. This pole line will need to be helicopter set and holes hand-dug. A redundant gang switch needs to be removed outside the substation and a recommended new gang switch placed at existing 60C34. Guying/anchoring will definitely need to be vastly improved to accommodate the new conductor.

Option #1 totals $1,225,000.00

OPTION #2 – Columbia Gardens Road re-route/ reconductor add three phase distribution line. Remove 20 Line U/B and cross-country pole line with .90 copper.

- Involves rebuilding, upgrading and installing new three phase line and conductor for 4KM.

- **Option #2 totals $1,245,000.00**

-
- Will run into lands acquisitions for improved anchor locations. Lands are a larger risk on option #2 as road-way land base appears to be traveled portion only. A survey would be necessary to determine this

Financial Analysis/Assumptions Used

- Estimate based on 2008 information.
- Work will be performed with internal labor forces.

Options Selected:

Option #1 is the lower cost option and has a lower level of risk due to upgrading of our existing facilities rather than constructing new line. In addition, Option 1 will address sections that are identified and planned for upgrade as a part of the Copper Replacement program.

Implementation Process

This project will be completed before the end of 2010.

Other Considerations

This project defers possible station upgrade projects in the Fruitvale/Beaver Park area.

Risks

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Capital Expenditure
Justification Document

Project Name: Oliver Feeder 1 – New Regulator

Project Number: STP DG3800

Project Cost: $137,800

Project Classification:

Project Description:

The five year load forecast for the Oliver 1 feeder shows a modest but sustained growth of 2% with a projected 20010/2011 winter peak of 7037 KVA. With this peak, the capacity of the existing 50A regulator bank is exceeded and sections of the feeder see 112.1V for three phase and 111.2V for single phase at its extremes, both below voltage criteria of 115V and 113V respectively.

The proposal is to move the location of the regulator bank and upgrade it to a 150A bank at a more accessible location.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Reliability, customer service

Background:

Options Considered:

Option:1
Reconductor feeder sections to accommodate load growth
Pros:
Cons:

Option:2
Upgrade regulator on feeder
Pros:
Cons:

Financial Analysis/Assumptions Used

Option Selected
Option 1 (cost)

Implementation Process
Construction in

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Small Unplanned Capacity Improvements

Project Number: STP DG 2810

Project Cost: $974,000 / $994,000

Project Classification: G T&D

Project Description:

This project includes service upgrades, voltage regulation, tie to accommodate load splitting, single to three phase upgrades and conductor upgrades that are necessary due to load growth, but were unforeseen at the time the expenditure plan was prepared.

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

Unplanned Growth Projects

Year	**2005**	**2006**	**2007**	**2008F**	**2009**	**2010**
Cost ($000s)	962	954	1063	817	974	994

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Capacity

Background:

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 consistent with 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.

Background

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 for 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, regulation, shunt capacitors, re-conductoring, line additions, load splitting and new source locations. Growth capacity increase projects do not encompass line extension to new load centers, but 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 significantly different between rural low density and high density urban centers. Rural areas usually have a single transformer supply point with 1 or 2 radial feeders. The feeders are expected to provide reciprocal redundancy, but 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 are almost always loaded above the rating of a single transformer. The excess load is expected to be transferred to an adjacent 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 the existing transformation capacity.

As high density urban areas expand their perimeters, feeder extensions become less economic, and ultimately, new supply points are required at 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.

Experience has also 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, tie to accommodate load splitting, single to three phase upgrades and conductor upgrades.

Options Considered:

Options are evaluated at the time the need for a particular project occurs.

Option:1

Pros:

Cons:

Option 2:

Pros:

Cons:

Financial Analysis/Assumptions Used

The estimate expenditure for this project is based on historical information.

Option Selected

Implementation Process

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Distribution Pole Condition Assessment.

Project Number: STP DS0100/ STP DS0200

Project Cost: $599,000 / $667,000
Project Classification: G T&D

Project Description:

The project involves expenditures for structural stabilization of multiple distribution lines.

Included in the scope of work is pole testing, the application of wood preservatives and pole wraps to extend the life of the structure, and replacement of cross-arms, poles, and apparatus on structures according to the needs at each specific pole location. Also, there are some minor requirements in terms of insulator and guy wire changes.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability

Background:

The distribution system requires a proactive program to manage the risk of 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 of FortisBC's distribution 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 program extends the life of the pole plus ensures the integrity of the lines as well as employee and public safety. The program is managed in an eight-year cycle since this is the cycle time that a patroller could assess the safety and integrity of the structures and levelizes both budgets and resources for testing and treating the poles in the distribution system.

Extending the life of poles limits the number of new poles required and costs associated with replacement. A wood pole management program facilitates economic life extension of the wood poles in the system. The proper combination of replacement, stubbing, wrapping, and internal treatment of poles significantly reduces the incidence of rot and can extend the life of the poles by 7 to 30 years depending on the type of treatment. Pole testers condemn poles because of severe internal decay, surface rot or damage near or below ground line.

The condition assessment project will include the following lines in 2009 and 2010.

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

Options Considered

The key stakeholders in this project are customers, property owners and the general public along the route of the subject lines. The customers' interests are related to reliability of service. The property owners' and the general publics' interest relates to the potential for property damage or personal injury in the event that the lines failed mechanically. A proactive preventive maintenance program that minimizes the risk of structural failure best serves their interests.

Available courses of action are as follows:

1. Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

2. Take measures to restore service life to all structures requiring remediation.

The first course of action is not a legitimate planning option. Since FortisBC has conducted condition assessments and are aware of certain deficiencies, it would be imprudent not to rectify the deficiencies.

The second course of action involves replacement or refurbishment of deteriorated structures and hardware. Specifically, all poles labeled as "reject" in the test data would be replaced, and all poles labeled as "stub" would be stubbed. All fix maintenance items would be completed.

Option selected

The second option is selected.

The proposed approach is consistent with FortisBC's strategic plan, in that it focuses on improving reliability, provides improvements in general public and employee safety and reduces the risk of public property damage while conforming to the long-term plan for system development.

Financial Analysis/Assumptions Used

The estimate for this project was based on historical experience, the number of poles to be tested and the number of deficiencies identified. The funds for this project are to test and treat poles and to acquire materials, engineering design, patrol and rehabilitate the lines identified above.

A cost comparison was not completed for this business case because there are no viable alternatives to the proposed line stabilization project. No attempt has been made to quantify the benefits due to reliability improvements or to quantify the avoided property damage or public injury, although these factors form the strong argument for proceeding with this work.

Implementation Process

Other Considerations

Risks

2007/08 Capital Expenditure Justification Document

Project Name: Distribution Rehabilitation

Project Number: STP DS0100/ STP DS0200

Project Cost: $3,124,000 / $3,470,000

Project Classification: G T&D

Project Description:

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.

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability

Background:

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

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 in excess of 40 thousand locations without stirrups in the system. In order to mitigate this safety issue the Company plans to replace connectors starting in 2009 and 2010. 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.

Options Considered

The key stakeholders in this project are customers, property owners and the general public along the route of the subject lines. The customers' interests are related to reliability of service. The property owners' and the general publics' interest relates to the potential for property damage or personal injury in the event that the lines failed mechanically. A proactive preventive maintenance program that minimizes the risk of structural failure best serves their interests.

Available courses of action are as follows:

1. Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

2. Take measures to restore service life to all structures requiring remediation.

The first course of action is not a legitimate planning option. Since FortisBC has conducted condition assessments and are aware of certain deficiencies, it would be imprudent not to rectify the deficiencies.

The second course of action involves replacement or refurbishment of deteriorated structures and hardware. Specifically, all poles labeled as "reject" in the test data would be replaced, and all poles labeled as "stub" would be stubbed. All fix maintenance items would be completed.

Option selected

The second option is selected.

The proposed approach is consistent with FortisBC's strategic plan, in that it focuses on improving reliability, provides improvements in general public and employee safety and reduces the risk of public property damage while conforming to the long-term plan for system development.

Financial Analysis/Assumptions Used

A cost comparison was not completed for this business case because there are no viable alternatives to the proposed line stabilization project. No attempt has been made to quantify the benefits due to reliability improvements or to quantify the avoided property damage or public injury, although these factors form the strong argument for proceeding with this work.

Implementation Process

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Distribution ROW Reclamation

Project Number: SDP DS 0300

Project Cost: SDP DS 0300 $621,000 / $646,000

Project Classification: G T&D

Project Description:

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)
Safety, Reliability

Background:

FortisBC's program for brushing includes the goal of removing trees that are of high risk to fail and hit distribution lines. Trees that meet the criteria as hazard or danger trees have a high probability of failing and hitting the lines. These types of trees are identified during the cyclic patrols performed on lines and are removed on a scheduled basis.

The following points influence the distribution ROW reclamation program.

- Forest fires can result from a failure of one of these trees.
- Removal of these trees would considered due diligence in the industry.

Options Considered:

1 Do nothing….
1. Implement program.

Option 1 presents a huge risk in terms of liability and greatly impacts stakeholders.

Option 2 reduces the risk to employees, the public, our lines and therefore our shareholders and improves reliability.

Financial Analysis/Assumptions Used

Option Selected

Option 2 offers the best alternative as it does reduce risk to all stakeholders.

Implementation Process

Sustain and continuous improvement of current programs

Other Considerations

Risks

2009/10 Capital Expenditure Plan

Project Name: Right-of-Way Reclamation – Pine Beetle Kill Hazard Trees

Pro**ject Number** - SDP DS0250

Project Cost: $722, 000/$551, 000

Project Classification: T&D Sustaining

Project Description:
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.

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

Key Drivers: Safety, Reliability

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.

Background:

F 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.

Financial Analysis/Assumptions Used

Implementation Process

Other Considerations

Having first experienced MPB impacts within their service territory in the western and central interior part of the province, BC Hydro has a very similar program underway at this time. The beetle has moved progressively south and east from the initially affected BC Hydro areas and is expected to impact the entire FortisBC service territory heavily in 2008 through to 2013. FortisBC has approximately 5,300 kilometers of distribution and 1,400 kilometers of transmission line. Due to the location and limited size of the FortisBC system, it is expected that the MPB impact will be intense, but over in a shorter period of time than BC Hydro will experience.

The comparative BC Hydro MPB tree removal program carries an approved budget of $10.4 million for the 2008 fiscal year (end of March) and an approved budget of $11.4 million for the 2009 fiscal year. Subsequent BC Hydro annual expenditure levels are as yet unapproved, but FortisBC understands that they expect to require MPB funding to 2020 given its large service territory (an approximate total of 50,000 kilometers of distribution system, of which 30-40% is expected to suffer some degree of MPB impact).

Both FortisBC and BC Hydro are expending approximately $200/kilometer of distribution circuit annually due to MPB kill.

2009/10 Capital Expenditure Justification Document

Project Name: Distribution Line Rebuilds

Project Number: STP DS0400

Project Cost: $1,178,000 / $1,167,000

Project Classification: G T&D

Project Description:

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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability, customer service

Background:

On a regular basis Distribution Planning Engineers undertake site assessments of the distribution system in their respective areas. They review the system from a safety, reliability and capacity perspective. Any sections of lines that have deficiencies are identified and a proactive project is established to correct the problem and to manage the risk associated with safety, and reliability.

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 2 107 th 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

Options Considered

The key stakeholders in this project are customers, property owners and employees. The customers' interests are related to reliability of service. The property owners' and employees interest relates to the potential for property damage or personal injury in the event that the lines failed mechanically. Replacement of deteriorated equipment that minimizes the risk of structural failure best serves their interests.

Available courses of action are as follows:

1. Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

2. Take measures to repair or replace all structures requiring remediation.

The first course of action is not a legitimate planning option. Since FortisBC has conducted assessments and are aware of certain deficiencies, it would be imprudent not to rectify the deficiencies.

The second course of action involves replacement or refurbishment of deteriorated structures and hardware.

Option selected

The second option is selected.

The proposed approach is consistent with FortisBC's strategic plan, in that it focuses on improving reliability, provides improvements in general public and employee safety and reduces the risk of public property damage while conforming to the long-term plan for system development.

Financial Analysis/Assumptions Used

The estimate for this project is based on specific estimates for specific projects, taking into account the best technical and most economical solution for the specific problem.

A cost comparison was not completed for this business case because there are no viable alternatives to the proposed line rebuild projects. No attempt has been made to quantify the benefits due to reliability improvements or to quantify the avoided property damage or public injury, although these factors form the strong argument for proceeding with this work.

Implementation Process

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Small Planned Capital

Project Number: STP DS0500

Project Cost: $668,000 / $747,000

Project Classification: G T&D

Project Description:

This project involves expenditures for repairs that are identified on the Distribution system as a result of storm damage, clearance problems, aging equipment, reports by linemen and other inspections. The repairs are generally non-urgent in nature and consequently are not completed under the Distribution Urgent repair Project. 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

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability

Background:

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.

Options Considered

The key stakeholders in this project are customers, employees, property owners and the general public. The customers' interests are related to reliability of service. The employees, property owners' and the general publics' interest relates to the potential for property damage or personal injury in the event that the lines failed mechanically. A proactive preventive maintenance program that minimizes the risk of structural failure best serves their interests.

Available courses of action are as follows:

1. Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

2. Take measures to restore service life to all structures requiring remediation.

The first course of action is not a legitimate planning option. Since FortisBC is aware of certain deficiencies, it would be imprudent not to rectify the deficiencies.

The second course of action involves replacement or refurbishment of deteriorated structures and hardware.

Option selected

The second option is selected.

The proposed approach is consistent with FortisBC's strategic plan, in that it focuses on improving reliability, provides improvements in general public and employee safety and reduces the risk of public property damage while conforming to the long-term plan for system development.

Financial Analysis/Assumptions Used

The estimate for this project was based on historical experience.
A cost comparison was not completed for this project because there are no viable alternatives to the proposed project. No attempt has been made to quantify the benefits due to reliability improvements or to quantify the avoided property damage or public injury, although these factors form the strong argument for proceeding with this work.

Implementation Process

Other Considerations

Risks

2009/10 Capital Expenditure Justification Document

Project Name: Forced Upgrades and Line Moves

Project Number: STP DS0700

Project Cost: $1,518,000 / $1,581,000

Project Classification: G T&D

Project Description:

This project is required to complete distribution upgrades driven by third party requests. 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

This project involves expenditures associated with line moves that are requested by third parties.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Customer Service

Background:

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.

Options Considered:

In each case, alternatives will be considered and the most cost effective solution will be selected

2009/10 Capital Expenditure
Justification Document

Project Name: Distribution Urgent Repair

Project Number: STP DS0800

Project Cost: $1,911,000 / $1,805,000

Project Classification: G T&S

Project Description:

This Project involves the repair or replacement of Distribution equipment that fail in service due to severe weather, vandalism or for other unexpected reasons.

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.

Table 4.13
Distribution Urgent Repairs

Year	2005	2006	2007	2008F	2009	2010
Cost ($000s)	1,001	2,295	2,239	1,411	1,911	1,805

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)

Safety, Reliability, Capacity

Background:

Component failures on the Distribution system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained.

Options Considered:

Option 1: Do nothing
Option 2: Repair all failures that cannot be deferred to the upcoming year.

Option:1
Pros: Nil
Cons: Unacceptable due to safety concerns and system reliability issues

Option 2:
Pros: Ensures that safety and reliability issues are addressed in a timely manner
Cons: Nil

Financial Analysis/Assumptions Used

The estimates are based on historical information.

Option Selected

Implementation Process

Other Considerations

Risks

Project Name: Telecom, SCADA, P&C Sustaining

Project Cost

$868,000/ $738,000

Executive Summary

This is a multiyear project that includes, harmonic remediation, protection and communication upgrades. It will enhance the protection, control and monitoring of the FortisBC power system as well as operations and business communications requirements.

Background

Harmonic Remediation

This project provides for investigating and resolving harmonic problems as they arise. FortisBC's experience with harmonic difficulties is that they arise periodically and typically need to be investigated, although only infrequently mitigated. Investigation involves installing test equipment for a period of time, then engaging a consultant for detailed analysis.

Protection Upgrades

This multiyear program will upgrade protection and control equipment in several substations. Much of the FortisBC protection is near or beyond its designed operational life, some being up to 40 years old. It is no longer reliable, and the manufacturers no longer supply spare parts. In some extreme cases, equipment can no longer be tested and adjusted regularly because it fails when test systems are operated, and cannot reliably be put back into service. The impact is that 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. FortisBC plans to pursue a two-fold strategy to address this issue; upgrade parts of the protection and control systems regularly over several years, and prepare an emergency response plan and supply spare new systems that may be used in emergency restoration.

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.

Communication Upgrades

This multiyear program will upgrade telecommunications routes in FortisBC, and will improve emergency response capability. Much of the FortisBC telecom equipment is near or beyond its designed operational life. It is no longer reliable, and the manufacturers no longer supply spare parts. In some extreme cases, equipment can no longer be tested and adjusted regularly because it fails when test systems are operated, and cannot reliably be put back into service. 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. FortisBC plans to pursue a two-fold strategy to address this issue; upgrade parts of the telecom system regularly over several years, and prepare an emergency response plan and supply spare new systems that may be used in emergency restoration.

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.

Options Considered

Harmonic Remediation
Option 1: Do not address the harmonic issues.
Affects the quality of power supply to customers some time resulting in equipment damage.

Option 2: Address and investigate harmonic issues as they arise.
FortisBC is obligated to maintain the quality of power supply to its customers.

.

Protection Upgrades

Option 1: Continue to use existing equipment at Rosemont.
Unsafe operation both for operating personnel and general public, detecting equipment faults and repairing them takes longer increasing outage durations.

Option 2: Replace the existing electromechanical relays at Rosemont with new relays and install line-to-ground voltage transformers. Also install the necessary communications and SCADA equipment for remote tagging and remote fault indication.
Improves safety, provides better communication between SCC and the substation and makes fault location easier and reduces outage durations.

Communication Upgrades

Option 1: Continue to use existing equipment.
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.

Option 2: Upgrade the existing old equipment.
Improves safety, diminishes the exposure of the system to unnecessary outages and equipment damage, reduces outage durations. Provides better communication and visibility to SCC.

Financial Analysis/Assumptions Used

PROJECT NAME	2009COST (1000'S)	2010COST (1000'S
HARMONIC REMEDIATION	$ 117	$119
PROTECTION UPGRADES	$448	$508
COMMUNICATIONS UPGRADES	$ 229	$738

	$864	**$738**

Option Selected

Option 2 selected in all cases.

Implementation Process

Harmonic Remediation

Carry out the investigations and analysis as needed.

Protection Upgrades

Upgrade the protection and communication equipment at Rosemont in 2005. Continue with the required upgrades at other substations over the capital plan period.

Communication Upgrades

Carry out the phased upgrade of all old communication equipment over the capital plan period.

Other Considerations

Approvals Required

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Doug Ruse
Manger T & D Planning FortisBC

	General Plant
1	Vehicles
2	Advanced Metering Infrastructure - CPCN filed
3	Metering Changes to Uninstalled Meter Inventory
4	Information Systems
5	Telecommunications
6	Buildings
7	Furniture and Fixtures
8	Tools and Equipment
9	**TOTAL**

FortisBC Business Case

Project Name:

Fleet Equipment 2009 and 2010

Executive Summary

An expenditure of $1.3 million is planned for 2009 and $2.8 million in 2010 (excluding Capital loading). A total of 33 replacement units are involved, with the potential to increase the Fleet inventory, if necessary, by four units at a total cost of $0.2 million. The fifteen year outlook for planned expenditures was updated in order to better understand the short term budget and its impact on future years.

Background

Replacements

FortisBC's guideline that triggers equipment to be considered for replacement is listed in the table below. Simply meeting the trigger criteria does not indicate that a unit will be replaced and occasionally a unit will be replaced prior meeting the criteria.
In making the actual replacement decision many key issues are considered such as; suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, feasibility to maintain compliance with regulations, etc. This is done on a unit by unit basis.
Also included is a guideline budget cost for acquisition and commissioning of new units, by class.

Class #	Description	Trigger	Average Unit Cost
1	Passenger Vehicles	5 years 160,000 Kms	$38,000
2	3/4 Tons & Smaller	5 years 160,000 Kms	$40,000
3	Service Vehicles (3/4 & 1 Tons) 2 Wheel Drive	5 years 160,000 Kms	$75,000
4	Service Vehicles (3/4 & 1 Tons) 4 Wheel Drive	5 years 160,000 Kms	$80,000
5	Single Axle Line Truck (Digger or Aerial) 2 Wheel Drive	10 years 160,000 Kms	$275,000
6	Single Axle Line Truck (Digger or Aerial) 4 Wheel Drive	10 years 160,000 Kms	$290,000
7	Specialty and Small Horsepower (Forklifts, Snowmobiles, ATV's, etc.)	Individual Review	Individual
8	Trailers	20 years	$18,000
9	Tandem Axle Line Truck (Digger or Aerial)	10 years 160,000 Kms	$320,000

Additions/Surpluses

As a result of continuous changes in terms of the type of work being performed as well as how it is managed and executed, provision has been made for the addition of four units at a total cost of $0.2 million for 2009 and 2010.
The effect of 17 vehicles associated with the meter reading process has been removed from the capital plan but the vehicles will remain listed until they are declared surplus and have been disposed.

Lease Buyouts

Two line trucks (radial boom derricks) will reach the end of their lease period in 2010 and will be purchased.

Options Considered

In creating the 2009/10 capital plan each and every unit was considered on its own merits of safety, age, condition, suitability to current and future business requirements, feasibility to maintain compliance with regulations and the possibility of unit re-assignment to lower utilization areas. Wherever practical, overhaul/ULE costs were eliminated and life cycles were extended, contingent upon the unit leaving active service with FortisBC according to the 15 year outlook.

Option 2:
Pros:
-

Cons:
-

Option 3:

Pros:
-

Cons:
-

Financial Analysis/Assumptions Used

Option 1: $

Rate Impact (0.05% per million $s)

Option Selected

Implementation Process

Other Considerations

Risks

Approvals Required

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Manager Budgets & Forecasts FortisBC

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FORTISBC

2009-10 Capital Expenditure
Justification Document

Project Name: Metering Inventory and Meter Exchange/Compliance

Project Number: To be assigned

Project Cost: $526,000 in 2009
$559,000 in 2010

Project Classification: General Plant

Executive Summary:

This budget reflects the forecast capital costs to meet the overall metering requirements for 2009 and 2010.

Background:

This budget includes the capital costs associated with metering requirements in the following areas and for the following activities:

- Meter purchases required for compliance/exchange program
- Meter purchases required for issue of meters, current transformers and potential transformers to the field for new connects.

Options Considered:

Option 1: Status Quo Option (Do Nothing)
Pros:

- No up front capital costs

Cons:

- No meters is not an option for compliance and billing reasons.

<u>Option 2:</u> Purchase Metering Equipment

Pros:

- Meet our compliance requirements and billing requirements

Cons:

- Up front capital costs

Financial Analysis/Assumptions Used:

Option 2: $526,000 for 2009 and $559,000 for 2010

Rate Impact (0.05% per million $s):

Option 2: 0.005% for 2009 and 0.005% for 2010

Option Selected:

Option 2 Purchase Metering Equipment.

Implementation Process:

Purchase in 2009 and 2010.

Other Considerations:

N/A

Risks:

Not proceeding with the program is not an option.

Approvals Required:

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Manager Budgets & Forecasts FortisBC

Barry Smithson
Manager of Network Services

Information Systems

Index of Business Cases

1	Infrastructure Upgrade
2	Desktop Infrastructure Upgrade
3	SAP & Operations System Enhancements
4	AM/FM Enhancements
5	Customer Service Systems Enhancements
6	SCADA Enhancements
7	Distribution Design Software - provided in Exhibit B-1, Appendix 3

FortisBC Business Case

Project Name: Infrastructure Upgrade

Executive Summary

The scope of this project includes replacing outdated hardware and software in Data Centre and supporting infrastructure e.g. servers incapable of running current software, drive space upgrades, operating system and database version upgrades, etc.

Life expectancy of the hardware infrastructure is 5 years, and replacement is planned accordingly.

Operating systems and databases are upgraded about once every two years at least to maintain support.

FortisBC Infrastructure includes:

- 10 – IBM Servers with an AIX operating system
- 4 – IBM AIX Storage Area Network (SAN) devices
- 49 – HP Servers with Microsoft Server operating system
- 1 – HP SAN with Microsoft Server operating system 1.5
- 3 – Spectra tape libraries for backing up all systems
- 7 – Avaya IP Telephony servers
- 4 – Avaya IP Telephony Media Server smart switches
- 24 – Cisco intelligent switches
- Primary production data centre in Trail with UPS and backup generator
- Disaster Recovery data centre in Warfield

Approximate value of this infrastructure is $2.627 million.

Excluded from the scope will be the following:

- Hardware and software associated with any new applications.

Background

This has been normal capital work to keep the equipment in the data centre and infrastructure up to date and supported. The infrastructure required to support the FortisBC business has grown to serve the technology requirements.

Options Considered

Option 1: Replacing hardware and software on failed or oudated software and hardware in the data centre and related infrastructure in order to keep reliability at acceptable levels.

Option 2: Replace the equipment as it fails.

Pros:

- May save some money on hardware by pushing end of life out

Cons:

- Potential for significant server downtime, which would be completely unacceptable to the business and our customers. Also a potential safety risk, as all standards, policies, procedures, customer information and safety information are housed on this infrastructure.

Financial Analysis/Assumptions Used

Option 1: $750,000 for 2009 & $750,000 for 2010
Budget is based on 20% replacement annually ($525K) plus labour.

Rate Impact (0.05% per million $s)

0.0375% rate impact.

Option Selected

Option 1

Implementation Process

Upgrades carried out during the year.

Other Considerations

Risks

Not keeping the equipment in the data centre up to date will result in unsupported equipment that is near or past its end of life. This puts all the company and customer data at risk.

Approvals Required

Manager Budgets & Forecasts FortisBC

Tim Swanson
Manger Information Systems FortisBC

FortisBC Business Case

Project Name: Desktop Infrastructure Upgrade 2009 and 2010

Executive Summary

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 over 600 PCs current and supportable, rather than replacing all PC equipment and software every 5 years. The phased strategy avoids the resourcing issues that happen with large wholesale changes. The total value of all the PCs, and related peripherals, in FortisBC is approximately $2.9 million.

This project also includes the cost necessary to keep faxes, telephones and photocopiers/printers up to date. Again this is a staged approach based on five to seven year lifecycles.

An asset management tool is used to track the age of all technology assets in BC, to ensure they are changed in timely manner to realize maximum life expectancy without jeopardizing productivity.

Volume buying advantages are already realized by being part of the Fortis Inc. group. Thus, procuring everything in one year does not carry a significant cost advantage from a purchasing perspective.

Background

This has been normal yearly capital work to keep FortisBC desktop infrastructure up to date maintaining an efficient and productive technical working environment.

Options Considered

Option 1: Staged upgrade software resulting in a 4 to 5 year overall life expectancy of each asset. Hardware is replaced on a 5 year schedule, or if it is irreparbly damaged. Some hardware can stay in service longer, however on average 5 years is standard.
Pros:

- Minimizes cost impacts by spreading costs over the four year term rather than a one time major impact every 5 years.
- Maintains reasonably current technology throughout the organization at a phased in cost while avoiding the disparity of supporting differing technologies that might result if equipment and software were maintained for longer terms
- Allows existing staff to do the work, thus maintaining their familiarity with the business.

Cons

- Requires accurate asset management to ensure customer equipment is adequate for their needs and some increased support for different hard and software.

Option 2: Complete upgrade of all hardware and sofware every 4-5 years.
Pros:

- Ensures the replacement of technology prior to failure and potential business disruption.

Cons:

- Requires additional implementation support (and costs) to manage a rapid change over to minimize business impact
- Creates a very large peak for implementing and availability of contract technical resources can be a risk.
- Knowledge gained by contract resources deploying equipment to the business is lost.

Financial Analysis/Assumptions Used

Option 1: $800,000 for 2009 and $800,000 for 2010
Budget is based on 20% replacement annually ($580K) plus labour. Labour is higher on this project due to the fact that the equipment is spread throughout the service area in various offices.

Rate Impact (0.05% per million $s)

0.04% rate impact.

Option Selected

Option 1

Implementation Process

Work carried out during the year.

Other Considerations

Risks

Outdated desktop software is often incompatible with new software used by organizations that FortisBC does business with. Aging technology represents a system failure risk with subsequent business disruption, as well as potentially being incompatible with normal software upgrades.

Approvals Required

Chuck Lee
Controller FortisBC

Dennis Swanson
Manager Budgets & Forecasts FortisBC

Tim Swanson
Manger Information Systems FortisBC

FORTISBC

FortisBC Business Case

Project Name: SAP & Operations Systems Enhancements

Executive Summary

The scope of this project includes all enhancements to the SAP, and all other HR and operations focused applications. This includes Cascade maintenance management software, and work management applications, Utility Risk Management System and several other small internally developed applications.

FortisBC has a well established core of applications and enhancement projects are necessary to ensure they meet ever changing business requirements. These requirements can include interfaces, functionality changes and upgrades. The cost of the project is based on historical requirements for these applications.

Background

FortisBC implemented its main enterprise solution, SAP, in 2002. SAP provides financial, HR, materials management, plant maintenance and other key enterprise software functionality. It has served, and continues to serve the companies needs. There was a significant investment made in implementing the system, and continued enhancements have ensured its ability to meet the company's needs.

Implementing a new enterprise solution is very costly, and by continuing to upgrade and enhance the existing system significant costs are avoided.

FortisBC has also implemented a number of HR and Operations based applications, such as Utility Risk Management to track training and incidents, and Cascade maintenance management system for substation and generation equipment maintenance scheduling and planning.

All these applications have been carefully chosen and developed to deliver specific needs for FortisBC based on requirements and cost benefit.

Options Considered

Option 1: Continue to enhance and upgrade the existing SAP & Operations systems to meet the company's requirements

Pros:

- Well established and understood systems
- Well supported
- Inexpensive to operate
- Meets company and customer requirements
- Flexible

Cons:

- Requires ongoing enhancement funding to ensure business and customer needs are met

Option 2: Do nothing to the applications.
Pros:
- Minimal cost upfront

Cons:
- Systems become less productive as changing customer and business needs are not met
- Systems become stagnent and updating becomes a much bigger task creating a significant resource requirement behond internal capability

Option 3: Replace the Financial, HR and Operations Systems every 5 years

Pros:
- Potential feature enhancements behond current systems

Cons:
- Cost
- Retraining of all users
- Retraining of technical support staff

Financial Analysis/Assumptions Used

Option 1: $900,000 for 2009 & $900,000 for 2010
Budget is based on historical requirements for SAP, HR and Operations systems.

Rate Impact (0.05% per million $s)

0.045% rate impact.

Option Selected

Option 1

Implementation Process

Enhancements carried out during the year.

Other Considerations

Risks

Not enhancing and upgrading these systems continually can result in loss of support and loss of potential productivity gains.

Approvals Required

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Manager Budgets & Forecasts FortisBC

____
Tim Swanson
Manger Information Systems FortisBC

FORTISBC

FortisBC Business Case

Project Name: AM/FM Enhancements

Executive Summary

The scope of this project includes all enhancements to the AM/FM system at FortisBC. Enhancements based on business requirements for an operationally oriented system such as this are critical to improve safety, productivity and usability of the system. Without ongoing enhancements the full potential of the application cannot be realized, as business requirements do not stay static.

Background

FortisBC completed the implementation of the ESRI AM/FM system in 2008. It has been identified that any core application, such as ESRI, requires ongoing enhancements to meet business needs.

The ESRI system was chosen for what it delivered, but also its ability to be modified to meet changing business needs.

Options Considered

Option 1: Continue to enhance the ESRI AM/FM Software
Pros:

- Meets company and customer requirements
- Flexible
- Efficient

Cons:

- Requires ongoing enhancement funding to ensure business and customer needs are met

Option 2: Do nothing to the applications.
Pros:

- Minimal cost upfront

Cons:

- Systems become less productive as changing customer and business needs are not met
- Reliance on the system declines, as business requirements change

Option 3: Major ehnacement project every 3 to 5 years

Pros:
- Enhancements eventually get done

Cons:
- Does not meet business needs in a timely manner
- Requires more outside consulting due to peak nature of big enhancment projects – increase cost
- Spikes in capital requirements

Financial Analysis/Assumptions Used

Option 1: $200,000 for 2009 & $400,000 for 2010
Budget is based on historical requirements from legacy Intergraph system.

Rate Impact (0.05% per million $s)

0.01% in 2009 & 0.02% in 2010.

Option Selected

Option 1

Implementation Process

Enhancements carried out during the year.

Other Considerations

Risks

Not enhancing and upgrading these systems continually can result in loss of support and loss of potential productivity gains.

Approvals Required

Manager Budgets & Forecasts FortisBC

Tim Swanson
Manger Information Systems FortisBC

FortisBC Business Case

Project Name: Customer Systems Enhancements

Executive Summary

The scope of this project includes all enhancements to the Customer Information System (CIS), and all other Customer Service focused applications. This includes web based systems (fortisbc.com), Contact Centre systems (Monet scheduling software), bill printing software (Metavante CSF) and dispatching application.

FortisBC has a well established core of applications and enhancement projects are necessary to ensure they meet ever changing business requirements. These requirements can include interfaces, functionality changes and upgrades. The cost of the project is based on historical requirements for these applications.

Background

FortisBC implemented the current CIS system in 2000. It has served, and continues to serve the companies needs. There was a significant investment made in implementing the system, and continued enhancements have ensured its ability to meet the company's needs.

Implementing new Customer Information Systems is very costly, and by continuing to upgrade and enhance the existing system significant costs are avoided.

FortisBC has also implemented a number of Customer Service focused applications, such as Monet scheduling software for employee scheduling, Metavante bill print software for formatting bills for electronic or hard copy delivery and fortisbc.com web site with its associated customer information and service delivery. There are also a number of small internal web based applications that have been developed to support Customer Service.

All these applications have been carefully chosen and developed to deliver specific needs for Customer Service based on requirements and cost benefit.

Options Considered

Option 1: Continue to enhance and upgrade the existing Customer Service systems to meet the company's requirements

Pros:

- Well established and understood systems
- Well supported
- Inexpensive to operate
- Meets company and customer requirements
- Flexible
- Efficient

Cons:

- Requires ongoing enhancement funding to ensure business and customer needs are met

Option 2: Do nothing to the applications.
Pros:

- Minimal cost upfront

Cons:

- Systems become less productive as changing customer and business needs are not met
- Systems become stagnent and updating becomes a much bigger task creating a significant resource requirement behond internal capability

Option 3: Replace the Customer Service Systems every 5 years

Pros:

- Potential feature enhancements behond current systems

Cons:

- Cost
- Retraining of all users
- Retraining of technical support staff

Financial Analysis/Assumptions Used

Option 1: $750,000 for 2009 & $750,000 for 2010
Budget is based on historical requirements for the Customer Service systems.

Rate Impact (0.05% per million $s)

0.0375% rate impact.

Option Selected

Option 1

Implementation Process

Enhancements carried out during the year.

Other Considerations

Risks

Not enhancing and upgrading these systems continually can result in loss of support and loss of potential productivity gains.

Approvals Required

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Manager Budgets & Forecasts FortisBC

____

Tim Swanson
Manger Information Systems FortisBC

FORTISBC

FortisBC Business Case

Project Name: SCADA Systems Sustainment

Executive Summary

The scope of this project includes all enhancement and upgrade requirements for all systems and infrastructure supporting SCADA and System Control. This includes WorldView SCADA control software and the supporting infrastructure.

FortisBC has increasing demands on automated system control. There are additional requirements of the system including interfaces to reporting tools, increased accessibility requirements in the field, functionality changes and upgrades. These requirements are also increasing to meet the needs of the Energy Plan and NERC compliance. Without ongoing upgrades and enhancements to the SCADA system and related infrastructure the requirements to meet the Energy Plan criteria and required NERC compliancy would not be met.

The SCADA systems and infrastructure used at System Control are also critical to the safety of anybody working on the electrical network.

The cost of the project is based on estimated software and hardware requirements.

Background

FortisBC has a comprehensive SCADA control system that has been in place since 1989. With the increase in automation and safety requirements it has become a much more integral part of day-to-day operations.

Options Considered

Option 1: Continue to enhance and upgrade the SCADA systems to meet all requirements.
Pros:

- Well established and understood systems
- Well supported

Cons:

- Requires ongoing enhancement funding to ensure business and customer needs are met

Option 2: Do nothing to the SCADA Systems.
Pros:

- Minimal cost upfront

Cons:

- Potential safety issues
- Inability to support technically driven initiatives – Energy Plan, etc.

Financial Analysis/Assumptions Used

Option 1: $750,000 for 2009 & $650,000 for 2010
Budget is based on estimated software and hardware requirements.

Rate Impact (0.05% per million $s)

Option 1: 0.0375% in 2009 & 0.0325% in 2010

Option Selected

Option 1

Implementation Process

Enhancements carried out during the year as required.

Other Considerations

Risks

Not enhancing and upgrading the SCADA systems continually can result in loss of support, technical weaknesses and safety issues.

Approvals Required

____
Manager Budgets & Forecasts FortisBC

____
Dave Cochrane
Manager System Control

FORTISBC

2009-10 Capital Expenditure Justification Document

Project Name: General Telecom

Project Number: To be assigned

Project Cost: $105, 000 in 2009
$106, 000 in 2010

Project Classification: General Plant

Executive Summary:

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

Background:

This equipment includes landline equipment, VHF field communications equipment, mountain top repeater equipment, outfitting new vehicles, 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 System Control Center.

The following items are examples of some tools to be purchased for 2009 and 2010:

2009

- $25,000 – outfitting of new vehicles

2010

- $25,000 – outfitting of new vehicles

Options Considered:

Option 1: Status Quo Option (Do Nothing)
Pros:
- No up front capital costs

Cons:
- High risk of equipment failure

Option 2: Purchase Telecommunications Equipment
Pros:
- Improved employee safety injuries to workers
- Reduction of lost time incidents and improved productivity

Cons:
- Up front capital costs

Financial Analysis/Assumptions Used:

Option 2: $100,000 for 2009 and $100,000 for 2010

Rate Impact (0.05% per million $s):

Option 2: 0.001% for 2009 and 0.01% for 2010

Option Selected:

Option 2 Purchase Telecommunications Equipment.

Implementation Process:

Purchase in 2009 and 2010.

Other Considerations:

N/A

Risks:

Not proceeding with the program would increase the risk to employee and public safety.

Approvals Required:

____
Manager Budgets & Forecasts FortisBC

____
Barry Smithson OR Paul Chernikowsky

Buildings

1	All	Facility Upgrades
2	All	Facilities Emergency
3	All	Construction Projects Requirements
4	All	Security System Upgrades

2009 Capital Expenditure Justification Document

Project Name: Facility Upgrades

Project Number:

Project Cost: $2.637 Million

Project Classification: GP BLDGS

Project Description: Facility upgrade needs have been determined through building audits. Items identified include:

- Generator installations at Warfield, Castlegar, and Oliver
- Security upgrades – fencing, security systems
- Heating and cooling upgrades
- Safety items – lighting, drainage projects, vehicle exhaust evacuation
- Building upgrades – roofing, insulation, doors, flooring
- South Slocan upgrades – aging infrastructure, upgrades focused on safety, health & environment as recommended by building audits
- Pavement upgrades

Key Drivers:

- Emergency Response Plan – generators to maintain operations during disasters
- Company security maintenance
- Employee safety & health
- Replacement of aging infrastructure
- Drainage issues / environmental protection

Background:

- Building upgrades to meet the changing needs of the Company and Employees
- Aging equipment and facilities identified in Building Audits

Options Considered:

Option:1 status quo
Pros: lower initial cost
Cons: does not address aging infrastructure, ERP, or security issues

Option 2: upgrade as outlined
Pros: corrects issues with aging infrastructure, ERP, and security issues
Cons: higher initial cost

Financial Analysis/Assumptions Used
Estimates based on 2007 contractor and material costs

Option Selected 2

Implementation Process

- Prioritize projects for safety, environment, health
- Generators require 1-year lead time for purchase, engineering, and design
- Scheduled repairs based on weather, contractor availability and material availability

Other Considerations

Risks

2010 Capital Expenditure
Justification Document

Project Name: Facility Upgrades

Project Number:

Project Cost: $1,368,000.

Project Classification: GP BLDGS

Project Description: Facility upgrade needs have been determined through building audits. Items identified include:

- Outside storage projects
- Upgrades due to changes in staffing
- Heating and cooling upgrades
- Safety items – lighting, drainage projects, septic systems removal/fill, oil storage building
- Building upgrades – roofing, insulation, doors, fascia
- South Slocan upgrades – safety, building code compliance as per consultant's recommendations
- Pavement upgrades

Key Drivers:

- Outside storage for protection of equipment from weather, maintain winter access to spare parts
- Company security maintenance
- Employee health and safety
- Replacement of aging materials
- Drainage issues / environmental protection

Background:

- Building upgrades to meet the changing needs of the Company and Employees
- Aging equipment and facilities identified in Building Audits

Options Considered:

Option:1 status quo
Pros: lower initial cost
Cons: does not address aging infrastructure or security issues

Option 2: upgrade as outlined
Pros: corrects issues with aging infrastructure and security issues
Cons: higher initial cost

Financial Analysis/Assumptions Used
Estimates based on 2007 contractor and material costs

Option Selected 2

Implementation Process

- Prioritize projects for safety, environment, comfort
- Scheduled repairs based on weather, contractor availability and material availability

Other Considerations

Risks

2009 Capital Expenditure Justification Document

Project Name: Emergency Upgrades

Project Number:

Project Cost: $88K

Project Classification: GP BLDGS

Project Description:
- Repairs/upgrades to mechanical, electrical, structural, or security systems all sites that may fail unexpectedly and require immediate repair/replacement
- Unforeseen changes in employee requirements at a work site

Key Drivers:
- Breakdowns are not predictable and when they happen on systems as outlined above, they require immediate attention

Background:
- We have based this figure on the last 4 years experience

Options Considered:

Option:1 not to identify any dollars for emergency
Pros: no costs
Cons: unprepared for emergencies
Option 2: budget amount available
Pros: potential for emergencies prepared for
Cons: cost

Financial Analysis/Assumptions Used

Option Selected

Implementation Process

Other Considerations

Risks

2010 Capital Expenditure Justification Document

Project Name: Emergency Upgrades

Project Number:

Project Cost: $89K

Project Classification: GP BLDGS

Project Description:
- Repairs/upgrades to mechanical, electrical, structural, or security systems all sites that may fail unexpectedly and require immediate repair/replacement
- Unforeseen changes in employee requirements at a work site

Key Drivers:
- Breakdowns are not predictable and when they happen on systems as outlined above, they require immediate attention

Background:
- We have based this figure on the last 4 years experience

Options Considered:

Option:1 not to identify any dollars for emergency
Pros: no costs
Cons: unprepared for emergencies
Option 2: budget amount available
Pros: potential for emergencies prepared for
Cons: cost

Financial Analysis/Assumptions Used

Option Selected

Implementation Process

Other Considerations

Risks

2009 Capital Expenditure Justification Document

Project Name: Construction Projects Requirements

Project Number:

Project Cost: $218,000

Project Classification: GP BLDGS

Project Description:

- Capital construction projects intersection with Facilities

Key Drivers:

- Items identified by Capital Projects, these include material yard set-ups (fencing, covered storage, paved pads for off-loading) and temporary office requirements

Background:

Options Considered:

Option:1 Status quo
Pros: low initial cost
Cons: unable to respond to the needs of other departments

Option 2: budget for requirements by Capital projects group
Pros: able to respond to changing needs
Cons: cost

Financial Analysis/Assumptions Used

Option Selected 2

Implementation Process

Other Considerations

Risks

2010 Capital Expenditure Justification Document

Project Name: Construction Projects Requirements

Project Number:

Project Cost: $219,000

Project Classification: GP BLDGS

Project Description:
- Capital construction projects intersection with Facilities

Key Drivers:
- Items identified by Capital Projects, these include material yard set-ups (fencing, covered storage, paved pads for off-loading) and temporary office requirements

Background:

Options Considered:

Option:1 Status quo
Pros: low initial cost
Cons: unable to respond to the needs of other departments

Option 2: budget for requirements by Capital projects group
Pros: able to respond to changing needs
Cons: cost

Financial Analysis/Assumptions Used

Option Selected 2

Implementation Process

Other Considerations

Risks

2009-10 Capital Expenditure
Justification Document

Project Name: Security System Upgrades

Project Number:

Project Cost: $305,000 / $305,000

Project Classification: GP BLDGS

Project Description:
In 2008, FortisBC is undertaking a study which will provide a cross section of Electrical Industry Security Standards in all areas of business. Our sites will then be reviewed and required upgrades will be ranked and projects initiated accordingly

Key Drivers:
- Significant increase in the number of substation and storage yard break-ins, and the inherent risk to public safety associated with such break-ins
- Assurance FortisBC compares favorably to best in practice electrical industry security standards

Background:
FortisBC has undertaken a study of Electrical Industry Security Standards in all areas of its business. Proactive

Options Considered:

Option:1 Status quo
Pros: initial low cost
Cons: future planning for security upgrades will be limited.
Option 2: Plan for the future
Pros: Having reviewed a cross section of Electrical Industry Security Standards, FortisBC will be in a position to plan security upgrades in a pro-active manner
Cons: higher initial cost
Financial Analysis/Assumptions Used

Option Selected 2
Implementation Process
Following review of Study, determine and rank upgrades necessary
Initiate projects accordingly
Other Considerations

Risks

2009 Capital Expenditure Justification Document

Project Name: Furniture & Fixtures Upgrades

Project Number:

Project Cost: $347

Project Classification: GP BLDGS

Project Description:
- Workstations, lockers, cabinets, appliances, etc. for all sites due to changes in staffing and aging replacements

Key Drivers:
- Changes in staffing, work methods, and facility function

Background:
- Aging equipment, chairs, and furniture, and the need to adapt to new work areas and methods require updates

Options Considered:

Option:1 Status quo
Pros: lower initial cost
Cons: unable to keep up with facility needs

Option 2: budget for furniture and fixture upgrades
Pros: adapt to changing needs of the facility and staff
Cons: higher initial cost

Financial Analysis/Assumptions Used
Estimates based on 2007 contractors and materials costs

Option Selected 2

Implementation Process

Other Considerations

Risks

2010 Capital Expenditure Justification Document

Project Name: Furniture & Fixtures Upgrades

Project Number:

Project Cost: $393

Project Classification: GP BLDGS

Project Description:
- Workstations, lockers, cabinets, appliances, etc. for all sites due to changes in staffing and aging replacements
- SCC operator console replacement

Key Drivers:
- Changes in staffing, work methods, and facility function

Background:
- Aging equipment, chairs, and furniture, and the need to adapt to new work areas and methods require updates

Options Considered:

Option:1 Status quo
Pros: lower initial cost
Cons: unable to keep up with facility needs

Option 2: budget for furniture and fixture upgrades
Pros: adapt to changing needs of the facility and staff
Cons: higher initial cost

Financial Analysis/Assumptions Used
Estimates based on 2007 contractors and materials costs

Option Selected 2

Implementation Process

Other Considerations

Risks

2009-10 Capital Expenditure Justification Document

Project Name: Tools and Equipment

Project Number: To be assigned

Project Cost: $572,000 in 2009
$575,000 in 2010

Project Classification: General Plant

Project Description:
Annual expenditures on tools and equipment are necessary for the efficient and effective management of the transmission and distribution facilities as well as public and employee safety.

Key Drivers: (Employee Safety, Public Safety, Customer Service, Reliability, Capacity, etc…)
Employee Safety, Public Safety, Reliability

Background:
This involves the replacement of tools and equipment that have reached the end of their service life and the purchase of new tools that are better suited to the various trades from an ergonomic and safety perspective. These tools and equipment are maintained on a regular basis however, over time they wear out. Some of this equipment, such as live line tools and rigging equipment is also replaced due to the ongoing improvements in work methods or changes to the Work Safe BC guidelines. Ergonomic and safety concerns related to the difficulty of using certain types of cutting and compression hand tools is an industry issue and continues to be addressed with each budget cycle. Where feasible such tools will be replaced with battery and hydraulic alternatives to reduce the possibility of strain related injuries to workers. These injuries in conjunction with an aging workforce, have negative short and long term issues with lost time and reduced productivity.

The following items are examples of some tools to be purchased for 2009 and 2010:

- Tools to outfit an additional service vehicles being purchased

- 25 kW multi tap portable generator
- Cable fault locator (Cable Thumper)
- Battery powered crimping tool and accessories
- Hydraulic cutters
- Splice tent

Test and Maintenance Equipment

This budget is for the acquisition of maintenance and test equipment for telecommunications, substations, metering, and line operations for predictive, preventative and corrective maintenance activities.

Testing equipment is used as a predictive maintenance tool for the equipment located in the substations across the service territory. This equipment is also used to identify problems and assist in making decisions for the course of action to be taken should a piece of equipment fail. The electrical equipment includes transformers, breakers, reclosers, voltage regulators, three phase pad mount transformers and step down transformers. Diagnostic testing and repair of the various types of equipment requires specialized tools and test equipment. Innovations in tools and test equipment often lead to diagnostic tools that result in less equipment failures. As well, normal deterioration and the inability to maintain obsolete test equipment requires that some of these items be replaced at regular intervals.

The electrical test equipment is required to ensure the integrity and reliability of the equipment located in the Company’s substations across the service territory. This equipment is also used extensively to support the commissioning of new substations and electrical equipment.

The following items are examples of test and analysis equipment that will be purchased in 2009 and 2010:

- Breaker Analyzer

- Voltage and Power Quality Analyzer
- Infrared camera for equipment assessment
- Underground locating equipment
- Ground resistance tester

Options Considered:

Option 1: Status Quo Option (Do Nothing)
Pros:
- No up front capital costs

Cons:
- High risk of equipment failure

Option 2: Purchase Tools
Pros:
- Improved equipment reliability as tools available to perform maintenance tasks
- Improved employee safety and reduction of the possibility of strain related injuries to workers
- Reduction of lost time incidents and improved productivity

Cons:
- Up front capital costs

Option 3: Rent tools or contract out maintenance work

Pros:
- No up front capital costs
- Equipment maintenance will be done

Cons:
- High maintenance costs
- Loss of maintenance experience

Financial Analysis/Assumptions Used:

Option 2: $572,000 for 2009 and $575,000 for 2010

Rate Impact (0.05% per million $s):

Option Selected:

Option 2 Purchase Tools. This option will ensure the maintenance on plant equipment can be performed safely and efficiently by FortisBC employees.

Implementation Process:

Purchase in 2009 and 2010

Other Considerations:

N/A

Risks:

Not purchasing tools will decrease efficiency and increase the risk of equipment failures and employee safety.

Approvals Required:

____
Manager Budgets & Forecasts FortisBC

____

29.0 Project Cost Estimate

Reference: Exhibit B-1-1, Tab 5, p. 2; Exhibit B-1-3, Appendix G, p. 3

Q29.1 Table 5-1 provides a first-level breakdown of the cost estimate for the Project of $141.4 million under Option 1A. Further to Appendix G, page 3, please confirm that this estimate is in real 2007 dollars.

A29.1 No, this cost estimates is in nominal dollars. Please see the response to BCUC IR No.1 Q37.2.

Q29.2 Please provide a table that is similar to Table 5-1 that is expressed in nominal dollars and confirm that the inflation factors used are those on page 3 of Appendix G.

A29.2 Table 5-1 is in nominal dollars, using the inflation factors referred to in the Application on page 3 in Appendix G.

Q29.3 What was the estimated cost of the OTR Project that was in the 2005 Resource Plan that was generally accepted by Order No. G-52-05, and what dollars was the estimated cost expressed in?

A29.3 The reference above should be “the 2005 – 2024 System Development Plan”. The OTR Project components were included in the 2005 – 2024 System Development Plan at an estimated cost of $57.0 million (real dollars, $2005).

Q29.4 The FortisBC 2007-2008 Capital Expenditure Plan at pages 39 to 41 identified a cost for the OTR Project of $75.0 million. Please provide a table that compares the breakdown of the 2005 Resource Plan estimate and this cost estimate to the estimate in Table 5-1. If the dollar bases for the 2005 Resource Plan estimate and the 2007-2008 Capital Plan estimate are not the same as the basis as Table 5-1, please include columns that show the 2005 Resource Plan estimate and the 2007-2008 Capital Plan estimate on the same basis as Table 5-1. Please show the difference in estimated cost for each item.

A29.4 The reference above should be "the 2005 – 2024 System Development Plan". Please see Table A29.4 below.

Table: A29.4 OTR Capital Cost Summary Comparisons

Project Component	2005 SDP	2007-08 Capital Plan	Table 5-1 OTR CPCN
Double Circuit 230kV Vaseux to RGA Penticton (75/76 Line)	29,500	36,300	55,527
Single Circuit 230kV Vaseux to Bentley (40 Line)	5,000	6,150	4,550
63 & 138kV Circuits Bentley to Oliver			672
New Bentley Terminal	20,500	25,200	30,990
Oliver Substation Upgrade		4,900	5,687
RG Anderson Terminal Upgrade			10,498
Lee & Bell Terminals 138kV Capacitor Upgrade (formerly Kelowna Shunt Capacitors)	2,000	2,450	3,297
Vaseux 230kV Terminal Upgrade			4,440
Vaseux 500kV Terminal Upgrade			2,928
Planning & Preliminary Engineering			5,363
Project Management, Engineering & Operations Support			3,807
Sub Total	**57,000**	**75,000**	**127,760**
AFUDC			9,736
Removals & Salvage		3,050	3,912
TOTAL	**57,000**	**78,050**	**141,408**

Q29.5 Further to the response to the previous question, for each item where there is a material difference between the estimates, please provide a detailed explanation of the causes for the difference. Where the scope of the project has changed, please justify why the change to scope is necessary. Where the change to the estimate for an item has several significant causes, please identify the portion of the increase that is due to each. Please specifically address the double circuit for the connection from Vaseux Lake to RG Anderson, and the separation of the transformers at Vaseux Lake.

A29.5 The estimates included in the 2005 SDP and 2007/08 Capital Plan were at a conceptual level only for planning purposes only and not for rate setting purposes. The original 2005 estimate of $57.0 million was in $2005 dollars excluding overheads, and was adjusted to $75.0 million for the Capital Plan based on inflation and required overheads. The $75.0 million did not include $3.05 million in removals and salvage budgeted at the time. Detailed scope refinement and preliminary engineering had not taken place in the development of these estimates.

The conceptual scope for the development of the 2005 SDP included the double circuit 230kV from Vaseux to RGA, a single circuit 230kV from Vaseux to Oliver, the Bentley Terminal, and Shunt Capacitors in the Kelowna region.

Detailed engineering, planning and estimating in 2007/08 for inclusion in the CPCN had refined the conceptual scope to meet the primary requirements of the project. The main conceptual scope elements had not changed from the 2005 SDP and 2007/08 Capital Plan with the exception of:

- The replacement of one transformer at RGA and its subsequent relocation to Bentley to provide additional capacity and to reduce operational

68.0 Engineering Design – Appropriateness

Reference: Exhibit B-3, BCUC IR 7.5, 29.1, 29.2, 29.3, 29.4, 29.5, 31.9

Q68.1 FortisBC states that the current cost estimate for the OTR is $141.4 million in nominal dollars, and that the $57 million estimate in the 2005-2040 System Development Plan ("2005 SDP") was in real 2005 dollars. In what terms was the $75 million in the 2007/08 Capital Plan expressed?

A68.1 The $57 million discussed in BCUC IR1 Q29.3 should have read $61 million which would have included the Oliver substation upgrade of $4.0 million. The original cost estimate for this component can be found in the 2005-2024 System Development Plan (2005-2024 SDP), Appendix C, page 2 - Osoyoos/Oliver Area - Distribution Source Station. The revised response to BCUC IR1 Q29.4 is found in ERRATA 2 filed April 17, 2008.

The 2005 SDP cost estimates were prepared without AFUDC and capitalized overheads. The 2007 SDP Update estimates totaling $75.0 million) were also presented in 2005 (real) dollars, inclusive of AFUDC and capitalized overheads. Please also see the response to Q68.2 below.

Q68.2 Please repeat the response to BCUC IR 29.4, and this time provide the three cost estimates on the same basis, preferably the nominal dollar basis used for OTR.

A68.2 Please see BCUC Table A68.2 below. Please note that the 2005 SDP cost estimates in Column A include the Oliver Substation upgrade of $4.0 million.

BCUC Table A68.2

		2005 SDP			2007 SDP Update		OTR
		$ 2005	$ 2005	$ Nominal	$ 2005	$ Nominal	$ Nominal
		(A)	(B)	(C)	(D)	(E)	(F)
	Project Component	($ 000s)					
1	Double Circuit 230 kV Vaseux to RGA Penticton (75/76 Line)	29,500	36,215	41,955	38,995	45,741	55,527
2	Single Circuit 230 kV Vaseux to Bentley (40 Line)	5,000	6,140	7,253	6,499	7,710	4,550
3	63 & 138kV Circuits Bentley to Oliver						672
4	New Bentley Terminal	20,500	25,205	29,919	21,933	26,391	30,990
5	Oliver Substation	4,000	4,910	5,596	4,716	5,880	5,687
6	RG Anderson Terminal Upgrade						10,498
7	Lee & Bell Terminals 138 kV Capacitor Upgrade (formerly Kelowna Shunt Capacitors)	2,000	2,460	2,891	2,930	3,668	3,297
8	Vaseux 230 kV Terminal Upgrade						4,440
9	Vaseux 500 kV Terminal Upgrade						2,928
10	Planning & Preliminary Engineering						5,363
11	Project Management, Engineering & Operations Support						3,807
12	**Sub Total**	**61,000**	**74,930**	**87,613**	**75,073**	**89,389**	**127,760**
13	AFUDC						9,736
14	Removals & Salvage				3,050	3,713	3,912
15	**TOTAL**	**61,000**	**74,930**	**87,613**	**78,123**	**93,102**	**141,408**

Notes:
Column (A) - the 2005 SDP was presented without AFUDC and capitalized overheads.
Column (B) - includes AFUDC and capitalized overheads.
Columns (C), (D), (E) include AFUDC and capitalized overheads.
Column (F) - components include capitalized overheads. AFUDC aggregated for Project total.

The 2005 SDP and 2007 Capital Plan estimates have been adjusted to nominal dollars based on cost escalation rates of 3 percent for 2006, 6 percent for 2007, 5 percent for 2008, 5 percent for 2009 and 4 percent for 2010.

Please refer to the MMK report in Appendix G of the CPCN (Exhibit B-1-3) with regard to cost escalations.

Q68.3 Further to the response to BCUC IR 7.5, please clarify whether the Vaseux Lake to Penticton connection that was included in the $57 million estimate in the 2005 SDP was for a single or double circuit.

A68.3 The Vaseux Lake to Penticton connection included in the 2005 SDP was for a double circuit transmission line. Section 2.4.1.1 of the 2005 SDP states: "The ultimate configuration will involve a six position 230 kV ring bus terminating three 500/230 kV transformers, two 230 kV circuits between Vaseux Lake and Anderson and a single 230 kV circuit between Vaseux Lake and the proposed new Bentley Terminal near Oliver."

Q68.4 Further to Table A 29.4, please explain in terms of design, materials, labour, and other components why the 2005 SDP cost for a double circuit from Vaseux to Penticton of $29.5 million increased to $55.5 million in this Application.

A68.4 The 2005 SDP estimates were presented without AFUDC or capitalized overheads. 2005 line estimates were based on a major BC contractor's budget price assuming two H-frame single circuits, wood construction with reasonable access and normal digging. Line design refinement coupled with cost escalations for concrete, steel, aluminum and copper (materials) and labour markets increased the cost to $55.5 million. Refer to the MMK report in Appendix G of the CPCN (Exhibit B-1-3) with regard to cost escalations.

Q68.5 In the 2005 SDP, did FortisBC assume that the Oliver Substation would not need to be upgraded, or that the new Bentley Terminal would completely replace the Oliver Substation?

A68.5 FortisBC did assume the Oliver Terminal station would need to be upgraded in the 2005 SDP. The 2005 SDP and 2007/08 Capital Plan estimates on page 17 of the 2005 SDP states *"The 138 kV bus will be used to feed Oliver Terminal Station which will be reconfigured to include a 138 kV ring bus..."*

Q68.6 Further to Table A29.4, please explain in terms of design, materials, labour and other costs why the cost for the Bentley Terminal in the 2005 SDP of $20.5 million increased to $36.7 million for Bentley and Oliver.

A68.6 The Bentley Terminal station was estimated at $20.5 million in 2005 while the Oliver Substation was estimated at $4.0 million (as noted in the response to Q68.1 above) thus totaling $24.5 million. These estimates were based on the cost of substation construction at that time. Station design refinement coupled with cost escalations for concrete, steel, aluminum and copper (materials) and labour markets increased the combined cost of both stations to the $36.7 million. The $24.5 million escalated to the current OTR Project timeframe is $35.5 million (as shown in BCUC Table A68.2 above) which is 3.2 percent lower than the $36.7 million currently estimated.

Please refer to the MMK report in Appendix G of the CPCN (Exhibit B-1-3) with regard to cost escalations.

Q68.7 Please confirm that the information in Table A31.9 remains current, or provide an updated version of the Table and explain all significant changes.

A68.7 The information provided in Table A31.9 remains current.

Q29.4 The FortisBC 2007-2008 Capital Expenditure Plan at pages 39 to 41 identified a cost for the OTR Project of $75.0 million. Please provide a table that compares the breakdown of the 2005 Resource Plan estimate and this cost estimate to the estimate in Table 5-1. If the dollar bases for the 2005 Resource Plan estimate and the 2007-2008 Capital Plan estimate are not the same as the basis as Table 5-1, please include columns that show the 2005 Resource Plan estimate and the 2007-2008 Capital Plan estimate on the same basis as Table 5-1. Please show the difference in estimated cost for each item.

A29.4 The references above should be to the "2005-2024 System Development Plan" and the "2007 System Development Plan Update". Please see Table A29.4 below.

Table: A29.4 OTR Capital Cost Summary Comparisons

	2005 SDP (A)	2007 SDP Update (B)	Table 5.1 OTR (C)
		($ 000s)	
Double Circuit 230kV Vaseux to RGA Penticton (75/76 Line)	29,500	38,995	55,527
Single Circuit 230kV Vaseux to Bentley (40 Line)	5,000	6,499	4,550
63 & 138kV Circuits Bentley to Oliver			672
New Bentley Terminal	20,500	21,933	30,990
Oliver Substation	4,000	4,716	5,687
RG Anderson Terminal Upgrade			10,498
Lee & Bell Terminals 138kV Capacitor Upgrade (formerly Kelowna Shunt Capacitors)	2,000	2,930	3,297
Vaseux 230kV Terminal Upgrade			4,440
Vaseux 500kV Terminal Upgrade			2,928
Planning & Preliminary Engineering			5,363
Project Management, Engineering & Operations Support			3,807
Sub Total	**61,000**	**75,073**	**127,760**
AFUDC			9,736
Removals & Salvage		3,050	3,912
TOTAL	**61,000**	**78,123**	**141,408**

Notes:
Column (A) - the 2005 SDP was presented without AFUDC and capitalized overheads.
Column (B) - includes AFUDC and capitalized overheads.
Column (C) - components include capitalized overheads. AFUDC aggregated for Project total.

Line No.	Project Name	Additions to Plant in Service				Total 2009/10	Generic Rate Impact	CPCN (Order or date if future CPCN)	STATUS (D) Definition, (P) Preliminary, (U) Underway	BCR – Benefit Cost Ratio (Note 1)	IMPROVED SYSTEM REILIABILITY	IMPROVED SYSTEM SAFETY	NPV (Note 2)	Percentage of Total Capital Expenditures	USEFUL LIFE (Note 3)	RELIABILITY LEVEL
		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
	Generation															
1	South Slocan Unit 1 Life Extension (replace turbine)	-	17,822	39		17,861	0.714%	G-52-05	U		10	5		4.03%	75	N/A
2	South Slocan Unit 3 Life Extension (no Turbine)	13,061	-			13,061	0.522%	G-147-06	U		10	5		2.95%	75	N/A
3	South Slocan Plant Completion	-	3,551			3,551	0.142%	G-147-06	U		10	5		0.80%	75	N/A
4	Upper Bonnington Old Unit Repowering (Ph.1)	1,045	1,651			2,696	0.108%	G-147-06	U		9	7		0.61%	75	N/A
5	South Slocan Unit 1 Head Gate Rebuild	-	856			856	0.034%	G-147-06	U		5	10		0.19%	75	N/A
6	South Slocan Headgate Hoist, Control, Wire Rope Upgrade	1,103	-			1,103	0.044%	G-147-06	U		7	10		0.25%	75	N/A
7	All Plants Upgrade Station Service Supply	1,478	1,342	1,309	883	5,012	0.200%	G-147-06	U		10	10		1.13%	45	N/A
8	All Plants Lighting Upgrade	365	451			816	0.033%		U		5	8		0.18%	40	N/A
9	All Plants Spare Unit Transformer	1,849	-			1,849	0.074%		U		8	1		0.42%	45	N/A
10	All Plants Fire Safety Upgrade Ph.1	241	-			241	0.010%		D		7	4		0.05%	40	N/A
11	All Plants Public Safety & Security Ph.1	34	-	99		133	0.005%		D		4	7		0.03%	40	N/A
12	Lower Bonnington Power House Crane Upgrade	174	-			174	0.007%		P		4	7		0.04%	75	N/A
13	Corra Linn Unit I Life Upgrade			18,950		18,950	0.758%				10	5		4.28%	75	N/A
14	Corra Linn Unit 2 Life Upgrade			14,696	7,984	22,680	0.907%		P		10	5		5.12%	75	N/A
15	Corra Linn Spillway Gate Isolation Study			46		46	.002%		D		8	9		0.01%	75	N/A

Line No.	Project Name	Additions to Plant in Service				Total 2009/10	Generic Rate Impact	CPCN (Order or date if future CPCN)	STATUS (D) Definition, (P) Preliminary, (U) Underway	BCR – Benefit Cost Ratio (Note 1)	IMPROVED SYSTEM REILIABILITY	IMPROVED SYSTEM SAFETY	NPV (Note 2)	Percentage of Total Capital Expenditures	USEFUL LIFE (Note 3)	RELIABILITY LEVEL
		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
16	South Slocan Dam Study			46		46	.002%		D		8	9		0.01%		N/A
17	Corra Linn Power House Crane Upgrade	172	-			172	0.007%	0.007%	P		4	7		0.04%	75	N/A
18	Corra Linn East Wingdam Handrail Upgrade	78	-			78	0.003%	0.003%	P		1	9		0.02%	65	N/A
19	All Plants Portable Headgate Closing Device	50	-			50	0.002%	0.002%	D		9	1		0.01%	75	N/A
20	All Plants Spare Exciter Transformer	-	140			140	0.006%	0.006%	P		8	1		0.03%	45	N/A
21	South Slocan Domestic Water Supply Ph.3	-	97			97	0.004%	0.004%	P		7	9		0.02%	40	N/A
22	All Plants 2009 Pump Upgrades	233	-			233	0.009%	0.009%	P		9	2		0.05%	45	N/A
23	Upper Bonnington & Corra Linn Deluge Valves	50	-			50	0.002%	50	P		9	2		0.01%	45	N/A
24	Lower Bonnington Forebay Access Road and Intake Upgrade (see lines 32 and 33)			0	0	0										
25	Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm Sys U/G	128	-			128	0.005%	128	P		5	1		0.03%	45	N/A
26	Lower Bonnington & Upper Bonnington Upgrade Spillway Gate Cntrl Ph.1	40	-			40	0.002%	40	D		4	6		0.01%	75	N/A
27	Upper Bonnington & South Slocan Airwash Tank Rehab	108	-			108	0.004%	108	P		6	1		0.02%	45	N/A
28	South Slocan Tailrace Gate Corrosion Control	-	114			114	0.005%	-	P		6	9		0.03%	75	N/A
29	Queen’s Bay Level Gauge Building Ph. 1	67				67	0.003%	67	P		2	9		0.02%	65	N/A

Line No.	Project Name	Additions to Plant in Service				Total 2009/10	Generic Rate Impact	CPCN (Order or date if future CPCN)	STATUS (D) Definition, (P) Preliminary, (U) Underway	BCR – Benefit Cost Ratio (Note 1)	IMPROVED SYSTEM REILIABILITY	IMPROVED SYSTEM SAFETY	NPV (Note 2)	Percentage of Total Capital Expenditures	USEFUL LIFE (Note 3)	RELIABILITY LEVEL
		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
30	Upper Bonnington Unit 5/Unit 6 Tailrace Gate Corrosion Control		139			139	0.006%		P		6	9		0.03%	75	N/A
31	Upper Bonnington Extension Trash Rack Gantry Replacement	-	417			417	0.017%	-	P		4	10		0.09%	75	N/A
32	Lower Bonnington Intake Area Upgrade Ph.1	393	-			393	0.016%	393	P		1	5		0.09%	75	N/A
33	Lower Bonnington Intake Area Upgrade Ph.2	-	102			102	0.004%	-	D		6	1		0.02%	75	N/A
34	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade	-	212			212	0.008%	-	P		10	1		0.05%	45	N/A
35	Lower Bonnington & Upper Bonnington Comm. Network Comp.	-	392			392	0.016%	-	P		8	2		0.09%	15	N/A
36	Transmission Growth															
37	Ellison Distribution Source	1,734				1,734	0.069%	C-4-07	U		10	1		0.39%	45	N-0
38	Black Mountain Distribution Source	14,430	-			14,430	0.577%	C-7-07	U		10	1		3.26%	45	N-0
39	Naramata Rehab	7,524	-			7,524	0.301%	C-124-07	U		10	5		1.70%	45	N-0
40	Okanagan Transmission Reinforcement	-	137,487			137,487	5.499%	Dec 14/07	P		10	1		31.07%	45	N-0
41	Ootischenia Substation	389	-			389	0.016%	C-10-07	U		10	1		0.09%	45	N-0
42	Benvoulin Distribution Source	-	17,685			17,685	0.707%	Q3-2008	D		10	1		4.00%	45	N-0
43	Recreation Capacity Increase Stage 1,2,3	-	3,578			3,578	0.143%		P		10	1		0.81%	45	N-0
44	Kelowna Distribution Capacity Requirements			1,035		1,035	.041%		D		10	1		0.23%	45	N-0

Line No.	Project Name	Additions to Plant in Service				Total 2009/10	Generic Rate Impact	CPCN (Order or date if future CPCN)	STATUS (D) Definition, (P) Preliminary, (U) Underway	BCR – Benefit Cost Ratio (Note 1)	IMPROVED SYSTEM REILIABILITY	IMPROVED SYSTEM SAFETY	NPV (Note 2)	Percentage of Total Capital Expenditures	USEFUL LIFE (Note 3)	RELIABILITY LEVEL
		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
45	Tarrys Capacity Increase	403	-			403	0.016%		P		5	3		0.09%	45	N-0
46	Huth Substation Upgrade			3,413		3,413	0.137%		P		7	1		0.77%	45	N-1
47	30 Line Conversion	4,500				4,500	0.180%		P		7	6		1.02%	45-50	N-1
48	Static VAR Compensators (SVC) Kelowna			400		400	0.016%		D		6	1		0.09%	50	N-2(2010) N-1(2013)
49	Transmission Line Urgent Repairs	288	293			581	0.023%		P		9	9		0.13%	45-50	N-0
50	Transmission Right of Way Acquisition	311	345			656	0.026%		P		8	8		0.15%	75	N/A
51	Transmission ROW Reclamation	550	602			1,152	0.046%		P		8	8		0.26%	75	N/A
52	Transmission Line Pine Beetle Hazard Allocation	1,217	821			2,038	0.082%		P		8	8		0.46%	75	N-0
53	Transmission Line Condition Assessment	427	496			923	0.037%		P		7	7		0.21%	45-50	N-0
54	Transmission Line Rehabilitation	1,639	1,888			3,527	0.141%		P		6	6		0.80%	45-50	N-0
55	Castlegar Substation Switch CAS-6 & CAS-26 Upgrade	-	132			132	0.005%		P		4	3		0.03%	50	N-1
56	20 Line Rebuild	1,943	1,540			3,483	0.139%		P		6	7		0.79%	45-50	N-0
57	27 Line Rebuild	648	642			1,290	0.052%		P		6	7		0.29%	45-50	N-0
58	30 Line Crossing Rehabilitation	-	350			350	0.014%		P		6	7		0.08%	45-50	N-0
59	Station Condition assessment and Minor Repair	620	680			1,300	0.052%		P		5	6		0.29%	50	N-0
60	Replace Gap-Type Silicon Carbide Arrestors (included in line 59)					0										
61	Castlegar Substation Ground Grid Upgrade	572	-			572	0.023%		P		1	8		0.13%	50	N-1
62	Station Unforeseen	473	448			921	0.037%		P		9	9		0.21%	50	N-0

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		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
	/Urgent Repairs															
63	Kootenay 12 MVA Mobile Breaker Replacement	-	292			292	0.012%		P		6	6		0.07%	50	N-0
64	LTC Oil Filtration for Westminister T2	-	32			32	0.001%		P		3	2		0.01%	45	N-0
65	LTC Oil Filtration for OK Mission T1	-	32			32	0.001%		P		3	2		0.01%	45	N-0
66	LTC Oil Filtration for Summerland T2	32	-			32	0.001%		P		3	2		0.01%	45	N-0
67	Slocan City – Valhalla	2,173	-			2,173	0.087%		P		4	6		0.49%	45	N-0
68	Passmore - 19L Breaker	-	1,987			1,987	0.079%		P		8	5		0.45%	50	N-1
69	Pine Street Replacement of Distribution Breakers (F-1, F-2, F-3 Breaker Replacement & Protection upgrade)	345	-			345	0.014%		P		6	8		0.08%	45	N-0
70	Princeton old PLP Reclosers with new Breakers	-	1,513			1,513	0.061%		P		6	9		0.34%	45	N-1
71	Joe Rich Breaker Addition	-	404			404	0.016%		P		6	5		0.09%	50	N-1
72	Creston Substation Transformer T1&T2 Circuit Switchers	488	-			488	0.020%		P		6	6		0.11%	45	N-0
73	Distribution Growth															
74	New Connects System Wide	9,788	10,670			20,458	0.818%		P		N/A	N/A		4.62%	25	N-0
75	New Glenmore Feeder	788	-			788	0.032%		P		9	N/A		0.18%	40	N-0
76	Airport Way Upgrade (Ellison Feeder - 3)	-	1,551			1,551	0.062%		P		7	N/A		0.35%	40	N-0
77	Hollywood-3 & Sexsmith-4 Tie	-	365			365	0.015%		P		5	N/A		0.08%	40	N-1
78	Christina Lake Feeder-1 Capacity Upgrade	-	1,098			1,098	0.044%		P		6	N/A		0.25%	40	N-0
79	Beaver Park Feeder-2 to Fruitvale Feeder-1	-	1,227			1,227	0.049%		P		5	N/A		0.28%	40	N-1

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		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
	Distribution Tie Upgrade															
80	Oliver Feeder-1 New Regulator	-	137			137	0.005%		P		7	N/A		0.03%	40	N-0
81	Small Capacity Improvements Unplanned	974	994			1,968	0.079%		P		7	N/A		0.44%	40	N-0
82	Unplanned Growth Projects (included in line 70)					0			P		7	N/A		0.00%	40	N-0
83	Distribution Sustaining															
84	Distribution Line Condition Assessment	599	667			1,266	0.051%		P		6	7		0.29%	40	N-0
85	Distribution Line Rehabilitation (Hot Tap Replacement)	3,124	3,470			6,594	0.264%		P		6	9		1.49%	40	N-0
86	Distribution Right-of-Way Reclamation	621	646			1,267	0.051%		P		8	8		0.29%	75	N-0
87	Distribution Pine Beetle Hazard Allocation	722	551			1,273	0.051%		P		8	8		0.29%	75	N-0
88	Distribution Line Rebuilds	1,178	1,167			2,345	0.094%		P		5	6		0.53%	75	N-0
89	Small Planned Capital	668	747			1,415	0.057%		P		6	5		0.32%	40	N-0
90	2008 FortisBC Forced Upgrades	1,255	1,461			2,716	0.109%		P		N/A	N/A		0.61%	40	N-0
91	Distribution Urgent Repairs	1,911	1,805			3,716	0.149%		P		9	9		0.84%	40	N-0
92	PCB Testing Program - Distribution	1,073	1,117			2,190	0.088%		P		N/A	8		0.49%	45	N/A
93	Aesthetic & Environmental Upgrades	100	100			200	0.008%		P		N/A	N/A		0.05%	40	N/A
94	Copper Conductor Replacement Program	4,952	6,271			11,223	0.449%		P		6	10		2.54%	40	N-0
95	Telecommunications Growth															
96	Distribution	2,341	1,953	1,860		6,154	0.246%		U		8	6		1.39%	45	N-0

Line No.	Project Name	Additions to Plant in Service 2009	2010	2011	2012	Total 2009/10	Generic Rate Impact	CPCN (Order or date if future CPCN)	STATUS (D) Definition, (P) Preliminary, (U) Underway	BCR – Benefit Cost Ratio (Note 1)	IMPROVED SYSTEM REILIABILITY RISK RANKING	IMPROVED SYSTEM SAFETY RISK RANKING	NPV (Note 2)	Percentage of Total Capital Expenditures %	USEFUL LIFE (Note 3) YEARS	RELIABILITY LEVEL (N. N-1, N-1-1, N-2)
		$000s					%									
	Automation															
97	Telecommunications Sustaining															
98	Harmonic Remediation	117	119			236	0.009%		P		4	5		0.05%	15	N-0
99	Protection Upgrades	448	508			956	0.038%		P		7	8		0.22%	15	N-0
100	Communication Upgrades	299	111			410	0.016%		P		7	7		0.09%	15	N-0
101	Demand Side Management															
102	Demand Side Management	2,513	2,707			5,220	0.209%		P		N/A	N/A		1.18%	Various	N-0
103	Vehicles															
104	Vehicles	1,326	2,868			4,194	0.168%		P		N/A	N/A		0.95%	13	n/a
105	Metering															
106	Advanced Metering Infrastructure	16,492	20,240			36,732	1.469%	Dec 19/07	P		4	N/A		8.30%	25 (See CPCN Application for further information)	N-0
107	Metering Changes to Uninstalled Meter Inventory	526	559			1,085	0.043%		P		N/A	N/A		0.25%	25	N/A
108	Information Technology															
109	Desktop Infrastructure Upgrades	842	847			1,689	0.068%		P		N/A	N/A		0.38%	5	N/A
110	AM/FM Systems Enhancements	211	423			634	0.025%		P		4	6		0.14%	5	N-0
111	Customer Systems Enhancements	789	794			1,583	0.063%		P		N/A	N/A		0.36%	5	N/A
112	Infrastructure Upgrades	789	794			1,583	0.063%		P		N/A	N/A		0.36%	5	N/A
113	SAP Operations Systems	947	953			1,900	0.076%		P		N/A	N/A		0.43%	5	

Line No.	Project Name	Additions to Plant in Service				Total 2009/10	Generic Rate Impact	CPCN (Order or date if future CPCN)	STATUS (D) Definition, (P) Preliminary, (U) Underway	BCR – Benefit Cost Ratio (Note 1)	IMPROVED SYSTEM REILIABILITY	IMPROVED SYSTEM SAFETY	NPV (Note 2)	Percentage of Total Capital Expenditures	USEFUL LIFE (Note 3)	RELIABILITY LEVEL
		2009	2010	2011	2012						RISK RANKING	RISK RANKING		%	YEARS	(N. N-1, N-1-1, N-2)
		$000s					%									
	Enhancements															
114	SCADA Systems Enhancements	789	688			1,477	0.059%		P		7	7		0.33%	5	N-0
115	Distribution Design Software	799	-			799	0.032%		P		N/A	N/A	(683)	0.18%	5	N/A
116	Telecommunications															
117	Telecommunications	105	106			211	0.008%		P		6	8		0.05%	15	N-0
118	Facilities															
119	Construction Projects Requirements	218	219			437	0.017%		P		N/A	N/A		0.10%	40	N/A
120	Emergency Building Upgrades	88	89			177	0.007%		P		N/A	N/A		0.04%	30	N/A
121	Corporate Security System	305	305			610	0.024%		P		N/A	8		0.14%	30	N/A
122	Facility Upgrades	2,637	1,368			4,005	0.160%		P		N/A	N/A		0.90%	30	N/A
123	Furniture															
124	Furniture & Fixtures	347	393			740	0.030%		P		N/A	N/A		0.17%	15	N/A
125	Tools															
126	Tools and Equipment	572	575			1,147	0.046%		P		N/A	N/A		0.26%	15	N/A
	Grand Total (Note 4)	122,628	269,196	41,893	8,867	442,584										

Note 1 –The majority of projects do not lend themselves to a Benefit Cost Ratio. In general, these projects undertaken by the public utility are required to provide service or part of the utility's obligation to serve, or to maintain employee or public safety.
Note 2 – The NPV for projects which have not been subject to a CPCN are noted. NPV calculations have not been performed for other projects.
Note 3 – Based on depreciation schedules.
Note 4 – Differences due to rounding.

Q1.0 Reference: CEP, page 5, lines 4-8

Q1.1 Please provide a schedule that identifies those capital spending projects that are directly attributable to the BC Government's energy objectives and are not necessary "to ensure the ability to provide service, public and employee safety and reliability of supply".

A1.1 The Governments Energy Objectives are outlined in Section 1 of the Utilities Commission Act. Specifically,

> "government's energy objectives" means the following objectives of the government:
>
> (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;

Capital Projects in the 2009/10 Capital Plan that are directly attributable to the BC Government's energy objectives and are not necessary "to ensure the ability to provide service, public and employee safety and reliability of supply" are listed in Table A1.1 below, along with the energy objective that is supported. AMI is included as the portion of the project as described by the Amended Application filed with Commission on March 28, 2008 is attributable to the Energy Objectives. The scope contained in the original Application was justified on operational benefits.

Table A1.1

	Capital Project	Energy Objective
1	Advanced Metering Infrastructure (AMI)	• to encourage public utilities to take demand-side measures; • to encourage public utilities to reduce greenhouse gas emissions
2	Demand Side Management	• to encourage public utilities to take demand-side measures

Q2.0 Reference: CEP, page 6, Table 1.1 and page 10, Table 1.3

Q2.1 Please provide a revised Table 1.1 that includes the following columns:

- **2007 Capital Expenditures (per approved 2007/08 CEP)**
- **2007 Actual Capital Expenditures**
- **2008 Capital Expenditures (per approved 2007/08 CEP)**
- **2008 Actual Capital Expenditures**

A2.1 Please see Table A2.1 below. As actual 2008 expenditures will not be available until after December 31, 2008, forecast expenditures have been provided in the table below.

Table A2.1
2009/10 Capital Plan Actual vs. Approved Expenditures

		2007	**2007**	**2008**	**2008**
		Approved	**Actual**	**Approved**	**Year End Forecast (as of July 2008)**
		($millions)			
1	Generation	21.7	20.4	19.0	18.4
2	Transmission & Stations	64.4	69.1	59.3	52.9
3	Distribution	19.8	25.5	20.2	24.0
4	Telecom, SCADA, Protection and Control	4.9	1.2	3.1	3.2
5	Demand Side Management	1.7	1.6	1.6	1.6
6	Information Systems	5.6	6.7	3.5	4.3
6	General Plant	10.0	7.8	5.0	5.5
7	**Total Capital**	**128.1**	**132.3**	**111.7**	**109.9**

Q3.0 Reference: CEP, pages 7 & 8

Q3.1 The explanation of the $75.2 M in increased spending for the 2009/10 period (relative to the 2007 SDP) suggests that most of it ($71.6 M) is due to the OTR project. How much of the increase is due to the shift in completion date versus scope refinement?

A3.1 Please see the response to BCUC IR No. 2 Q122.1.

Q4.0 Reference: CEP, page 10, lines 5-6 and 9-11

Q4.1 Do the expenditures on South Slocan Units 1 and 3 and Units 1 and 2 at Corra Linn result in any increase in the output (MW's or MWhs) for these units? If so, by how much?

A4.1 There are no increases anticipated in the output for any of these units.

Q5.0 Reference: CEP, page 21, lines 1-18 and BCUC #1.10.1 & #1.12.1

Q5.1 How much of the $4.56 M increase in cost for South Slocan Unit #1 was due to higher than expected cost escalation versus cost escalation due to delays in completion?

A5.1 The $2.1 million was due to the escalation in the cost of the turbine. The remaining $2.46 million is due to increased cost of materials and labour as a result of the delay in completion from 2007 to 2009.

Q6.0 Reference: CEP, page 27, lines 1-16

Q6.1 Will the upgrades to station service facilities lead to a reduction in station service use?

A6.1 No, the upgrades to station service facilities will not lead to a material reduction in station service use.

Q7.0 Reference: CEP, page 42, Table 3.1

Q7.1 Please indicate the budget for the OTR project as filed in the December 2007 CPCN. Please provide an explanation if there is a material (<5%) difference between the original cost and the current $141.4 M estimate.

A7.1 The budget for the OTR Project as filed in the December 2007 CPCN was $141.4 million.

Q8.0 Reference: CEP, page 49, lines 16-17 and BCUC IR#1.31.1 & 1.31.2

Q8.1 Please identify the stations that would be affected by the load transfer option and dates at which each would experience "capacity deficiency". Please clarify what is meant by a "capacity deficiency", in light of the responses to BCUC IR#1.31.1 & 1.31.2.

A8.1 FortisBC's Recreation Substation serves loads solely for the City of Kelowna. Transferring load would only be possible to Saucier Substation and the Glenmore Substation. The Saucier Substation feeds loads solely for the City of Kelowna whereas the Glenmore Substation feeds FortisBC customers in the Springfield and Glenmore regions. Transferring this load growth to these stations would require significant changes in each distribution feeder (from all 3 stations) which would result in overload conditions arising on circuit segments and the inability for the feeders to back up each other in the event of an outage.

Capacity deficiency in this instance would be defined as the inability to effectively provide supply on a distribution feeder rather than at a substation level.

Q9.0 Reference: CEP, page 50, lines 1-19

Q9.1 Please explain how the $500,000 in annual spending will be treated for revenue requirement purposes (e.g., will it be deferred and amortized and, if so, over what timeframe?)

A9.1 The expenditures will be recorded as capital work in progress ("CWIP") until the project(s) scope is defined at which time the costs will be allocated to the project(s). CWIP is not included in rate base and therefore until the assets are placed in service there is no impact on revenue requirements. Once the assets are placed in service, the costs will be amortized in accordance with depreciation rates agreed to in Commission Order G-58-06.

Q10.0 Reference: CEP, page 57, lines 8-10 and BCUC #1.35.2

Q10.1 How much of the $821 k spending in 2007 is related to the Mountain Pine Beetle Hazard?

A10.1 Approximately $0.23 million was spent in 2007 related to Mountain Pine Beetle within the Transmission Right-of-Way Reclamation budget.

Q11.0 Reference: CEP, pages 59-60

Q11.1 Please indicate the number of poles associated with the transmission line condition assessments undertaken in 2006, 2007 and 2008 respectively.

A11.1 The number of poles planned for condition assessment were identified in the respective Capital Plans for each year. The tables provided below have been reproduced from previous Capital Plan filings.

As noted in the response to Q12.1 below, not all assessments were completed in 2007 for a variety of reasons. Work that was not completed in 2007 has been deferred until 2008 and is forecast to be completed by the end of 2008.

From FortisBC's 2006 Capital Plan, page 32:

Table 3.7

	Line	Location	Poles
1	26	Brilliant to Castlegar to Celgar	372
2	20	Warfield Terminal Station (W261S) to Salmo	523
3	10B	Tap from 10 Line to Baldy (now used to supply Baldy at 25 kV)	81
4		TOTAL UNITS:	976

From FortisBC's 2007 Capital Plan, page 53-54:

Table 3.6(a)
Transmission Line Condition Assessment Projects 2007

	Line	Location	Poles
1	52	RG Anderson to Huth Penticton	41
2	53	RG Anderson to Huth Penticton	36
3	21, 22, 23 & 24	Slocan/Brilliant Generation River Lines	285
4	27	South Slocan/Nelson and Salmo	443
5	77	Warfield Terminal to Brilliant Terminal	196
6	79	Brilliant Terminal to Kootenay Canal	83
		TOTAL UNITS	**1,084**

Table 3.6(b)
Transmission Line Condition Assessment Projects 2008

	Line	Location	Poles
1	8	Brilliant Generation to Brilliant Terminal	6
2	12	Kootenay Canal to South Slocan Terminal	6
3	28	Upper Bonnington to City of Nelson	17
4	34	Warfield to Mawdsley	43
5	37	Coffee Creek to Kaslo	241
6	44	Oliver to Pine to Osoyoos	169
7	51	DG Bell to OK Mission Kelowna	258
8	54L/54AL	Kelowna Lee station through DG Bell	150
9	74	Lee Terminal to Vernon	199
		Total	**1,089**

Q12.0 Reference: CEF, page 61 and BCUC IR#1.42.1

Q12.1 Please explain the significant increase in transmission line rehabilitation spending in 2008, particularly in view of the low level of spending on transmission line condition assessment in 2007.

A12.1 Please refer to the response to BCUC IR No. 1 Q41.1.

Q13.0 Reference: CEP, pages 62-63 and BCUC IR#1.44.1 & 1.45.1

Q13.1 Please explain why the 20 Line rebuild costs 2.7 times more than the 27 Line rebuild when the former involves only 1.75 times as many poles.

A13.1 The structure quantities for replacement on 27 Line are lower than 20 Line largely as a function of pole vintages on each of the lines and rehabilitation work previously completed. 27 Line has had approximately 41 kilometres of line rebuilt and reconductored in the 1980s and 1990s, whereas 20 Line has only had approximately 14 kilometres of upgrading in the 1990s.

Also contributing to the amount of work and structure loadings on each of the lines is the distribution underbuild. 20 Line has underbuild distribution on the bulk of the line length while 27 Line has underbuild distribution on only portions of the circuit and in some areas only small single phase distribution.

The actual quantities and estimates for the work on each of the circuits was based on actual field inspections/patrols, as well as condition assessement information.

Q14.0 Reference: CEP, page 69, lines 10-12 and BCUC IR#1.50.1 & 1.50.2

Q14.1 How many bulk oil circuit breakers will be replaced with modern SF6 breakers in 2009 and 2010 respectively?

A14.1 FortisBC plans to replace the bulk oil breaker on its 12 MVA mobile transformer in 2010. There are no other bulk oil circuit breaker replacements planned for these years.

Q15.0 Reference: CEP, page 88, line 11

Q15.1 Please explain the reason for the significantly higher level of spending on distribution line condition assessments in 2007.

A15.1 The proposed expenditure estimates are based on historical cost. The expenditures are forecast in anticipation of issues that will arise in 2009 and 2010 based on past experience. Due to scheduling of work in 2007 and 2008, expenditures on Distribution Line Condition Assessments are forecast to be lower in 2008 than in 2007; however expenditures in 2009 and 2010 are budgeted to be in line with the three year historical rolling average.

Q16.0 Reference: CEP, pages 88-90 and BCUC IR#1.66.1 & 1.67.4

Q16.1 Please confirm that the high level of spending on distribution line rehabilitation in 2008 is due to the higher than historical level of spending on distribution line condition assessment in 2007. If this is not the case, please explain the reason for the high level of spending on rehabilitation in 2008.

A16.1 The difference in spending levels between 2007 and 2008 on Distribution Rehabilitation is due to a variety of reasons including scheduling of other projects and resources. For this reason, a large amount of the 2007 planned work was carried forward from 2007 into 2008.

It is anticipated that the work planned for 2007 and 2008 will be substantially completed by the end of 2008.

Q16.2 After accounting for the $750,000 annual spending on "Hot Tap Connector Replacement" the spending on Distribution Line Rehabilitation is $2,374 k in 2009 and $2,720 k in 2010. This level of spending is significantly higher than past levels for all years except 2008 and does not appear to reconcile with the previous years' planned condition assessment activity. Please provide further explanation for the 2009 and 2010 increases.

A16.2 Upon review, FortisBC determined that it had inadvertently inserted additional costs into the calculations for the 2009 and 2010 budget. The corrected budget is shown in Table A16.2 below.

Table A16.2

	2005	2006	2007	2008F	2009F	2010F
	($000s)					
Cost	569	1,961	1,231	2,582	2,848	3,209

Q17.0 Reference: CEP, pages 90-91

Q17.1 Is the spending on Distribution Right of Way Reclamation expected to result in lower annual OM&A expenditures for vegetation management? If not, why not? If yes, what is the estimated impact?

A17.1 The spending on Distribution Right-of-Way Reclamation will not materially impact OM&A expenditures. The reclamation project is required to increase the tree-free zone around the distribution lines and is associated with tree removals that are occurring for the first time.

The Company charges as an operating expense vegetation management expenditures associated with trimming, brushing and removal of trees that do not contribute to widening an existing right of way.

Q18.0 Reference: CEP, page 101, lines 13-15

Q18.1 Please compare the current expected cost and schedule for the Distribution Substation Automation Program with that approved in Order C-11-07 and explain any material changes.

A18.1 The Commission Decision for the Distribution Substation Automation Program included a provision for FortisBC to update its expected costs for the project to the +/- 10 percent level. These figures, as provided to the Commission, are included in Table A18.1 below. Table A18.1a contains the project schedule.

Table A18.1

Station	Application Budget	Revised Budget	Explanation
	($000s)		
Bell Terminal	24	31	Refined scoping identified additional two feeders requiring tagging.
Castlegar	345	312	
Duck Lake	131	123	
Fruitvale	42	42	
Glenmore	125	248	Refined scoping identified additional relay change-outs and monitoring.
Hollywood	375	359	
Keremeos	54	26	Refined scoping identified that only communications is required.
Summerland	89	151	Refined scoping identified relay change-outs, additional devices to control and the requirement of the mobile substation to complete the work.
Beaver Park	152	102	Refined scoping identified that a smaller RTU could be utilized.
Summerland	89	151	Refined scoping identified relay change-outs, additional devices to control and the requirement of the mobile substation to complete the work.
Beaver Park	152	102	Refined scoping identified that a smaller RTU could be utilized.
Blueberry	140	170	Refined scoping identified additional feeder monitoring and additional devices to control.

Table A18.1 cont'd

Station	Application Budget	Revised Budget	Explanation
	($000s)		
OK Mission	383	376	
Osoyoos	122	182	Refined scoping identified additional relay changes were required
Playmor	183	204	
Saucier	37	0	Saucier completed in 2007 under Station Assessment and Minor Planned Project 2006 SDP-SS0100.06.01 "Replacement of Demand Ammeters & PML Meters at Dist. Stations" Amount spent was $52,000.
Valhalla	91	173	Refined scoping identified a relay change and communication solution utilizing satellite technology.
Westminster	140	296	Refined scoping identified transformer monitoring and additional devices to control.
Christina Lake	180	206	
Glenmerry	186	202	
Hedley	348	371	
Salmo	155	142	
Trout Creek	223	162	Refined scoping identified that a dial-up phone line was not required.
West Bench	286	222	
Huth	190	299	Refined scoping identified feeder relay changes and additional feeder monitoring.
Passmore	139	337	Refined scoping identified feeder relay changes and additional device controls.
Sexsmith	272	248	
Slocan City	95	0	This substation has been cancelled because of the intent to move the transformer to Valhalla which is part of the 2009/2010 Capital Plan.
Stoney Creek	291	297	
Tarrys	348	287	
Additional Costs:			
Estimating / Engineering / Procurement	462	127	The $462,000 in the original application was for Estimating / Engineering / Procurement in 2007. The reduction of cost to $127,000 is due to procurement and engineering costs being allocated directly to the substation rather than this line item.
Data server hardware & Software	173	173	
Contingency	578	578	$5,000 of contingency utilized for Keremeos overspending.

Table A18.1 cont'd

Station	Application Budget	Revised Budget	Explanation
	($000s)		
AFUDC	18	9	Due to timing of costs. Procurement and engineering costs were shifted to the individual substation line.
Total Annual Cost	**6,378**	**6,458**	

Table A18.1a

Milestone	Planned Finish Date
Detailed Scopes and Estimates	Jun-08
Complete detailed design & procurement 2008 Stations	Sep-08
2008 Station Construction	Dec-08
Detailed design & procurement 2009 Stations	Dec-08
Data Historian Software & Hardware Vendor Selection	Oct-08
Complete 2008 Station Construction	Dec-08
Data Historian Software & Hardware Implementation	Apr-09
2009 Station Construction	Dec-09
Detailed design & procurement 2010 Stations	Dec-09
2010 Station Construction	Dec-10
Detailed design & procurement 2011 Stations	Dec-10
2011 Station Construction	Dec-11

Q19.0 Reference: CEP, page 107 and BCUC IR#1.77.2

Q19.1 Does the 301.2 GWh cumulative savings figure (BCUC IR#1.77.2) assume that all DSM savings achieved in previous years are permanent? If yes, what is the basis for this assumption? If not, what attrition rate has been assumed?

A19.1 The 301.2 GWh figure is a simple sum of the annual DSM results over the years for illustrative purposes. There is no attempt to adjust the cumulative total for attrition of individual measures, or programs as a whole. FortisBC considers this practice acceptable for short-term (revenue requirements) and medium-term (capital planning) forecasts.

Q19.2 What is the amortization rate use by FortisBC for DSM spending? Please reconcile this rate with the assumptions underlying the response to part 1 of the question.

A19.2 The amortization schedule was changed by the 2006 Negotiated Settlement Agreement approved by BCUC Order G-58-06. In 2009, the weighted average portfolio amortization is forecast to be 7.3 years. This is an accounting process and does not apply to the 301.2 GWh figure quoted in response to Q19.1 above.

Q20.0 Reference: CEP, page 106, lines 5-6; page 108, Table 6.2; & page 109, Table 6.3

Q20.1 Please confirm whether “incentive payments” are included in the economic test (per page 106) applied to DSM programs.

A20.1 Yes, incentive payments made to customers are included in program costs, thus they are factored into the TRC Benefit/Cost calculations.

Q20.2 For each of the three sectors (Residential, General Service and Industrial) please indicate how much of the Plan Costs (per Table 6.2) in each year (2008, 2009 and 2010) are associated with incentive payments.

A20.2 Please see Table A20.2 below.

Table A20.2

	2008	**2009**	**2010**
	(%)		
Residential	62	62	64
General Service	55	57	58
Industrial	64	68	71
Total	50	50	52

Q21.0 Reference: CEP, pages 110-111

Q21.1 Do any of the Residential programs have a component that is specifically targeted/designed for low-income customers? If yes, please describe? If not, why not?

A21.1 Please see the response to OEIA IR No. 1 Q15.9.

Q22.0 Reference: CEP, page 106, lines 5-6 and pages 110-113

Q22.1 Please provide the analysis that demonstrates that each of the proposed new programs (Residential, General Service and Industrial) cost less than the avoided cost of delivered power.

A22.1 All of the new programs have a Utility Benefit/Cost ratio greater than one, which the exception of the residential Net-Zero new home pilot project. The expenditures on the Net-Zero program total approximately $86,000 before tax in 2009 and 2010, a relatively small cost that allows the New Home

Construction portfolio of programs to maintain a benefit/cost ratio greater than one.

Q23.0 Reference: CEP, page 110, lines 16 – 23

Q23.1 What role is FortisBC playing in launching the LiveSmartBC home retrofit program?

A23.1 FortisBC is a funding partner under which eligible customers, within the Company's service area, have their ecoEnergy audits subsidized and any energy-saving measures incented to the amount authorized by the Company's approved Electric Tariff (DSM Rate Schedules).

FortisBC is also the major marketing partner in terms of promoting and referring customers within the service area to the LiveSmart BC program.

Q23.2 How much of FortisBC's DSM budget will be allocated to the LiveSmartBC program, and what will this money be used for?

A23.2 $0.06 million and $0.07 million has been allocated for 2009 and 2010 respectively, which is the estimated uplift required to the Home Improvement program. The monies will be used to partially reimburse homeowners for the ecoEnergy audit fees, and rebates for installed retrofit measures. In addition customers will receive incentives from measure specific programs, such as Air Source Heat Pumps, where applicable.

Q23.3 What role is FortisBC playing in the SolarBC program?

A23.3 The Company will advise customers of the availability of the SolarBC program through existing channels including PowerLines billing insert and website links. Also, the Company will offer an incentive to customers with electrically heated hot water tanks who install a solar thermal system to reduce their electrical load.

Q23.4 How much of FortisBC's DSM budget will be allocated to the SolarBC program, and what will this money be used for?

A23.4 Amounts of $30,000 and $40,000 have been allocated in 2009 and 2010 respectively.

Q23.5 Will SolarBC programs require participants to contribute or spend money in order to participate?

A23.5 The estimated cost of an installed solar thermal system is $5,000, and the incentives from various agencies, including FortisBC, will cover about 25 percent of the total.

Q24.0 Reference: CEP, page 111, lines 3-5

Q24.1 Please provide a list of members of the "provincial working group on affordable housing", and the group's terms of reference and/or mandate, if available.

A24.1 FortisBC is a member of this informal working group which is chaired by Terasen Gas. FortisBC does not have the list of members, and to the best of FortisBC's knowledge the group's Terms of Reference are not finalized.

Q25.0 Reference: CEP, page 114, lines 6 – 8

Q25.1 Please provide a list of members of the "provincial DSM steering committee", and the committee's terms of reference and/or mandate, if available.

A25.1 The members of the "provincial DSM steering committee", or BC Partnership for Energy Conservation and Efficiency, currently include representatives from FortisBC, BC Hydro, Terasen Gas, Pacific Northern Gas, Ministry of Energy Mines and Petroleum Resources, Climate Action Secretariat and the BCUC. Please see BCOAPO Appendix A25.1 for the committee's terms of reference.

Q26.0 Reference: CEP, page 116, Table 7.1

Q26.1 Please provide a revised version of Table 7.1 that includes actual 2007 spending and forecast 2008 spending for each line item.

A26.1 Please see Table A26.1 below.

Table A26.1
General Plant Expenditures

General Plant	CPCN filed	2007	2008 Forecast	2009	2010
Vehicles		4,431	2,733	1,326	2,868
Advanced Metering Infrastructure	Dec. 19, 2007			16,492	20,240
Metering Changes to Uninstalled Meter Inventory		542	263	526	559
Information Systems		6,655	4,290	5,167	4,499
Telecommunications		221	177	105	106
Buildings		1,565	1,536	3,248	1,981
Furniture and Fixtures		248	252	347	393
Tools and Equipment		936	569	572	575
TOTAL		**14,598**	**9,820**	**27,783**	**31,221**

Q27.0 Reference: CEP, page 125, line 10 and BCUC IR#1.90.1

Q27.1 Please explain why the anticipated spending level for 2010 ($423 k) is more than twice that for 2009 ($211 k).

A27.1 With 2009 being the first full year of the ESRI AM/FM system being in place, a majority of the year will be spent ensuring data is complete and up to date in the system, therefore there will not be time available to implement as many enhancements or interfaces. In 2010 there are planned to be more enhancements and interfaces undertaken with the system being fully entrenched in the organization.

Q27.2 Why is it that available resources determine the level of spending (per BCUC IR#1.90.1) as opposed to system requirements?

A27.2 Internal resources make up the major portion of the project teams on enhancement and upgrade projects due to their knowledge of FortisBC systems for development and testing. A balance between resource availability for project work, and the benefit or requirement of the upgrade or enhancement identified determines priority.

Q28.0 Reference: CEP, page 127, line 9

Q28.1 Please explain why the spending on SCADA Systems Enhancement for 2009 and 2010 is so much higher than the spending levels for 2007 and 2008.

A28.1 The upgraded SCADA system allows FortisBC to develop enhancements and interfaces to other systems, such as ESRI AM/FM, that were not possible with the old version of SCADA. The benefits include continuity of data between systems, improved information availability in the field and more efficiency in data entry through interfaces. This is primarily what the budget has been developed around.

Q29.0 Reference: SDP, page 3, lines 27-28 and BCUC IR#1.98.1

Q29.1 Please confirm whether the phrase “as originally scheduled” refers to the 2005 SDP or the 2007 SDP Update.

A29.1 The phrase “as originally scheduled” refers to the 2007 update.

Q30.0 Reference: SDP, page 4, lines 5-6, and pages 4-6

Q30.1 Please confirm whether all of the changes discussed on pages 4-6 are with respect to the 2007 SDP Update (per page 4, lines 5-6). If not, please identify those items that are not.

A30.1 Confirmed.

Q30.2 Were the new items arising from the updated scope of the proposed OTR (per page 5, lines 2-3) identified in the 2007 SDP Update?

A30.2 No. The updated scope was provided in the CPCN Application for the OTR Project.

Q31.0 Reference: SDP, Appendix 1

Preamble: The tables provided in Appendix 1 do not indicate the "capability" of each of the substations/transformers listed.

Q31.1 What are the criteria that FortisBC uses to determine a substation/transformer is not able to reliably supply the forecasted load?

A31.1 In general, FortisBC uses the Oil Natural Air Forced (fan cooled) transformer nameplate rating as the load limit for substation planning. No overload capacity is assumed for planning purposes, this capability is reserved for operational flexibility in the event that load growth materializes more quickly than expected. Note that some transformers have been de-rated below nameplate due to known internal limitations.

Q31.2 Based on the current capital spending plan for 2009 and 2010, are there any substations/transformers that will not meet this criteria for summer of 2010 or the winter of 2010/2011? If so, please identify the stations/transformers and any contingency plans FortisBC has with respect to meeting customers' forecast load requirements.

A31.2 Assuming the projects identified in the 2009/10 Capital Plan are completed, there will be no transformers other than Tarrys that are projected to exceed their nameplate ratings for the dates requested. The contingency plan for Tarrys involves the transfer of load to an adjacent substation.

Terms of Reference:
BC Partnership for Energy Conservation and Efficiency

Context:

BC Energy Plan

In February 2007, the government of British Columbia released the BC Energy Plan: A Vision for Clean Energy Leadership (BC Energy Plan) which establishes ambitious provincial targets for energy conservation and reducing greenhouse gas emissions.

The BC Energy Plan includes the following relevant policy actions that call for greater collaboration and coordination among utility DSM programs and provincial energy conservation and efficiency policies and programs:

Policy Action 2: Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.

Policy Action 3: Encourage utilities and the BC Utilities Commission to pursue cost-effective and competitive demand side management opportunities.

Policy Action 4: Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

Utilities and Provincial Energy/Climate Change Targets

Since the release of the BC Energy Plan, provincial goals to reduce greenhouse gas emissions by 33% below current levels by 2020 and by 80% below current levels by 2050, and the Energy Plan target to achieve 50% of BC Hydro's incremental resource needs through conservation, have been enshrined in legislation.

Achieving these targets will only be possible through aggressive and coordinated action by the provincial government and public and private utilities, acting in concert with a broad range of stakeholders including industry, local government, relevant federal agencies, environmental NGOs, and the applicable trades.

Government is giving utilities new tools to help meet the targets. Amendments to the *Utilities Commission Act*, introduced on March 31, 2008, bring the legislation in line with the conservation, energy security and climate action goals of the BC Energy Plan. The amendments align the Act with the province's energy objectives — to encourage utilities to reduce greenhouse gas emissions, pursue energy conservation and efficiency, produce and obtain electricity from clean or renewable sources, develop energy transmission infrastructure and capacity in time to meet customers' needs, and leverage innovative energy technologies.

Developing an ongoing and focused partnership with utilities will also help to resolve potentially conflicting objectives, such as the tension between reducing greenhouse gas emissions from fossil fuels and reducing electricity usage to meet the BC Energy Plan conservation target.

Terms of Reference:
BC Partnership for Energy Conservation and Efficiency

BC Partnership for Energy Conservation and Efficiency

In March 2008, the Deputy Minister of the Ministry of Energy, Mines and Petroleum Resources announced the creation of the British Columbia Partnership for Energy Conservation and Efficiency, to work on setting targets and to contribute towards ensuring that the regulatory framework for the British Columbia Utilities Commission supports cost-effective demand-side management measures.

Steering Committee
The Partnership Steering Committee had its first meeting on March 18, 2008. A proposed membership list and objectives are outlined below. Depending on the subject matter of Steering Committee meetings, other stakeholders may be invited to attend individual meetings where items of particular interest to their sector are being discussed.

Working Groups
The following key issue areas have been identified as potential candidates for working groups (with examples of related projects in brackets):

1. Built Environment (updated Energy Efficient Buildings Strategy),
2. Industrial Customers (Industrial Energy Efficiency Program),
3. Communities (Community Action on Energy and Emissions), and
4. Transportation (in 2009).

The Steering Committee also identified the need for an Analysis, Measurement and Reporting task group that could meet for a limited time to come up with recommendations.

The role, composition and scope of the working groups will be defined by the Steering Committee. It is understood that the working groups will have broader membership than the Steering Committee and will provide recommendations and information to the Steering Committee for consideration.

Proposed Steering Committee Membership:

Government:

Ministry of Energy, Mines and Petroleum Resources (MEMPR)*:*	Les MacLaren Andrew Pape-Salmon Erik Kaye Chris Frye
Climate Action Secretariat	CAS Rep to be confirmed
British Columbia Utilities Commission	Erica Hamilton Jim Fraser

Terms of Reference:
BC Partnership for Energy Conservation and Efficiency

Utilities:	
BC Hydro	Lisa Coltart
	Bev Van Ruyven
FortisBC	Mark Warren
	Michael Mulcahy
Terasen Gas	Doug Stout
	Sarah Smith
Pacific Northern Gas Ltd.	Craig Donohue

Steering Committee objectives:

1. Define a common vision for energy conservation and efficiency in British Columbia

2. Serve as a forum for coordinating key energy conservation and efficiency initiatives

3. Identify provincial policy opportunities and challenges, and identify and resolve conflicting policy directions.

4. Develop an integrated public and industry engagement strategy to foster a culture of conservation in British Columbia.

Steering Committee Projects

Note: The list below is a compilation of broad policy issues that cut across the various working group sectors and is proposed as the initial project list for the Steering Committee:

1. Agree on a common definition of cost-effective DSM programs, with a particular focus on avoided cost and achievable potential.
2. Review the regulatory framework of the *Utilities Commission Act* (as amended)and identify opportunities to further support cost-effective DSM programs.
3. Define a common platform for utilities to monitor and report out on their progress towards meeting provincial energy conservation and GHG reduction targets.
4. Define how to allocate ownership of, or credit for, energy conservation and GHG reduction achievements across utilities and other stakeholders if applicable.
5. Develop strategies to achieve provincial energy conservation and greenhouse gas reduction targets while minimizing any conflicts between the two.
6. Coordinate DSM programs to achieve current provincial targets and support upcoming sectoral strategies, i.e. the updated Energy Efficient Buildings Strategy, which underpin the provincial targets.
7. Propose improvements to DSM programs to provide greater assistance to low-income ratepayers.

Question 1: Kelowna Distribution

Reference

BCUC: Q30.2 Would FortisBC please provide a listing of the distribution areas perceived to be at risk and rank them by the level of risk by year over the next five years?

BCUC: A30.2 As noted in response to BCUC IR No. 1 Q30.1, the greater Kelowna area is facing high sustained growth levels. The specific areas of concern are: Kelowna north / Sexsmith / Highway 97 commercial area served by the Sexsmith Substation [risk ranking: high] Kelowna downtown served by the Saucier Station [risk ranking: high].

BCUC: Q30.3 Would FortisBC please provide an outline of the engineering work (i.e., scope)?

BCUC: A30.3 The Project in 2009/10 will develop a long-range plan to assist FortisBC in documenting major additions and reconfiguration changes required to accommodate load growth projections in the greater Kelowna area. While a detailed scope has not been completed, it is anticipated that the project will involve detailed planning and engineering analysis to identify alternative solutions and projects which will be required to maintain system stability and accommodate customer growth.

BCUC: Q30.4 Would FortisBC please provide a rough estimate of the total project cost?

BCUC: A30.4 FortisBC is unable to provide estimates as a detailed plan has not been developed.

Q1.1 When will the detailed plan be completed?

A1.1 The detailed plan will be completed in 2010.

Q1.2 Have you communicated this concern to the City Manager and/or City Council, if not, when will you be doing so?

A1.2 FortisBC has ongoing communication with the City of Kelowna planning department on all projects. The City will be involved with this project from the onset and meetings will be coordinated with stakeholders.

Question 2: CEP Resources

Reference

CEP p.60 Transmission Line Condition Assessment

BCUC: Q41.1 Please explain the dramatic increase from $152,000 in 2007 to $845,000 forecasted in 2008 for transmission line condition assessment expenditures [Table 3.2(c)].

BCUC: A41.1 The proposed budget filed in the 2007-2008 Capital Plan (page 52) for Transmission Line Condition Assessment was $0.616 in 2007 and $0.647 in 2008 for a total of $1.263 million. Due to a variety of reasons including scheduling of other projects and resources, a large amount of the planned work was carried forward from 2007 into 2008. The total value of Transmission Line Condition Assessment work for 2007 and 2008 is now forecast to be $0.997 million over the two years, with the bulk of the spending occurring in 2008.

Q2.1 If FortisBC couldn't complete their work in 2007 how do they plan to complete the entire 2009 and 2010 Capital plan? Can the company cut back on Capital and instead of spending the $359.8 million over 2 years, do it over 3 years? How would that affect the rate impact?

A2.1 The 2009/10 Capital Plan contains projects with expenditures totaling $359.8 million. Of that total, $178.1 million is attributed to two projects, the Okanagan Transmission Reinforcement (OTR) Project and the Advanced Metering Infrastructure (AMI) Project. The remaining expenditure of $181.7 million is less than the combined 2007/08 expenditure forecast of approximately $240 million.

Much of the delay in 2007/08 was in the approvals and permitting of some major projects. The 2009/10 projects include the execution of these major projects with the approvals and permits almost completed. While the exact ratio has not been determined, it is expected that the majority of these projects will be completed using external resources. During the development of the 2009/10 Capital Plan, many projects in addition to those currently in the plan were considered and ultimately deferred in an effort to reduce the cumulative rate impact as much as possible. The 2009/10 Capital Plan contains only those projects that the Company feels are necessary to ensure that reliable and safe service is maintained or Provincial energy objectives are served. Delaying or spreading out of these projects would increase the impact of inflation and where applicable AFUDC.

Q2.2 The 2009/10 CEP represents approximately $50M/year increase in capital spending over the 2007/08 CEP. How will FortisBC provide resources to undertake this work? How much is expected to be from internal and external resources?

A2.2 Please see the response to Q2.1 above.

Q2.3 Can FortisBC forecast their Capital spending for the next 10 years? Do they anticipate spending $180 Million a year or will the capital program drop off in years 5,6, and 7…..if so why not take a balanced approach where the Capital program gets flattened out instead of spiking for 2 or 3 years and then decreasing for a couple years……….Can FortisBC set a 10 year capital plan sustaining a $150 million year for the next 10 years………..no more no less

A2.3 FortisBC cannot forecast the capital spending levels for the next ten years. This forecast will come from the updated integrated plan which will include the impacts of the next long term System Development Plan, the long term DSM Plan and the long term Resource Plan. FortisBC is planning to complete an integrated long term plan for submission to the BCUC in the third quarter of 2010. The results of the long term plan will determine the required capital spending requirements for future years.

FortisBC attempts to levelize expenditures as much as possible during the Capital planning process. Where practical, routine program spending such as condition assessments and brushing are budgeted in this manner. The 2009/10 Capital Plan is front-loaded due to the OTR and AMI Projects which comprise $178.1 million of the $359.8 million total. Placing a cap on the capital program would potentially result in portions of required projects not being completed or included in the plan. The impacts of load growth, including the impacts of DSM and aging infrastructure, will determine the capital spending required to serve FortisBC customers' electrical needs. It is the opinion of FortisBC that the current process of Commission review and oversight is adequate to ensure that expenditures are in the public interest. Please also see the response to BCUC IR No. 2 Q127.2

Q2.4 Because of the lack of resources (i.e. lineman, engineering etc.) are all utilities paying a premium to the contractors and consultants;

Q2.4a How is this affecting our annual rate increases?

A2.4a One of the primary factors affecting customer rates is Capital Plant additions. With reference to the response to BCUC IR No. 1 Q1.3, approximately $25 million in Capital Plant additions may translate into a rate impact of one percent.

With respect to the use of external resources, FortisBC recognizes the current market conditions and expects continued upward pressure on both material and labor over the next ten years. The effect of escalating costs upon customer rate impact, as discussed above, helps provide a generic understanding of the relationship between these market pressures and FortisBC annual rate increases.

Q2.4b Does FortisBC think the cost will go down after 2010?

A2.4b No, FortisBC does not expect costs will go down after 2010. Current demographics of North American utilities and worldwide commodity supply and demand for utility infrastructure are expected to increase pressure on costs beyond 2010. FortisBC's project management team will continually monitor the project and implement any measures it can to ensure a safe, reliable, low cost delivery of the project.

Q2.4c How does FortisBC measure the Contractors performance? (What we as municipalities are hearing is; every utility is busy, and the Contractors are over charging for their work).

A2.4c Contractor costs are kept competitive through the competitive bidding process and are a true reflection of market pricing at the time of the bid.

Q2.4d How can the Company make sure we as customers are getting the "Best Value For Our Dollar"?

A2.4d FortisBC is a regulated public utility operating within the jurisdiction of the BC Utilities Commission. All capital spending is subject to review by the Commission in accordance with its role to administer the Utilities Commission Act. Individuals and organizations may play an active role in this process. The regulatory process surrounding this Application is transparent and intended to ensure that expenditures are prudent, in the public interest, and aligned with the Provincial Energy Objectives.

In addition, when sourcing both materials and labour for projects, FortisBC continues to use a competitive bidding process to ensure that the company is utilizing the lowest cost resources available.

Q2.4e How do the Contractors work by unit cost, flat rate fees or hourly rate?

A2.4e Contractors work for FortisBC under various cost structures including; unit cost, flat rate fees (fixed price), and hourly rate (time and material).

Q2.4f What is FortisBC's process for selecting Contractors?

A2.4f Following pre-qualification, FortisBC used competitive bid and direct award processes for selecting contractors. Selection is also based on safety performance, work quality, work schedule and costs.

Question 3: Rate Impact

Reference

BCUC A1.3 Fortis indicates that rate increases due to capital spending is roughly 1% per $25 million in plant additions.

Q3.1 Do we then take this to mean that a $360 million capital plan over two years would result in an approximate rate increase of 14.4%?

A3.1 Yes. However, generically speaking, customer rate impact takes effect once the Plant is in useful service and not at the point of incurring the capital expenditure. Hence the cumulative rate impact of 14.4 percent as indicated above may take effect over a period of more than two years. It must also be noted that other factors including customer growth and sales influence the final customer rate impact.

Q3.2 After taking the forecast load growth and 2009/10 CEP both into account what is the expected rate impact of the 2009/10 CEP?

A3.2 Rate impacts are determined annually through FortisBC's Revenue Requirements Application. The Company's 2009 Revenue Requirements Application will be filed no later than October 2008. The Company does expect its load to continue to increase for the foreseeable future and any increase in load will serve to reduce rate increases.

Question 4: Grand Forks Conversion

Reference

From the August 12, 2008 workshop and CEP page 8 we understand the Grand Forks conversion has been deferred due to load uncertainty.

Q4.1 Once there is certainty about the load how long will it take to implement the conversion?

A4.1 A detailed review of the Grand Forks area has not been completed. It is premature to comment on the duration of the Engineering and Construction portion of the project at this time. This detail is expected to be included in the 2011 Capital Expenditure Plan.

Question 5: Lines Reliability

Reference - CEP pg 88, pg 62-63, pg 56

Q5.1 Please provide historic reliability for the 20 & 27 lines, as well as the expected reliability once the line rebuilds are completed.

A5.1 Please see Table A5.1a and Table A5.1b below for historic reliability data for 20 Line and 27 Line.

Table A5.1a
20 Line Reliability

Year	No. of Outages	No. of Customers Affected	Customer Hours
2005	0	0	0
2006	3	8,474	484
2007	3	7,161	2,204
2008 (to end of June)	4	22,001	10,943

Table A5.1b
27 Line Reliability

Year	No. of Outages	No. of Customers Affected	Customer Hours
2005	3	1,945	171
2006	8	8,583	6,468
2007	11	12,089	3,285
2008 (to end of June)	5	6,494	2,292

Q5.2 FortisBC plans on Transmission line urgent repairs and distribution line rehabilitation. Can you quantify the improvements in reliability expected from these projects?

A5.2 FortisBC cannot quantify the reliability improvements from the transmission and distribution line urgent repairs.

Q1.0 Public Consultation

It is noted in the FortisBC 2009-2010 Capital Plan Expenditure Plan application ("the Capital Plan") that "FortisBC recognizes the value of stakeholder consultation in the planning and implementation of projects to meet customers' needs."[1]

Q1.1 Please describe the "*stakeholder consultation*" process used for the planning of the Demand Side Management programs contained in the Capital Plan ("*the DSM programs"*).

A1.1 Please see the response to OEIA IR No. 1 Q1.2 below.

Q1.2 FortisBC notes that "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."[2]

Please describe how this "*wider public consultation process*" was developed in the planning for "*the DSM programs"*. Please also describe how the "*wider public consultation process*" will be used for the implementation of "*the DSM programs"*.

A1.2 The description of Public Consultation included in the Application (Exhibit B-1) on pages 12 and 13 pertains primarily to those Capital Projects that involve construction and/or rehabilitation of infrastructure having potential community impacts. This passage was not intended to convey the process that is typical in

1 Exhibit B-1, Page 12
2 Exhibit B-1, Page 12

the development of DSM programming.

Q1.3 Please provide the list of "*local issues and concerns*" brought forward by stakeholders dealing with the planning for "*the DSM programs*".

A1.3 Please see the response to OEIA IR No. 1 Q1.2 above.

Q1.4 Please provide the list of stakeholders and meetings dealing with the planning for "*the DSM programs*".

A1.4 Please see the response to OEIA IR No. 1 Q1.2 above.

Q1.5 Please provide the list of DSM questions asked by stakeholders, corresponding answers from FortisBC, and the final results regarding the planning for "*the DSM programs*".

A1.5 Please see the response to OEIA IR No. 1 Q1.2 above.

Q1.6 Please list the "*constructive local relationships*" established regarding the planning for "*the DSM programs*".

A1.6 Please see the response to OEIA IR No. 1 Q1.2 above.

FortisBC notes that "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."[3]

Q1.7 Please provide copies of the newspaper listing for the information sessions regarding "*the DSM programs*".

A1.7 Please see the response to OEIA IR No. 1 Q1.2 above.

Q1.8 Please provide the mail, telephone and email invitation records for "*the DSM programs*".

A1.8 Please see the response to OEIA IR No. 1 Q1.2 above.

FortisBC notes that "attendees are provided with a FortisBC contact person for future information, comment, or follow-up."[4]

Q1.9 Please provide name, phone number and email address for the FortisBC contact person for "*the DSM programs*".

A1.9 Please see the response to OEIA IR No. 1 Q1.2 above.

[3] Exhibit B-1, Page 12
[4] Exhibit B-1, Page 12

FortisBC notes that "the Company continues to solicit input from its stakeholders throughout the planning, regulatory and construction stages to project completion."[5]

Q1.10 Please indicate how FortisBC will continue its solicitation of input regarding "*the DSM programs*".

A1.10 Please see the response to OEIA IR No. 1 Q1.2 above.

[5] Exhibit B-1, Page 13

Q2.0 Bill 15

Various sections of Bill 15 are re-written into "*the Capital Plan*" by FortisBC. A noticeable exception is the definition of "*demand-side measure*" [6].

Q2.1 Please provide a copy of the Bill 15.

A2.1 A copy of Bill 15 is attached as OEIA Appendix A2.1.

Q2.2 Please confirm that FortisBC will use the definition of "*demand-side measure*" as contained in Bill 15 which is:

***"'demand-side measure'* means a rate, measure, action or program undertaken**

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand;"[7]

Section 44.2(5)(b) of Bill 15 states that the commission must consider "the most recent long-term resource plan filed by the public utility under section 44.1, if any,"[8].

A2.2 Confirmed.

[6] Bill 15, Section 1
[7] Bill 15, Section 1

Q2.3 Please attach the "most recent long-term resource plan".

A2.3 The 2005 Resource Plan was filed with the Commission as part of the 2005 Revenue Requirements Application. The document can be found at the following link:

http://www.fortisbc.com/about_fortisbc/rates/rev_requirements/rev_requirements_2005.html

Q2.4 Please indicate when the next "*long-term resource plan*" is expected to be completed by FortisBC and submitted to the BCUC.

A2.4 The next Resource Plan is expected to be filed with the Commission in late 2008 or early 2009.

Q2.5 Please indicate the "*stakeholder consultation*" process intended to be used in conjunction with the next "*long-term resource plan*". Please mention the stakeholders to be contacted, the number of meetings planned, and the subject matter planned to be covered in each meeting.

A2.5 Please see the response to OEIA IR No. 1 Q2.8 below.

Q2.6 Is the "*long-term resource plan*" discussed in this section the same as the "*2008 Resource Plan*"[9] discussed in the FortisBC 2008 Revenue Requirements Application (2008 RRA)?

A2.6 Yes, these reference the same document.

[8] Bill 15, Section 44.2(5)(b)
[9] FortisBC Updated 2008 Revenue Requirements, Tab 3, Page 36

Q2.7 The "*2008 Resource Plan*" is expected to be "*filed during the first quarter of 2008*" [10]. Please provide a copy of the 2008 Resource Plan and the 2005 Resource Plan.

A2.7 For the 2005 Resource plan, please refer to the response to OEIA IR No. 1 Q2.3. The 2008 Resource Plan was not filed in the first quarter of 2008 and will not be available until it is completed and filed with the Commission. Also see the response to OEIA IR No. 1 Q2.4 above.

Q2.8 FortisBC noted in response to an IR from Horizon in the 2008 RRA: "As part of the resources planning process FortisBC will hold workshops with its stakeholders and the BC Utilities Commission to obtain feedback on how best it can incorporate elements of the 2007 BC Energy Plan in its resource plan."[11] Please list the workshops that FortisBC held and the stakeholders involved. Please describe how this feedback was used to incorporate the 2007 BC Energy Plan.

A2.8 As part of its 2008 Resource Planning process, FortisBC developed a multi-stage stakeholder engagement process.

The Company made presentations to 15 local government entities in its service territory. The presentation outlined the power supply/demand context, various resource options under consideration, and portfolios of resources that may provide a solution to the forecast energy and capacity gaps. Further, the presentation spoke to the factors influencing the decision process including:

- Capacity and energy gap;
- Environmental considerations;

[10] FortisBC Updated 2008 Revenue Requirements, Tab 3, Page 36
[11] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A3.1, Page 7

- Transmission considerations;
- Economic considerations; and
- BC Energy Plan objectives.

FortisBC engaged Environics Research Group (Environics), a nationally recognized opinion research organization, to assist in discovering and analyzing the customers' perspective. Information gathering took two forms:

1. A broad-based public survey targeting FortisBC, and
2. Two "workshop" forums that consisted of a pre-presentation questionnaire, followed by a presentation by FortisBC similar to that provided to the local government councils, and a question/answer period, followed by a post-presentation questionnaire. This methodology specifically tested the impact of subject matter education on the perceptions that the Company's stakeholders have regarding the various potential resource solutions.

Participants consistently expressed the themes of reliability, green energy/the environment, costs, transmission, and the need to maximize conservation.

They emphasized that ensuring a reliable source of power is a key consideration for FortisBC's Resource Planning.

Participants expressed concerns about the ramifications of changing environmental impacts upon power generation choices, and suggested FortisBC should consider diversifying its generation mix. Wind energy was given as a popular example of alternative sources that should be considered. Concern was also expressed about how to "back up" the intermittent nature of some green power options (such as Wind), and it was suggested that FortisBC consider creating storage capacity, such as new hydro projects, in order to meet that concern.

Participants recognized the challenges involved in balancing costs with environmental considerations, however, reminded FortisBC that the longer the Company waits to solve the capacity/energy gap, the more it will cost.

Potential transmission impacts (cost, siting, and environmental) were voiced as concerns.

FortisBC was advised that it must do all it can to encourage conservation efforts and Demand Side Management.

Q2.9 The application itself discusses the "*2008 Resource Plan Update*"[12] while the IR response from FortisBC mentions the "*2007 Resource Plan*"[13]. Please clarify that these two terms reference the same plan. If not please explain.

A2.9 These reference the same document.

Section 64.02 (2)(b) of Bill 15 states that this section applies to "a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any "[14].

Q2.10 Please define "a prescribed public utility".

A2.10 FortisBC Inc. ("FortisBC") assumes that this Information Request refers to the term "prescribed public utility" as used in section 64.02(2)(b) of the Utilities Commission Act, R.S.B.C. 1996, c. 473, as amended (the "Act"). Based on

[12] FortisBC Updated 2008 Revenue Requirements, Tab 3, Page 36
[13] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A3.1.2, Page 7

that assumption, FortisBC understands that a "prescribed public utility" is a public utility that has been prescribed, either individually or as a member of a class of public utilities, for the purposes of section 64.02(2)(b) by ministerial regulation made pursuant to section 125.1(4)(l) of the Act.

Q2.11 Does FortisBC considered itself "*a prescribed public utility*". If not, why not?

A2.11 To FortisBC's knowledge, FortisBC is not a "prescribed public utility" nor a public utility in a "class of prescribed public utilities" for the purposes of section 64.02(2)(b) of the Act.

[14] Bill 15, Section 64.02(2)(b)

Q3.0 DSM Energy Savings

FortisBC notes in "*the Capital Plan*" that "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."[15]

"In response to the Energy Plan, the two-year plan, 2009 (. . . 25.3 GWh) and 2010 (. . . 27.5 GWh), contain higher levels of . . . energy savings, than the 2008 plan (. . . with 19.5 GWh savings)"[16].

Q3.1 Please provide a copy of the 2007 BC Energy Plan.

A3.1 A copy of the 2007 BC Energy Plan is available for viewing at: http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf.

A copy of the 2007 BC Energy Plan will be forwarded to the OEIA.

Q3.2 Please confirm that the actual energy savings reported in the Semi-Annual DSM report for Dec 31, 2007 is 27.9 GWh[17].

A3.2 Confirmed.

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[15] Exhibit B-1, Page 107
[16] Exhibit B-1, Page 107
[17] Exhibit B-2, BCUC IR#1, Table A77.2a, Page 150

Q3.3 Please provide the Dec 31, 2007, Dec 31, 2006, and June 30, 2006 Semi-Annual DSM reports and the dates of their filings with the BCUC.

A3.3 The requested reports have been attached as Appendices OEIA A3.3a, A3.3b, and A3.3c respectively. The June 30, 2006 Report was filed with the Commission on October 27, 2006. The December 31, 2006 Report was filed with the Commission on October 11, 2007. The December 31, 2007 Report was filed with the Commission on June 4, 2008.

Q3.4 Please explain why the FortisBC website does not provide easy access to the Semi-Annual DSM Reports while providing easy access to Rates and the Electric Tariff, Revenue Requirement Applications, Capital Plans & System Development Plans, CPCNs and Annual Reports. Does FortisBC plan to improve this in the future?

A3.4 The Semi-Annual DSM Reports are available upon request.

Q3.5 We note that in the last Revenue Requirements settlement "*FortisBC commits to filing DSM results for previous year and previous six months before or with the Annual Review materials*"[18]. Please indicate the date when the June 30, 2008 Semi-Annual DSM report will be completed and ready for filing. Please provide if available. If that date is after this Capital Plan proceeding, please provide the latest up-to-date estimate for what would be expected in the June 30, 2008 report.

A3.5 The June 30, 2008 report is expected to be complete and filed by the end of the third quarter 2008. The draft mid-year results, subject to due diligence, are 16.1 GWh saved and $1.33 million in expenditures

[18] FortisBC Inc. 2008 Revenue Requirements Negotiated Settlement Agreement, Nov 23, 2007, Page 7

Q3.6 Please confirm that every year since 1999 the actual DSM savings has been above the plan[19] and confirm that the actual savings in the last 4 years have been 27% above the plan[20].

A3.6 FortisBC confirms the above. Please also refer to the response in BCUC IR No. 1 Q77.2.

Q3.7 Please indicate what the acceptable target range for these values are expected (e.g. +/- percentage) to be.

A3.7 Actual results rely on customer participation levels.

of issue list
[19] Exhibit B-2, BCUC IR#1, Table A77.2a, Page 150
[20] Exhibit B-2, BCUC IR#1, Table A77.2a, Page 150; (21.3+23.9+23.1+27.9)/(14.7+19.0+20.4+21.8)=1.27

Q3.8 Please confirm that the chart below in Figure 1 is an accurate representation of the DSM actual energy savings for 2004 to 2007, present estimate for 2008 and the planned 2009 and 2010 DSM energy savings submitted in this Capital Plan application.

DSM Energy Savings

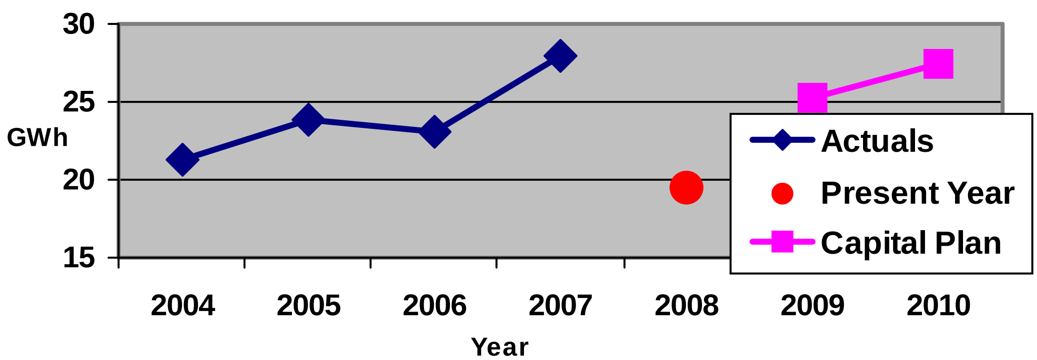


Figure 1

A3.8 Based on the granularity of the attached chart, FortisBC is unable to confirm the accuracy of the representation. If the OEIA chooses to provide detailed numbers FortisBC will provide confirmation.

Q3.9 Using the latest information from item 3.3 above and referring to Figure 1, is the estimate for 2008 still expected to be 19.5 GWh? If so, please explain how a 30% drop from 2007 to 2008 (27.9 GWh to 19.5 GWh) can be justified? If the 2008 estimate is changed please explain the change, and please explain how its new value can be justified in relation to 2004 to 2007.

A3.9 Please refer to the response to OEIA IR No. 1 Q3.8 above. The 2008 plan figure of 19.5 GWh was established in early 2006 as part of a two-year capital filing, and relied upon a forecast reduction in housing starts for 2008.

Subsequently, the residential housing market stayed strong and customer participation in programs grew. It should be noted that the plan figures are not used for the purposes of determining any DSM incentive amounts the Company may be eligible for.

Q3.10 Given the expected increase of DSM due to the Energy Plan and Bill 15 (as noted in the statements in the first paragraphs of Section 3.0 above) and referring to Figure 1 above, please discuss why the "Capital Plan" energy saving values are so low (for 2009 and 2010). Why are the values lower than 2007, and only marginally higher than 2005 and 2006?

A3.10 The 2007 BC Energy Plan sets out long-term DSM goals, and Bill 15 puts those goals into effect. The 2009 and 2010 plan figures represent a prudent ramp-up, while the DSM Strategic plan will help inform the post 2010 planning horizon.

Q3.11 We note that the planned expenditures for DSM are $2.513 million for 2009 and $2.707 million for 2010[21]. Please estimate the expenditures and effect on the programs if the DSM Energy Saving targets for 2009 (25.3 GWh) and 2010 (27.5 GWh) were increased by 10%. Please estimate also for a 20% increase and 10% decrease.

A3.11 Incremental expenditures on DSM programs are expected to yield approximately 0.005 GWh per $1,000 (net of tax). Therefore, an addition or reduction of $250,000 (approximately 10 percent) would result in additional or reduced savings of 1.25 GWh. A 20 percent change in expenditures would result in approximately 2.5 GWh change in energy savings.

[21] Exhibit B-1, Table 1.5, 2009/10 Capital Plan, Page 17

Q4.0 DSM Expenditures

We note that BC Hydro in its new 2008 LTAP application is planning for $487.3 million expenditure in "*DSM Plan Costs*" over three years: $129.8 million in F2009, $161.8 million in F2010 and $195.6 million in F2011[22], in response to the 2007 Energy Plan and Bill 15[23].

Q4.1 We note that "DSM Plan Cost" values includes "Capital Overhead"[24] and "Costs to be Included in Other Expenditure Requests"[25]. Please indicate the "DSM Plan Costs", "Capital Overhead" and "Costs to be Included in Other Expenditure Requests" for FortisBC in the Capital Plan for F2009 and F2010.

A4.1 FortisBC DSM Plan costs are inclusive of all costs, there are no "other expenditure requests" for DSM in the 2009/10 period.

Q4.2 Please list the overall domestic sales of BC Hydro and FortisBC.

A4.2 BC Hydro actual domestic sales for 2007 (as listed in the 2009/10 Revenue Requirements Application) were $ 2,749.1 million. FortisBC 2007 forecast domestic sales as approved by Order G-147-07 were $210.5 million.

Q4.3 Please calculate the percentage of DSM costs to sales for both BC Hydro and FortisBC.

A4.3 With BC Hydro DSM expenditures of $46.4 million in 2007, the percentage of

[22] BC Hydro 2008 LTAP, Exhibit B-1, Page 6-2
[23] BC Hydro 2008 LTAP, Exhibit B-1, Page 1-7 to 1-13
[24] BC Hydro 2008 LTAP, Exhibit B-1, Page 6-2

DSM expenditures relative to 2007 domestic sales was approximately 1.7 percent.

With FortisBC DSM expenditures of $2.5 million in 2007, the percentage of DSM expenditures relative to forecast 2007 domestic sales is approximately 1.9 percent.

Q4.4 Please discuss the reasoning behind any significant differences between FortisBC and BC Hydro.

A4.4 FortisBC cannot provide the comparison requested as it is not privy to the processes, criteria, or rationale used by BC Hydro in the development of its programs.

Q4.5 We note that a table was produced in the FortisBC 2008 Revenue Requirements comparing the percentage energy consumption and system peak DSM savings to other jurisdictions[26].

Please update this table with the latest information; for BC Hydro use BC Hydro's 2008 LTAP and use this new Capital Plan for FortisBC.

A4.5 The table was prepared with publicly available information at the time, namely annual reports. It is not possible to update it with prospective information that is not readily available.

[25] BC Hydro 2008 LTAP, Exhibit B-1, Page 6-2
[26] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A6.5, Page 10 to 11

Q4.6 Please discuss the reasoning behind any significant differences.

A4.6 Please see the response to OEIA IR No. 1 Q4.4 above.

Q4.7 Please provide reference web-links or sources of information and calculations for the other utilities.

A4.7 Please see the response to OEIA IR No. 1 Q4.4 above.

Q4.8 We note that a table was produced in the BC Hydro 2008 LTAP proceeding comparing different jurisdictions[27].

It is noted that FortisBC is the third lowest on the list. Please confirm that the information provided for FortisBC was correct for the values that BC Hydro utilized at the time of creating the list. If incorrect, please supply correct values and explain.

A4.8 Referring to the period 2005 to 2007 inclusive, the value shown of 0.5 percent is incorrect. Please see the response to OEIA IR No. 1 Q4.9 below for the correct values.

Q4.9 Please indicate the references that support the calculations for FortisBC and show how the calculations were made.

A4.9 The DSM savings of 23.9 GWh, 23.1 GWh and 27.9 GWh divided by sales of 2,969, 3,040 and 3,090 GWh/year for the period 2005 to 2007 respectively, yields 0.8 percent, 0.8 percent and 0.9 percent. Refer also to the response to BCUC IR No. 2 Q160.1.

[27] BC Hydro 2008 LTAP, Exhibit B-1, Appendix K, Page 29 to 31

Q4.10 Please discuss why FortisBC placed so low on the original list as presented by BC Hydro.

A4.10 FortisBC's placement on the list was a result of incorrect data.

Q4.11 Please update for FortisBC using the new values of "*the Capital Plan*", and please show the calculations.

A4.11 Using DSM plan figures of 25.3 GWh and 27.5 GWh divided by the sales forecast of 3,149 and 3,227 GWh/year, for 2009 and 2010 respectively, yields 0.8 percent and 0.9 percent.

Q4.12 Please discuss the new FortisBC placement in the list using "*the Capital Plan*" values, and discuss the goals for the future in regards to target placement on this list.

A4.12 The Company has not defined goals with respect to placement on this list.

Q5.0 Municipal Utilities

FortisBC notes in "the Capital Plan" in regards to Demand Side Management programs that "the programs are available to all customers served by FortisBC and its wholesale customers of Grand Forks, Kelowna, Nelson Hydro, Penticton, and Summerland."[28]

Q5.1 Please describe the relationship of these wholesale customers to FortisBC.

A5.1 These wholesale customers purchase power from FortisBC pursuant to the Company's Electric Tariff.

Q5.2 Schedules 40 to 47 of the Electric Tariff refer to certain wholesale customers[29]. Please confirm that the "*municipal wholesale customers*" referred to in various places throughout Schedule 90 (Energy Management Service) [30] of the Electric Tariff are the same as those customers using Schedules 40 to 47[31].

A5.2 Confirmed.

[28] Exhibit B-1, Section 6, Page 106
[29] Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan areas, Schedules 40 to 47
[30] Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan areas, Schedule 90
[31] Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan areas, Schedules 40 to 47

Q5.3 For clarity, please confirm in regards to the Schedule 90 programs[32] that there is no difference in the services provided nor difference in costs between FortisBC customers and the customers of the Municipal Wholesale utilities.

A5.3 There is no difference in the services provided to the customers of the Municipal wholesale utilities. FortisBC does not understand what is meant by 'costs' in the question, although program costs are clearly driven by the number and type of services requested by customers.

Q5.4 On the first sheet of Schedule 90, Sheet 58, there is the following statement: "*APPLICABLE: To all residential Customers in all areas served by the Company and its municipal wholesale customers*" [33]. The placement of this statement would make it apply to the entire Schedule 90 because it appears immediately after the title "*Schedule 90 – Energy Management Service*". However, from its context, it would seem that the statement is intended to only apply to residential programs and should appear after "*Residential Programs*" and not before. Please confirm that this statement only applies to the residential programs and it should be moved after "*Residential Programs*". Does FortisBC plan to move this statement in the next update of the Electric Tariff?

A5.4 Schedule 90 applies in its entirety to all customers, including municipal wholesale customers.

[32] Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan areas, Schedule 90
[33] Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan areas, Schedule 90, Sheet 58

Q5.5 On sheet 71 of the Electric Tariff, there is no listing for Applicable customers for "*Other Programs*" [34]. Please clarify by providing an appropriate statement dealing with applicability. Does FortisBC plan to this statement in the next update of the Electric Tariff.

A5.5 Please refer to the response to OEIA IR No. 1 Q5.4 above.

[34] Electric Tariff BCUC No. 1 for service in the West Kootenay and Okanagan areas, Schedule 90, Sheet 71

Q6.0 Provincial Objectives

FortisBC states in "the Capital Plan" that in regards to the DSM programs that "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.*"[35]**

Q6.1 Please confirm that the statements above refer to Bill 15.

A6.1 Confirmed.

Q6.2 Does FortisBC consider each of its existing Schedule 90 programs is a demand-side measure as defined in Bill 15?

A6.2 Yes, FortisBC considers each of its existing Schedule 90 programs is a demand-side measure as defined in Bill 15.

Q6.3 Does FortisBC consider each of its "*time of use*" and "*green power*" rates listed in the Electric Tariff a type of demand-side measure as defined in Bill 15?

A6.3 FortisBC considers that Time-of-Use rates satisfy the definition of the "Demand Measure" described in Section 1 (c) *to shift the use of energy to periods of lower demand.* Green rates are not consistent with any of the Demand Measures as defined in Bill 15.

[35] Exhibit B-1, Page 106

Q6.4 Please provide a table listing each FortisBC project (e.g. CFL, Heat Pump etc.), tariff schedule # (e.g. Schedule 90 – Sheet 58), type (rate, measure, action or program), benefit (conserve energy, reduce demand or shift energy) and number of customers using the measure. The table would look like the following:

Description	Schedule #	Type	Benefit	Number of Customers
Name of project	Schedule number – Sheet number	Rate, measure, action or program	Conserve energy, reduce demand or shift energy	Number of customers

A6.4 Please see Table A6.4 below.

Table A6.4
DSM Projects

Description	Schedule	Sheet	Type	Benefits	Number of Projects**
Residential Lighting*	90	60	Program	Conserve Energy & Reduce Demand	2,002
New Home Construction	90	58	Program	Conserve Energy & Reduce Demand	2,244
Home Improvement	90	59	Program	Conserve Energy & Reduce Demand	10,347
Ground Source Heat Pump	90	60	Program	Conserve Energy & Reduce Demand	630
Air Source Heat Pump	90	60	Program	Conserve Energy & Reduce Demand	4,747
New Process Design	90	68	Program	Conserve Energy & Reduce Demand	9
Pumps & Fans	90	70	Program	Conserve Energy & Reduce Demand	67
Motors	90	69	Program	Conserve Energy & Reduce Demand	434
FortisBC Property	90	64	Program	Conserve Energy & Reduce Demand	50
Water Savers	90	59	Program	Conserve Energy & Reduce Demand	13,334
Building Improvement New	90	63	Program	Conserve Energy & Reduce Demand	485
Building Improvement Retrofit	90	64	Program	Conserve Energy & Reduce Demand	654
Industrial Efficiency	90	69	Program	Conserve Energy & Reduce Demand	67
Commercial/Industrial Lighting*	90	64	Program	Conserve Energy & Reduce Demand	2,345
Compressors	90	71	Program	Conserve Energy & Reduce Demand	62

* In the case of lighting programs, rebates are batched with as many as 50 participants per entry

** A customer count per se is not available as there may be multiple projects (entries) under various programs for the same customer.

Q7.0 DSM Offset Load Growth

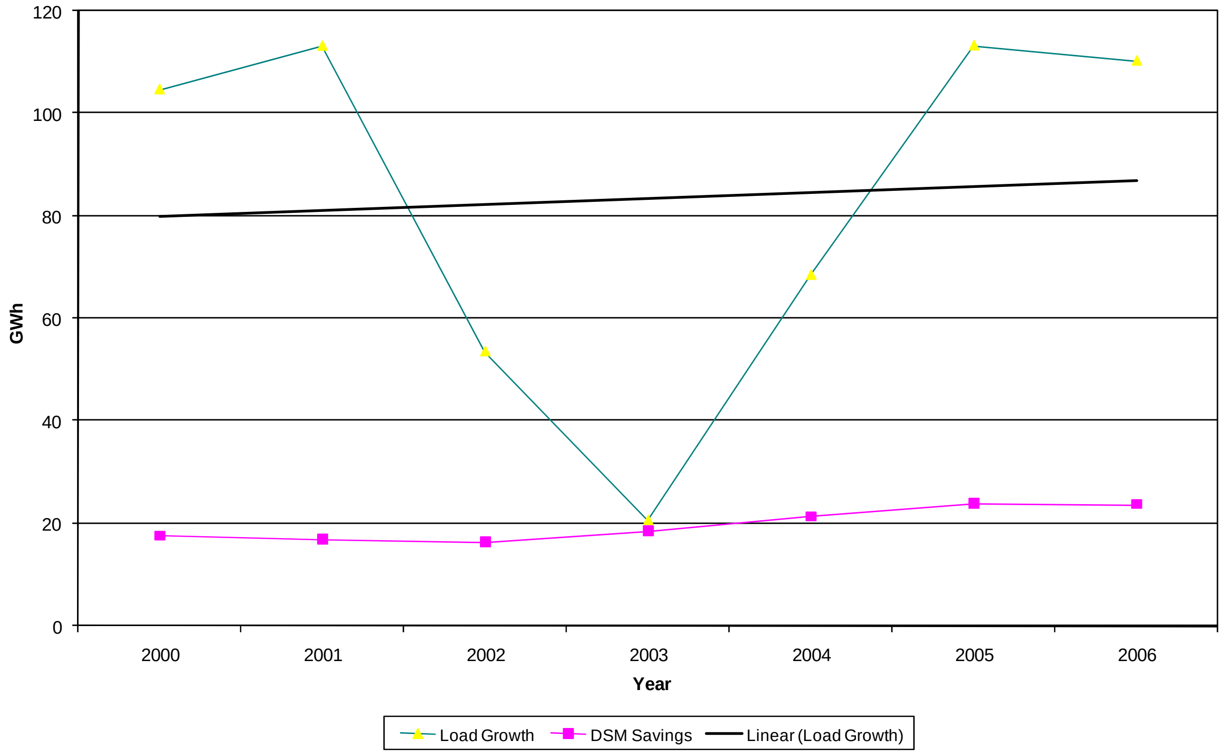
FortisBC states in "the Capital Plan" that "the Company is supportive of the Energy Plan goal of having conservation offset 50 percent of cumulative load growth by 2020. Over the last number of years, DSM has offset approximately 25 percent of FortisBC's annual energy growth requirements, thus effectively requiring an overall doubling of the current DSM resource acquisition rate in order to meet the Provincial Government's objective."[36]

Q7.1 Please provide a chart (graph) to support the statement that "*over the last number of years, DSM has offset approximately 25 percent of FortisBC's annual energy growth requirements*". Please provide show both how much generation is supplied by BC Hydro and also by FortisBC's own generation.

A7.1 Please see Figure A7.1 below. The graph shows total load growth (DSM savings added back to net load growth), and the DSM energy savings acquired in each corresponding year.

[36] Exhibit B-1, Section 6, Pages 108 to 109

Figure A7.1


120
100
80
60
40
20
0
GWh
2000
2001
2002
2003
2004
2005
2006
Year
Load Growth
DSM Savings
Linear (Load Growth)

1

Q7.2 Please also provide a table listing the values in item #7.1.

A7.2 Please see Table A7.2 below.

Table A7.2

Year	Normalized Net Load (MWh)	Annual Change in Load Served	DSM Savings	Total Annual Change	DSM portion of Total Annual Change (%)
2000	2,694,524	87,138	17,516	104,654	17
2001	2,790,787	96,263	16,892	113,155	15
2002	2,828,022	37,235	16,261	53,496	30
2003	2,830,031	2,009	18,530	20,539	90
2004	2,877,135	47,104	21,339	68,443	31
2005	2,966,451	89,316	23,906	113,222	21
2006	3,052,948	86,497	23,750	110,247	22
Total		**445,562**	**138,192**	**583,754**	**24**

Q7.3 Please provide a chart showing all years from 2009 to 2020 on how FortisBC intends to provide "*an overall doubling of the current DSM resource acquisition rate*". Please provide show both BC Hydro supply and FortisBC generation.

A7.3 Plan years beyond 2010 will be informed by the DSM Strategic Plan/Review.

Q7.4 Please also provide a table listing the values in item #7.3.

A7.4 Please refer to the response to OEIA IR No. 1 Q7.3 above.

Q8.0 Long-Term Strategic DSM Plan

It is noted in "the Capital Plan" that "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."[37]

Q8.1 Please indicate the years that the "*long-term DSM plan*" is expected to cover.

A8.1 It is expected that the "long-term DSM plan" will cover years 2011 – 2020.

Q8.2 Please detail the costs to develop the plan and reference where the budget is covered.

A8.2 The cost to develop the Strategic Plan is estimated at approximately $0.05 million. FortisBC intends to request that this amount be amortized in the 2009 Revenue Requirements.

[37] Exhibit B-1, Section 6, Page 109

Q8.3 Please indicate the "*stakeholder consultation"* process intended to be used in conjunction with the "*long-term DSM plan*". Please mention the stakeholders to be contacted, the number of meetings planned, and the subject matter planned to be covered in each meeting.

A8.3 Please refer to the response to OEIA IR No. 1 Q1.2 above. FortisBC also has a DSM advisory committee comprised of customer and industry representatives.

Q8.4 Please indicate the relationship of this "*long-term DSM plan*" to next "*long-term resource plan*" discussed in item 2.3 above.

A8.4 "Long-term resource plans" will incorporate the best DSM information available at the time of filing, including any information from "long-term DSM plans".

Q9.0 Overall integrated plan

An integrated plan to be developed in 2010 was mentioned by Doug Ruse at the August 12, 2008 Capital Plan Workshop.

Q9.1 Please describe fully this integrated plan, including its name, its purpose, what regulatory process is intended to used, date for completion and estimated budget.

A9.1 The integrated plan is a plan that includes the Transmission and Distribution (formerly the System Development Plan [SDP]), Generation and General Plant (Formerly Capital Expenditure Plan), Resource Plan, and DSM. The purpose of the integrated plan is to ensure all aspects of the capital expenditure plan work together and complement each other.

It is too early in the process to determine the name of the new plan or identify the regulatory process to be used. The planned completion date is anticipated to be the third quarter of 2010. The impacts of Bill 15 and the complexities of the plan need to be further understood before a budget for the project can be reached.

Q9.2 Please indicate the relationship of this plan to the "*long-term DSM plan*" discussed in item 8.0 above and the next "*long-term resource plan*" discussed in item 2.3 above.

A9.2 The purpose of the integrated plan is to ensure impacts of both the long term DSM Plan and long term Resource Plan are considered in the overall capital planning process. The Long Term Resource plan and Long Term DSM plan are being developed in the next few months and the results of these plans need to be included in the integrated plan.

Q9.3 Please indicate the "*stakeholder consultation*" process intended to be used in conjunction with this integrated plan. Please mention the stakeholders to be contacted, the number of meetings planned, and the subject matter planned to be covered in each meeting.

A9.3 It is too early in the process to determine a detailed stakeholder consultation process however FortisBC believes stakeholder consultation is an important aspect of a planning process.

Q10.0 DSM Advisory Committee

FortisBC notes that the budget for Planning and Evaluation in "*the Capital Plan*" includes provision for facilitating the DSM Advisory Committee[38].

Q10.1 Please provide the current list of members of the DSM Advisory Committee.

A10.1 Please see OEIA Appendix A10.3 for a list of members of the DSM Advisory Committee.

Q10.2 Please list and provide the minutes of all meetings and conference calls, agendas and background information of the DSM Advisory Committee in the last three years.

A10.2 This information will be filed separately by Tuesday, September 16, 2008.

Q10.3 Please include the minutes and agenda of the Sept 4, 2008 meeting in Osoyoos.

A10.3 The Agenda for the September 4, 2008 is attached as OEIA Appendix A10.3. The minutes for this meeting have not been prepared or circulated for approval by the committee members and will not be available until that has taken place.

Q10.4 Please provide all terms of reference, guidelines and procedures of the committee.

A10.4 The Terms of Reference for the DSM Committee have been attached as OEIA

Appendix A10.4. Please note that the document is in draft form and is subject to review and revision by the Committee.

Q10.5 Please indicate how new members are added and what criteria is used to determine appropriateness of the new members.

A10.5 Please see OEIA Appendix A10.4 as referenced in response to OEIA IR No. 1 Q10.4 above. The selection process is contained in the Terms-of-Reference and is repeated below for convenience.

<u>Membership</u>

The Committee comprises FortisBC staff, customers and/or customer interest groups, and businesses or associations with a direct interest in DSM in the FortisBC service territory.

The non-FortisBC members shall be comprised of:

- A minimum of four member representing customers and/or customer interest groups from a variety of customer classes, including wholesale, residential, general service and industrial,
- A maximum of two representing businesses or associations,
- Members from all regions of the Company's service area, specifically the South Okanagan-Similkameen, Kelowna, and the West Kootenay-Boundary,
- BC Utilities Commission and Ministry of Energy, Mines, and Petroleum Resources staff who serve *ex officio*

[38] Exhibit B-1, Page 113

Members of the Committee may nominate candidates for membership from time to time as vacancies occur. New members must be accepted by a majority of members and FortisBC.

Interested parties can go to the FortisBC website to find out how to volunteer.

Q10.6 Please indicate the rules for which visitors may wish to attend a meeting.

A10.6 Guests at meetings are by invitation.

Q10.7 Please indicate how the meeting times and dates are released, and who receives notice of the meetings. Are the notices available on FortisBC's website?

A10.7 Meeting and conference calls are scheduled in advance in consultation with committee members.

Q10.8 Please detail the involvement of the committee in developing or advising for "*the Capital Plan*". What is their expected involvement in the next Capital Plan?

A10.8 The committee was given a preview of the Company's intended DSM filing in the 2009/10 Capital Plan prior to filing.

Q10.9 In the 2008 FortisBC Revenue Requirements FortisBC supplied the November 2006 Terms of Reference ("*Nov 2006 TOR*") in response to Horizon's IR Q13.2.4[39]. Three reports were mentioned: "*2003 DSM Review*", "*the 2005 Energy Efficiency Potential Update*" and "*2005 PowerSense Five-Year Business Plan*" [40]. Please provide all three reports, and any updates to those reports.

A10.9 The "2003 DSM Management Review" filed February 12, 2004 as part of the 2003 Revenue Requirements is attached as OEIA Appendix A10.9a. The "2005 Energy Efficiency Potential Update" filed on September 15, 2005 as directed by Commission Order G-52-05 is attached as OEIA Appendix A10.9b. The "DSM Five Year Business Plan 2006- 2010" filed October 31, 2005 is attached as OEIA Appendix A10.9c.

Q10.10 Please indicate when the three reports mentioned in item #10.9 will be updated next.

A10.10 The reports mentioned in response to OEIA IR No. 1 were stand-alone reports, and are not intended to be updated per se. The Company will participate in the 2010 province-wide Conservation Potential Review (CPR), and will likely issue a new five-year plan based its energy savings allocation.

Q10.11 Please provide a copy of the DSM incentive mechanism as described in the "*Nov 2006 TOR*"[41].

A10.11 Please see OEIA Appendix A10.11.

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[39] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.2.4, Page 1
[40] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.2.4, Page 1
[41] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.2.4, Page 2, Activity #1

Q10.12 Please describe the DSM incentive mechanism and its effect on the decisions made in "*the Capital Plan*".

A10.12 The DSM incentive is a Shared Savings Mechanism as described in response to OEIA IR No. 1 Q10.11 above. It encourages the Company to plan, pursue and acquire DSM resources with net benefits that exceed the rolling three year average.

Q10.13 The "*Nov 2006 TOR*" suggests that "*interested parties can go to the FortisBC website to find out how to volunteer*"[42]. However, it is not clear how to navigate through the website to find this information. Please provide the specific link to the webpage. Will FortisBC be making this easier to navigate to this page from the home page?

A10.13 The Terms-of-Reference document indicates as a footnote to the passage referenced that "Contact information will be available for those wishing more information about the Committee's activities and opportunities to participate." (November 2006 TOR, page 2). Contact information for the FortisBC DSM department is located on the FortisBC website at http://www.fortisbc.com/powersense/contact_ps.html using the "Contact" link.

[42] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.2.4, Page 2

Q10.14 The "*Nov 2006 TOR*" mentions that the committee reviews the Semi-Annual DSM reports[43]. As of the September 4 meeting, has the committee reviewed the June 30, 2008 Semi-Annual DSM report? If so, please provide the report or if report is not available, please provide the preliminary results. If the committee has not reviewed the report, when will the committee review it?

A10.14 The June 20, 2008 semi-annual DSM report was not ready for the meeting held September 4, 2008, but will be circulated to the committee members prior to the filing date.

Q10.15 The "*Nov 2006 TOR*" mentions that the committee "*reviews planned spending and savings targets and estimated incentive amount for the following year*" [44]. As of the September 4 meeting, has the committee reviewed these plans? If so, please provide details. If not, when will those plans be reviewed?

A10.15 The projected 2008 year-end results and estimated incentive amount will be included in the June 30, 2008 report.

Q10.16 Are agendas and background material provided to participants before the meetings?

A10.16 The draft agendas are sent out by the meeting facilitator prior to the meeting date, with background materials typically provided at the meeting itself.

[43] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.2.4, Page 3, Activity #2
[44] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.2.4, Page 3, Activity #3

Q10.17 Are there opportunities for participants to add new agenda items?

A10.17 Committee members are welcome to add items to the agenda prior to, or at the start of the meeting.

Q11.0 DSM Strategy & M&E Plans

FortisBC notes in "the Capital Plan" that it "has committed to filing a Monitoring and Evaluation (M&E) plan in 2008, as well as filing an M&E report."[45].

Q11.1 Please clarify what the plan and report are intended to cover – e.g. what is being monitored and what are the "*provisions*" [46] as noted in "*the Capital Plan*".

A11.1 The plan will outline a schedule and methodology for selecting DSM programs for periodic review of their effectiveness. The provisions refer to the resources, primarily monetary, required to prepare an M&E report.

Q11.2 FortisBC notes in "the Capital Plan" that "a DSM strategy report is being prepared . . "[47]

Please clarify if the "*DSM strategy report*" is the same as the "*long-term Strategic DSM Plan*" noted in section 8.0 above. If not, please discuss the differences.

A11.2 It is confirmed that these refer to the same report.

[45] Exhibit B-1, Page 113
[46] Exhibit B-1, Page 113
[47] Exhibit B-1, Page 113

Q12.0 DSM Management Business Plan 2006-2010

FortisBC referred to a "*Demand Side Management Business Plan 2006-2010*"[48] in response to an IR from Horizon in the 2008 RRA.

Q12.1 Please provide a copy of the "Demand Side Management Business Plan 2006-2010"[49].

A12.1 A copy of the document titled "DSM Management Five Year Business Plan 2006-2010" is attached as OEIA Appendix A10.9c.

Q12.2 When will a new plan be developed?

A12.2 Please refer to the response to OEIA IR No. 1 Q10.10 above.

[48] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A6.3, Page 9
[49] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A6.3, Page 9

Q13.0 DSM Spending Level

The DSM Spending Level was discussed in the FortisBC 2008 RRA[50] and IR responses to Horizon[51].

Q13.1 Given the BC Energy Plan and Bill 15 considerations as discussed throughout "*the Capital Plan*", has the spending level of 1.25%[52] been increased? If so, what is the new level. If not, why not? How is the level determined?

A13.1 FortisBC did not budget for DSM spending in terms of "spending level" for 2009 and 2010. The spending level is determined by dividing the DSM expenditure by the year's revenue requirements, expressed as a percentage. The exact spending level will not be known until the revenue requirements for 2009 and 2010 have been determined.

Q13.2 A survey of North American jurisdictions and utilities in North America is mentioned in the IR response[53] in the 2008 RRA. Please provide an up-to-date survey.

A13.2 No up-to-date survey is available.

Q13.3 Please show the calculations confirming the spending levels in "*the Capital Plan*".

A13.3 FortisBC does not understand this question. The spending levels on DSM are

[50] FortisBC 2008 Updated Revenue Requirements, Tab 7, Section 7.2.7, Page 15
[51] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.3, Page 20 to 21
[52] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.3, Page 21
[53] FortisBC 2008 Revenue Requirements, Exhibit B-2, Horizon A13.3, Page 20

as outlined in the 2009/10 Capital Plan (Exhibit B-1). There are no supporting calculations.

Q14.0 Incentive Levels

Increased incentive levels are listed in Table 6.3 of "*the Capital Plan*"[54].

Q14.1 If these new incentive levels are accepted, please indicate the specific changes in FortisBC documentation that would result – e.g. updates in Schedule 90 in the Electric Tariff or elsewhere.

A14.1 FortisBC would change the PowerSense literature and website information available to customers specifying the new incentive levels.

Q14.2 FortisBC suggests the increase incentive levels "*is intended to encourage and support higher take-up rates*"[55]. Please discuss the expected levels of increase for these "*take-up rates*" (e.g. percentage).

A14.2 FortisBC expects that the increased incentive levels specified will increase program participation approximately 2-3 percent. An increase of this magnitude will be difficult to measure, but given the increasing customer costs associated with many DSM measures FortisBC feels the increase is prudent. The increased incentives are measured at the portfolio level – in other words, within a portfolio some programs may remain at current levels (for example, heat pumps for home retrofits) while others may increase (for example, heat pumps for new houses).

[54] Exhibit B-1, Section 6, Page 109
[55] Exhibit B-1, Section 6, Page 109

Q15.0 Residential Sector

Q15.1 Please describe the LED lamp program[56] in more detail.

A15.1 LED lamps are incented in the same manner as compact fluorescent lamps, i.e. $5 per lamp, to a maximum of 50 percent of the product cost.

Q15.2 What levels of participation of LED lamps[57] are expected in 2009 and 2010?

A15.2 This is difficult to predict, as the LED product market is still maturing.

Q15.3 Will the Heat Pump incentive of 5 cents per kWh[58] be increased to 6.5 and 7.0 cents per kWh in 2008 and 2009 according to Table 6.3[59]?

A15.3 Heat pump incentives will increase on average from 5.0 to 5.5 cents per kWh. The figures shown in Table 6.3 from the Application (Exhibit B-1) are the residential portfolio average, which include more expensive offerings such as the EnergyStar window rebates.

Q15.4 Please include provide more information on the LiveSmart BC and SolarBC programs[60], including lists of rebates and incentives.

A15.4 Both LiveSmart BC and SolarBC are programs run by organizations other than FortisBC. Details about the two programs are continuing to evolve. Please see the respective websites for the latest details on rebates and incentives

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[56] Exhibit B-1, Section 6, Page 110
[57] Exhibit B-1, Section 6, Page 110
[58] Exhibit B-1, Section 6, Page 110
[59] Exhibit B-1, Section 6, Page 109
[60] Exhibit B-1, Section 6, Page 110

http://www.livesmartbc.ca and www.solarbc.org.

Q15.5 Please include how FortisBC participates in the LiveSmart BC program and SolarBC[61] and expected participation levels.

A15.5 FortisBC is a funding partner and our DSM incentives are bundled into the LiveSmart BC incentives to offer customers a one-stop comprehensive residential retrofit offering. The plan is for 300 and 400 electric heat participants in 2009 and 2010.

Q15.6 Please provide the incentive breakdown between the Provincial Government and FortisBC over the entire LiveSmart BC and SolarBC program list.

A15.6 With respect to LiveSmart BC, a Memorandum of Agreement is currently under negotiation with the provincial government. With SolarBC, FortisBC has budgeted for a rebate of $300 per residential solar thermal system.

Q15.7 Please provide the incentive breakdown of LiveSmart BC between the Provincial Government and FortisBC for specific products – Air Source Heat Pump, Attic Insulation and Solar Water Heater[62].

A15.7 Please see the response to OEIA IR No. 1 Q15.6 above.

[61] Exhibit B-1, Section 6, Page 110
[62] SmartLive BC incentive guide, Pages 2 to 3

Q15.8 Please explain how FortisBC customers can participate in the "*Distributed Power Generation*" [63] of LiveSmart BC yet Net Metering is not yet approved[64].

A15.8 The Provincial Government provides incentives even without a Net Metering tariff in place.

Q15.9 Please define what is meant by "*traditionally underserved customers*"[65], how the programs are going to be revamped, and the level of funding for such programs.

A15.9 Certain customer segments, i.e. small retail shops, and low-income residential, have not been able to access existing program offerings due to various barriers.

In the case of retail storefronts, the Company has brought in the Cool Shops program, which offers the storefront retailer a free walk-through lighting audit, energy-saving advice and a discounted lighting products offer. The Company has budgeted $0.15 million in 2009 and 2010 respectively to offer Cool Shops in each of the three sub-regions of the service area.

In the case of low-income residential customers, the Company is looking to the provincial "affordable housing" working group for assistance in designing a suitable program. FortisBC has budgeted $0.1 million in 2009 and 2010 respectively, and expects to leverage that with provincial dollars allocated to this sector.

[63] SmartLive BC incentive guide, Page 4
[64] Exhibit B-2, BCUC IR#1, A80.1, Page 154
[65] Exhibit B-1, Section 6, Page 111

Q15.10 Are any other new Residential programs anticipated for 2009 and 2010 – if so please list.

A15.10 There are no other new residential programs anticipated for 2009 and 2010.

Q16.0 General Service Sector

Q16.1 Please explain why there is no expected "*2009 Plan Savings GWh*" for "*Change to 2008 Base*" for General Service in Table 6.2[66] in spite of an increase of $98,000 expenditure.

A16.1 The base programs were escalated according to medium term trends, which had been flat in General Service sector prior to 2008. Due to an update in labour loading rates, and the additional position of a DSM Operations Manager, the base costs have increased.

Q16.2 Find the attached document[67] which is labeled "BC Hydro's Power Smart Incentive Program, Eligible Product Incentives".

Please confirm that this attached document describes the eligible product incentives of BC Hydro's Power Smart Incentive Program.

A16.2 While the referenced document appears to be a legitimate BC Hydro publication, FortisBC cannot guarantee its validity.

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[66] Exhibit B-1, Section 6, Page 108
[67] Attached psbusiness47976.pdf

Q16.3 Please list each product from the document which FortisBC presently also has incentives and indicate the difference in incentive level.

A16.3 Since FortisBC does not know the basis of BC Hydro's calculations, it is not possible to make an item by item comparison. The current FortisBC incentive structure is based on 5 cents per kWh saved.

Q16.4 Please indicate the new products in "*the Capital Plan*" which FortisBC intends to cover and their difference in incentive levels.

A16.4 The Capital Plan is constructed by sector and by program, and does not delve into specific product offers.

Q16.5 Please indicate the new products in future Capital Plans that FortisBC intends to cover.

A16.5 Please see the response to OEIA IR No. 1 Q16.4 above.

Q16.6 Please discuss any plans for consistency between BC Hydro and FortisBC. If not, why not?

A16.6 The Company looks for opportunities to collaborate with the other public utilities, but does not plan for consistency since it is an independent public utility with different customer needs and environmental factors.

Q17.0 General Plant

Q17.1 In support of the 2007 Energy Plan and Bill 15, is fuel source and energy efficiency a consideration when replacing vehicles?[68] – please discuss.

A17.1 Fuel type and energy efficiency have been, and continue to be important considerations when replacing vehicles. Through a collaborative process, FortisBC reviews the sustainability, type and amount of work being done by the Company for which any specific vehicle is required. Once the work is defined, the Company utilizes the information gathered to acquire a vehicle which meets Company requirements including fuel type and efficiency. FortisBC has been referencing Natural Resources Canada's EnerGuide during this process which is readily available online as well as at new car dealerships.

Q17.2 What will the effect on the replacement of vehicles if the Advanced Metering Infrastructure (AMI) is approved and is implemented[69]?

A17.2 The current fifteen year Fleet Capital Plan accommodates the AMI proceeding as explained in Exhibit B-1, page 116, lines 10 through 12:

"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."

[68] Exhibit B-1, Section 7, Page 116 to 118
[69] Exhibit B-1, Section 7, Page 118 to 119

Q17.3 What are the ramifications if the AMI is not implemented[70]?

A17.3 If the AMI is not implemented then the required vehicles will be added back into the fifteen year Fleet Capital Plan and the cost will increase accordingly.

Q17.4 What level of energy efficiency and standby power regulations will be used for the computers and electronic equipment that are purchased[71]?

A17.4 Wherever possible FortisBC will use current standards for infrastructure such as servers, networking infrastructure and related peripherals. These standards take into consideration energy requirements on our existing backup supplies. Energy conservation is considered for all equipment through the implementation of “stand-by” modes and “shut down when not in use” policy.

Q17.5 Please describe in more detail how the “enhancements to SCADA control systems” [72] will help “meet the Energy Plan requirements or recommendations” [73].

A17.5 SCADA systems will help meet some of the 2007 BC Energy Plan requirements through better control and more informational data from transmission and distribution systems.

Q17.6 Please describe the DSM measures already implemented and those that are planned to be implemented for the 15 FortisBC building sites[74].

A17.6 The following are some DSM measures that have already been implemented:

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[70] Exhibit B-1, Section 7, Page 118 to 119
[71] Exhibit B-1, Section 7, Page 120 to 123
[72] Exhibit B-1, Section 7, Page 126 to 127
[73] Exhibit B-1, Section 7, Page 126 to 127
[74] Exhibit B-1, Section 7, Page 128 to 129

- Reduction in server load achieved in Trail by turning off servers at night;
- New central lighting timer in Trail office to turn lights off after hours;
- Occupancy and vacancy automatic lighting controls installed at Springfield and Trail offices; and
- When providing upgrades at all sites DSM is taken into account and FortisBC installs recommended lighting, insulation, windows, etc.

The following are DSM measures planned for FortisBC building sites:

- DSM audit of our facilities
- Review results of audit, prioritize items and upgrade accordingly
- Pilot project at FortisBC's Oliver site to include:
  - Water usage – low flow toilets; tap aerators, xeriscape landscaping;
- Waste reduction – ouside recycling station, indoors recycling station, battery recycling; and
- Energy
  1. lighting occupancy sensors;
  2. automatic setback thermostats;
  3. photovoltaic solar panels to power nighttime security lighting;
  4. insulating windows;
  5. new heat pump units to replace the existing aging units c/w improved controls; and
  6. adding insulation and reflective roofing membrane.

Q18.0 Transmission and Distribution

It is noted in "*the Capital Plan*" that the Transmission Growth is the largest capital expenditure at $160.6 million[75] and largest change for expenditure increases at $75.2 million[76].

Q18.1 Should DSM become successful or load requirements decrease, please discuss the ramifications on Transmission Growth.

A18.1 Current FortisBC DSM programs focus on energy consumption and not planned growth in demand capacity. FortisBC does incorporate a 10 percent annual reduction in capacity demand growth which takes into account some reduction based on DSM initiatives.

Q18.2 Please discuss specific lines or areas in Transmission Growth in which a decrease in load could result in a significant reduction in future transmission investments or requirements. Please discuss the circumstances needed in order to trigger the reduction.

A18.2 Transmission growth projects shown in the Capital Plan are based on capacity demand growth which is within the immediate timeframe. FortisBC does not see any large reductions in load which would delay the timelines of these projects.

[75] Exhibit B-1, Section 1, Page 7
[76] Exhibit B-1, Section 1, Page 7

It was noted in response to a BCUC IR that FortisBC is considering "*Customer-owned Generation*" due to "*Net Metering*" [77]. It is also noted in the 2007 BC Energy Plan that "*renewable electricity generation continue to account for at least 90 per cent of total generation*"[78]. It is also noted that Bill 15 notes that the "*government's energy objectives*"[79] include "*to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources*"[80].

Q18.3 We will define the term "renewable energy sources" to reference "all pilot projects within FortisBC territory related to 'Customer-owned Generation', 'Net Metering', feed-in tariffs, district level generation or renewable electricity generation besides those listed in 'the Capital Plan" already". Please list and describe all pilot projects related to "renewable energy sources".

A18.3 FortisBC is not currently undertaking any pilot projects related to renewable energy resources.

Q18.4 Please discuss any specific lines or areas in which "*renewable energy sources*" could help reduce future transmission/distribution investments or requirements.

A18.4 It is difficult to identify specific feeders or regions where "renewable energy sources" would be effective, however, as a general rule the sources would have to be close to existing load centers and existing distribution infrastructure.

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[77] Exhibit B-2, BCUC IR#1, A80.1, Page 154
[78] 2007 BC Energy Plan, Policy Action Item #21
[79] Exhibit B-1, Section 1, Page 13
[80] Exhibit B-1, Section 1, Page 13

Q18.5 Please discuss the level of "*renewable energy sources*" penetration necessary across the FortisBC system to make a significant impact on the future transmission/distribution investments or requirements. Please discuss the hurdles that are necessary to overcome in order to achieve those levels of penetration.

A18.5 At a distribution level, a minimum of 1 MVA from a renewable energy source would be required to make an impact. These "renewable energy sources" would then contribute to the growth needs on the distribution level which would have an impact on the transmission level.

Since renewable energy distribution sources are generally small, a large number would need to be present on the distribution network to show some level of penetration.

Q18.6 Please discuss the promotion and incentives that FortisBC is planning in support of "*renewable energy sources*".

A18.6 FortisBC is not contemplating promotion or incentives for "renewable energy sources" at this time.

Q18.7 Please discuss any preparation that FortisBC is planning for the transmission system to deal with the particular characteristics of new and upcoming "*renewable energy sources*".

A18.7 FortisBC will deal with each renewable energy source proposal as and when they arise. At this point, there are no specific plans under consideration for the transmission system.

Q18.8 It is noted in "*the Capital Plan*" that the new Benvoulin Substation is driven by increasing demand[81]. If there were no further increases in demand, would the Benvoulin Substation be required? Please comment on the factors driving the increased demand.

A18.8 The Benvoulin Substation would still be required to address backup capacity for the DG Bell Terminal Station. The load growth in these areas is increasing due to commercial development and high density housing.

Q18.9 It is noted in "*the Capital Plan*" that several large buildings are planned for the service area of the Recreation Substation[82]. Should the present housing downturn delay or cancel the construction of the buildings, please comment on the affect on the substation.

A18.9 The Recreation Substation transformer addition is required based on existing growth within the immediate time frame. It should be noted that construction is well underway on residential and commercial buildings within the immediate vicinity with some due for completion in the 2009/10 time frame.

Q18.10 It is noted in "*the Capital Plan*" that the Passmore Substation Upgrade "*follows the highway in a very tight corridor and has a high outage rate*"[83]. Please comment on how the "*tight corridor*" is related to this upgrade. Please indicate the present outage rate for this substation, and the target outage rate after completion.

A18.10 There are several factors that contribute to the high outage rate of the transmission line that supplies the Passmore Substation. One of these factors

[81] Exhibit B-1, Section 3, Page 47
[82] Exhibit B-1, Section 3, Page 49
[83] Exhibit B-1, Sectio5n 3, Page 71

is the tight corridor which makes it difficult in certain sections to provide an adequately wide right-of-way to avoid tree related outages due to the steep slopes along the highway and the private property issues related to acquiring additional right-of-way. Please see Table A18.10 below for the historical and year-to-date reliability for the Passmore Substation.

Table A18.10
Passmore Substation Reliability

Year	No. of Outages	No. of Customer Affected	Customer Hours
2003	6	3,982	1,249
2004	9	6,039	9,709
2005	4	2,684	1,264
2006	5	3,822	13,575
2007	5	3,959	3,089
2008 (to July 31)	5	3,970	7,358

On average the Passmore substation outages have contributed to about 1/3rd of the SAIDI value for the transmission line in the Slocan Valley (19 Line). In addition, this transmission line has been the first or second highest contributor to transmission SAIDI for FortisBC. Since most of the outages on 19 Line are after the Passmore Substation, FortisBC forecasts that the breaker addition will improve the yearly Slocan Valley transmission SAIDI by about 25 percent.

Q18.11 It is noted in "the Capital Plan" that the Huth Substation upgrade is "required to maintain service reliability for the growing customer base in the south Okanagan area"[84].

[84] Exhibit B-1, Section 3, Page 51

Please describe the present service reliability in overall quantitative numbers, plus the future targets for the Huth Substation upgrade.

A18.11 As discussed on page 51 of the 2009/10 Capital Plan Application (Exhibit B-1), at the present time it may take approximately 2 hours to fully restore power to the Penticton area following the loss of the normal 63-kV supply line from the R.G. Anderson Terminal to the Huth Substation. Also, as noted the Huth Substation is responsible for supplying approximately 50,000 customers. If it is assumed that a permanent line fault occurs once every five years on average, then this is equivalent to:

$$50{,}000 \text{ customers} \cdot \left(\frac{2 \text{ hrs}}{1 \text{ outage}}\right) \cdot \left(\frac{1 \text{ outage}}{5 \text{ years}}\right) \approx \mathbf{20{,}000 \text{ customer} \cdot \text{hrs / year}}$$

Operating the two lines in parallel would reduce this number to near zero, as a single contingency event would no longer be expected to cause an outage to the Huth Substation supply.

Q18.12 Please summarize the growth pattern of the customer in the past and predictions for the future for the area covered by the Huth Substation upgrade.

A18.12 Historical readings indicate modest load growth in the Penticton area. Current load projections forecast the load in the area growing by approximately 2 percent per year.

Q18.13 Please comment on the need for the Huth Substation upgrade if the customer growth does not materialize.

A18.13 The Huth Substation is a major transmission supply point for the Penticton area and already supplies over 80 MVA of load (50,000 customers) based on historical readings. FortisBC feels that it is unacceptable for this amount of load to be exposed to an extended outage due to a single-contingency event. Thus, even if no further load growth occurred, the station upgrade would still be a prudent investment.

Q19.0 Generation

It is noted in "*the Capital Plan*" that there are several options for the Corra Linn Unit #2 Life Extension [85] and it is following the Corra Linn Unit #1 Life Extension[86].

Q19.1 Please indicate the cost of a "*turbine condition assessment*"[87] and the degree of certainty one can expect in the results from such an assessment.

A19.1 The cost of a turbine condition assessment is approximately $17,000. This assessment, combined with previously conducted assessments, is used to make the determination between refurbishment or replacement of the turbine. This inspection is conducted by a third party engineering resource from BC Hydro, who draws on experience from that utility. It is felt that this assessment provides high certainty in the decision making process around turbine refurbishment versus replacement.

Q19.2 With the Corra Linn Unit #1 still to be completed, is there any further information that can be gathered through completing that project that could be useful for determining the condition or preferred option for Corra Linn Unit #2?

A19.2 There can be some general conclusions drawn, but due to the fact that the units experience different run times and operating conditions, an individual assessment is required to make the final decision.

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[85] Exhibit B-1, Appendix 2, Pages 1 to 6
[86] Exhibit B-1, Section 2, Page 22 to 23
[87] Exhibit B-1, Section 2, Page 23 to 24

Q20.0 General

It is noted in "*the Capital Plan*" that distribution, generation and transmission are contained within FortisBC as presented together in Table 1.3[88], which is in contrast to the two separate companies of BC Hydro and BCTC.

Q20.1 Please discuss the advantages to FortisBC of maintaining all these areas within the one entity of FortisBC.

A20.1 As noted in the Aquila Sale Application filed with the Commission on December 1, 2003:

> All of the electric utilities in which Fortis has an interest have substantial rural service territories and customer bases. Fortis' utilities have considerable experience in all aspects of hydro-electricity generation, electricity delivery and customer service in low-density rural areas as well as small to mid-size urban areas.
>
> Fortis' utilities provide electrical service in integrated utility environments such as Newfoundland and Labrador and Prince Edward Island and in open access markets such as Ontario. (FortisBC Aquila Sale Application Page 4)

FortisBC believes that its experience in operating vertically integrated utilities that provides advantages for its customers, rather than the specific market structure itself. It should be noted that the BCTC/BC Hydro circumstances are distinct from that of FortisBC in that in order to facilitate trade, functional separation was required of the former to comply with FERC requirements to provide fair and open access to its transmission system.

For FortisBC, experience with the integrated structure allows for cost efficiencies and enhanced reliability also plays a large role in system planning. FortisBC is constantly evaluating the long-term needs of its customers and the areas growth to ensure that the generation supply and transmission infrastructure are considered. FortisBC believes that in continuing to communicate with the Commission and other stakeholders in planning for generation, transmission, distribution, and customer service, the Company can best meet the continuing objective to provide safe, reliable power at the lowest reasonable cost.

Q20.2 Are there any considerations or discussions looking to deviate from this structure?

A20.2 No.

[88] Exhibit B-1, Section 1, Table 1.1, Page 6

Certified correct as passed Third Reading on the 8th day of April, 2008

Ian D. Izard, Q.C., Law Clerk

MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 15 – 2008

UTILITIES COMMISSION AMENDMENT ACT, 2008

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

1 ***Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by adding the following definitions:***

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand;

"government's energy objectives" means the following objectives of the government:

(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;

"transmission corporation" has the same meaning as in the *Transmission Corporation Act*;.

2 ***Section 2 (4) is amended by striking out*** "1 to 3 and 5 to 13" ***and substituting*** "1 to 13".

3 ***Section 3 is repealed and the following substituted:***

Commission subject to direction

3 (1) Subject to subsection (3), the Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the powers and the performance of the duties of the commission, including, without limitation, a direction requiring the commission to exercise a power or perform a duty, or to refrain from doing either, as specified in the regulation.

(2) The commission must comply with a direction issued under subsection (1), despite

(a) any other provision of

(i) this Act, except subsection (3) of this section, or

(ii) the regulations, or

(b) any previous decision of the commission.

(3) The Lieutenant Governor in Council may not under subsection (1) specifically and expressly

(a) declare an order or decision of the commission to be of no force or effect, or

(b) require the commission to rescind an order or a decision.

4 Section 5 is amended

(a) by adding the following subsection:

(0.1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act.*,

(b) in subsection (3) by adding "British Columbia or" ***after*** "enactment of"***, and***

(c) by adding the following subsections:

(4) The commission, in accordance with subsection (5), must conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins or, if the terms of reference given under subsection (6) specify a different period, for that period.

(5) An inquiry under subsection (4) must begin

(a) by March 31, 2009, and

(b) at least once every 6 years after the conclusion of the previous inquiry,

unless otherwise ordered by the Lieutenant Governor in Council.

(6) For an inquiry under subsection (4), the minister may specify, by order, terms of reference requiring and empowering the commission to inquire into the matter referred to in that subsection, including terms of reference regarding the manner

in which and the time by which the commission must issue its determinations under subsection (4).

(7) The minister may declare, by regulation, that the commission may not, during the period specified in the regulation, reconsider, vary or rescind a determination made under subsection (4).

(8) Despite section 75, if a regulation is made for the purposes of subsection (7) of this section with respect to a determination, the commission is bound by that determination in any hearing or proceeding held during the period specified in the regulation.

(9) The commission may order a public utility to submit an application under section 46, by the time specified in the order, in relation to a determination made under subsection (4).

5 ***Section 22 is repealed and the following substituted***

Exemptions

22 (1) In this section:

"eligible person" means a person, or a class of persons, that

(a) generates, produces, transmits, distributes or sells electricity,

(b) for the purpose of heating or cooling any building, structure or equipment or for any industrial purpose, heats, cools or refrigerates water, air or any heating medium or coolant, using for that purpose equipment powered by a fuel, a geothermal resource or solar energy, or

(c) enters into an energy supply contract, within the meaning of section 68, for the provision of electricity;

"minister" means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister, by regulation, may

(a) exempt from any or all of section 71 and the provisions of this Part

(i) an eligible person, or

(ii) an eligible person in respect of any equipment, facility, plant, project, activity, contract, service or system of the eligible person, and

(b) in respect of an exemption made under paragraph (a), impose any terms and conditions the minister considers to be in the public interest.

(3) The minister, before making a regulation under subsection (2), may refer the matter to the commission for a review.

6 ***Section 43 (1) is repealed and the following substituted:***

(1) A public utility must, for the purposes of this Act,

(a) answer specifically all questions of the commission, and

(b) provide to the commission

(i) the information the commission requires, and

(ii) a report, submitted annually and in the manner the commission requires, regarding the demand-side measures taken by the public utility during the period addressed by the report, and the effectiveness of those measures.

(1.1) The authority, in addition to providing the information and reports referred to in subsection (1), must provide to the commission, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of whether the authority's electricity rates are competitive with those other rates.

7 *The following sections are added:*

Long-term resource and conservation planning

44.1 (1) In this section, **"demand increase"** means the greater of

(a) the difference between

(i) the sum of the estimate referred to in subsection (4) (b) and a prescribed amount, if any, and

(ii) the demand the authority would serve during the period referred to in subsection (4) (b) if the demand in each year of that period remains equal to the demand referred to in subsection (4) (a), and

(b) zero.

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility.

(4) A long-term resource plan filed under subsection (2) by the authority before the end of the 2020 calendar year must include, in addition to everything referred to in subsection (2) (a) to (g), all of the following:

(a) a statement of the demand for electricity the authority served in the year beginning on April 1, 2007, and ending on March 31, 2008;

(b) an estimate of the total demand for electricity the authority would expect to serve in the period beginning on April 1, 2008, and ending on March 31, 2021, if no new demand-side measures are taken during that period;

(c) a statement of the demand-side measures the authority would need to take so that, in combination with demand-side measures taken by the government of British Columbia or of Canada or a local authority, the demand increase would be reduced by 50% by 2020.

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

(a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or

(b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

(a) the public utility may resubmit the part within a time specified by the commission, and

(b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

(a) the government's energy objectives,

(b) whether the plan is consistent with the requirements under sections 64.01 and 64.02, if applicable,

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

(a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);

(b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

8 ***Section 45 (6.1) and (6.2) is repealed.***

9 ***Section 46 is amended***

(a) in subsection (3) by striking out "The commission" ***and substituting*** "Subject to subsections (3.1) and (3.2), the commission"***, and***

(b) by adding the following subsections:

(3.1) In deciding whether to issue a certificate under subsection (3), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) whether the application for the certificate is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable.

(3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

10 Section 58 is amended by adding the following subsections:

(2.1) The commission must set rates for the authority in accordance with

(a) the prescribed requirements, if any, and

(b) the prescribed factors and guidelines, if any.

(2.2) A requirement prescribed for the purposes of subsection (2.1) (a) applies despite

(a) any other provision of

(i) this Act, including, for greater certainty, section 58.1, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

11 The following section is added:

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3 or 125.1 (4) (f), or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission may not set rates for the authority for the purpose of changing the revenue-cost ratio for a class of customers.

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

12 ***Section 61 (2) is amended by adding*** "rescinded or" ***after*** "must not be".

13 ***The following Part is added:***

PART 3.1 – ENERGY SECURITY AND THE ENVIRONMENT

Electricity self-sufficiency

64.01 (1) The authority must

(a) by the 2016 calendar year, achieve electricity self-sufficiency according to the prescribed criteria, and

(b) maintain, according to the prescribed criteria, electricity self-sufficiency in each calendar year after achieving it.

(2) A public utility, in planning for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year.

Clean and renewable resources

64.02 (1) To facilitate the achievement of the government's goal that at least 90% of the electricity generated in British Columbia be generated from clean or renewable resources, a person to whom this section applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) This section applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

Standing offer

64.03 (1) In this section, **"eligible facility"** means a generation facility that

(a) either

(i) has only one generator with a nameplate capacity of 10 megawatts or less or has more than one generator and the total nameplate capacity of all of them is 10 megawatts or less, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities.

(2) The authority must establish and maintain a standing offer

(a) during the times prescribed by and in accordance with the regulations, if any, and

(b) on the terms and conditions, if any, approved by the commission under subsection (3),

to enter into an energy supply contract for the purchase of electricity from eligible facilities.

(3) Subject to regulations made for the purposes of subsection (2) (a), the commission, by order and on application by the authority, may approve terms and conditions for the purposes of subsection (2) (b) if the commission considers that the terms and conditions are in the public interest.

(4) The commission may not issue an order under section 71 (3) with respect to a contract entered into in accordance with the regulations made for the purposes of subsection (2) (a), and exclusively on the terms and conditions referred to in subsection (2) (b), of this section.

Smart meters

64.04 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) If a public utility, other than the authority, makes an application under the Act in relation to advanced meters, the commission, in considering that application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters.

14 Section 71 (2) is repealed and the following substituted:

(2) The commission may make an order under subsection (3) if the commission, after a hearing, determines that an energy supply contract to which subsection (1) applies is not in the public interest.

(2.1) In determining under subsection (2) whether an energy supply contract is in the public interest, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the energy supply contract is consistent with requirements imposed under section 64.01 or 64.02, if applicable,

(d) the interests of persons in British Columbia who receive or may receive service from the public utility,

(e) the quantity of the energy to be supplied under the contract,

(f) the availability of supplies of the energy referred to in paragraph (e),

(g) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (e), and

(h) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (e).

(2.2) Subsection (2.1) (a) to (c) does not apply if the commission considers that the matters addressed in the energy supply contract filed under subsection (1) were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(2.3) A public utility may submit to the commission a proposed energy supply contract setting out the terms and conditions of the contract and a process the public utility intends to use to acquire power from other persons in accordance with those terms and conditions.

(2.4) If satisfied that it is in the public interest to do so, the commission, by order, may approve a proposed contract submitted under subsection (2.3) and a process referred to in that subsection.

(2.5) In considering the public interest under subsection (2.4), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1,

(c) whether the application for the proposed contract is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(2.6) If the commission issues an order under subsection (2.4), the commission may not issue an order under subsection (3) with respect to a contract

(a) entered into exclusively on the terms and conditions, and

(b) as a result of the process

referred to in subsection (2.3).

15 ***Section 88 (4) is amended by striking out*** "a matter that is subject" ***and substituting*** "a person, or a person in respect of a matter, who has been exempted under".

16 ***Section 108 (b) is amended by adding*** "responsible for the administration of the *Hydro and Power Authority Act*" ***after*** "minister".

17 ***The following sections are added:***

Minister's regulations

125.1 (1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister may make regulations respecting the government's energy objectives, as defined in section 1, including, without limitation, regulations as follows:

(a) defining a word or phrase used in the definition;

(b) prescribing actions and goals for the purposes of paragraph (f) of the definition;

(c) establishing factors or guidelines the commission must use in considering the government's energy objectives, including guidelines regarding the relative priority of the objectives referred to in paragraphs (a) to (f) of the definition.

(3) A regulation under subsection (2) may be made with respect to the government's energy objectives generally or with respect to their application in any particular case.

(4) The minister may make regulations as follows:

(a) making declarations for the purposes of section 5 (7);

(b) respecting exemptions under section 22;

(c) respecting reports to be provided to the commission by the authority under section 43 (1.1), including, without limitation, respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(d) prescribing, for the purposes of paragraph (a) (i) of the definition of "demand increase" in section 44.1 (1), an amount representing an increase in resource requirements of the authority not related to an estimated increased demand referred to in section 44.1 (4) (b);

(e) for the purposes of section 44.1 and 44.2,

(i) prescribing rules for determining whether a demand-side measure, or a class of demand-side measures, is adequate, cost-effective or both,

(ii) declaring a demand-side measure, or a class of demand-side measures, to be cost effective and necessary for adequacy,

(iii) prescribing rules or factors a public utility must use in making the estimate referred to in section 44.1 (2) (a), and

(iv) prescribing rules or factors the authority must use in making the estimate referred to in section 44.1 (4) (b);

(f) prescribing requirements for the purposes of section 58 (2.1) (a);

(g) prescribing factors and guidelines for the purposes of section 58 (2.1) (b), including, without limitation, factors and guidelines to encourage

(i) energy conservation or efficiency,

(ii) the use of energy during periods of lower demand,

(iii) the development and use of energy from clean or renewable resources, or

(iv) the reduction of the energy demand a public utility must serve;

(h) defining a term or phrase used in section 58.1 and not defined in this Act;

(i) identifying facts that must be used in interpreting the definition in section 58.1;

(j) defining a term or phrase used in Part 3.1 and not defined in that Part;

(k) prescribing criteria respecting self-sufficiency for the purposes of section 64.01 (1) (a) and (b);

(l) prescribing targets for the purposes of section 64.02 (1) (a), guidelines for the purposes of section 64.02 (1) (b) and public utilities and classes of public utilities for the purposes of section 64.02 (2) (b);

(m) for the purposes of section 64.03, respecting eligible facilities, including prescribing generation facilities and classes of generation facilities, and respecting the standing offer to be established and maintained under that section;

(n) for the purposes of section 64.04, respecting smart meters and their installation, including, without limitation,

(i) the types of smart meters to be installed, including the features or functions each meter must have or be able to perform, and

(ii) the classes of users for whom smart meters must be installed, and requiring the authority to install different types of smart meters for different classes of users;

(o) prescribing standard-making bodies for the purposes of section 125.2 (1) and matters for the purposes of section 125.2 (3) (d);

(p) prescribing owners, operators, direct users, generators and distributors, or classes of any of them, for the purposes of section 125.2 (8).

(5) In making a regulation under this section, the minister may

(a) make regulations of specific or general application, and

(b) make different regulations for different persons, places, things, measures, transactions or activities.

Adoption of reliability standards, rules or codes

125.2 (1) In this section:

"reliability standard" means a reliability standard, rule or code established by a standard-making body for the purpose of being a mandatory reliability standard for planning and operating the North American bulk power system, and includes any substantial change to any of those standards, rules or codes;

"standard-making body" means

(a) the North American Electric Reliability Corporation,

(b) the Western Electricity Coordinating Council, and

(c) a prescribed standard-making body.

(2) For greater certainty, the commission has exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in British Columbia.

(3) The transmission corporation must review each reliability standard and provide to the commission, in accordance with the regulations, a report assessing

(a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted under subsection (6),

(b) the suitability of the reliability standard for British Columbia,

(c) the potential cost of the reliability standard if it were adopted under subsection (6), and

(d) any other matter prescribed by regulation or identified by order of the commission for the purposes of this section.

(4) The commission may make an order for the purposes of subsection (3) (d).

(5) If the commission receives a report under subsection (3), the commission must

(a) make the report available to the public in a reasonable manner, which may include by electronic means, and for a reasonable period of time, and

(b) consider any comments the commission receives in reply to the publication referred to in paragraph (a).

(6) After complying with subsection (5), the commission, subject to subsection (7), must adopt the reliability standards addressed in the report if the commission considers that the reliability standards are required to maintain or achieve consistency in British Columbia with other jurisdictions that have adopted the reliability standards.

(7) The commission is not required to adopt a reliability standard under subsection (6) if the commission determines, after a hearing, that the reliability standard is not in the public interest.

(8) A reliability standard adopted under subsection (6) applies to every

(a) prescribed owner, operator and direct user of the bulk power system, and

(b) prescribed generator and distributor of electricity.

(9) Subsection (8) applies to a person prescribed for the purposes of that subsection despite any exemption issued to the person under section 22 or 88 (3).

(10) The commission may make orders providing for the administration of adopted reliability standards.

(11) The commission, on its own motion or on complaint, may

(a) rescind an adoption made under subsection (6), or

(b) adopt a reliability standard previously rejected under subsection (7) if the commission determines, after a hearing, that the rescission or adoption is in the public interest.

(12) The commission, without the approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, may not set a standard or rule under section 26 of this Act with respect to a matter addressed by a reliability standard assessed in a report submitted to the commission under subsection (3) of this section.

Consequential Amendments and Transition

Insurance Corporation Act

18 ***Section 44 of the Insurance Corporation Act, R.S.B.C. 1996, c. 228, is amended by striking out*** "other than sections 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), 97, 98, 106 (1) (k), 107 to 109 and 114 and Parts 4 and 5 of that Act," ***and substituting*** "other than sections 3, 5 (4) to (9), 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 43 (1) (b) (ii), 44.1, 44.2, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), Part 3.1, 97, 98, 106 (1) (k), 107 to 109 and 114, Parts 4 and 5 and sections 125.1 and 125.2 of that Act,".

Water Utility Act

19 ***Section 4 (b) of the Water Utility Act, R.S.B.C. 1996, c. 485, is amended by striking out*** "other than sections 28, 29 and 45 (2), (3), (5) and (6)," ***and substituting*** "other than sections 28, 29, 44.1, 44.2, 45 (2), (3), (5) and (6), 58 (2.1) and (2.2) and 58.1, Part 3.1 and sections 125.1 and 125.2,".

Transition

20 (1) For greater certainty, a regulation made under section 3 of the *Utilities Commission Act*, as that section read immediately before the date section 3 of this Act comes into force, if that regulation was in effect immediately before that date, remains in effect and is deemed to be a regulation under section 3 of the *Utilities Commission Act* as that section reads immediately after section 3 of this Act comes into force.

(2) An exemption under section 22 of the *Utilities Commission Act*, as that section read immediately before the date section 5 of this Act comes into force, if that exemption was in effect immediately before that date, remains in effect and is deemed to be an exemption under section 22 of the *Utilities Commission Act* as that section reads immediately after section 5 of this Act comes into force.

Commencement

21 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 11	March 31, 2008

FORTISBC

David Bennett
General Counsel and
Corporate Secretary

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October 27, 2006

Via Email
Original via Courier

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

Dear Mr. Pellatt:

Re: Semi-Annual Demand Side Management Report

Please find enclosed for filing FortisBC Inc.'s Semi-Annual Demand Side Management Report ending June 30, 2006.

If further information is required, please Brian Parent at (250) 717 0851.

Sincerely,

David Bennett
General Counsel and Corporate Secretary

FORTISBC

FORTISBC INC.

SEMI-ANNUAL DSM REPORT

SIX MONTHS ENDED JUNE 30, 2006

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Report Objective:

This report provides highlights of the Company's Demand Side Management ("DSM") programs for the six months ending June 30, 2006. The presentation format compares actual energy savings and costs to plan, provides a statement of financial results and details the estimated DSM incentive for the period.

Overview of Results for the Six Months Ended June 30, 2006:

Energy efficiency savings for the six months ended June 30, 2006 were 12.9 GW.h, 126% percent of the plan of 10.2 GW.h for the same period. Costs for the year were $1,197,000, 53% of the $2,234,000 plan. The Total Resource Benefit/Cost ratio for the six months ended June 30, 2006 was 1.8.

Energy Savings per Sector:

	GW.h		% of Plan
	YTD Plan	Actual	Achieved
Residential	4.8	5.0	104%
General Service	4.6	6.5	141%
Industrial	0.8	1.4	175%
Total savings (GW.h)	**10.2**	**12.9**	**126%**

The Residential, General Service and Industrial sectors all exceeded their energy savings target for the period.

Detail of Energy Savings:

Residential Programs:	GW.h		% of Plan
	YTD Plan	Actual	Achieved
HIP/Watersavers	0.1	0.2	200%
New Home Program	0.8	0.6	75%
Heat Pumps (Air & Ground Source)	2.8	2.6	93%
Residential Lighting	1.1	1.6	145%
	4.8	**5.0**	**104%**

The residential construction and renovation activity is still brisk. In the New Home program, there were 201 (187 in 2005) single family and 76 (212 in 2005) multiple unit prticipants in 2006. Residential Lighting and Home Improvements programs programs exceeded plan expectations. There were 274 participants in the Air Source Heat Pump program compared to 269 for the same period in in 2005.

General Service Programs:	**GW.h**		**% of Plan Achieved**
	YTD Plan	**Actual**	
Lighting	1.5	1.5	100%
Building and Process Improvement	3.1	5.0	161%
	4.6	**6.5**	**141%**

The General Service sector recorded savings of 6.5 GW.h, 141% of plan to June 30, 2006. Larger projects included savings of 1.4 GW.h due to the removal of motors in Nelson's tertiary treatment sewerage plant, 0.6 GW.h for geo-exchange systems in Kelowna office buildings, 1.25 GW.h for lighting in Summerland and Nelson senior centres and 0.6 GW.h for HVAC and lighting systems at Selkirk College and UBC Kelowna campuses.

Industrial Programs:	**GW.h**		**% of Plan Achieved**
	YTD Plan	**Actual**	
Compressed Air	0.2	0.5	250%
Industrial Efficiencies	0.6	0.9	150%
	0.8	**1.4**	**175%**

Both programs within this sector exceeded target savings. The implementation of variable speed drives for compressors was responsible for most of the energy savings in the compressed air program. Within the Industrial Efficiencies program, a single forest industry project involving poly chain drives accounted for 0.5 GW.h of energy savings.

Program Costs:

Summary of Costs by Sector

	YTD Plan	Actual	% of Plan
	($000s)		
Residential	498	480	96%
General service	345	404	117%
Industrial	90	106	118%
Planning & Evaluation	184	203	110%
	1,117	**1,193**	**107%**

Costs amounted to $1,193,000, 107% of plan to June 30, 2006.

Costs per Sector:

Residential	YTD Plan	Actual	% of Plan
	($000s)		
H.I.P./Watersavers	32	58	181%
New Home Program	152	118	78%
Heat Pumps (Air & Ground)	231	234	101%
Residential Lighting	83	70	84%
	498	**480**	96%

The cost of Residential programs was $480,000, 96% of plan. The largest cost component of Residential programs is the Heat Pumps Program followed by the New Home Program. Incentives paid to participants amounted to $244,000 during the period.

General Service	YTD Plan	Actual	% of Plan
	($000s)		
Lighting	128	109	85%
Building and Process Improvement	217	295	136%
	345	**404**	**117%**

Costs to June 30, 2006 for General Service amounted to $404,000 or 117% of plan. Incentives paid amounted to $195,600 and exceeded plan by 15% or $26,000. This corresponds to the savings activity within this sector which also exceeds plan.

Industrial	YTD Plan	Actual	% of Plan
	($000s)		
Industrial Efficiencies	69	70	101%
Compressed Air	21	36	171%
	90	**106**	**118%**

Industrial sector costs were $106,000 for the period, 118% of plan. Incentives paid during the period amounted to $52,000, $16,000 in excess of plan, driven by savings which were 175 % of plan.

Financial Results:

FINANCIAL RESULTS for the Six Months ended June 30, 2006

Financial Results by Program ($000s)

Program	**Program Benefits**	**Program Costs**	**Planning & Evaluation Costs**	**Customer Costs**	**Total Costs**	**Benefit Cost Ratio**
Residential						
HIP/Watersavers	**63**	**58**	**4**	**12**	**74**	**0.9**
New Home program	**302**	**118**	**10**	**8**	**136**	**2.2**
Heat Pumps	**954**	**234**	**42**	**589**	**865**	**1.1**
Residential Lighting	**339**	**70**	**25**	**15**	**110**	**3.1**
Residential Total	**1,658**	**480**	**80**	**624**	**1,184**	**1.4**
General Service						
Lighting	**518**	**109**	**23**	**68**	**200**	**2.6**
Building and Process Improvement	**1,801**	**295**	**79**	**437**	**811**	**2.2**
General Service Total	**2,319**	**404**	**103**	**505**	**1,012**	**2.3**
Industrial						
Industrial Efficiencies	**270**	**70**	**14**	**60**	**144**	**1.9**
Compressed Air	**85**	**36**	**7**	**29**	**72**	**1.2**
Industrial Total	**355**	**106**	**21**	**89**	**216**	**1.6**
Total	4,332	990	203	1,218	2,411	**1.8**

An overall Benefit/Cost ratio of 1.8 has been achieved to June 30, 2006.

Residential Results

The residential sector had good results with an overall benefit/cost ratio of 1.4. As noted in the savings narrative, both Heat Pump and New Home construction programs were very successful and were the main contributors to this positive performance. The volume in these programs is due to the brisk construction pace in the Okanagan portion of our services area.

General Service and Industrial Results

The General and Industrial financial results are excellent with benefit/cost ratios of 2.3 and 1.6 respectively. Savings potential are identified through key customer contacts, trade ally relationships with architectural and engineering firms and the review of capital plans with larger customers.

The general service annual results are related to infrastructure, retail and office space development aimed at supporting future population growth.

Industrial results are related to new process improvements in compressed air technology which is cost effective for lumber mills in our service area.

Assistance with Federal and Provincial Government Programs:

In 2005, the provincial and federal governments requested the company's assistance in promoting a number of energy efficiency initiatives. The costs and funding related to these initiatives is summarized below:

Summary of Transactions with Provincial and Federal Governments

Expenditures to be recovered:	
Programs:	
NHP - Govt Gas Windows	17,914
NHP - NRG80	8,307
H.I.P. - Govt Gas Windows.	14,358
NR Can ASHP	63,608
	104,187
Amounts received for past and future activities:	
Provincial	201,368
Federal	39,000
	240,368

The costs and energy and capacity savings related to this undertaking have been excluded from the Company's savings, costs and financial results in this semi-annual DSM report. A reconciliation and accounting for these activities will be performed upon the completion of this program. Presently, the Company has received $136,181 over it current year's expenditures with $60,000 of this provided in recognition of the Company's program administration and the balance requiring a commitment for program expenditures by the Company.

Incentive Mechanism:

The incentive mechanism provides for incentives based on Net Benefits being achieved beyond 100% of plan. The maximum benefit available is allowable on 150% of plan benefits. The Residential incentive ranges from 3% to 6%, starting at the achievement of 101% of plan Net benefits. The General Service range is from 2% to 4% and Industrial 1% to 3%, also both starting from achievement of 101% of plan Net benefits.

A penalty is possible if less than 90% of Net Benefits is achieved in each sector. There is a maximum penalty set at 50% of plan Net Benefits.

Net Benefits are defined as benefits assigned to energy and capacity savings based on avoided power purchase costs, less Fortis program costs and customer-incurred costs pertinent to the energy savings system being installed.

The target for 2006 is based on a yearly average of actual costs, savings and benefits for the proceeding immediate three year period. The costs are escalated into 2006 dollars and the benefits are priced at BC Hydro Rate Schedule 3808 for 2006.

Net Benefits				Net Benefits For Incentive	% of YTD Plan	Forecast Incentive
	Actual to: 30-Jun	Plan to: 30-Jun	Variance			
	($000s)					
Residential	554	632	-78	554	88%	-16.62
General Service	1,410	1,114	296	1,410	127%	56.40
Industrial	160	149	11	160	107%	1.60
	2,124	1,895	229	2,124		41.38

Actual Net Benefits to June 30, 2006 amounted to $2,124,000, a $229,000 favourable variance over the plan Net Benefits of $1,895,000.

Based on current costs, savings and benefit calculations to June 30, 2006 an incentive of $41,000 has been calculated. This amount will change based on the performance during the second half of the year.

Appendix A DSM Summary Report BCUC Format

FortisBC
for Six Months Ending June 30, 2006

Sector/Program	Utility Costs: Direct Incentives	Utility Costs: Direct Information	Utility Costs: Program Labour	Program Evaluation	Research Adm & OH	Total	Customer Incurred Cost	Total Resource Cost	Benefit/Cost Ratios: Societal Cost	Benefit/Cost Ratios: Total Resource	Benefit/Cost Ratios: Rate Impact	Levelised Cost
	($000s)											
RESIDENTIAL:												
Heat Pumps	120.5	57.7	55.6	25.1	16.7	275.6	589.2	864.8	n/a	1.1	0.5	3.6
New Home Program	73.0	35.4	9.6	5.3	3.5	126.8	8.0	134.8	n/a	2.2	0.6	2.1
Residential Lighting	32.1	5.2	32.3	14.9	10.0	94.5	15.0	109.5	n/a	3.1	0.7	1.7
Home Improvements Program	18.0	29.7	10.3	2.0	1.3	61.3	12.0	73.3	n/a	0.9	0.4	3.4
	243.6	128.0	107.8	47.3	31.5	558.2	624.2	1,182.5		1.4	0.6	3.1
GENERAL SERVICE												
Lighting	51.0	5.9	52.6	14.1	9.4	133.0	67.8	200.8	n/a	2.6	0.6	1.8
Building and Process Improvement	145.0	40.1	109.9	47.9	31.8	374.7	437.1	811.8	n/a	2.2	0.5	1.6
	196.0	46.0	162.5	62.0	41.2	507.7	504.9	1,012.6		2.3	0.5	1.7
INDUSTRIAL:												
Industrial Efficiencies	28.0	11.3	29.9	8.2	5.4	82.8	60.0	142.8	n/a	1.9	0.6	1.4
Compressors	25.0	5.4	6.7	4.4	2.9	44.4	29.0	73.4	n/a	1.2	0.6	3.0
	53.0	16.7	36.6	12.6	8.3	127.2	89.0	216.2		1.6	0.6	2.0
TOTAL:	492.6	190.7	306.9	121.9	81.0	1,193.1	1,218.1	2,411.3		1.8	0.6	2.2

Levelised Energy Unit Cost - Cents per kWh	2.2	Energy Savings - kWh	12,905,932
Levelised Capacity Unit Cost - Dollars per kW	159.8	Capacity Savings - kW	1,907

FORTISBC

Brian Parent
Manager
Revenue Requirements
Regulatory

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Kelowna BC V1Y 9X1
250-717-0851
Brian.parent@fortisbc.com
www.fortisbc.com

October 11, 2007

Via Email
Originals Sent by Courier

Ms. Erica Hamilton
Commission Secretary
B.C. Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Dear Ms. Hamilton:

Re: Semi-Annual DSM Report

Pursuant to B.C. Utilities Commission Order G-41-94, please find enclosed five copies of the FortisBC Semi-Annual Demand Side Management (DSM) Report for the period ended December 31, 2006.

We will provide a copy of this report to the DSM Advisory Committee members and our DSM Wholesale Partners within the next week.

Should you require any further information or extra copies, please contact Keith Veerman at (250) 469-8072.

Sincerely,

Brian A. Parent
Manager, Revenue Requirements

Attach.

FORTISBC

SEMI-ANNUAL DSM REPORT

YEAR ENDED DECEMBER 31, 2006

Issue Date:
October 11, 2007

FortisBC Inc.

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ENERGY SAVINGS PER SECTOR: **1**

PROGRAM COSTS: **3**

FINANCIAL RESULTS: **4**

INCENTIVE MECHANISM: **6**

APPENDIX A **8**

Report Objective:

This report provides highlights of the Company's Demand Side Management ("DSM") programs for the year ending December 31, 2006. The presentation format compares actual energy savings and costs to plan, provides a statement of financial results and details the DSM incentive for the year.

Executive Summary:

Energy efficiency savings for the year ended December 31, 2006 were 23.1 GW.h, or 113% of the plan of 20.4 GW.h. Total costs were $2,242,000 or $8,000 more than the plan $2,234,000. The Total Resource Benefit/Cost ratio for the year ended December 31, 2006 was 1.8.

Energy Savings by Sector:

	YTD Plan GW.h	Actual	% of Plan Achieved
Residential	9.6	10.9	114%
General Service	9.2	9.7	105%
Industrial	1.6	2.5	156%
Total savings (GW.h)	**20.4**	**23.1**	**113%**

The Residential, General Service and Industrial sectors all exceeded their energy saving targets for the year.

Detail of Energy Savings:

Residential Programs:	**YTD Plan GW.h**	**Actual**	**% of Plan Achieved**
HIP/Watersavers	0.2	0.5	250%
New Home Program	1.6	1.3	81%
Heat Pumps (Air & Ground Source)	5.6	6.6	118%
Residential Lighting	2.2	2.5	114%
	9.6*	**10.9***	**114%**

* HIP is the abbreviation for Home Improvement Program

The residential construction and renovation activity continues to be strong. In the New Home program, there were 489 single family and 418 multiple unit participants, compared to 352 and

376 respectively in 2005. Residential Lighting and Home Improvements programs exceeded plan expectations. There were 711 participants in the Air Source Heat Pump program compared to 622 in 2005, with the increase attributable to additional customer awareness activities and capacity building efforts attained by the industry co-op plan and federal NRCan[1] funding.

General Service Programs:	**YTD Plan GW.h**	**Actual**	**% of Plan Achieved**
Lighting	3.0	3.0	100%
Building and Process Improvement	6.2	6.7	108%
	9.2	**9.7**	**105%**

The General Service sector recorded savings of 9.7 GW.h, 105% of plan to December 31, 2006. Larger projects included savings of 1.4 GW.h by using rotating biological contactors in Nelson's sewage plant, 0.6 GW.h for geo-exchange systems in Kelowna office buildings, 1.25 GW.h for lighting in Summerland and Nelson senior centres and 0.9 GW.h for heating, ventilation and air conditioning ("HVAC") and lighting systems at Selkirk College and UBC-Okanagan campuses.

Industrial Programs:	**YTD Plan GW.h**	**Actual**	**% of Plan Achieved**
Compressed Air	0.4	0.5	125%
Industrial Efficiencies	1.2	2.0	167%
	1.6	**2.5**	**156%**

Both programs within this sector exceeded target savings. The installation of compressors with variable speed drives was responsible for most of the energy savings in the compressed air program. Within the Industrial Efficiencies program, savings of 0.9 GW.h was attributable to modernization in a pulp operation, most of which came from the installation of variable speed drives on 300 Hp motors used for pumping control. A forest industry project involving an upgrade to poly chain drives accounted for another 0.5 GW.h of energy savings.

1 Natural Resources Canada, a department of the federal government.

Program Costs:

Summary of Costs by Sector

	YTD Plan	Actual	% of Plan
Sector:	$'000		
Residential	996	1,026	103%
General service	689	743	108%
Industrial	182	159	87%
Planning & Evaluation	367	314	86%
	2,234	**2,242**	**100%**

Total program costs amounted to $2,242,000, which was $8,000 in excess of the plan for the year ended December 31, 2006.

Costs per Sector:

Residential	**YTD Plan**	**Actual**	**% of Plan**
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H.I.P./Watersavers	63	58	92%
New Home Program	304	324	107%
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The cost of Residential programs was $1,026,000, 103% of plan. The largest cost component of Residential programs is the Heat Pumps Program followed by the New Home Program. Incentives paid to participants amounted to $643,000 during the period.

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Lighting	256	203	79%
Building and Process Improvement	433	540	125%
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Costs to December 31, 2006 for General Service amounted to $743,000 or 108% of plan. Incentives paid amounted to $360,000 and exceeded plan by 8% or $50,000. This corresponds to the savings activity within this sector which also exceeds plan.

Industrial	YTD Plan	Actual	% of Plan
	$'000		
Industrial Efficiencies	140	114	81%
Compressed Air	42	45	107%
	182	**159**	**87%**

Industrial sector costs were $159,000 for the period, 87% of plan. The $23,000 underspend is attributed to the 2-year payback clause invoked in a large project, which limited the usual five cents per annual kWh incentive rate otherwise payable.

	YTD Plan	Actual	% of Plan
	$’000		
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Planning and Evaluation cost was $53,000 under budget principally due to the 18-month secondment of the DSM engineer to MEMPR[2] which began October 1st, 2005. The costs related to the DSM engineer were paid by MEMPR as part of the secondment arrangements. During this period the Company used contracted engineering services for key project evaluations.

Financial Results:

FINANCIAL RESULTS for the Year ended December 31, 2006

Financial Results by Program ($’000)

Program	Program Benefits	Program Costs	Planning & Evaluation Costs	Customer Costs	Total Costs	Benefit Cost Ratio
Residential						
H.I.P./Watersavers	**182**	**58**	**7**	**22**	**87**	**2.1**
New Home program	**714**	**324**	**18**	**15**	**357**	**2.0**
Heat Pumps	**2,269**	**523**	**90**	**1,236**	**1,849**	**1.2**
Residential Lighting	**615**	**121**	**34**	**27**	**182**	**3.4**
Residential Total	**3,780**	**1,026**	**148**	**1,300**	**2,474**	**1.5**
General Service						
Lighting	**1,168**	**203**	**41**	**115**	**359**	**3.3**
Building and Process Improvement	**2,434**	**540**	**91**	**650**	**1,281**	**1.9**
General Service Total	**3,602**	**743**	**132**	**765**	**1,640**	**2.2**
Industrial						
Industrial Efficiencies	**563**	**114**	**26**	**98**	**238**	**2.4**
Compressed Air	**93**	**45**	**7**	**33**	**85**	**1.1**
Industrial Total	**656**	**159**	**33**	**131**	**323**	**2.0**
Total	8,038	1,928	314	2,196	4,438	**1.8**

[2] Ministry of Energy, Mines and Petroleum Resources is a department of the provincial government.

An overall Benefit/Cost ratio of 1.8 has been achieved to December 31, 2006.

Residential Results:

The residential sector had an overall benefit/cost ratio of 1.5. As noted in the savings narrative, both Heat Pump and New Home construction programs were very successful and were the main contributors to this positive performance. The volume in these programs is due to continued strong construction pace in the Okanagan portion of our services area.

General Service and Industrial Results:

The General and Industrial financial results achieved benefit/cost ratios of 2.2 and 2.0 respectively. Savings potential are identified through key customer contacts, trade ally relationships with architectural and engineering firms and the review of capital plans with larger customers.

The general service annual results are related to infrastructure, retail and office space development aimed at supporting future population growth.

Industrial results are related to the adoption of improved compressed air technology by medium size enterprises, and upgrading of motors and their associated controls.

Federal and Provincial Government Programs:

In 2005, the Company negotiated contribution agreements with both the provincial and federal governments to promote a number of energy efficiency initiatives, which extended to the end of the first quarter of 2007. Where the funding provided direct product incentives, e.g. EnergyStar window rebates; the Company does not claim the energy savings. Where the funding provided for additional customer awareness activities and/or capacity building, the Company included the additional energy savings in this report.

The costs and funding related to these initiatives are summarized below:

Summary of Transactions with Federal and Provincial Governments:	
Expenditures to be recovered:	
H.I.P. - Govt Electric Windows	$65,347
H.I.P. - Govt Gas Windows.	58,248
NR Can ASHP	106,641
NHP- NRG 80	9,222
NHP - Govt Gas Windows	49,582
	$289,040
Amounts received for past and future activities:	
Provincial	$201,368
Federal	39,000
	$240,368

As of year-end the Company had received $48,672 less than the 2006 expenditures incurred, due to the lag in reimbursement. The Company will be fully reimbursed for these costs in 2007.

DSM Incentive Mechanism:

Total resource cost (TRC) Net Benefits are the gross benefits of lifecycle energy and capacity savings less the total resource cost (FortisBC program costs plus customer-incurred costs) for the energy savings measures installed.

The DSM incentive mechanism measures the variance between the actual TRC Net Benefits (Actual) and the Base TRC Net Benefits (Base) set for each sector for the year. There are different incentive or penalty levels based on the size of the variance for each of the three sectors. Incentives for the sectors are calculated for performances of 100% to 150% of the Base. There is no calculation for performance between 90% and 100% of Base for all sectors. A performance below 90% of Base results in a penalty for that sector, which is capped at 50% of Base. If the sum of the sector incentives or penalties is greater than zero, then that sum is the DSM incentive for FortisBC for the year. If the sum is less than zero, then there is no DSM incentive for FortisBC for the year and no penalty is charged.

The Residential incentive ranges from 3% to 6%, starting at the achievement of 101% of Base, while the penalty ranges from -3% to -6%. The incentive range for General Service is 2% to 4%

and for Industrial is 1% to 3%, while the penalty ranges are -2% to -4% and -1% to -3%, respectively.

The target for 2006 is based on the rolling average of actual costs, savings and benefits for the proceeding immediate three year period. The costs are escalated into 2006 dollars and the benefits are priced at BC Hydro Rate Schedule 3808 for 2006.

2006 DSM Incentive Calculation:

Sector	Base Net Benefits A	Actual Net Benefits B	% of Base C	Eligible Amount D	Incentive Rate E	Incentive Amount (D x E)
	($'000)	($'000)		($'000)		($'000)
Industrial	290	366	126	366	3%	11.0
General Service	2,171	2,094	96	2,094	0%	0.0
Residential	1,222	1,454	119	1,454	4.5%	65.4
Total	3,683	3,914	106			76.4

Notes:

1. *Net benefits is the value of power saved less the utility and customer costs to save that power*
2. *Energy is valued at 2.75 cents per kW.h, capacity at $46.61 per annual kVA, and deferred capital expenditures at $350 per kVA*

Actual TRC Net Benefits to December 31, 2006 amounted to $3.914 million over the Base Net Benefits of $3.683 million.

As indicated in the table above, the DSM incentive is $76,400 for the year ended December 31, 2006.

Appendix A

FORTISBC
Demand-Side Management Summary Report in BCUC Format
For the Twelve Months Ending December 31, 2006

	Costs ($'000)								Benefit/Cost Ratios			Levelised
Sector/Program	Direct Incentives	Direct Info	Program Labour	Program Evaluation	Research Admin	Total Program	Customer Incurred	Total Resource	Societal Cost	Total Resource	Rate Impact	Cost $/kWh
RESIDENTIAL:												
Heat Pumps	302	165	56	54	36	613	1,236	1,848	n/a	1.2	0.5	$0.031
New Home Program	252	62	10	11	7	342	15	357	n/a	2.0	0.6	$0.024
Residential Lighting	58	31	32	20	14	155	27	182	n/a	3.4	0.8	$0.018
Home Improvement Program	31	17	10	4	3	65	22	87	n/a	2.1	0.5	$0.020
	643	276	108	89	59	1,175	1,300	2,475		1.5	0.6	$0.028
GENERAL SERVICE												
Lighting	98	52	53	25	16	244	115	359	n/a	3.3	0.6	$0.016
Building and Process Improvemen	263	166	110	55	37	631	651	1,281	n/a	1.9	0.5	$0.018
	361	219	163	80	53	875	765	1,640		2.2	0.5	$0.018
INDUSTRIAL:												
Industrial Efficiencies	46	38	30	16	10	140	98	238	n/a	2.4	0.6	$0.013
Compressors	27	11	7	4	3	52	33	85	n/a	1.1	0.6	$0.031
	73	49	37	20	13	192	131	323		2.0	0.6	$0.015
TOTAL:	1,077	544	307	189	125	2,242	2,196	4,438		1.8	0.6	$0.022

Levelised Energy Unit Cost - Dollars per kWh	$0.022	Energy Savings - kWh	23,093,354
Levelised Capacity Unit Cost - Dollars per kW	$142	Capacity Savings - kW	4,000

FORTISBC

Brian Parent
Manager
Revenue Requirements
Regulatory

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October 11, 2007

Via Email
Originals Sent by Courier

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B A Parent

Brian A. Parent
Manager, Revenue Requirements

Attach.

FORTISBC

SEMI-ANNUAL DSM REPORT

YEAR ENDED DECEMBER 31, 2006

Issue Date:
October 11, 2007

FortisBC Inc.

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FINANCIAL RESULTS for the Year ended December 31, 2006

Financial Results by Program ($’000)

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Industrial results are related to the adoption of improved compressed air technology by medium size enterprises, and upgrading of motors and their associated controls.

Federal and Provincial Government Programs:

In 2005, the Company negotiated contribution agreements with both the provincial and federal governments to promote a number of energy efficiency initiatives, which extended to the end of the first quarter of 2007. Where the funding provided direct product incentives, e.g. EnergyStar window rebates; the Company does not claim the energy savings. Where the funding provided for additional customer awareness activities and/or capacity building, the Company included the additional energy savings in this report.

The costs and funding related to these initiatives are summarized below:

Summary of Transactions with Federal and Provincial Governments:

Expenditures to be recovered:	
H.I.P. - Govt Electric Windows	$65,347
H.I.P. - Govt Gas Windows.	58,248
NR Can ASHP	106,641
NHP- NRG 80	9,222
NHP - Govt Gas Windows	49,582
	$289,040
Amounts received for past and future activities:	
Provincial	$201,368
Federal	39,000
	$240,368

As of year-end the Company had received $48,672 less than the 2006 expenditures incurred, due to the lag in reimbursement. The Company will be fully reimbursed for these costs in 2007.

DSM Incentive Mechanism:

Total resource cost (TRC) Net Benefits are the gross benefits of lifecycle energy and capacity savings less the total resource cost (FortisBC program costs plus customer-incurred costs) for the energy savings measures installed.

The DSM incentive mechanism measures the variance between the actual TRC Net Benefits (Actual) and the Base TRC Net Benefits (Base) set for each sector for the year. There are different incentive or penalty levels based on the size of the variance for each of the three sectors. Incentives for the sectors are calculated for performances of 100% to 150% of the Base. There is no calculation for performance between 90% and 100% of Base for all sectors. A performance below 90% of Base results in a penalty for that sector, which is capped at 50% of Base. If the sum of the sector incentives or penalties is greater than zero, then that sum is the DSM incentive for FortisBC for the year. If the sum is less than zero, then there is no DSM incentive for FortisBC for the year and no penalty is charged.

The Residential incentive ranges from 3% to 6%, starting at the achievement of 101% of Base, while the penalty ranges from -3% to -6%. The incentive range for General Service is 2% to 4%

and for Industrial is 1% to 3%, while the penalty ranges are -2% to -4% and -1% to -3%, respectively.

The target for 2006 is based on the rolling average of actual costs, savings and benefits for the proceeding immediate three year period. The costs are escalated into 2006 dollars and the benefits are priced at BC Hydro Rate Schedule 3808 for 2006.

2006 DSM Incentive Calculation:

Sector	Base Net Benefits A	Actual Net Benefits B	% of Base C	Eligible Amount D	Incentive Rate E	Incentive Amount (D x E)
	($'000)	($'000)		($'000)		($'000)
Industrial	290	366	126	366	3%	11.0
General Service	2,171	2,094	96	2,094	0%	0.0
Residential	1,222	1,454	119	1,454	4.5%	65.4
Total	3,683	3,914	106			76.4

Notes:

1. *Net benefits is the value of power saved less the utility and customer costs to save that power*
2. *Energy is valued at 2.75 cents per kW.h, capacity at $46.61 per annual kVA, and deferred capital expenditures at $350 per kVA*

Actual TRC Net Benefits to December 31, 2006 amounted to $3.914 million over the Base Net Benefits of $3.683 million.

As indicated in the table above, the DSM incentive is $76,400 for the year ended December 31, 2006.

Appendix A

FORTISBC
Demand-Side Management Summary Report in BCUC Format
For the Twelve Months Ending December 31, 2006

Sector/Program	Costs ($'000) Direct Incentives	Direct Info	Program Labour	Program Evaluation	Research Admin	Total Program	Customer Incurred	Total Resource	Benefit/Cost Ratios Societal Cost	Total Resource	Rate Impact	Levelised Cost $/kWh
RESIDENTIAL:												
Heat Pumps	302	165	56	54	36	613	1,236	1,848	n/a	1.2	0.5	$0.031
New Home Program	252	62	10	11	7	342	15	357	n/a	2.0	0.6	$0.024
Residential Lighting	58	31	32	20	14	155	27	182	n/a	3.4	0.8	$0.018
Home Improvement Program	31	17	10	4	3	65	22	87	n/a	2.1	0.5	$0.020
	643	276	108	89	59	1,175	1,300	2,475		1.5	0.6	$0.028
GENERAL SERVICE												
Lighting	98	52	53	25	16	244	115	359	n/a	3.3	0.6	$0.016
Building and Process Improvemen	263	166	110	55	37	631	651	1,281	n/a	1.9	0.5	$0.018
	361	219	163	80	53	875	765	1,640		2.2	0.5	$0.018
INDUSTRIAL:												
Industrial Efficiencies	46	38	30	16	10	140	98	238	n/a	2.4	0.6	$0.013
Compressors	27	11	7	4	3	52	33	85	n/a	1.1	0.6	$0.031
	73	49	37	20	13	192	131	323		2.0	0.6	$0.015
TOTAL:	1,077	544	307	189	125	2,242	2,196	4,438		1.8	0.6	$0.022

Levelised Energy Unit Cost - Dollars per kWh	$0.022	Energy Savings - kWh	23,093,354
Levelised Capacity Unit Cost - Dollars per kW	$142	Capacity Savings - kW	4,000

FORTISBC

DSM ADVISORY COMMITTEE
Thursday, September 4, 2008
8:45 a.m. to 4:00 p.m.

Inkaneep Point Resort
16235 – 87th Street, Osoyoos, B.C. V0H 1V2
Telephone: (250) 495-6353

AGENDA

Meeting Attendees

Attending:

Sarah Kahn, Public Interest Advocacy Centre	Keith Veerman, FortisBC
Richard Tarnoff, NRI, Hedley Improvement District	Mark Warren, FortisBC
Buryl Goodman, South Okanagan	Nancy Macleod, FortisBC, Corporate Communications
Al Wait, Boundary	Jodie Foster Sexsmith, FortisBC, Corporate Communications
Andrew Pape-Salmon, Ministry of Energy, Mines, and Petroleum Resources	Jill Neumann, Willis Energy Services
	Penny Cochrane, Willis Energy Services

Guest:

David Mayes, Guest, Okanagan Environmental Industry Association

Invited:

Eileen Cheng, BC Utilities Commission

Robert Macrae, Selkirk College, West Kootenay

	8:00 am	BREAKFAST served in meeting room	
1.	8:45	Welcome, Introductions, and Agenda Review	MW
2.	8:50	**PowerSense Update**	
		June 30 Results	KV
		Program Activity	KV
		2009-2010 Capital Plan	MW
3.	9:30	**Conservation Culture**	JFS, NM
	10:20	Break	
4.	10:20	**Conservation Culture cont'd**	
	12:00 pm	Lunch Served	
5.	12:30	**Energy Plan Update**	
		2008 Energy Plan Programs and Activity	
		Outlook for 2009	
6.	13:15	**DSM Strategy Development**	KV/PC
7.	13:25	**Energy Policy and Setting Targets**	KV
		Establishing savings target	Roundtable
		Treatment of costs and savings attributable to Codes and Standards	Roundtable
8.	13:40	**DSM Strategy Options**	KV/PC
		Market Transformation	
		Integrated DSM	
		Sustainability Management	
		Criteria for Evaluation of Strategy Options	Roundtable
9.	14:00	**PowerSense Post 2010**	KV/PC
		BCs DSM Backdrop	
		DSM Supply Chain	

DSM ADVISORY COMMITTEE
Thursday, September 4, 2008
8:45 a.m. to 4:00 p.m.

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AGENDA

		Quality Assurance	
	14:45	Break	
9a.	15:00	**PowerSense Post 2010** Renewable Power and Alternative Energy Systems Benefits of DSM Post 2010	KV/PC Roundtable Roundtable
10.	15:30	**Next steps** DSM Strategy Development Draft Advisory Committee Terms of Reference Update	KV
11.	16:00	**Wrap up**	KV/MW

DSM ADVISORY COMMITTEE
TERMS OF REFERENCE
Sept 2008

Purpose

The purpose of the DSM Advisory Committee is:

- To review the effectiveness of the DSM incentive mechanism employed by FortisBC to report DSM performance, and to revise its structure as required, from time to time;
- To review DSM operating results for incentive calculation purposes;
- To provide advice and comment to FortisBC on programs, targets and the semi-annual DSM operating results;
- To provide advice and comment to FortisBC on energy efficiency potential studies, business plan preparation, capital plan, program design strategies, and program evaluation studies; and
- To report the Committee's activities and its comments on the incentive calculation to an annual review process before the BC Utilities Commission.

FortisBC shall endeavor to seek consensus to the greatest extent possible on all DSM Advisory Committee recommendations made to the BCUC regarding the annual DSM performance.

Membership

The Committee comprises FortisBC staff, customers and/or customer interest groups, and businesses or associations with a direct interest in DSM in the FortisBC service territory.

The non-FortisBC members shall be comprised of:

- A minimum of four member representing customers and/or customer interest groups from a variety of customer classes, including wholesale, residential, general service and industrial,
- A maximum of two representing businesses or associations,
- Members from all regions of the Company's service area, specifically the South Okanagan-Similkameen, Kelowna, and the West Kootenay-Boundary,
- BC Utilities Commission and Ministry of Energy, Mines, and Petroleum Resources staff who serve *ex officio*

Members of the Committee may nominate candidates for membership from time to time as vacancies occur. New members must be accepted by a majority of members and FortisBC.

Term of Service

A term of service is two years from first appointment, with one renewal term. Members may serve additional terms with the approval of a majority of members and FortisBC.

Meetings

Electronic formats such as video conferencing, telephone conferencing, and email may be employed, in addition to face-to-face meetings. Notes shall be taken at committee meetings and circulated on a timely basis.

Activities

The DSM Advisory Committee will be involved directly in the DSM Incentive Mechanism development, design, or revision.

1. The DSM Advisory Committee will review FortisBC' Semi-Annual DSM reports that are prepared for filing with the BCUC in order to assess the DSM performance and calculate the annual incentive amount earned by the Company.

2. The DSM Advisory Committee will review planned spending and savings targets and estimated incentive amount for the following year, prior to delivering the annual performance report to the BCUC.

Schedule Example

Schedule	Deliverable	Committee Role
Annual	- December 31 Semi-Annual DSM report or projections	Review, comment prior to Annual Review and filing with BCUC
	- Performance Incentive Calculation	Review, comment on performance, acceptances for the Annual Review
	- Committee report to Annual Review	List committee activities, contributions, and accomplishments for the year, and planned activities for the next year; endorse incentive calculation
Third Quarter	Annual plan implementation progress, and program development	Comment, input, participation
	June 30 Semi-Annual DSM report	Review, comment prior to filing with BCUC
As Required	Capital plans, operating plans, program design, scope for studies, draft reports, policy	Review, comment, input, and advise
	DSM Incentive Mechanism	Review, study, revise, and recommend

Other Items

In fulfilling its purpose the DSM Advisory Committee shall take into account the following conditions related to FortisBC demand-side management efforts:

- The DSM portfolio of programs must have a cumulative benefit cost ratio that is greater than one, and individual projects must pass this test before full allocation of overhead costs;
- Benefits are defined as avoided power purchase costs and the value of deferred capital expenditures and,
- Annual budgets and annual targets are determined on a reasonable effort basis.

APPENDIX

DSM Incentive Committee Background

In 1996 the BC Utilities Commission asked for performance reporting from several operating areas of the Company, in conjunction with the settlement agreement for a revenue requirement application. Industry-wide measures and criteria for electric utilities, such as Customer Average Interruption Duration Index (CAIDI), were well established, but the same was not true for the performance measurement of utility demand-side management resources. In order to establish appropriate criteria to measure DSM performance, FortisBC invited interested participants in the Negotiated Settlement Process (NSP) for the Application to form a DSM Incentive Committee.

The Demand-Side Management Incentive Committee was established in 1997/98 and began work with FortisBC to determine the appropriate performance measures and incentive mechanism that could be applied to DSM annual results. In 1999 the Tellus Institute assisted FortisBC and the Committee members to devise the shared savings mechanism (SSM), whereby an incentive is provided to the Company as it meets formula target levels set at the beginning of each year.

The SSM continues to be refined to address issues such as economic downturn in the service area and utility program overspending.[1] The role of the Committee expanded over the years with the members reviewing draft reports; study terms of reference, conclusions, and action plans, prior to filing with the BCUC. These included the *2003 DSM Review*, the *2005 Energy Efficiency Potential Update*, and the *2005 PowerSense Five-Year Business Plan*.

Over the same period, demand-side management performance reporting became a requirement of either a Revenue Requirement Application or an Annual Review under a Negotiated Settlement Process. To recognize the need for the Committee's continued involvement and the permanent performance reporting requirement, in 2006 the BC Utilities Commission approved FortisBC's request that the Incentive Committee be renamed the DSM Advisory Committee.

[1] Economic risk adjustment factors for savings targets were considered, and, to address overspending, annual expenditures were capped at 110% of planned expenditures for incentive calculation purposes

Aquila Networks Canada (British Columbia) Ltd.

2003 Demand Side Management Review

FINAL

January 2004

Prepared by

Willis
ENERGY SERVICES LTD.

EXECUTIVE SUMMARY

The Negotiated Settlement of the 2003 Revenue Requirements Application, approved by the BC Utilities Commission (BCUC), Order G-10-03, asked for a "fresh and comprehensive assessment" of Aquila Networks Canada (British Columbia) Ltd.'s (Aquila) DSM strategy (PowerSense), in response to a request, during the Annual Review, from Aquila's Demand Side Management (DSM) Incentive Committee. This report, *Demand Side Management Review*, assesses the DSM resource acquisition programming of Aquila through a review of selected North American electric utilities' DSM program activities. The review found, in general, that:

- DSM for electric utilities in 2003 appears similar to DSM programming of a decade ago. The programs offer a similar range of delivery approaches and measures focused on improving customers' energy use by increasing energy use efficiency.
- The Total Resource Cost (TRC) continues to be the economic test for program effectiveness that must be met for approved implementation of a utility DSM program.
- The costs of regulated utilities' DSM programs are rate-based and amortized over 8 to 20 years.
- Regulated utilities treat DSM as a resource acquisition initiative. Program results must be measurable and confirm the TRC.
- DSM as a service activity has been adopted over the last decade by several others, including municipalities and environmental, health, and climate change agencies. The imperative to reduce the environmental impact of human settlements is being met by strategies that include DSM and energy use efficiency improvement.

Limited availability of quality program performance, cost and evaluation information prevented the preparation of comprehensive comparisons of savings acquisition and costs across surveyed utilities. However, comparing Aquila's annual expenditures and achieved savings for 2002 for similar programs with those of other utilities (Table 3 *DSM Resource Acquisition Programs*) shows Aquila's results to be exemplary. The great number of variables involved, including, for example, utility selection of algorithms, differing treatment of costs and foreign exchange rates, limited the usefulness of this information in forming conclusions and recommendations in this report.

Review Process

- *Utility DSM Activity and Information Survey* (See Appendices B, C and D)

  Utilities, or jurisdictions, from Canada and the United States currently operating demand side management programs and, if possible, hydro based generating systems, were chosen as survey candidates. Amongst those selected were BC Hydro, Manitoba Hydro, Hydro Quebec, and Ontario Power Generation in Canada and Idaho Power and Portland General Electric (Oregon). The American Council for an Energy-Efficient Economy (ACEEE) and the Energy Information Administration of the Department of Energy web sites provided the primary sources of the DSM spending and savings data, along with utility sales and revenue data.

- *DSM Resource Issues Interviews*

  Several issues arose from the survey results, including:

  - The decoupling of funding and delivery of DSM programs through the prevalence of public benefit funds. That is, utility ratepayers continue to pay the cost of program planning, design, administration and operation through electric system charges, but those functions may be fulfilled outside their utility. The effectiveness of this change in delivery approach is unknown because no process evaluation reports were available.

- Most jurisdictions are in transition at the time of this study, recovering from the 2000/2001 energy pricing crisis, returning to utility planning regulation, and accelerating the deployment of market transformation DSM programs.
- The survey found incongruity and inconsistency in the data reported for DSM planning and program activities among survey candidates. The US Department of Energy's Energy Information Administration (EIA) confirmed that their reports, under scrutiny, also reflected reporting inconsistencies. Data problems due to self-reporting have been cited by the ACEEE in their studies as well.
- The decline of DSM activity since the mid-90s has resulted in limited availability of verifiable third party impact evaluation data for operational DSM programs.

In order to distill the survey results despite data inconsistencies, the Oregon Office of Energy, the Tellus Institute, D. Nichols and Associates, and Pacific Gas and Electric were consulted. Also a brief meeting was held with the Rocky Mountain Institute staff during a Vancouver visit.

- *Aquila DSM Incentive Committee* (See Appendix F)

  The DSM Incentive Committee (committee) members reviewed the draft version of Sections 1 to 5 of this study. Their comments, suggested revisions and additional recommendations are reflected in the final version of the study Sections 1 to 6 and Appendix F.

Report Format

The headings in the Executive Summary and the body of the report refer directly to the Terms of Reference as shown in Appendix A.

Conclusions

1. **DSM Economic Test**

(a) Applicability of California Standard Practice Manual's total resource cost test

The California Standard Practice total resource cost (TRC) economic test continues to be applied to resource acquisition programs by the surveyed utilities and their regulators across North America.

(b) Risk of DSM resource valuation

The role of DSM savings is to displace electricity supply resources or purchases and defer capital spending requirements for the electric system. DSM savings acquisition can be accelerated or slowed to meet changing load growth requirements with least cost measures that help to smooth existing customer load profiles and reduce the electricity needs of new facilities and housing.

2. **Aquila Integrated Resource Acquisition**

For annual resource acquisition planning purposes, the annual gross energy load forecast is reduced by the annual planned DSM savings targets. Utility supply resources and purchases to meet the net energy requirement are included in the revenue requirement for operations in the forecast year. PowerSense works with transmission and distribution to identify critical system constraints and apply appropriate DSM solutions.

3. **Funding Resource Acquisition Programs versus Research Development Support**

DSM resource acquisition programs can provide measurable, enduring and stable results, while enabling customers to respond, within a reasonably short time period, to utility spending for incentives, loans, or financing. DSM spending on investments in energy efficient technology development does not provide the utility or its customers with any measurable benefits within a reasonable timeframe. Surveyed utilities focused on resource acquisition programs, with a growing trend for information and research programs to be planned and administered by non-utility agencies paid for with funds collected from consumers through their electricity bills.

4. **DSM Program Design**

Utilities are offering DSM programs that improve program participants' energy use by increasing use efficiency. The programs are designed to increase the market penetration of commercially available efficient technologies and measures. Market-ready measures allow the utilities to match their DSM spending with DSM resource acquisition, within a short time period, from within their service area. A review of incentive-based programs is included in *Table 1 Utility Program Activities*, from the body of the report and included below. The table summarizes the program activities of surveyed utilities. PowerSense program design is similar to that of the utilities shown.

5. **DSM Measure Selection Criteria**

DSM measures are selected for their effectiveness in reducing energy requirements and for their suitability to meet customer needs for energy services. The task of determining the savings attributes and costs of efficient technologies is being centralized for several classes of energy using devices and equipment. Using the centralized analysis results, called "deemed savings", in DSM planning and programming will reduce the efforts and costs formerly undertaken by utilities to select measures.

Measures for residential and small commercial customers are based on common energy uses and market-ready efficient products. Measure selection for large customers requires the utility to match not only the customer's process requirement with an appropriate energy saving technology or process, but also to match the customer's project schedule for capital spending.

Table 1 Utility Program Activities

CATEGORIZATION	Share	SURVEYED UTILITIES								
		Aquila (BC)	BC Hydro	Manitoba Hydro	Hydro Quebec	Nova Scotia Power	Portland General Electric	Pacific Gas & Electric	Idaho Power	SCE
DSM Programs										
INCENTIVES										
Rebates	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Loans	33%	✓		✓	✓					
Financing Services	67%	✓	✓	✓	✓	✓		✓		
Lease	11%					✓				
Grants	33%		✓				✓		✓	
INFORMATION										
Information	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Advertising	67%	✓	✓	✓	✓		✓	✓		
Training	44%	✓	✓					✓	✓	
Education	56%		✓	✓			✓	✓	✓	
Research	22%				✓			✓		
Pilot projects	56%	✓		✓	✓		✓		✓	
Group Sponsorship	33%			✓				✓		✓
AUDITS	67%	✓	✓	✓	✓			✓	✓	
CODES & STANDARDS	33%	✓	✓					✓		
DSM Program Objectives										
Energy Efficiency	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Conservation	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Load Management	33%					✓	✓		✓	
Demand Response	22%					✓				
Customer Sectors										
Residential	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Commercial/Institutional	89%	✓	✓	✓	✓		✓	✓	✓	✓
Industrial/Agricultural	89%	✓	✓	✓	✓		✓	✓	✓	✓
Market Transactions										
New construction	67%	✓	✓	✓			✓	✓		✓
Replacement	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Retrofit	67%	✓	✓	✓	✓			✓	✓	

SCE – Southern California Edison

6. **DSM Funding Sources and Cost Recovery**

   Surveyed regulated utilities obtain funding for utility DSM programs as part of their regulated revenue requirements and recover costs through customer rates. Electricity consumers are also paying for other non-utility DSM through their electricity rates. State governments and regulators in several jurisdictions have established non-utility agencies, funded by electricity rates, to provide DSM services.

7. **DSM Expenditures**

   DSM spending as a portion of annual gross revenue ranged up to approximately 2 percent for surveyed utilities. See *Table 4 Utility DSM Summary*, from the body of the report, included below. For selected Canadian utilities in 2002, see Chart 1 below, Aquila was second, along with Manitoba Hydro, with DSM spending levels reaching one percent. Aquila, when compared to selected US utilities in 2000, see Chart 2, was second highest at 1.17 percent of gross revenue spent on PowerSense.

Table 4 Utility DSM Summary

Utility	DSM TRC Economic Test	Program Design Type			Program Funding	Cost Recovery	DSM Spending/ Gross Revenue	Year
		Product/Market Incentives	Information & Research	Legislation/ Rulemaking				
BC Hydro	✓	6	12		Revenue Requirement	Electricity/DSM Tariffs	1.9%	2002
Aquila Canada Networks (BC)	✓	7	3		Revenue Requirement	Electricity/DSM Tariffs	1.05%	2002
Manitoba Hydro	✓	11	14		Revenue Requirement/ Partners	Electricity Tariffs	1.0%	2002
Hydro Quebec (DSM Plan)	✓	19	11 (overlap)	✓	Revenue Requirement	Electricity Tariffs	0.2%	2002
Aquila Canada Networks (BC)	✓	7	3		Revenue Requirement	Electricity/DSM Tariffs	1.17%	2000
Pacific Gas & Electric Co	✓	15	25	✓	Revenue Requirement	Public Goods Charge	0.25%	2000
Idaho Power Co	✓	4	1	✓	Revenue Requirement	Electricity/DSM Tariffs	0.24%	2000
Southern California Edison (SCE)	✓	14	11	✓	Revenue Requirement	Public Goods Charge	0.21%	2000
Portland General Electric Co	✓	19	2	✓	Public Benefits Fund	Public Benefits Fund	0.03%	2000

Chart 1 DSM Spending as a Percent of Total Revenue (Canada, 2002)

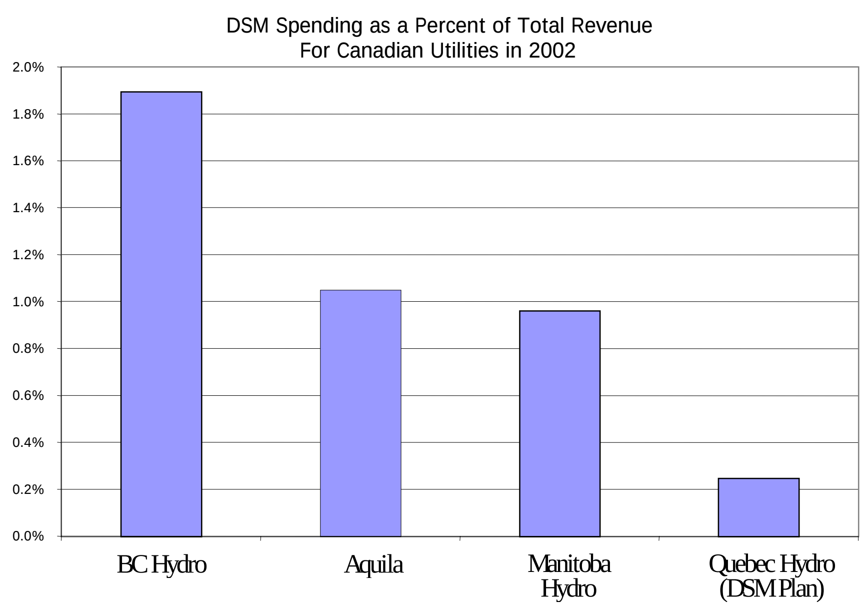
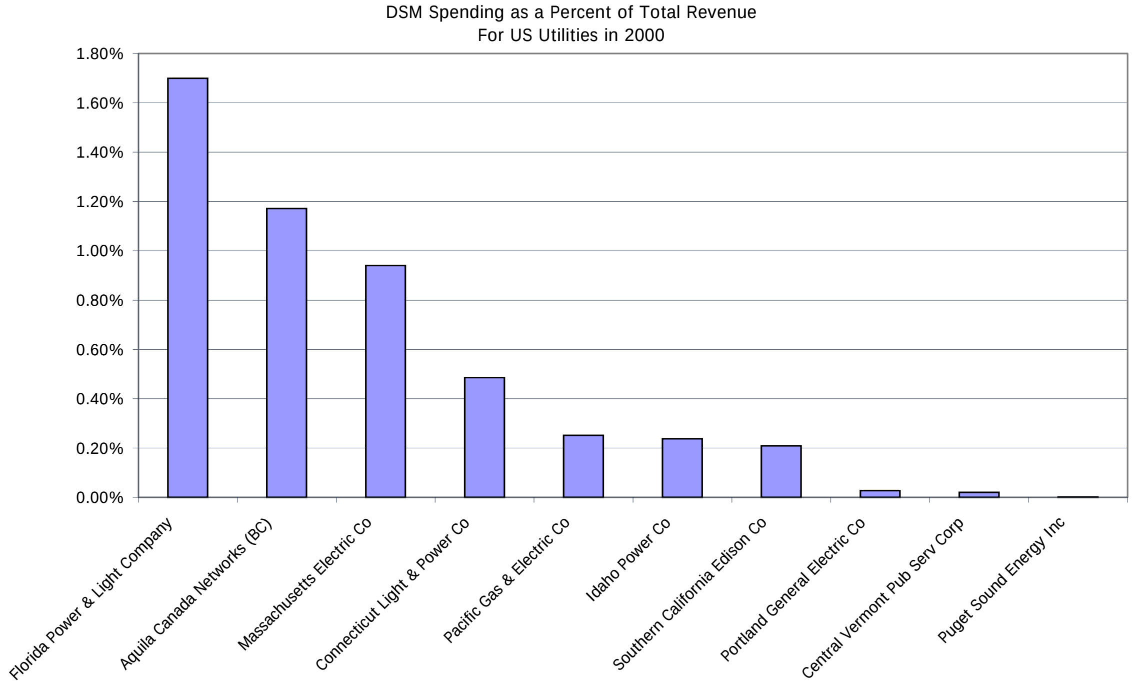


Chart 2 DSM Spending as a Percent of Total Revenue (US, 2000)



8. **PowerSense Comparison**

Aquila's DSM portfolio continues to meet the total resource cost test and the average unit cost of savings is less than Aquila's cost of power purchases under Rate Schedule 3808. Approximately 1 percent of Aquila's revenue is spent to reduce energy purchases, reduce total cost of power supply, and defer capital spending.

In 2002, Aquila's energy savings were appropriately 0.6 percent of total energy sales, while in 2000, energy savings were 0.9 percent of annual sales. For this comparison of energy savings as a percentage of energy sales see Chart 3 for Canadian utilities for 2002 and Chart 4 for US utilities and Aquila (BC) for 2000.

Chart 3 DSM Energy Savings as a Percent of Total Energy Sales (Canada, 2002)

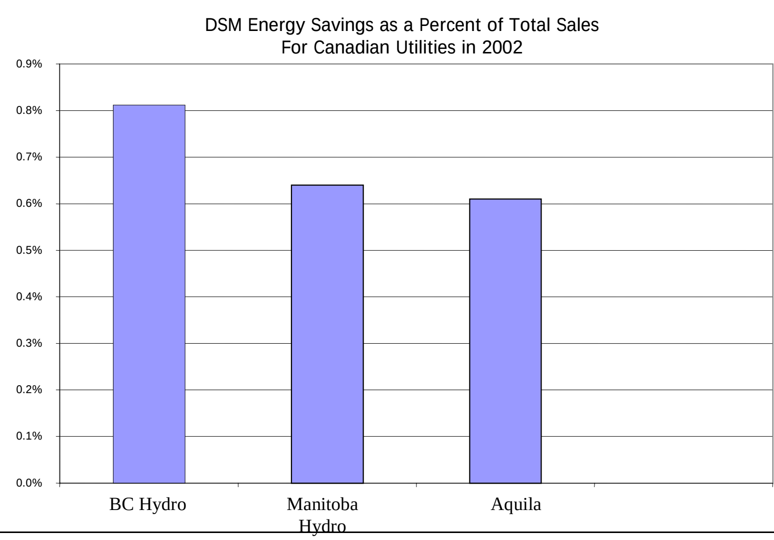
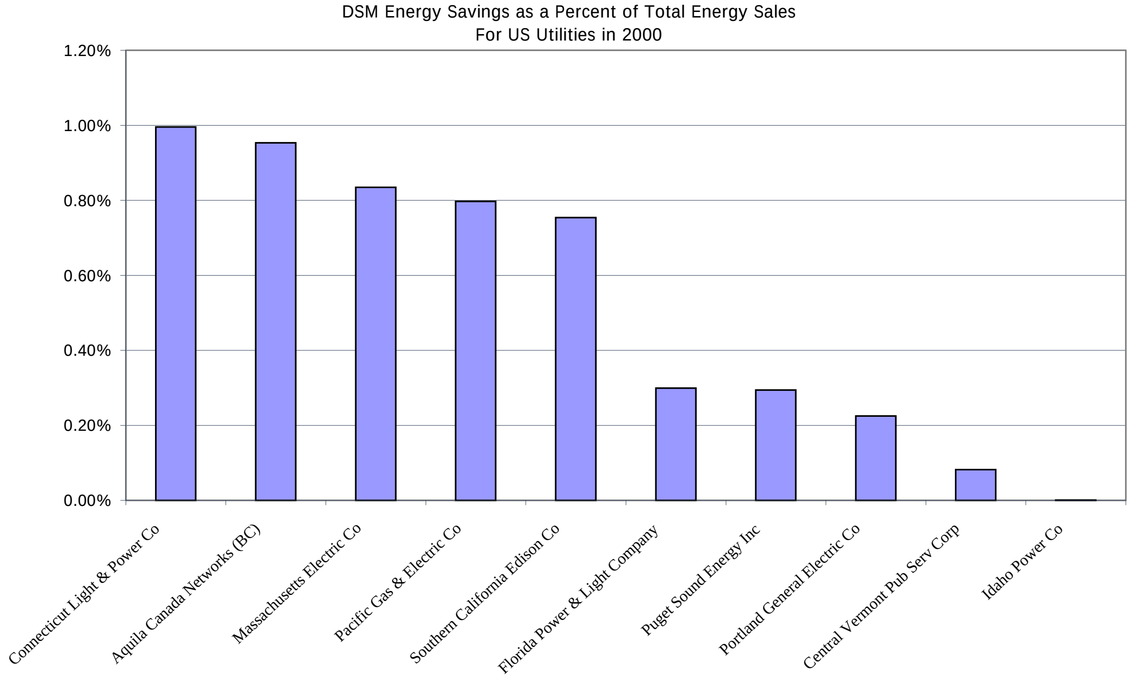


Chart 4 DSM Energy Savings as a Percent of Total Energy Sales (US, 2000)



Recommendations

The Recommendation headings (1 to 10) below refer directly to the Terms of Reference as shown in Appendix A.

The DSM Incentive Committee members recommended that a reiteration of the case for utility DSM investment be included in this report, as follows.

Why DSM?

Restating the question in the section title to read “Why would an electric utility pursue DSM savings as an energy resource to meet customer needs?” provides an opportunity to discuss the basis for utility DSM programming.

- *Efficiency Potential and Market Failure*
  The consumer market has failed to capture potential energy savings through improved energy use efficiency. Energy pricing, market structure, utility rate design, cost accounting, capital authorization, codes and standards, and lack of consumer awareness are examples of barriers that continue to prevent the evolution of mature energy efficiency markets in North America.

  Utility DSM programs accelerate the acceptance of, and increase the market share for energy efficient products and technologies. Programs can be designed to stimulate manufacturers, distributors, and/or retailers to develop, handle and sell products and technologies that are more efficient than what would have been purchased otherwise. The captured retail customer base of electric utilities provides the market scale and scope needed to successfully and economically deliver universal DSM programming. The utility’s non-participating customers share the long-term benefits of DSM.

- *Regulatory History:*
  The April 25, 1989 Decision by the BC Utilities Commission in the matter of an Application by West Kootenay Power Ltd. stating on page 23, Section 4.2.6.5 DSM as Rate Base, states that "The Commission sees no conceptual distinction between resources that generate power and resources that conserve power. Both are assets used to meet load growth." This decision led the way for Aquila's pursuit of DSM savings as a low cost resource to meet customer load growth and reduce the average cost of new energy supply.

- *Least Cost Resource Planning:*
  In determining resource investments necessary to meet load growth, utilities identify and assess resources that can supply energy services at costs lower than the long run incremental cost. Acquisition of these resources drives down the long run costs and minimizes the customer's overall cost of power, assuring the utility's continued competitiveness. The low-cost conservation potential, if achieved, can contribute significantly to dampening load growth, deferring capital expenditures for system improvements, and reducing the average cost of new supply.

- *BC Energy Policy*
  DSM as an energy resource is consistent with the following action items identified in BC's Energy Plan released in November 2003. The Energy Plan, through the described action items, leaves no doubt that BC energy utilities will continue to be responsive for DSM savings program design, implementation and evaluation.

  Policy Action #9
  Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
  The BC Utilities Commission will oversee the new supply acquisition process to ensure that utility resource planning compares the costs of all sources of new supply and that resource plans are consistent with the new clean energy goal of meeting 50 percent of new electricity supply between 2002 and 2012 with BC Clean electricity. The broad definition of BC Clean includes efficiency improvements.

  Policy Action #22
  The Province will update and expand its Energy Efficiency Act and work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
  The Ministry of Energy and Mines is already, at the time of this writing, working with utilities, among others, to expand the legislation to cover additional energy use equipment and to upgrade existing standards. The Province plans to continue to work with utilities and others to identify ways to further strengthen and supplement the updated Energy Efficiency Act.

  Policy Action #23
  The Utilities Commission Act (UCA) will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency
  The Province wishes to encourage further investment in conservation and energy efficiency by utilities. Amending the UCA clearly demonstrates the intent and commitment of the Province to advance the role of efficiency as a resource and accelerate the rate at which BC improves energy use efficiency.

  Policy Action #24
  The government is developing strategies to manage BC's greenhouse gas emissions and air quality in threatened airsheds.

> Pressure is mounting in BC between new least cost electricity generated with abundant fossil fuels and the need for improved environmental management and performance of all fossil fuel production and utilization. Conservation and energy efficiency are means of mitigating actual environmental impact of production and distribution of fossil fuels. They also minimize the impact on air sheds where fossil fuels are consumed.

Utilities pursue DSM programming in order to overcome market failure and capture the economic benefits of conservation and energy efficiency, all directed and supported by government policy and utility regulation. This discussion is the basis for the recommendations presented in this report and should be kept in mind by the reader.

1. **DSM Economic Test**

(a) <u>Endorsement</u> Aquila continue to rely on the Standard Practice Manual policy and the TRC for program planning and selection.

<u>Change</u> Aquila investigate, with the BCUC, the introduction of applying externality cost reductions as credits to the TRC.

(b) <u>Endorsement</u> Aquila continue to plan to acquire DSM savings in order to reduce the overall risk of their energy supply portfolio.

2. **Integrated Resource Acquisition**

<u>Endorsement</u> Aquila continue to adjust annual load forecasts by estimated DSM annual savings to produce the annual energy sales forecast.

<u>Adjustment</u> Aquila DSM meet semi-annually and as required with system planning and operations to identify opportunities that further reduce costs while maintaining system reliability and improving customer service.

3. **Resource Acquisition Programs versus Research Development Support**

<u>Endorsement</u> Aquila continue to focus on resource acquisition DSM programming.

<u>Endorsement</u> PowerSense continue to provide, on request, technical expertise and technology experience to government agencies, as it currently does for Natural Resources Canada on heat pump technology, for the Mines and Energy update to the BC Energy Efficiency Act.

<u>Adjustment</u> Aquila investigate improvement to providing web-based information with appropriate links to other energy use websites and information groups.

4. **DSM Program Design**

<u>Endorsement</u> Aquila continue to plan and design PowerSense programs to acquire resource savings.

<u>Adjustment</u> Aquila develop a pilot project to investigate demand response technologies and their suitability, customer impact, costs and demand savings impact.

<u>Adjustment</u> Aquila investigate leasing options that could be offered by the utility, for technologies such as Ground Source Heat Pump systems.

5. **DSM Measure Selection Criteria**

<u>Endorsement</u> PowerSense continue to select appropriate and cost-effective measures to capture a broad base of customers' DSM opportunities and meet their energy service needs.

6. **DSM Program Survey**

<u>Endorsement</u> Aquila maintain the mix of resource acquisition programs and measures.

Additional areas of programming effort:

Demand Reduction

<u>Adjustment</u> PowerSense investigate innovative peak load reduction.

<u>Adjustment</u> Aquila develop a portfolio of demand reduction savings opportunities to estimate the seasonal peak reduction potential.

Education and Awareness

<u>Adjustment</u> Aquila establish a DSM budget to develop an education program jointly with a steering committee, whose members are representative of Aquila's service area.

Adjustment Aquila provide strategy to build broad-based customer awareness of DSM activities and behaviour that readily lead to savings.

Adjustment Aquila investigate the distribution of energy savings information into educational institutions.

Tariff and Rate Design and Bill Unbundling

Adjustment Aquila adapt a home improvement pilot project and submit proposal to BC Housing Corporation and the BC Utilities Commission, for the purpose of developing a design for a housing efficiency performance DSM tariff.

Adjustment Aquila provide preliminary estimates of costs for "Smart Meter" installations and unbundled billing information on customers' bills.

7. **DSM Funding Sources and Cost Recovery**

   Endorsement Aquila continue to recover its PowerSense costs as part of its revenue requirement in order to reduce the cost of meeting customer load growth.

8. **DSM Expenditures**

   Endorsement Aquila continue their level of DSM expenditures to capture economic energy savings.

9. **PowerSense Comparison**

   Endorsement Aquila continue at its current level of DSM expenditure subject to recommendations for new program development and the portfolio requirements of the 2004 Resource Plan.

10. **Follow Up to DSM Review by DSM Incentive Committee**

    Aquila to work with the DSM Incentive Committee in a "brainstorming" session. The purpose of this session would be to identify measures, processes and actions necessary to bring forward DSM as a more effective and acceptable resource for BC utilities. The DSM Incentive Committee and Aquila will jointly determine the follow up required to the session.

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1. INTRODUCTION

Since 1989, Aquila Networks Canada (BC) (Aquila) has been offering demand side management (DSM) services to its customers through its PowerSense initiative. Aquila is an integrated electric utility serving, directly and through its wholesale customers, over 120,000 residences and businesses in the Okanagan and West Kootenay regions of BC.

In 1996, under the regulation of the BC Utilities Commission's Performance Base Ratemaking mechanism, a committee of Aquila stakeholders was established to provide advice and comments to Aquila on DSM programs, targets and the semi-annual DSM operating results. During the 2002 Annual Review committee members queried the continued approach and design of PowerSense programs and the DSM resource acquisition role in Aquila's electricity planning. The DSM process approach comprises an assessment of the customer market, investigation of efficient energy use technologies program planning, delivery, and evaluation. The approach has continued since inception of the PowerSense initiative. The Negotiated Settlement of the 2003 Revenue Requirements Application, approved by the BC Utilities Commission (BCUC), Order G-10-03, asked for a "fresh and comprehensive assessment" of Aquila's DSM strategy.

Under the Terms of Reference, the general purpose of the assessment is to recommend endorsement, adjustment, or change to the resource acquisition strategy as it pertains to program design and delivery within the PowerSense initiative.

This report is structured by using each Term of Reference (Appendix A) to form a heading and subject area below. The study methodology can be found in Appendix B. The utility survey results, and data collection tables can be found in Appendix C. Appendix D contains program listings from the utilities surveyed, statewide programs for Oregon and California, and the American Council for an Energy-Efficient Economy (ACEEE) *"America's Best: Profiles of America's Leading Energy Efficiency Programs"*, March 2003, ACEEE Report Number U032.

2. DSM Economic Test

2.1 Total Resource Cost Test

Review the applicability of the California Standard Practice Manual "Economic Analysis of Demand-Side Management Programs", December 1987, to measure the effectiveness of PowerSense programs. (Terms of Reference)

Findings

- In 1983, the California Public Utilities Commission and the California Energy Commission (CEC) prepared the cost-benefit methodology used by energy utilities across North America to evaluate the cost-effectiveness of utility demand side management programs, the Standard Practice Manual – Economic Analysis of Demand-Side Management Programs (SPM). An updated SPM was reissued in 1986/87.
- The California Public Utilities Commission approved Resolution E-3592 in 1998 that included a public purpose test (PPT) to be used to determine the cost-effectiveness of DSM programs funded by the Public Goods Charge (PGC). Workshops and consultants had earlier identified particular shortcomings of the SPM total resource cost test (TRC). The SPM was

updated and reissued in October 2001. The updated version incorporates the effects of the restructuring of the electric and natural gas industries.

- In particular the manual needed to reflect the establishment of public goods charges on the electric side in 1996 and a natural gas surcharge in 2000, along with an electric distribution charge in 2001 to provide revenue for self-generation programs. The public goods charges and the natural gas surcharge provided for minimum funding for cost-effective DSM programs. The TRC has been modified to account for environmental benefits as part of the Societal Test.
- Self-generation is defined as a demand side activity and is distributed generation installed on the customer's side of the electric utility meter and serves all or a portion of the customer's electric load, that otherwise would have been provided by the central electric grid.

Conclusions

- Our research and interviews have found that, regardless of the reasons for pursuing DSM savings through utility programming, contacted utility and agency participants continue to choose the California Standard Practice Manual (SPM) to determine the economic effectiveness of their resource acquisition programs. The TRC formula is viewed as being based on sound economic principles and accepted common analytical practice.
- As a measure of acceptance and usage, the US Department of Energy's Energy Information Administration (EIA) reports the data components necessary to compute each of the tests in its *EIA-861 Annual Electricity Report*. Collection over the years of these data has created a reliable analytical source for monitoring, evaluating, and planning DSM programs.
- While it was found that determination of the cost-effectiveness and the economic value of a proposed program continues to rely on the total resource cost test (TRC) for ranking purposes, it was not possible to find regular reporting of the TRC for implemented programs. TRC is widely used in the program planning stage but does not appear to be tracked once a program is implemented.
- The California Standard Practice Manual (SPM) continues to be a common reference for assessment of the economics of DSM measures and programs. It is updated as required to respond to changes in markets and resources and serves as a methodological, as well as a formula reference.

Recommendation

Endorsement Aquila continue to rely on the Standard Practice Manual policy and the TRC for program planning and selection.
Rationale Utility and customer costs and benefits for the life of the program savings are the measure of the economic impact of DSM programs. The TRC provides this measurement. Its widespread use and the regular scrutiny received from regulators also contribute to the basis of this recommendation.
Change Aquila investigate, with the BCUC, the introduction of applying externality cost reductions as credits to the TRC.
Rationale DSM measures, while delivering end use energy and demand savings and reduced generation fuel consumption, also provide non-energy benefits, such as reduced emissions, local employment, business development, lower health care costs and economic equity for low income households. To implement provincial energy policy through more aggressive efficiency resource acquisition, DSM programming could receive credit for environmental and social benefits that could be assessed by modification to the current economic test. The government may direct the establishment of the values for these credits for their incorporation in the BCUC Resource Planning Guidelines.

2.2 Resource Risk Assessment

Provide an assessment of risk as it pertains to DSM program measures, expenditures, and savings for determining the value and benefits of DSM as a resource. (Terms of Reference)

Findings

- There are three general categories of risk associated with development projects. The first can be described as the technology risk. Will the project do, or deliver, what is expected? It refers to the uncertainty of the performance and reliability of the new facility, industrial plant, or, in the case of DSM, energy efficiency measure. The second is the construction risk defined as whether the new facility or DSM program can be built to do what is required, on time and on budget. And the third risk is the demand risk. Will there be a market for the output?
- While supply-side and demand-side investments face all of these risks, demand-side investments are smaller and more diverse, helping to mitigate the technology risk. With several types of programs being offered to different market segments, DSM also reduces the "construction" risk. The demand risk for DSM is markedly reduced from supply projects. The array of measures, discrete customer segments, and choice of delivery mechanisms help to create a portfolio of programs that mitigates demand risk by creating flexibility in the timing and size of resource additions.
- For those programs that yield unexpected results or for technologies that perform poorly, DSM resource acquisition strategy has built-in cycles for monitoring and evaluation, allowing for incremental improvement and economic changes.
- As the market shifts, as energy efficiency and performance standards are raised, as new technologies become available, DSM programs can be economically recreated continually to assist customers manage their energy use and costs.
- There are several contributing factors to the value of energy resources to a utility. Increased uncertainty for any of those factors increases investment risk. According to studies by the National Association of Regulatory Utility Commissioners (NARUC) and by others such as the US Department of Energy Oak Ridge National Laboratory, supply side resources present uncertainties, as do DSM resources. Utilities' long-term forecasts for energy and demand often are plus or minus 50 percent of actual consumer energy and system peak estimate has been off by almost the same. Growth forecasts, upon which investments in large-scale centralized plants were decided, have even greater uncertainties surrounding them.
- Supply side uncertainties include fuel price, plant availability, capital and operating costs of plants, energy and demand forecasts, regulatory requirements, public opposition, and duration of construction and development periods. The demand side shares the forecast risk, though not to the same degree. DSM can be dispatched in smaller increments, better matching changes in the rate of actual load growth. DSM planning incorporates customer energy use information including equipment stock and end use consumption. Customer energy use knowledge helps to reduce planning uncertainty.

Conclusions

- Forecasting demand represents risk for both the demand side and supply side investments. DSM is more flexible in shaping and matching incremental demand growth. The risk and cost are less should the growth not appear as forecast and, depending on the installed measures, the savings are in place to be realized when load growth returns.[1]

[1] Reference 17

- If electric industry restructuring occurs, it is likely that local distribution utilities remain regulated and, in general, do not own generation assets. This situation is presenting a new set of risks for utilities. Utility DSM, as an assured rate base investment, is a means of mitigating the risk of acquiring new supply resources and meeting customer load growth.

Recommendation

Endorsement Aquila continue to plan to acquire DSM savings in order to reduce the overall risk of their energy supply portfolio.
Rationale DSM is available in various sizes, profiles and locations throughout a utility's service area. DSM is the utility's lowest cost resource to meet load growth and it reduces the average cost of energy in the resource portfolio. With flexibility in size, and the ability to target specific end uses or locations at a low unit cost, DSM can reduce business and financial risk that is associated with supply side construction options or long term power purchase arrangements.

3. Integrated Resource Acquisition

Describe the role of DSM savings estimates and targets in Aquila's resource acquisition planning. (Terms of Reference)

Findings

- Forecast annual DSM savings are subtracted from the system wide energy forecast before the final sales forecast is calculated. The system peak forecast is adjusted by the peak reduction calculated from the forecast DSM demand reduction.
- Improving DSM planning and programming requires electric system planning information, along with the regional load forecast.
- The identification of system requirements provides input utility criteria for program selection, including targeting energy or demand savings, program location and timing, and customer class.

Conclusions

Aquila's Integrated Resource Plan was accepted by the BCUC in 1995. Aquila is preparing to file a resource plan in 2004. The current approach, applying forecast DSM savings to reduce the load forecast, is common practice amongst utilities. The resulting load/resource balance for the planning period determines the amount and timing of new resource acquisition. Additional DSM savings, from the acceleration and/or expansion of existing programs and/or the introduction of new programs, are assessed along with new supply resources to develop the portfolio of eligible resources for consideration in the planning process. The successful resource portfolio will include those DSM measures that can cost-effectively provide sufficient resources and meet the long-term needs of the utility system and customers.

Recommendations

Endorsement Aquila continue to adjust annual load forecasts by estimated DSM annual savings to produce the annual energy sales forecast.
Rationale The load forecast, as developed, represents the amount of energy that Aquila's customers will need annually. Reducing the gross load forecast by the estimated acquired DSM savings leaves the amount of energy Aquila must supply to meet customers' needs.
Adjustment Aquila DSM should meet semi-annually and as required with system planning and operations to identify opportunities that further reduce costs while maintaining system reliability and improving customer service.

Rationale Awareness of energy savings and peak reduction opportunities begins at the utility operation level. Regular exchange of intra-utility operating and program delivery information, along with current customer information, will identify more a timely and practical set of DSM options.

4. Resource Acquisition versus Technology Development Support

Develop recommendations concerning the extent to which DSM initiatives provide incentives for commercialized energy efficiency measures versus provide assistance, as a catalyst, to the development of new technologies and their implementation as energy efficiency measures. Commercialized energy efficiency measures are those products, equipment and services that are available and widely distributed at the retail level. The catalyst role would include making investments in technology and/or product development before they were market proven. (Terms of Reference)

Findings

- For over 20 years, DSM programs have been developed for the purposes of utility resource acquisition, economic development, environmental mitigation, and customer energy bill reduction. In response to restructuring of the electric industry since 1995 utilities chose to reduce their discretionary spending and DSM budgets were cut. Some states established statewide mechanisms such as public benefit funds, resource portfolio standards for new electricity generation projects, and regulated integrated resource planning.
- Programs designed to change the operation of a market, rather than to acquire energy savings, and to create outcomes that continue beyond the lifetime of the programs are termed market transformation programs.
- Statewide DSM agencies are developing market transformation programs.
- California and Oregon are in transition at this time and, indeed, have designated Transition Programs.
- In Oregon the programs the utilities offered, and paid for, before 2002 continue to be offered but are now funded by the Energy Trust (funded by the Pubic Benefit Funds, PBF) until such time as the Energy Trust develops its own programs to replace the utility programs.
- In California, the transition to statewide programs has meant that, for each program, management is done statewide by a single utility. As a result, investor-owned utilities continue to deliver many programs but manage only a few.
- Investment in technology development and DSM measure development is occurring with public benefit funds (Oregon) and with utility funds (Idaho) directed to the same regional utilities sponsored consortium, the Northwest Energy Efficiency Alliance.
- *Table 1 Utility Program Activities* summarizes the types of DSM program activities by the surveyed utilities. The eight surveyed utilities, plus Aquila, offer energy efficiency and conservation programs to their customers providing rebates to DSM program participants and energy use information to all customers. DSM programs for residential customers are operated by all of these utilities.

Conclusions

- Support or investment in DSM emerging technologies, as part of the regulated operation, is limited amongst the surveyed utilities. This is to be expected for two reasons. First, based on the utility's end-use analysis there are significant tangible savings to be acquired with existing DSM measures and technologies and second, there is no reliable measurement by which to attribute savings and benefits from utility investments in emerging technologies.

- The technologies being supported are the ones that the utility has defined direct benefits for the electric system, such as direct load technologies.
- Aquila is a valuable contributor to government and agencies planning and research. PowerSense staff regularly work with Natural Resources Canada on emerging technologies and, as staff of a long-running and successful DSM program, are regularly consulted by other utilities, energy efficiency practitioners and professionals, and government agencies.
- Information programs associated with technology development and long-term market transformation require resources and capabilities that Aquila does not have. The existing budget process directs one hundred percent of the PowerSense staff' workload. Additional workload would increase costs beyond what Aquila can justify under its economic test.

Recommendations

Endorsement Aquila continue to focus on resource acquisition DSM programming.
Rationale Aquila does not have the critical resource mass and size to transform the market. Resource acquisition is measurable and provides the tangible economic results for Aquila to meet its economic test.
Endorsement PowerSense continue to provide, on request, technical expertise and technology experience to government agencies, as it currently does for Natural Resources Canada on heat pump technology, and for the BC Ministry of Energy and Mines update to the BC Energy Efficiency Act.
Rationale Aquila has successfully operated PowerSense for over a decade and core staff have been with the program through its entirety. Experience has built expert capacity to address the technical and process issues arising from technology selection, program planning, and delivery. On an incremental basis, staff is able to provide expertise to others in those areas where PowerSense is operating, providing synergistic benefits to Aquila also.
Adjustment Aquila investigate improvement to providing web-based information with appropriate links to other energy use websites and information groups.
Rationale Additional and detailed DSM information, updated regularly, would increase the value of the Aquila website. In particular, the information will increasingly reach a growing audience as young adults and children grow into utility customers.

5. UTILITIES DSM PROGRAM OVERVIEW

Prepare an overview of DSM activities among energy utilities in North America. (Terms of Reference)

5.1 Program Design Type

Program design type: whether the design is based on product sales and market penetration, information, or policy and/or compliance with legislation or rulemaking (Terms of Reference)

DSM programs can be categorized by their objective, type, customer sector, and market transactions. See *Table 1 Utility Program Activities* for a list of DSM program categories and see Glossary for definitions. Product sales and market penetration are features of incentive programs. Gaining market share for efficient equipment and technologies increases the utility measurable savings. Information programs increase efficiency awareness and influence people's behaviour towards energy use. Research into emerging technologies and sponsorship of pilot projects further the objectives of information programs. For these programs there are no measurable savings that can be directly attributed to utility spending. Policy or rule directed DSM relies on the same design types as resource acquisition or information programs.

A description of the types of demand side management programs, or projects, is included in the Glossary. Summarized, according to the SPM, the resource acquisition program types are conservation, load management, fuel substitution, and self-generation. Conservation includes energy efficiency improvements.

Findings

- The fundamentals of resource acquisition DSM program design remain constant. The programs improve energy use efficiency for participating utility customers. Depending on the selected program measures, utilities and non-participating customers also benefit.
- According to Table 1, summarizing program offerings of surveyed utilities, PowerSense programs feature in most categories.
- In those areas with long-lived utility DSM programming, such as Oregon, the public benefit funds for energy conservation and efficiency will eventually focus entirely on market transformation programming. The utilities will continue to provide those resource acquisition programs that provide benefits to the electric system assets and to the utilities long-term customers.
- The treatment of public benefit funds within the scope of this study is focused on the characteristics of the program offerings as noted in *Table 1 Utility Program Activities.*

Table 1 Utility Program Activities

CATEGORIZATION	Share	SURVEYED UTILITIES								
		Aquila (BC)	BC Hydro	Manitoba Hydro	Hydro Quebec	Nova Scotia Power	Portland General Electric	Pacific Gas & Electric	Idaho Power	SCE
DSM Programs										
INCENTIVES										
Rebates	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Loans	33%	✓		✓	✓					
Financing Services	67%	✓	✓	✓	✓	✓		✓		
Lease	11%					✓				
Grants	33%		✓				✓		✓	
INFORMATION										
Information	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Advertising	67%	✓	✓	✓	✓		✓	✓		
Training	44%	✓	✓					✓	✓	
Education	56%		✓	✓			✓	✓	✓	
Research	22%				✓			✓		
Pilot projects	56%	✓		✓	✓		✓		✓	
Group Sponsorship	33%			✓				✓		✓
AUDITS	67%	✓	✓	✓	✓			✓	✓	
CODES & STANDARDS	33%	✓	✓					✓		
DSM Program Objectives										
Energy Efficiency	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Conservation	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Load Management	33%					✓	✓		✓	
Demand Response	22%					✓				
Customer Sectors										
Residential	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Commercial/Institutional	89%	✓	✓	✓	✓		✓	✓	✓	✓
Industrial/Agricultural	89%	✓	✓	✓	✓		✓	✓	✓	✓
Market Transactions										
New construction	67%	✓	✓	✓			✓	✓		✓
Replacement	100%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Retrofit	67%	✓	✓	✓	✓			✓	✓	

SCE – Southern California Edison

Conclusions

- Investor-owned utilities rely on incentive-based DSM programs with measurable savings allowing the costs to be included in rate base and fully recovered through revenue requirement.
- Policy and regulatory rulings in several jurisdictions are instituting agencies to provide program planning and administration, while offering information and education programs and providing funds for research and renewable energy projects. (Oregon, Vermont)
- Investor-owned utilities located in restructured jurisdictions are directed to participate as deliverers of the programs, and, in some cases, also as administrators. (California)
- "Deemed Savings" are savings amounts based on pre-determined engineering and statistical analysis of the measured impact on energy use. The data is being developed as a verifiable and reliable energy use information oriented towards product and region specific end use data. The coincidental development of data and protocol to determine "deemed savings" by California and the Bonneville Power Administration highlights the need for and value of this type of verifiable and reliable energy use information. Examples of "deemed savings" are the

predetermined allowable savings related to the installation of compact fluorescent lightbulbs, room air conditioners, and household appliances such as refrigerators.

- The centralization for the development, storage, management, access, distribution, maintenance and publication of DSM information is demonstrated by the Energy Star® program in the US, and now in Canada. It obtains appliance and equipment information from manufacturers and provides it to energy users, along with efficiency information.
- The results of restructuring are driving the need for quality demand side energy information by utilities, trade allies and consumers for planning and purchasing decisions. The need for rapid deployment of DSM measures to counter consumer energy price volatility is bringing government focus to the information needs of energy users.
- The demand for coordinated and packaged information and education programs remains strong. Working with other local utilities and agencies to centralize environmental and energy use resources for communities and schools can create synergies and produce greater results than each entity working on their own.

Recommendations

Endorsement Aquila continue to plan and design PowerSense programs to acquire resource savings.
Rationale The most efficient DSM programs for planning and delivery are resource acquisition programs. They comply with regulation and provide benefits to customers and utilities. It is prudent management to acquire identified potential resource savings with assured technologies and to maximize the amount of savings resulting from utility DSM expenditures.
Adjustment Aquila develop a pilot project to investigate demand response technologies and their suitability, customer impact, costs and demand savings impact.
Rationale As Aquila face constraints on system capacity, it would be prudent to direct DSM budgets towards capacity savings measures and programs. Pilot projects provide the technical information and technology evaluation needed as input to full program design.
Adjustment Aquila investigate leasing options that could be offered by the utility, for technologies such as Ground Source Heat Pump systems.
Rationale Aquila, by offering leasing arrangements, can further reduce administrative and marketing efforts by targeting the needs of individual developers, project owners and customers. Leasing options may be possibly viewed by developers as “low risk” to them and may provide a “transparent” approach for new owners to pay for alternative systems. Leasing arrangements offer Aquila the opportunity to monitor system or product performance and track operating cost impact on existing rates.

5.2 DSM Measure Selection Criteria

DSM measures are the actions and installations that modify the amount of energy consumed by an energy end use or by a consumer. *Table 2 Common DSM Measures* lists typical measures by energy end use.

Findings

- Since the early 90’s most jurisdictions have established, updated, or adopted legislative rules and bylaws stating minimum operating energy efficiency requirements for equipment, appliances and building performance.
- Measures for residential and small commercial customers are based on common energy uses and market ready efficient products. Measure selection for large customers requires the utility to match not only the customer’s process requirement with an appropriate energy

saving technology or process, but also matching the customer's project schedule for capital spending.

- Selection of cost-effective measures for a program is based on the current level of end-use technology at customer homes, offices and plants. Utility DSM planning staff match their customer end use characteristics with identified conservation and efficiency products and equipment.
- Cost-effective measures are selected also to fulfill the utility's requirements for universality (lighting programs), ease of program delivery, maximizing customer participation for customer equity purposes, staffing levels (retailer delivered appliance programs), or budget constraints.
- Utilities rely on resource potential studies to identify and prioritize end use opportunities for savings and to provide technology suggestions, with costs and savings estimates, to reduce the average energy end use.
- A significant change for utility DSM planning was the creation of central agencies, such as Energy Star, that work with manufacturers to educate and encourage economic efficiency improvements in products in advance of legislative updates. The utilities research job has been drastically streamlined.
- Several jurisdictions are incorporating emission reductions into the analysis and valuation of measures, to be considered as selection criteria or a weight to the measure's attributes.

Conclusions

- If a market is available and cost-effective savings can be provided through a selected DSM measure, then a utility that includes DSM in its resource portfolio should plan, design and implement a DSM program to capture the savings and benefits.
- Research and development of DSM products for end use efficiency improvements can be left with governments, their agencies and the manufacturing associations. Manufacturers will produce and sell consumer items that return a profit. If the economics are not present for manufacturers to take the risk in product development, governments can set standards and codes that will require efficiency improvements and other agencies, such as school boards, can set curricula to increase consumer awareness.
- "Deemed savings" are reliable and regularly updated savings and cost information for DSM products. Such comprehensive centralized product and savings data will further reduce utility DSM program development and evaluation costs. The availability and application of this data and information will increase the productivity of DSM planning and monitoring by increasing the products and technologies that are under regular scrutiny by utility DSM staff.

Recommendations

Endorsed PowerSense continue to select appropriate and cost-effective measures to capture a broad base of customers' DSM opportunities and meet their energy service needs.
Rationale Individual measures must contribute to the DSM portfolio's ability to meet Aquila's necessary resource characteristics, such as universality of program offerings to all sectors and rate classes of customers.

Table 2 Common DSM Measures

LIGHTING EFFICIENCY IMPROVEMENTS	MOTOR CONTROLS
Energy-efficient flurorescent lamps	Multi-speed controls
Compact fluorescent lamps	Variable speed drives
Electronic/hybrid ballasts	Timeclocks and energy management
Delamping / Delamping with reflector retrofits	control systems (EMCS or EMS)
High-efficiency fixture replacements	
LIGHTING CONTROLS	LOAD MANAGEMENT
Timeclocks	Thermal energy storage
Lighting energy management control systems	Direct load control
Occupancy sensors	Load limiting and cycling devices
Daylighting controls	EMCS or EMS
ENVELOPE IMPROVEMENTS	HIGH EFFICIENCY HVAC EQUIPMENT
Insulation	Energy-efficient packaged AC and heat
Weatherization	pumps
High-efficiency glazing	High-efficiency chillers
Sunshades and solar controls	
WATER HEATING MEASURES	REFRIGERATION EFFICIENCY IMPROVEMENTS
Energy-efficient water heaters	Refrigerated case improvements
Water heater wraps	
HVAC CONTROLS	
Reset controls	
Economizers	

5.3 Program Survey Summary

Program information including measure description, program objectives, delivery features and energy management impact. (Terms of Reference)

Findings

- See *Table 3 DSM Resource Acquisition Programs* below, listing information from a sample of utility resource acquisition programs for residential and commercial electricity consumers. The measures are typical. The delivery features of the program reflect regulatory, energy pricing and other regional factors.

Table 3 DSM Resource Acquisition Programs

RESIDENTIAL SECTOR

Utility	Program	Components	Participation/ Activity	Budget (USD)	Reported Savings		Costs per Reported Savings (USD)		Avoided Cost (USD)		Levelized Cost of Savings (USD)
				$000	MWh	MW	$/kWh	$/kW	$/kWh		$/kWh
Program Objective: Energy Efficiency/Conservation										RESIDENTIAL SECTOR	
Pacific Gas & Electric (PG&E)	Financial Incentives	Rebates for central cooling & heating contractors & high efficiency central air conditioners & heat pumps	7,800 Rebates	4,970	3,502	5.9	1.44	849.2	0.13		0.14
PG&E	Lighting	Manufacturers & customer incentive, education & outreach, & promotion for Energy Star lighting	35100 EE torchieres	1,630	7,129	2.1	0.241	805.6	0.13		0.02
Aquila	Lighting	Retailer coupons		27	763	0.2	0.035	21.51	0.024		0.01
PG&E	New Construction	Market Leader Incentives - improvement on building standards	7,100 Comfort Home and/or Energy Star units	5,397	7,232	4.8	0.884	1,328.5	0.13		0.07
Aquila	New Home Program			47	483	0.1	0.097	21.51	0.024		0.02
Southern California Edison	Single and Multi Family Contractor Program	Whole system approach.	Delivered by approved contractors	4,717	17,220	1.4	0.27	3,546	0.14		0.03
San Diego Gas & Electric	Downstream Appliance Incentive	Customer rebates to promote Energy Star and DOE compliant appliances	> 80 participating retail outlets	1,488.6	1,294	0.1	1.15	13,533	0.16		0.11
Program Objective: Load Management											
Portland General	Load Control Pilot - Heating (Proposed)	Test customer voluntary acceptance of system control (with customer override)	100 participants	200	-	0.9	-	-	NA		
Hydro Quebec	Low Income Housing Retrofits	Partner with Community Programs, Energy Efficiency Agency	To be launched	NA	NA	NA	NA	NA	NA		
Manitoba Hydro	Power Smart Residential Loan	Weatherization Loan	$5,000 per residence.	NA	NA	NA	NA	NA	NA		

Exchange Rate: 2002 - $1.38

Table 3 DSM Resource Acquisition Programs (con't)

COMMERCIAL/INDUSTRIAL SECTOR

COMMERCIAL / INDUSTRIAL SECTOR

Utility	Program	Components	Participation/ Activity	Budget (USD)	Reported Savings		Costs per Reported Savings (USD)		Avoided Cost (USD)	Levelized Cost of Savings (USD)
				$000	MWh	MW	$/kWh	$/kW	$/kWh	$/kWh
Program Objective: Energy Efficiency										
PG&E	Small Commercial Retrofits, Financial Incentives	Replace inefficient equipment: monthly peak demands <500 kW	7800 rebates	20,700	47,158	8.70	0.15	801.80	0.17	0.04
PG&E	HVAC Turnover	Incentive for distributors of package air conditioners	52 participating distributors	2,000	7,129	4.70	0.38	579.30	0.17	0.03
PG&E	Motor Turnover	Incentives to equipment distributors	1,600 motors	1,000	1,287	0.20	0.26	1,670	0.17	0.07
Aquila	Pumps and Fans			28	442	0.10	0.06	43	0.024	0.01
PG&E	Commercial Remodeling & Renovation	Financial incentives provided by Savings by Design	73 projects in 2001	2,000	144,239	26.900	0.11	580.10	0.17	0.00
Aquila	New Building and Process Improvement			157	6,462	0.680	0.02	21.51	0.022	0.01
Southern California Edison	Small Commercial Standard Performance Contracts	Performance based program that offers incentives (posted price) to customers or Energy Efficiency Service Providers (EESPs)	Installation of energy efficient equipment	1,943	7,770	1.50	0.25	1,262	0.17	0.02
Southern California Edison	Third Party Initiatives	Several projects targeted at the commercial sector (vending machines retrofits, duct testing)	Contractors & trade allies	2,721	-	-	NA	NA	0.18	
California Energy Commission	Energy Efficiency Financing	Public Agency 3% loans and grants	Reduction of peak period demand	2,100	18,000	5.30	NA	NA	NA	
Program Objective: Load Management										
California Energy Commission	Innovative Peak Load Reduction	Third parties bid for incentives	Focus on innovative measures	2,119	NA	9.40	NA	225	NA	
Los Angeles Dept. of Waste and Power	Cool Roofs	Non-residential and multi-family residential property owners	$0.15/sqft for cool rooftops ducts	238	36	0.4	6.64	564	NA	
PG&E	Industrial Agricultural Financial Incentives	Energy Efficiency pilot program	New refrigerated warehouses	180	NA	NA	NA	NA	0.14	

Exchange Rate: 2002 - $1.38

Conclusions

- Aquila offers programs similar to the samples shown, delivering approximately the same energy savings measures to each of the customer sectors.
- PowerSense programs, Residential Lighting, New Home Program, Commercial/Industrial Fans and Pumps and New Building and Process Improvement, on comparison in Table 3 above, are extremely cost effective on a unit cost basis for the 2002 annual spending and savings, shown in US dollars.
- PowerSense resource acquisition programs match the energy uses of Aquila's customers in much the same proportion as energy is consumed. As an example, space heating accounts for thirty three percent of Aquila's residential load and provides a significant opportunity for savings using heat pump or geoexchange technology. PowerSense budget for heat pumps is fifty two percent of the PowerSense residential annual budget and the forecast savings are fifty four percent of the forecast residential savings.

Recommendations

Endorsement Aquila maintain the mix of resource acquisition programs and measures. Additional areas of programming effort:

1. Demand Reduction
   Adjustment PowerSense investigate innovative peak load reduction.
   Adjustment Aquila develop a portfolio of demand reduction savings opportunities to estimate the seasonal peak reduction potential.
   Rationale In order to meet Aquila's increasing need for new capacity, DSM planning and program delivery should expand its focus from energy savings programs.

2. Education and Awareness
   Adjustment Aquila establish a DSM budget to develop an education program jointly with a steering committee, whose members are representative of Aquila's service area.
   Adjustment Aquila provide strategy to build broad-based customer awareness of DSM activities and behaviour that readily lead to savings.
   Adjustment Aquila investigate the distribution of energy savings information into educational institutions.
   Rationale Customers and students need to become aware of the impact and cost of their energy use before they need energy use efficiency information or can change their behaviour. Once aware, customers need information about energy efficient products and equipment.

3. Tariff and Rate Design and Bill Unbundling
   Adjustment Aquila adapt a home improvement pilot project and submit proposal to BC Housing Corporation and the BC Utilities Commission, for the purpose of developing a design for a housing efficiency performance DSM tariff.
   Rationale Savings potential remains in those households less able to take advantage of earlier DSM programs. The benefits of implemented savings are magnified from a societal perspective since energy bill reduction provides cash for other household essentials and health and comfort benefits can increase dramatically for residents. A concerted effort by not only the utility, but also other agencies that would benefit from reduced household energy bills, such as BC Housing, is required. An approved tariff for housing efficiency performance DSM would reduce program administration costs, set published targets for acceptable housing efficiency performance, build awareness for the program with eligible

customers and contractors, and accelerate the capture rate of efficiency savings and the social and health benefits associated with improved housing.
Adjustment Aquila provide preliminary estimates of costs for "Smart Meter" installations and unbundled billing information on customers' bills.
Rationale Bill unbundling can be accomplished through the utility billing information system without necessarily unbundling the rate design or tariff. Clear and direct prices, shown as line items on customer utility bills, can build customer awareness and inform their decisions to take action to reduce their costs. They can choose to participate in DSM programs or act on their own to lower their energy consumption or their billing demand and reduce their energy bill.

5.4 Funding and Cost Recovery

Sources of program funding and/or cost recovery and funding criteria, including rate design and tariff schedules. (Terms of Reference)

Findings

- Utility annual DSM expenditures are amortized over 8 to 20 years.
- Programs are designed and budgeted for an individual customer class, for example a residential efficient appliance program. A full program operation must meet the TRC test and provide a benefit/cost ratio of greater than 1. If after redesign, a program cannot meet the total resource cost test, then it is shelved or discarded.
- Regulators in the past, including the BC Utilities Commission, have approved portfolios of DSM programs based on the portfolio's TRC. This allows utilities to implement broad-based programs that may have a higher unit cost of savings, along with complementary lower cost programs acquiring savings from a few large energy users. Each customer sector's programs are often treated as separate portfolios.
- For the surveyed utilities, *Table 4 Utility DSM Summary* shows that DSM costs are included in the revenue requirement and recovered in retail rates.
- In the US, investor-owned utilities file individual tariffs with regulators for each DSM program. In Canada, the practice of individual tariffs is more sporadic. Allocated DSM costs are often bundled into existing rates for customer classes.
- Public benefit funds are paid by electricity customers, but are not immediate and direct sources of DSM funding for the utility.
- In reviewing BC's Energy Plan, it would appear, at the time of this study, that energy utilities will continue to be responsible for DSM program planning, design, delivery and evaluation, and that DSM program costs will be recovered in retail energy rates.
- Regulators in the past, including the BC Utilities Commission, have approved portfolios of DSM programs based on the portfolio's TRC. This allows utilities to implement broad-based programs that may have a higher unit cost of savings, along with complementary lower cost programs acquiring savings from a few large energy users. Programs for a customer class are often treated as a portfolio.

Conclusions

- Utilities' expenditures on DSM programs planned, implemented and delivered under their control continue to be rate based and recovered under revenue requirement regulation. This is consistent with the treatment of supply side resources built to meet customer loads.
- Utility DSM activity directed from outside the utility organization is funded through other government or non-government agencies. The source of funds, however, remains the utility ratepayers. This approach is practical because it continues to take advantage of the utility

customer base, not only as a market for DSM measures but also as the source of program funding, maximizing the total DSM investment while minimizing the cost per ratepayer.

Recommendation

Endorsed Aquila continue to recover its PowerSense costs as part of its revenue requirement in order to reduce the cost of meeting customer load growth.
Rationale Under the BC Energy Plan, Aquila will remain responsible for DSM planning, program implementation, delivery and cost recovery of all expenditures. Identified DSM savings measures and programs are assessed against supply side resources before being included in Aquila's resource plan. Once included in the selected and approved resource portfolio, DSM costs will be recovered through rates, along with the supply side costs.

5.5 Expenditures Survey

Survey of DSM expenditures as a proportion of utilities' annual sales revenue and DSM unit cost (cents per kilowatt-hour) comparison with the unit cost of new electricity supply and/or the marginal cost of electricity. (Terms of Reference)

For this study it has not been possible to capture program unit cost of savings data as a measure of program effectiveness. The actual data collected were for annual savings and expenditures for demand side resources. Currently, DSM is itself the focus of restructuring, and is reemerging in utility regulation, statutes, and utility resource planning. Little activity over the recent years, recognizing the reporting time lag, has left a dearth of specific program evaluation results from which to collect reliable performance data.

The most reliable data were from audited sources such as annual reports and Securities Exchange Commission Annual 10K reports. Publications warned of self-reported data (ACEEE) and the US Department of Energy, Energy Information Administration (EIA) staff cautioned drawing conclusions from the annual Form 861A report. The advent of the public benefit fund agencies as DSM program administrators has adversely affected the EIAs capability to collect annual program activity information. These non-utility agencies are not required to report to the EIA. There is an early trend to PBF agencies reporting "deemed" savings for programs. That is savings amounts based on pre-determined engineering and statistical analysis of the measure's impact on energy use.

Findings

- Public benefit funds (PBF) will most likely offer DSM information and training which cuts across all customer classes for all utilities in a state.
- Of the top ten energy saving states in 1998 that had restructured, all had adopted a PBF mechanism to sustain DSM programming. The PBF is a charge that is collected as a percentage of distribution utility revenue (Oregon), as a tariff on transmission services (Vermont), or as a separate tariff on distribution services (Texas).
- Aquila's DSM portfolio continues to meet the total resource cost test and the average unit cost of savings is less than $0.38/kWh, Aquila's cost of its power purchases under Rate Schedule 3808.
- The US utilities shown in *Table 4 Utility DSM Summary* spent up to 1.17 percent of gross revenue on DSM expenditures in 2000 and, in 2002, Canadian utilities spent up to 2 percent of total revenue on DSM.
- Aquila spends approximately 1 percent of gross revenue on DSM expenditures.

- Annual energy savings as a percentage of total annual energy sales ranged up to 1 percent for all utilities shown.

Conclusions

- The lack of quality program expenditure and savings data prevents any definitive conclusions about utility DSM expenditures and savings from programs.
- There is a growing correlation between sources of program funding, and types of programs delivered. Public benefit funded programs are planned, once fully implemented, to focus on market transformation activities including research, education, and emerging technologies. These programs are being delivered across utility service areas. Utilities that are continuing to invest in DSM programs are doing so for the purpose of acquiring immediate resource savings upon investment.

Recommendations

Endorsed Aquila continue their level of DSM expenditures to capture economic energy savings. *Rationale* Spending one percent of revenue on DSM by Aquila represents little risk, if any, for the utility given the variance in actual sales versus the forecast. Yet the amount is significant when considering that the savings acquired are able to meet over 20 percent of load growth.

Table 4 Utility DSM Summary

Utility	DSM TRC Economic Test	Program Design Type			Program Funding	Cost Recovery	DSM Spending/ Gross Revenue	Year
		Product/Market Incentives	Information & Research	Legislation/ Rulemaking				
BC Hydro	✓	6	12		Revenue Requirement	Electricity/DSM Tariffs	1.9%	2002
Aquila Canada Networks (BC)	✓	7	3		Revenue Requirement	Electricity/DSM Tariffs	1.05%	2002
Manitoba Hydro	✓	11	14		Revenue Requirement/ Partners	Electricity Tariffs	1.0%	2002
Hydro Quebec (DSM Plan)	✓	19	11 (overlap)	✓	Revenue Requirement	Electricity Tariffs	0.2%	2002
Aquila Canada Networks (BC)	✓	7	3		Revenue Requirement	Electricity/DSM Tariffs	1.17%	2000
Pacific Gas & Electric Co	✓	15	25	✓	Revenue Requirement	Public Goods Charge	0.25%	2000
Idaho Power Co	✓	4	1	✓	Revenue Requirement	Electricity/DSM Tariffs	0.24%	2000
Southern California Edison (SCE)	✓	14	11	✓	Revenue Requirement	Public Goods Charge	0.21%	2000
Portland General Electric Co	✓	19	2	✓	Public Benefits Fund	Public Benefits Fund	0.03%	2000

5.6 PowerSense Comparison

Compare and contrast the effectiveness of the PowerSense portfolio with programs of surveyed utilities. (Terms of Reference)

This comparison focuses on Canadian utilities.

Findings

- Hydro Quebec Distribution filed a DSM plan in January of this year and has begun implementation.
- BC Hydro launched Power Smart 2 in 2002 and it is too early for evaluation information.
- Nova Scotia Power has offered DSM programs since 1990 and in response to the 2001 *"Seizing the Opportunity: Nova Scotia's Energy Strategy"* is improving customer access to DSM information. DSM will become part of greenhouse gas emission reduction efforts for the utility.
- As part of its climate change action plan, the Alberta government announced, in September 2003, a four year, $100-million, interest-free, municipal loan program for investments in energy-efficiency. The investments should target increasing conservation, greenhouse gas emission reductions and renewable and alternative energy sources, with priority given to projects for city infrastructure.
- Manitoba Hydro's Power Smart has continued to offer programs over the years and its annual report to the Manitoba Public Utilities Commission provides summary information.

Chart 1 DSM Spending as a Percent of Total Revenue (Canada, 2002)

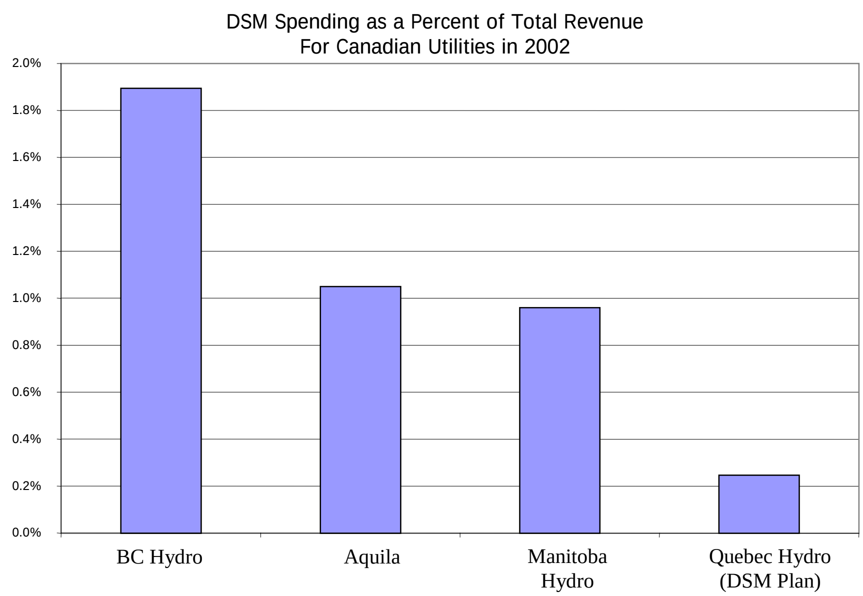


Chart 2 DSM Spending as a Percent of Total Revenue (US, 2000)

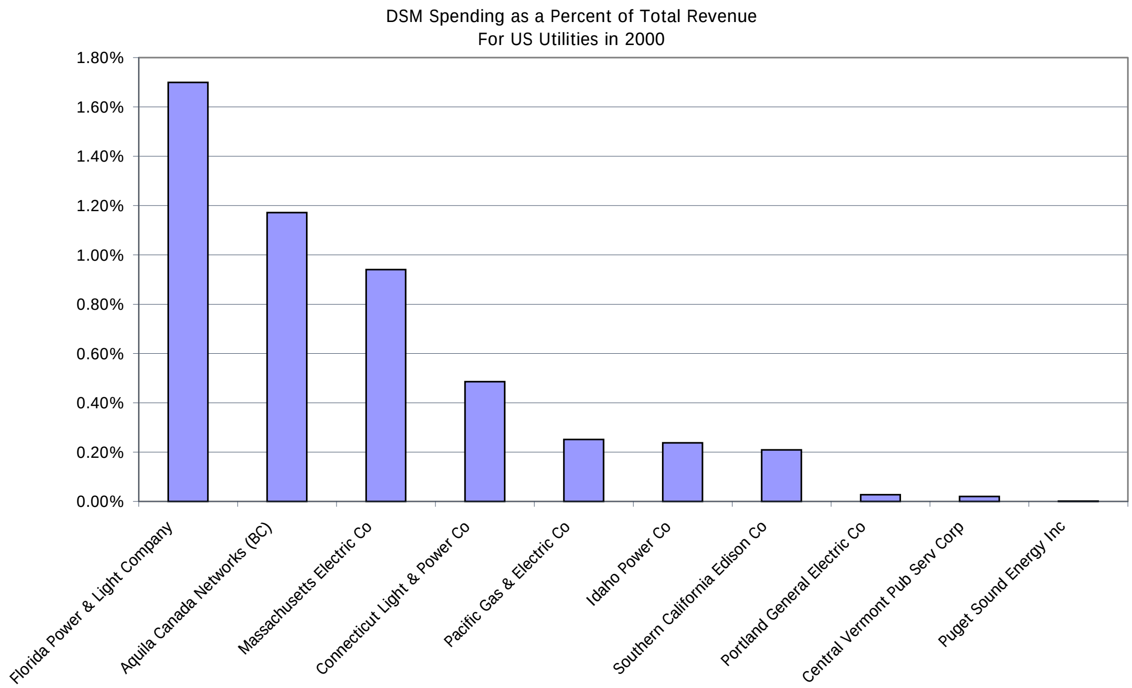


Chart 3 DSM Energy Savings as a Percent of Total Energy Sales (Canada, 2002)

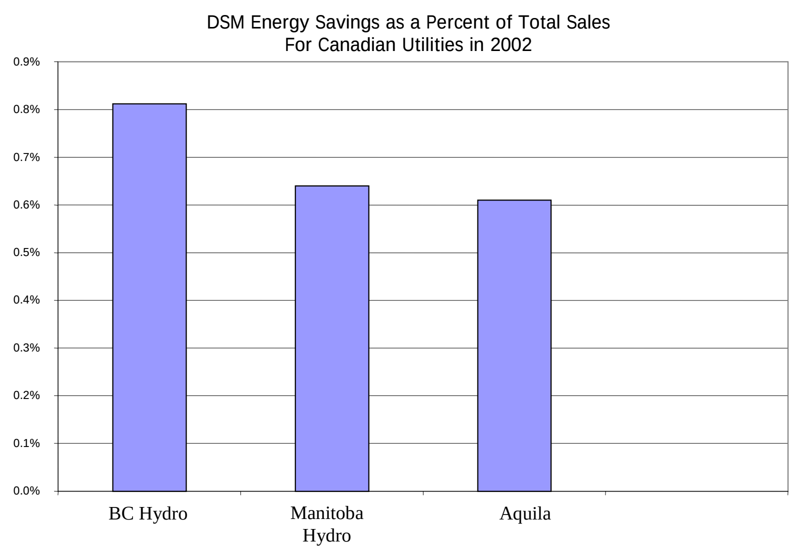
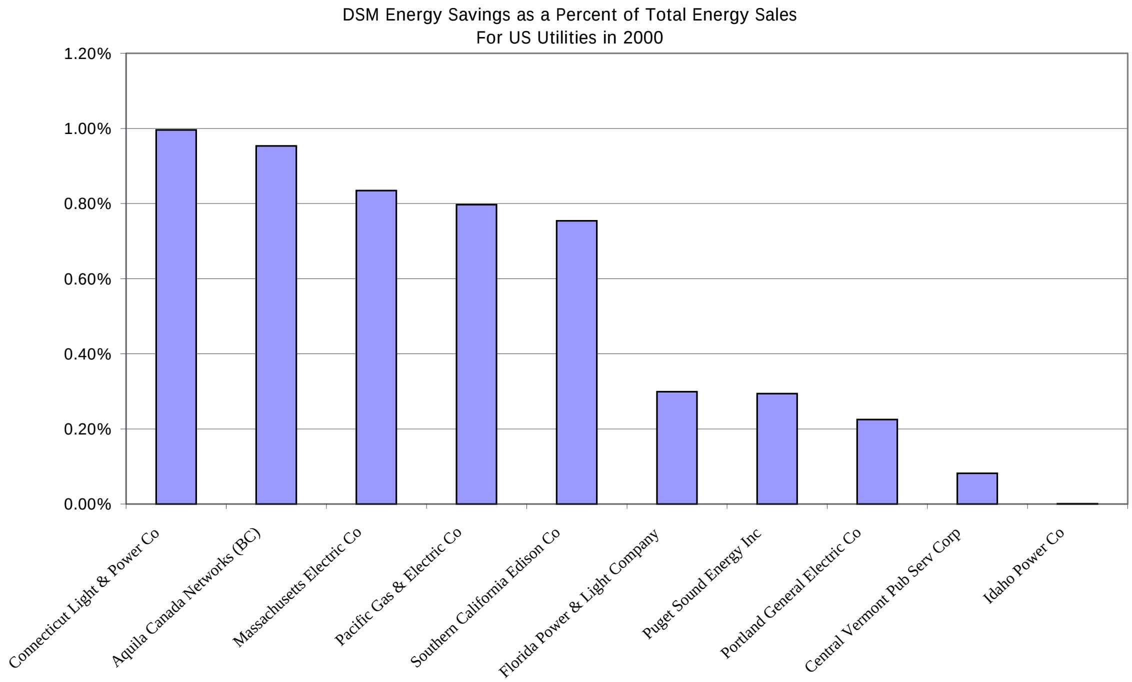


Chart 4 DSM Energy Savings as a Percent of Total Energy Sales (US, 2000)



Conclusions

- For comparing Aquila's PowerSense program effectiveness in light of the data findings, this study looked at utility annual energy savings as a percentage of total energy sales and utility annual DSM expenditures as a percentage of annual total revenue. Chart 1compares Aquila spending to Canadian utilities in 2002; Chart 2 compares Aquila spending to US utilities in 2000; Chart 3 compares Aquila energy savings to Canadian utilities in 2002; and Chart 4 compares Aquila energy savings to US utilities in 2000.
- Based on DSM spending in 2000 by 9 American investor-owned utilities, Aquila ranked second, at approximately one percent, in terms of DSM spending as a percent of total revenue and second, at approximately 1 percent in terms of energy savings as a percent of total energy sales. Against three Canadian utilities in 2002, Aquila ranked second in terms of DSM spending as a percent of total revenue and second in terms of energy savings as a percent of total energy sales.
- Aquila has offered programs in each of the categories shown in *Table 1 DSM Program Activities* on page 8. That is, programs for resource acquisition for each customer class, information and education programs and market transformation programs. The PowerSense programs have addressed technologies and end uses similar to those offered by other utilities. There has been a comprehensive effort to offer information and measures to all customers while capturing opportunities for economic savings with specific technologies and innovative delivery strategies.
- Annual savings of 17 GWh in 2002 represented a twenty three percent reduction in Aquila's annual load growth for the same year.

Recommendations

Endorsed Aquila continue at its current level of DSM expenditure subject to recommendations for new program development and the portfolio requirements of the 2004 Resource Plan. *Rationale* The Aquila DSM expenditures level ranks comparably with those of other Canadian and U.S utilities who have active DSM programs. In determining program development requirements it may become necessary to increase DSM spending to maintain existing programs and to add new programs, such as peak demand reduction. Preparation of the 2004 Resource Plan will identify the long-term resource requirements for Aquila and additional DSM options may be needed to expand the identified DSM measures and programs for portfolio assessment.

6. SUMMARY OF RECOMMENDATIONS

Total Resource Cost Test

(a) Endorsement: Aquila continue to rely on the Standard Practice Manual policy and the TRC for program planning and selection.
(b) Change: Aquila investigate the introduction of applying externality cost reductions as credits to the TRC with the BCUC.

Resource Risk Assessment

(a) Endorsement Aquila continue to plan to acquire DSM savings in order to reduce the overall risk of their energy supply portfolio.

Integrated Resource Acquisition

(a) Endorsement Aquila continue to adjust annual load forecasts by estimated DSM annual savings to produce the annual energy sales forecast.
(b) Adjustment Aquila DSM should meet semi-annually and as required with system planning and operations to identify opportunities that further reduce costs while maintaining system reliability and improving customer service.

Resource Acquisition versus Research Development Support

(a) Endorsement Aquila continue to focus on resource acquisition DSM programming.
(b) Endorsement PowerSense continue to provide, on request, technical expertise and technology experience to government agencies, as it currently does for Natural Resources Canada on heat pump technology, for the Mines and Energy update to the BC Energy Efficiency Act.
(c) Adjustment Aquila investigate improvement to providing web-based information with appropriate links to other energy use websites and information groups.

Program Design Type

(a) Endorsement Aquila continue to plan and design PowerSense programs to acquire resource savings.
(b) Adjustment Aquila develop a pilot project to investigate demand response technologies and their suitability, customer impact, costs and demand savings impact.
(c) Adjustment Aquila investigate leasing options that could be offered by the utility, for technologies such as Ground Source Heat Pump systems.

DSM Measure Selection Criteria

(a) Endorsement PowerSense continue to select appropriate and cost-effective measures to capture a broad base of customers' DSM opportunities and meet their energy service needs

Program Survey Summary

(a) Endorsement Aquila maintain the mix of resource acquisition programs and measures. Additional areas of programming effort:

Demand Reduction

(b) Adjustment PowerSense investigate innovative peak load reduction.
(c) Adjustment Aquila develop a portfolio of demand reduction savings opportunities to estimate the seasonal peak reduction potential.

Education and Awareness

(d) Adjustment Aquila establish a DSM budget to develop an education program jointly with a steering committee, whose members are representative of Aquila's service area.
(e) Adjustment Aquila provide strategy to build broad-based customer awareness of DSM activities and behaviour that readily lead to savings.
(f) Adjustment Aquila investigate the distribution of energy savings information into educational institutions.

Tariff and Rate Design and Bill Unbundling

(g) Adjustment Aquila adapt a home improvement pilot project and submit proposal to BC Housing Corporation and the BC Utilities Commission for the purpose of developing a design for a housing efficiency performance DSM tariff.
(h) Adjustment Aquila provide preliminary estimates of costs for "Smart Meter" installations and unbundled billing information on customers' bills

DSM Funding Sources and Cost Recovery Mechanisms

(a) Endorsement Aquila continue to recover its PowerSense costs as part of its revenue requirement in order to reduce the cost of meeting customer load growth.

Expenditures Survey

(a) Endorsement Aquila continue their level of DSM expenditures to capture economic energy savings.

PowerSense Comparison

(a) Endorsement Aquila continue at its current level of DSM expenditure subject to recommendations for new program development and the portfolio requirements of the 2004 Resource Plan.

Follow Up to DSM Review by DSM Incentive Committee

(a) Aquila to work with the DSM Incentive Committee in a "brainstorming" session. The purpose of this session would be to identify measures, processes and actions necessary to bring forward DSM as a more effective and acceptable resource for BC utilities. The DSM Incentive Committee and Aquila will jointly determine the follow up required to the session.

GLOSSARY

General 1

Financial Incentives Examples 4

DSM Tests Based on California Standard Practice Manual 6

General

Coincidental Peak Load: The sum of two or more peak loads that occur in the same time interval.

Commercial Sector: The commercial sector is generally defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule.

Conservation: Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Direct Load Control: Refers to program activities that can interrupt consumer load at the time of annual peak load by direct control of the utility system operator by interrupting power supply to individual appliances or equipment on consumer premises. This type of control usually involves residential consumers. Direct Load Control excludes Interruptible Load and Other Load Management effects. Direct Load Control (as defined here) is synonymous with Direct Load Control Management reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411: "Coordinated Regional Bulk Power Supply Program Report". The exception is that annual peak load effects are reported here and seasonal (i.e., summer and winter) peak load effects are reported on the OE-411.)

Direct Utility Cost: A utility cost that is identified with one of the DSM program categories (i.e., Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building).

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British Thermal Units.

Electric Capacity: The maximum electric power that a device or system is capable of producing or transferring. Electric capacity is measured in watts, kilowatts, megawatts, etc.

Electrical Efficiency: The ratio of the useful energy delivered by a system or end-use to the amount of electric energy supplied to it. This ratio measures how well electric energy is translated into another useful form of energy.

Electric Energy: It is the cumulative amount of electricity produced or consumed over a period of time. Electric energy is measured in kilowatthours, megawatthours, gigawatthours, etc..

Electric Power: The instantaneous rate at which electric energy is produced, transmitted or consumed. Electric power is measured in watts, kilowatts, megawatts etc.

Energy Efficiency of Equipment: The percentage of gross energy input that is realized as useful energy output of a piece of equipment.

Energy Efficiency Improvement: Reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting levels per square foot.

Energy Efficiency Investment: An investment that produces a reduction in energy use for a comparable level of service, compared to a specified base case.

Energy Efficiency of a Measure: A measure of the energy used to provide a specific service or to accomplish a specific amount of work (e.g., kWh per cubic meter of a refrigerator, therms per gallon of hot water).

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Free Driver: A nonparticipant who adopted a particular efficiency measure or practice as a result of a utility program. See "Spillover Effects" for aggregate impacts.

Free Rider: A program participant (see definition) who would have implemented the program measure or practice in the absence of the program.

Gigawatthour (GWh): One million kilowatthours.

Gross Load Impact: The change in energy consumption and/or demand that results directly from program-related actions taken by participants in the DSM program, regardless of why they participated.

Industrial Sector: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments (Standard Industrial Classification (SIC) codes 01-39). The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Integrated Resource Planning: A planning and selection process used to evaluate a wide range of electricity supply-side and demand-side options to determine the most appropriate mix of resources to reliably meet future electricity requirements. The economic, environmental and social impacts and risks of the resource options may be weighed by public input and ranked for priority selection.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): The amount of energy transferred at a rate of one kilowatt for one hour.

Load: The amount of electricity required by a device, customer or group of customers as measured by an electricity meter. Load may be measured instantaneously in terms of electric capacity in units such as kilowatts. Over time load may be measured in terms in units such as kilowatthours.

Load Building: Fuel substitution and load building share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas or electricity and gas (load building). Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

Load Impact: Changes in electric energy use, electric peak demand, or natural gas use.

Marketing Cost: Expenses directly associated with the preparation and implementation of the strategies designed to encourage participation in a DSM program. The category excludes general market and load research costs.

Measure (Energy Efficiency Measure): A product whose installation and operation at a customer's premises results in a reduction in the customer's on-site energy use, compared to what would have happened otherwise.

Monitoring & Evaluation Cost: Expenditures associated with the planning, collection, and analysis of data used to assess program operation and effects. It includes the activities such as load metering, customer surveys, new technology testing, and program evaluations that are intended to establish or improve the ability to monitor and evaluate the impacts of DSM programs, collectively or individually.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

Net Load Impact: The total change in load that is attributable to the utility DSM program. This change in load may include, implicitly or explicitly, the effects of free drivers, free riders, state or federal energy efficiency standards, changes in the level of energy service, and natural change effects.

Net-to-Gross Ratio: A factor representing net program load impacts divided by gross program load impacts that is applied to gross program load impacts to convert them into net program load impacts. This factor is also sometimes used to convert gross measure costs to net measure costs.

Non-coincidental Peak Load: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Other Costs: A residual category to capture the Indirect Costs of DSM programs that cannot be meaningfully included in any of the other cost categories listed and defined herein. Included are costs such as those incurred in the research and development of DSM technologies.

Other DSM Programs: A residual category to capture the effects of DSM programs that cannot be meaningfully included in any of the program categories listed and defined herein. The energy effects attributable to this category should be the net effects of all the residual programs. Programs that promote consumer's substitution of electricity by other energy types should be included in Other DSM Programs. Also, self-generation should be included in Other DSM Programs to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories.

Other Incentives: Energy Efficiency programs that offer cash or non-cash awards to electric energy efficiency deliverers, such as appliance and equipment dealers, building contractors, and architectural and engineering firms, that encourage consumer participation in a DSM program and adoption of recommended measures.

Other Load Management: Refers to programs other than Direct Load Control and Interruptible Load that limit or shift peak load from on-peak to off-peak time periods. It includes technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation of equipment from on-peak to off-peak periods through the application of time-differentiated rates.

Participant: An individual, household, business, or other utility customer that received the service or financial assistance offered through a particular aspect of a utility program in a given program year. Participation is determined in the same way as reported by a utility in its Annual DSM Summary.

Peak Demand: The maximum load during a specified period of time.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Residential Sector: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use.

Spillover Effects
Reductions in energy consumption and/or demand in a utility's service area caused by the presence of the DSM program, beyond program related gross savings of participants. These effects could result from: (a) additional energy efficiency actions that program participants take outside the program as a result of having participated; (b) changes in the

array of energy-using equipment that manufacturers, dealers, and contractors offer all customers as a result of program availability; and (c) changes in the energy use of non participants as a result of utility programs, whether direct (e.g., utility program advertising) or indirect (e.g., stocking practices such as (b) above, or changes in consumer buying habits).

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Tariff: The rate and the terms and conditions of sale of electric power and energy between utility and customer. It includes the type of service, delivery point(s), limitations of obligations to serve, minimum charges, etc.

Total DSM Cost: Refers to the sum of total utility cost and non-utility cost.

Total DSM Programs: Refers to the total net effects of all the utility's DSM programs. For the purpose of this survey, it is the sum of the effects for Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building. Net growth in energy or load effects should be reported as a negative number, shown with a minus sign.

Total Non-utility Costs: Refers to total cash expenditures incurred by consumers and trade allies that are associated with participation in a DSM program, but that are not reimbursed by the utility. The non-utility expenditures should include only those additional costs necessary to purchase or install an efficient measure relative to a less efficient one. Costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the actual effects occur. To the extent possible, respondents are asked to provide the best estimate of non-utility costs if actual costs are unavailable.

Total Utility Costs: Refers to the sum of the total Direct and Indirect Utility Costs for the year. Utility costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur.

Watt: The basic unit of measurement of electrical of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

Financial Incentives Examples

Corporate Tax Incentives: Corporate tax incentives allow corporations to receive credits or deductions ranging from 10% to 35% against the cost of equipment or installation to promote renewable energy equipment. In some cases, the incentive decreases over time. Some states allow the tax credit only if a corporation has invested a certain dollar amount into a given renewable energy project. In most cases, there is no maximum limit imposed on the amount of the deductible or credit.

Direct Equipment Sales: A few utilities sell renewable energy equipment to their customers as part of a buy-down, low-income assistance, lease, or remote power program.

Grant Programs: States offer a variety of grant programs to encourage the use and development of renewable energy technologies. Most programs offer support for a broad range of renewable energy technologies, while some states focus on promoting one particular type of renewable energy such as wind technology or alternative fuels.
Grants are available primarily to the commercial, industrial, utility, education, and government sectors. Some grant programs focus on research and development, while others are designed to help a project achieve commercialization. Programs vary in the amount offered--from $500 to $1,000,000--with some states not setting a limit.

Industrial Recruitment Incentives: This category focuses on special efforts and programs designed to attract renewable energy equipment manufacturers to locate within a state or city. Renewable energy industrial recruitment usually consists of financial incentives like tax credits, grants, or a commitment to purchase a specific amount of the product for use by a government agency. The recruitment incentives are designed to attract industries that will benefit the environment and create jobs. In most cases, the financial incentives are temporary measures that will help support the industries in their early years but include a sunset provision to encourage the industries to become self-sufficient within a number of years.

Leasing/Lease Purchase Programs: Utility leasing programs target remote power customers for which line extension would be very costly. The customers can lease the technology, e.g., photovoltaics, from the utility, and in some cases, the customer can opt to purchase the system after a specified number of years.

Loan Programs: Loan programs offer financing for the purchase of renewable energy equipment. Low-interest or no-interest loans for energy efficiency are a very common strategy for demand-side management by utilities. State governments also offer loans to assist in the purchase of renewable energy equipment. A broad range of renewable energy technologies are eligible. In many states, loans are available to residential, commercial, industrial, transportation, public, and nonprofit sectors. Repayment schedules vary; while most are determined on an individual project basis, some offer a 7-10 year loan term.

Personal Income Tax Incentives: Many states offer personal income tax credits or deductions to cover the expense of purchasing and installing renewable energy equipment. Some states offer personal income tax credits up to a certain percentage or predetermined dollar amount for the cost of installation of renewable energy equipment. Allowable credit may be limited to a certain number of years following the purchase or installation or renewable energy equipment. Eligible technologies may include solar and photovoltaic energy systems, geothermal energy, wind energy, biomass, hydroelectric, and alternative fuel technologies.

Production Incentives: Production incentives provide project owners with cash payments based on electricity production on a $/kWh basis, as is the case with the Federal Renewable Energy Production Incentive, or based on the volume of renewable fuels produced on a $/gallon basis, as is the case with a number of state ethanol production incentives. Payments based on performance rather than capital investments can often be a more effective mechanism for ensuring quality projects.

Property Tax Incentives: Property tax incentives typically follow one of three basic structures: exemptions, exclusions, and credits. The majority of the property tax provisions for renewable energy follow a simple model that provides the added value of the renewable device is not included in the valuation of the property for taxation purposes. That is, if a renewable energy heating system costs $1,500 to install versus $1000 for a conventional heating system, then the renewable energy system is assessed at $1000.

Property taxes are collected locally, so some states allow the local authorities the option of providing a property tax incentive for renewable energy devices. Six states have such provisions: Connecticut, Iowa, Maryland, New Hampshire, Vermont, and Virginia.

Rebate Programs: Rebate programs are offered at the state, local, and utility levels to promote the installation of renewable energy equipment. The majority of the programs are available from state agencies and municipally-owned utilities and support solar water heating and/or photovoltaic systems. Eligible sectors usually include residents and businesses, although some programs are available to industry, institutions, and government agencies as well. Rebates typically range from $150 to $4000. In some cases, rebate programs are combined with low or no-interest loans.

Sales Tax Incentives: Sales tax incentives typically provide an exemption from the state sales tax for the cost of renewable energy equipment.

DSM Tests Based on California Standard Practice Manual

The Utility Cost Test: Measures the net change in a utility's revenue requirement resulting from a DSM program. The test compares the reduction in marginal energy and demand costs with utility program costs, incentive payments and increased supply costs for a period in which load is increased. Designed to focus on a utility's revenue requirement, the test does not include any net costs incurred by participants.

The Participant Cost Test: Measures the benefits and costs of a DSM program to a customer by comparing the reduction in the customer's utility bill, plus any incentive paid by the utility bill, with the customer's out-of-pocket expenses. The test is often used as a "first-cut" in ranking program desirability and gauging potential program participation rates.

The Total Resource Cost Test: Measures the net costs of a DSM program as a resource option based on the total costs of the program, including both participant and utility costs. Like the utility cost test, it measures benefits as reductions to energy and demand costs, but also includes a review of all program costs, including installation, operation, maintenance, and administration, no matter who pays for them.

The Rate Impact Measure Test: Measures the direction and magnitude of the expected changes in rates for all customers when a utility implements a DSM program. The equation functions initially in the same manner as the utility cost test, comparing avoided supply costs savings with the cost to the utility. It also measures the revenue-shifting effect unique to DSM when costs must be spread over smaller sales volume. The shift reduces revenue requirements, but not to the same extent as sales are reduced by DSM programs. The difference causes an increase in rates on a cents per kWh basis. If a utility has excess capacity and its average costs exceed its marginal costs, a DSM program will likely increase rates. The converse is true when marginal costs are forecast to exceed average costs.

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Abbreviations and Acronyms

ACEEE – American Council for an Energy-Efficient Economy

BCUC – British Columbia Utilities Commission

BPA – Bonneville Power Administration

CEC – California Energy Commission

CFL – Compact Fluorescent Lights

DOE – Department of Energy

DSM – Demand Side Management

EIA – Energy Information Administration

FY – Fiscal Year

GWh – Gigawatt Hours

HVAC – Heating, Ventilation, and Air Conditioning

IPP – Independent Power Producer

IT – Information Technology

kg. – Kilogram

LED – Light Emitting Diode

m^3 – Cubic Meter

MW – Megawatt

NARUC – National Association of Regulatory Utility Commissioners

NCCP – National Climate Change Program

NEEA - Northwest Energy Efficiency Alliance

OEB – Ontario Energy Board

SPM – Standard Practice Manual

PBF – Public Benefit Funds

PGC – Public Goods Charge

PPT – Public Purpose Test

TRC – Total Resource Cost

SCE – Southern California Edison

UCA – Utilities Commission Act

FORTISBC

Efficiency Savings and Demand Reduction Potential

September 2005

September 15, 2005

Prepared by

Willis
ENERGY SERVICES LTD.

Executive Summary

FortisBC has operated the PowerSense energy efficiency program for its customers since 1989. Program planning has been based on the 1991 West Kootenay Power Electricity Potential Review and the 1999 *West Kootenay Power Conservation Potential Review – Residential Sector* and updated general service and industrial achievable energy efficiency potentials. The FortisBC Efficiency Savings and Demand Reduction Potential – September 2005 study is an update of the energy efficiency savings potential in the FortisBC service area for the purpose of:

- Determining the energy efficiency savings and the demand reduction resource available for planning purposes for the years 2004 to 2013,
- Updating customer energy end use information,
- Selecting economic savings measures applicable to FortisBCs service area,
- Providing a fresh basis for stakeholder review of the energy efficiency and demand reduction potential programs and,
- Updating the Five Year Business Plan.

This study is focused on determining the efficiency and demand reduction potential from technical measures that deliver reliable and persistent results. It relies on Deemed Savings[1], energy savings performance based on regulated equipment and appliance testing by regulatory agencies, in cooperation with manufacturers and utilities. Other energy savings measures are based on engineering estimates. The relevant measures have a unit cost of 6 cents per kilowatt-hour or less. Appropriate measure selection and participation estimates were developed in conjunction with FortisBC.

The 2003 energy consumption by customer consumption class for electricity consumers served by FortisBC and the efficiency savings potential in 2008 and 2013 are listed in Exhibit E-1 as follows:

Exhibit E-1 FortisBC 2003 Energy Consumption and Savings Potential Summary

Consumer Sector	2003 Combined Direct/Indirect Customer Consumption	2008 Savings Potential & Percentage Annual Consumption		2013 Savings Potential & Percentage Annual Consumption	
	GWh	GWh	Percent	GWh	Percent
Residential	1571	41	3	81	5
Commercial	896	60	7	120	13
Industrial	407	18	4	31	8
TOTAL	*2,874*	*119*	*4%*	*232*	*8%*

[1] See Glossary

The annual peak demand for 2003 was 678 MW. An estimated demand response potential, based on recent experience by Bonneville Power Administration and Portland General Electric, is 0.8 percent of demand, or about 5.5 MW for FortisBC load.

The updated sector efficiency potential savings are compared to the 2005 Resource Plan remaining potentials in Exhibit E-2 below:

Exhibit E-2 Updated Efficiency Potential Savings by Sector

Consumer Sector	2005 FortisBC Efficiency Potential Update	2005 FortisBC Resource Plan - Preliminary Efficiency Update
	MW	MW
Residential	81	92
Commercial	120	127
Industrial	31	35
TOTAL	*232*	*254*

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DSM Incentive Committee

➢ Brian Parent	FortisBC - PowerSense
➢ Dick Gathercole	BC Public Interest Advocacy Centre
➢ Richard Tarnoff	Natural Resources Industries
➢ Sam Costa	Princeton Light and Power
➢ Fred Marsh	Okanagan Kootenay Electrical Consumers' Association
➢ Alan Wait	Consumer Representative – Kootenay-Boundary
➢ Buryl Slack	Consumer Representative – South Okanagan
➢ Russ Foster	Consumer Representative – Central Okanagan
➢ Rod Carle	City of Kelowna
➢ Rob Gorter	BC Utilities Commission
➢ Andrew Pape-Salmon	BC Ministry of Energy and Mines

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Dan Egolf, Power Supply

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Consultants
The FortisBC Efficiency Savings and Demand Reduction Potential was undertaken by a team of consultants headed by Willis Energy Services Ltd. of Vancouver, BC. The team included:
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Stephen Hall - Stephen Hall and Associates

In Discussion:
John Nyboer EMRG at Simon Fraser University

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1.0 INTRODUCTION

1.1 Practices and Trends

1.1.1 Deemed Savings

During recent years much work has been completed in other jurisdictions to build rigorous databases of energy savings measure (ESM) information, including energy savings, incremental costs, equipment costs, and electric system impacts. As an example, Natural Resources Canada (NRCan) has implemented its own deemed savings program by bringing Energy Star™ to Canada.

In 1999 the Bonneville Power Administration representing Pacific Northwest interests asked for "a comprehensive list of energy efficiency measures and renewable resources actions that are predetermined"[2] in order to administer their Conservation and Renewable Resources Rate Discount. The documented evidence required to substantiate the efficiency claim had to include at least one of the following:

- Generally accepted engineering calculations,
- Independently reviewed evaluation report or case studies,
- Prototype testing and/or evaluation, metering results, and/or
- Peer reviewed scientific research.[3]

Once in place periodic energy savings performance evaluations are required to verify and update measure and practice information. This data is available in the 2002 Regional Technical Forum's Deemed Savings Database. It is based on a large volume of program evaluation data, and diverse and extensive program experience. As a result, the 2005 FortisBC Potential Study has used this deemed savings information, selected for applicability and relevancy, to assess the remaining energy efficiency potential in the FortisBC service area. See Measures Information Appendix.

1.1.2 Lifestyle Savings

This report only uses specific "hard-wired" measures with firm savings to estimate the energy efficiency and demand reduction potential within the FortisBC service area. There is a complementary approach to improving energy efficiency based on "lifestyle" changes that relies on raising public awareness and informing customers about how to achieve no/low cost energy savings through changes in practices. Based on the impact of education and awareness programs elsewhere, including California and the Pacific Northwest, an estimate of 10 percent of total savings potential is possible.

An example of residential lifestyle savings is only cold water washing for clothes. Because customers have choice through the dials on their machines, continuous messaging is needed

[2] Regional Technical Forum, September 2001. The Regional Technical Forum's Recommendations to the Bonneville Power Administration Regarding Conservation and Renewable Resources Eligible For the Conservation and Renewable Resources Rate Discount and Related Matters.
[3] See footnote 2 above

to ensure those customers continue washing their clothes in cold water, to encourage others to practice this habit, and thus provide persistent savings.

An example of a business "lifestyle" or habit change is to organize cleaning staff to complete each building area before moving to the next, so that lights may be shut off sooner. This procedural change can be incorporated into training for new staff.

For purposes of this report, lifestyle measures were not included in the potential.

1.1.3 Heat Pumps

Ground source and, air source heat pump systems are making significant advances into existing home retrofit projects and particularly into new housing construction of all types. The FortisBC service area has seen, since the energy events of 2000/2001 and in response to the PowerSense programs, a rapid growth in the penetration of heat pump technology. Significant utility impact savings are derived because heat pumps exchange heat from one body of matter to another, providing heating or cooling, depending on the season. As a result, utility energy is required to power the heat pump, while the heat pump system provides the building or facility with space heating or cooling. For every unit of electricity input, up to three units of serviceable heating or cooling are provided.

Appropriate sizing of the equipment for specific installations necessarily means that typical design temperatures are set at the coldest mean temperature day. In order to meet peak heating requirements that occur when the daily mean temperature is lower that the design temperature, heat backup is required. In this study, the savings from heat pump installations are net of electric heat backup.

1.1.4 Supplemental Heating

Due to the unbundling of transportation and commodity rates charged to natural gas consumers and the flow through commodity pricing rate design, consumer response to the natural gas price spikes in 2000 and 2001 has been to seek fuel-switching capability to turn away from gas during high-price periods. FortisBC, along with other electric utilities, has experienced this impact and this study incorporates an amount of electric space heating for non-electrically heated homes based on the penetration rates and energy use rates reported in BC Hydro's 2002 conservation potential update.

1.1.5 Appliances

Natural Resources Canada (NRCan) Office of Energy Efficiency administers ENERGY STAR® (E*), which is an international symbol displayed on appliance models that achieve premium levels of energy efficiency based on specific criteria endorsed by NRCan. E* design requires a minimum of 15% energy performance improvement over the legislated standard. Use of the label in Canada became widespread in 2004. The certification of the appliances and equipment as ENERGY STAR® is conducted in testing facilities according to regulated practices.

The FortisBC 2004 appliance sales review and a review of recently prepared savings potential studies and plans, including those of BC Hydro[4], Northwest Power and Conservation Council[5], and the Northwest Energy Coalition[6] show price point equivalency amongst ENERGY STAR® efficient appliances and non-certified appliances. That is, there are not additional purchase costs to acquire an efficient appliance as opposed to an inefficient appliance. The incremental savings provided by the highest efficiency models are also at a high incremental unit cost.

These studies and observations present a consumer market that is well able to provide customer selection and choice amongst efficient appliances at price levels equivalent to those offered by standard efficiency models. As a result, FortisBC action should be limited to the support of an Energy Star awareness campaign. The unit cost of the savings available from the most efficient models of appliances, based on the incremental price of the efficient versus standard appliance, will not meet the FortisBC total resource cost test that is applied to efficiency measures.

While the potential for savings may be large as appliance stock in existing households is replaced over time, it can be expected that all equivalent replacements, i.e. same size and features, will be more efficient.

1.1.6 Plug Load

While the end use efficiencies of plug-in appliances and entertainment and home office equipment are being reduced by with technological improvement, household demand is on the rise as additional electronic applications and equipment become affordable. An example is the improved efficiency of television and computer screens, moving from cathode ray tubes to liquid crystal display. Concurrent with that improvement are the rising sales of document scanners, photography printers, paper shredders, and other specialized digital input and output devices and other specialized devices which add more plug load.

1.2 Study Approach

Residential

The 2005 Efficiency Savings Potential brings forward the 1999 Residential Energy Efficiency Potential study that used the base year of 1998.

Base Year 2003

The year 2003 is the base year for this study. It is the latest year of published government statistics and completed major research publications regarding demand-side measures[7]. The year 2003 is the latest year for which complete electricity sales, sector consumption, and use per account. The study covers the ten-year period 2004 to 2013.

[4] BC Hydro. 2003. BC Hydro Conservation Potential Review 2002
[5] Northwest Power and Conservation Council. May 2005. The Fifth Northwest Electric Power and Conservation Plan.
[6] Tellus Institute. October 2002. Clean Electricity options ofr the Pacific Northwest.
[7] Deemed Savings update by the Regional Technical Forum (Bonneville Power Administration)

End Use Breakdown and Analysis
In order to determine the existing energy end-use levels, and as the basis from which to determine potential for savings, this study updated the 1998 residential end-use breakdown, adding new housing units with energy use levels, considered the demolition of existing stock as zero, and incorporated PowerSense impacts and updated energy use for equipment replaced in pre-1998 housing stock.

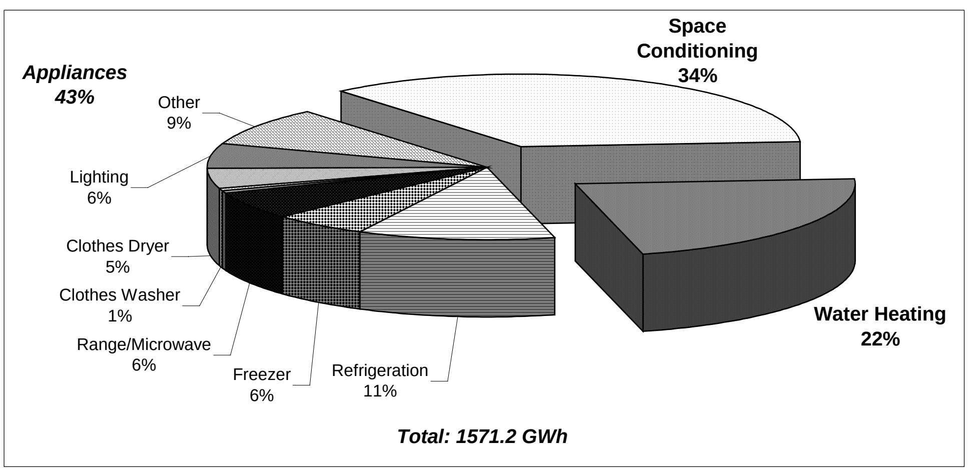
The end use breakdown for the five years of energy consumption by the residential sector considered:

- Population update;
- Accounts update based on population;
- Dwellings information updated by dwellings type, based on STATS CAN Dwelling Characteristics;
- New construction within the service area;
- Dwelling types of new added stock;
- Heating electric/gas share by dwelling type;
- Electric heating technology by dwelling type.

After updating the pre-1998 unit energy consumption for heating and hot water end-use, based on PowerSense information collected, the annual consumption was calculated by rolling up the end use annual consumption estimates for 2003. Please see Residential Appendix. This analysis provided the basis for examining energy use and energy savings measures available and their impact on residential consumption by FortisBCs direct and indirect residential customers.

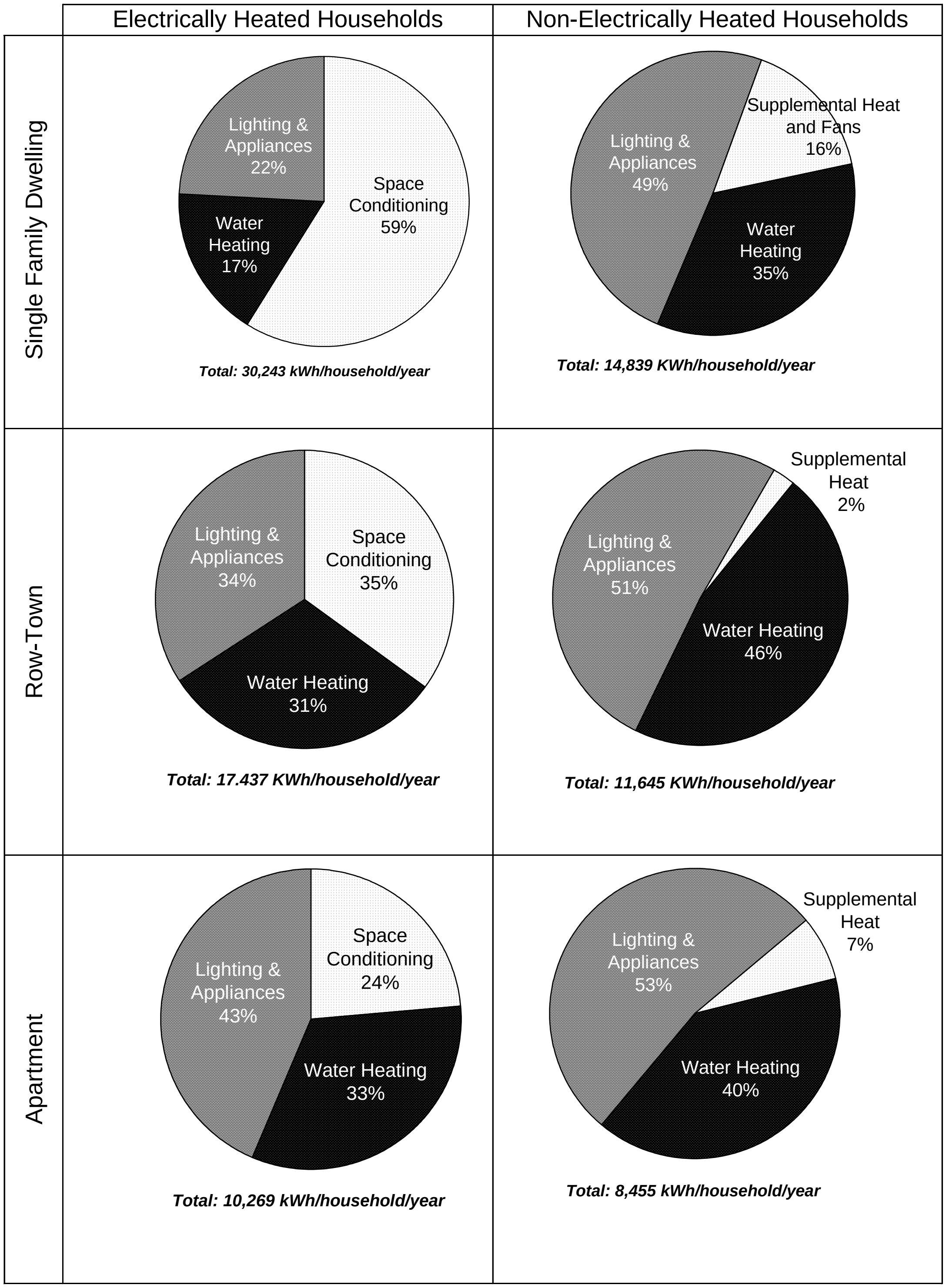
The end-use breakdown for all Residential customers energy use is in Exhibit 1-1, while the end-use breakdowns for single family households' energy use for electric heat and non-electric heat are in Exhibits 1-2 and 1-3 respectively.

Exhibit 1-1 Annual Total Electricity Consumption by End-Use (2003) – Residential All Housing Types



The annual average electricity consumption for each household type is shown in Exhibit 1-2 for electrically heated and non-electrically heated households.

Exhibit 1-2 *Annual Average Electricity Consumption by End Use (2003) – Residential Household Types*



PowerSense Results
The FortisBC program offerings have included Home Improvements, Watersavers, Residential Lighting, Appliance Pick Up, Heat Pumps and New Home. The Semi-Annual DSM Reports for the five-year period ending in 2003 included 25.5 GWh of savings and 9.2 MW of reduced demand. These results have been rolled into 2003 sales figures and therefore reflected in the end use breakdowns.

Market Activity
The study's 2003 end-use breakdown for existing housing and new housing construction was analyzed to estimate annual new housing construction and housing retrofit activity. The study estimates that 10% of the planned replacement activities will be subject to natural efficiency over the study period. This was also done for the 2008 and 2013 load forecast. The remaining replacement/addition of residential energy using equipment and appliances for the period can be viewed as the market opportunity to influence efficiency improvements and installations.

General Service and Industrial
Base Year 2003
This study amalgamated the direct and indirect electricity sales to commercial and industrial users by Standard Industrial Classification (SIC). Direct electricity sales, or FortisBC retail sales, are recorded by SIC, and indirect non-residential sales, or FortisBC wholesale sales, were prorated based on the direct sales. In order to determine an electricity end use analysis by economic activity in 2003, an electricity end-use breakdown was applied to combined (direct and indirect) commercial and combined (direct and indirect) industrial sales. The end-use breakdown was developed as part of the Reference Case in the BC Hydro 2002 Conservation Potential Review – Commercial and Industrial, for the total service area.

The end-use breakdown for commercial customers energy use is Exhibit 1-3. Total annual electricity consumption by SIC segments is shown in
Exhibit **1-4**.

Exhibit 1-3 Annual Total Electricity Consumption by End-Use (2003) – Commercial

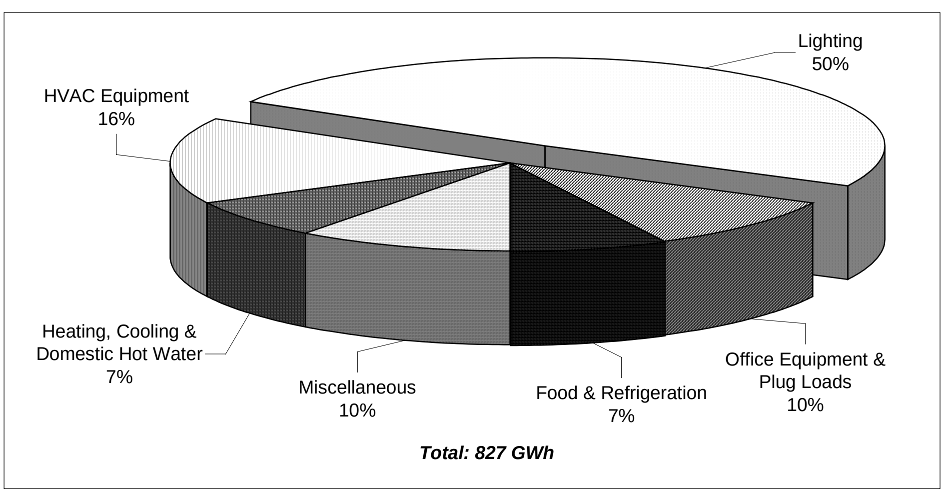
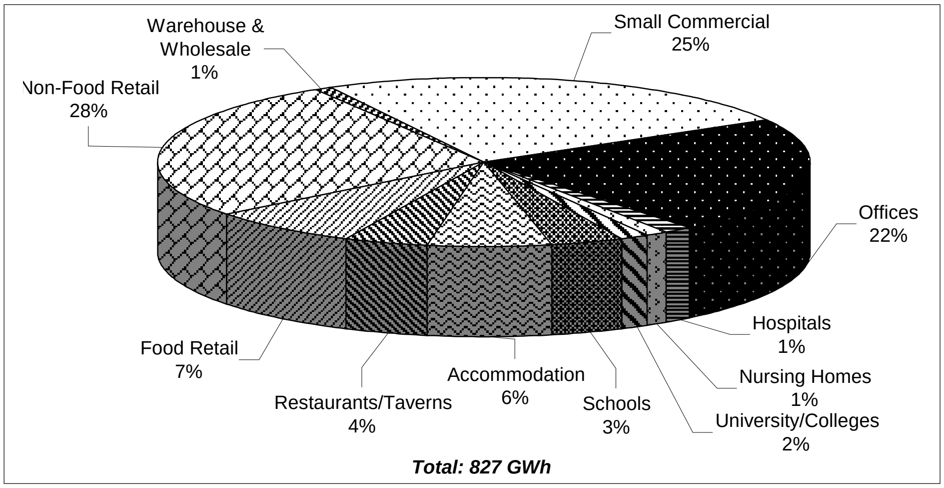


Exhibit 1-4 Annual Total Electricity Consumption by Building Type (2003) – Commercial



The end-use breakdown for Industrial customers energy use is Exhibit 1-6. The total annual electricity consumption by SIC segments is shown in Exhibit 1-7.

Exhibit 1-6 Annual Total Electricity Consumption by End-Use (2003) – Industrial

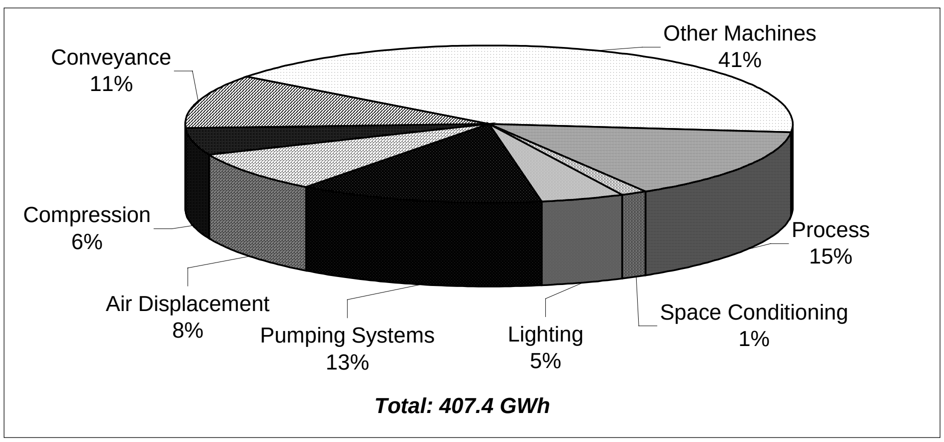
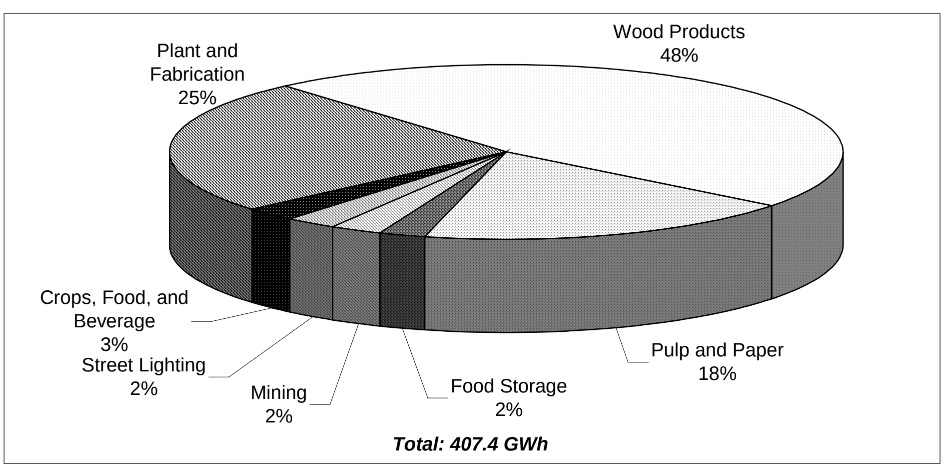


Exhibit 1-7 Annual Total Electricity Consumption by Activity Sector (2003) – Industrial



PowerSense Results
FortisBC PowerSense has been working with General Service and Industrial customers since 1990 achieving 153 GWh of energy savings and 34.8 MW of demand reduction during the period ending in2003. These results have been rolled into 2003 sales figures and therefore reflected in the end use breakdowns.

Demand Reduction
The purpose of DR review is to provide a preliminary assessment of the peak reduction resources that may be available to FortisBC's PowerSense program for demand side management (DSM) planning purposes. The study presents a summary of the background of demand response, characteristics of a demand response program, sample residential, commercial and industrial measures/programs, and measures applicable to FortisBCs customer load. Preliminary estimates of demand reduction are provided, based on a proposed methodology.

1.3 Study Findings

Efficiency Standards

Exhibit 1-8 shows the proposed revisions to NRCan energy efficiency standards for equipment and appliances.

Exhibit 1-8 Proposed Updates to Energy Efficiency Standards

Appliance/Equipment	Minimum Energy Efficiency		Proposed Effective Date
Commercial Refrigerators and Freezers	Maximum daily energy consumption (kWh)=0.00441V + 4.22		Jan-07
Beverage Vending Machines	Maximum daily energy consumption (kWh)= 55% (8.66 + 0.009C)		Jan-06
Air Conditioners and Heat Pumps under 19kW (65,000 Btu/h)	Cooling - SEER 10.9 HSPF V - 6.2		Mar-05
Ground Source Heat Pumps (closed loop)	Cooling - COPc 3.93 Heating - COPh 3.1		Jun-06
Water Source Heat Pumps and Internal Water Loop Heat Pump	Cooling - COPc 3.28 Heating - COPh 4.2		Sep-05
	New Construction	Replacement	
Packaged Terminal Air Conditioners and Heat Pump	Cooling - EER 12.3 Heating - COP 3.2	Cooling - EER 10.8 Heating - COP 2.9	Sep-05
Large Air Conditioners and Heat Pumps	Cooling - SEER 10.3 Heating - COP 3.2		Sep-05

Source: Natural Resources – Office of Energy Efficiency (http://oee.nrcan.gc.ca/regulations/home)

Expected regulation amendments are reflected in Market Activity forecasts for the residential and commercial sectors, based on annual retrofit and new construction activity.

Energy and Demand Avoided Costs

This study is consistent with *BC Hydro 2002 CPR Update* and has used 6 cents per kWh as the long-term incremental, or avoided cost of energy. BC Hydro's avoided cost is based on the cost of new, efficient, gas-fired Combined Cycle Gas Turbines (CCGT). This avoided has allowed this study to identify and include a broader range of measures, which can be input to DSM planning for the medium term.

The acquisition of incremental supply and meeting peak demand for the long-term will include a mixture of long-term and short-term purchases, coupled with spot purchases to meet super peak demand. The long-term price of power based on the Mid-Columbia trading hub index is also close to 6 cents per kWh for the planning period 2004 to 2013.

The avoided cost used for demand-reduction measures should reflect real-time market pricing for capacity during the November to February peak demand period.

Technology Improvement

Technology improvements have increased the potential savings for those facilities remaining unchanged since earlier studies (motors and auxiliary systems) and, in some cases, have created new potential for savings (liquid crystal display television and computer screens).

Cost Improvement of Energy Efficiency

Improvement in compact fluorescent lighting is an example of a technology that has raised customer satisfaction with better colour rendition, size and instant start capability, while at the same time reducing price. The combination of expanded product offerings and lower price is why the lighting efficiency potential remains as the major end-use for savings potential in the commercial sector.

2.0 RESIDENTIAL

The objectives for this section of the study are:

- Update housing stock information by vintage and dwelling type, space conditioning, water heating, and appliance stock information,
- Update energy use intensities based on deemed savings information, PowerSense evaluation, and BC Hydro's *2002 CPR – Residential* study,
- Incorporate appliance efficiency survey and analysis results, and
- Capture an expanded list of cost-effective energy saving measures based on an avoided cost of 6 cents/kWh.

An earlier study completed in 1999, "West Kootenay Power Residential Potential Energy Use Efficiency Review", served as input to PowerSense planning and has been used as a reference during the intervening years. The structure of the data model for energy consumption by end use, along with dwelling types and technologies are essential elements of the 1999 study which have been maintained for this report.

The following exhibit summarizes the findings of this study. The energy use breakdown for FortisBC residential customers for 2003 and the identified efficiency potential is listed in Exhibit 2-1.

Exhibit 2-1 Residential 2003 Energy Use and 2004-2013 Efficiency Potential

End Use	Customers	2003 Sales GWh	Share of Sales	2004-2013 Efficiency Potential GWh
Electric Heating	51,097	451.3	29%	60
Furnace Fans	45,100	40.7	3%	1.7
Supplemental Electric Heating	21,200	24.6	2%	
Cooling	66,401	34.4	2%	.1
Hot Water	83,760	349.4	22%	2
Appliances	124,196	583.4	37%	0.4
Lighting	124,196	86.9	6%	17
Deemed Savings Total		***1,571***	***100%***	***81***

2.1 Heating/Space Conditioning

<u>Sales Estimate</u>

Of FortisBC's 124,200 direct and indirect residential customers, approximately 51,000 use electricity to heat their homes. Of the remaining households, it is estimated that approximately 45,000 have forced-air furnace fans, and 21,000 households use electricity to provide supplemental heating. When combined for space heating purposes, these end uses amount to 517 GWh, or 34% of total annual residential consumption in the service area. This load contributes directly to the FortisBC system winter peak.

Technology Review

Energy Star® Windows

An Energy Star window is rated on air-tightness and conduction heat losses (U-value). The U-value measures how well a product prevents heat from escaping. U-Factor ratings generally fall between 0.20 and 1.20. The lower the U-value, the greater a window's resistance to heat flow and the better its insulating value.[8] Energy Star® windows must have a U factor of less than 0.35 Btu/h.ft^2.^{0}F in Canada. Deemed savings are calculated based on the size (square feet) of the glazed area.

Target Size

Electrically heated households 2003 base stock:

- Single Family Dwelling - Replacement for approximately 29,000 square feet
- Row/Town House - Replacement for approximately 6,300 square feet
- Apartment - Replacement for approximately 6,500 square feet

New electric heat households, annually for 10 years (2004 to 2013)

- Single Family Dwelling - New construction 75,000 square feet
- Row/Town House - New construction 55,000 square feet
- Apartment - New construction 290,000 square feet

Air Source Heat Pumps

The study includes the impact of installing air source heat pumps with a heating seasonal performance factor (HSPF) of 8.0 and a cooling seasonal energy efficiency ratio (SEER) of 13. The current technical minimum requirement listed by the Office of Energy Efficiency for air source heat pumps is a SEER of 10 and an HSPF of 5.9.

Target Size

2003 stock electric forced-air furnace (FAF):

- 10% of single family dwellings, with and without central air conditioning,
- Post 1992 15% of single family dwellings with air conditioning;
- 5% of ASHPs installed pre-1995 upgrade, and

New electric forced-air heat households, annually for the next 10 years:

- 70% of single family dwellings with central air conditioning.

Packaged Terminal Air Conditioners

The study includes the impact of installing packaged terminal air conditioners with a minimum coefficient of performance (COP) of 2 and a seasonal energy efficiency ratio (SEER) of 11, represented by commercially available appliances.

Target Size

2003 stock electric forced-air furnace:

- 2% of row/town house dwellings, with air conditioning,
- 2% of condominium/apartment dwellings with air conditioning; and

New zonal electric heat households, annually for the next 10 years:

- 35% of row/town house dwellings, with air conditioning,
- 15% of condominium/apartment dwellings with air conditioning.

Ground Source Heat Pumps

The study includes the impact of installing closed-loop ground source heat pumps with a minimum coefficient of performance (COP) of 2.8 and an energy efficiency ratio (EER) of 11.5.

[8] National Fenestration Rating Council www.nfrc.org

Target Size

New zonal electric heat households, annually for the next 10 years:
20% of condominium/apartment dwellings with central air conditioning savings.

Efficient Furnace Fans

The study includes the impact of replacing centrifugal designed, forward-curved impellor permanent, split capacitor induction motor fans with a backward inclined blower with a smaller brushless permanent magnet motor.

Target Size

2003 stock non-electric forced-air furnace:
5% of single family dwellings,
New non-electric forced-air furnace households, annually for the next 10 years:
10% of single family dwellings.

Efficiency Estimate

Exhibit 2-2 shows the residential heat and space conditioning savings potential.

Exhibit 2-2 Residential Heat Space Conditioning Savings Potential (2004-2013)

Weatherization and Space Conditioning		***Single Family Dwellings***	***Row/ Townhouses***	***Apartments***	***Total***
Energy Star® Windows	Households	380	508	4,255	5,143
	Average Annual Savings (kWh/year)	468,152	606,998	3,212,691	4,287,840
	2004-2013 Savings (GWh)	4.7	6.1	32.1	43
Air Source Heat Pumps	Households	916	202	592	1,710
(including PTAC/HP)	Average Annual Savings (kWh/year)	1,370,173	168,775	169,270	1,708,218
	2004-2013 Savings (GWh)	13.7	1.7	1.7	17
Ground Source Heat Pumps	Households			156	
	Average Annual Savings (kWh/year)			224,768	224,768
	2004-2013 Savings (GWh)			2.25	2
Packaged Terminal Air	Households			602	
Conditioners (PTAC)	Average Annual Savings (kWh/year)			3,758	3,758
- cooling	2004-2013 Savings (GWh)	-	0.01	0.04	0.1
Efficient Fans	Households	2,285			
	Average Annual Savings (kWh/year)	170,916	-	-	170,916
	2004-2013 Savings (GWh)	1.7			1.7
Total Space	Average Annual Savings (kWh/year)	2,009,241	775,773	3,610,487	6,395,500
Conditioning	2004-2013 Savings (GWh)	20	8	36	62

2.2 Water Heating

Sales Estimate

Of FortisBC's 124,200 direct and indirect residential customers, approximately 84,200 use electricity to provide domestic hot water. Estimated annual consumption for water heating is 352 GWh, or 24% of total annual residential consumption in the service area.

Technology Review

Improved Efficiency

The study includes the addition of insulation blankets to the tank (3.5" foam), and tank bottom and heat traps to reduce thermal losses where hot water leaves the tank, with minimum 20 year warranty.

Target Size

2003 stock:
5% of 40 gallon tanks,
New households, annually for the next 10 years:
25% of 40 gallon tanks.

Heat Recovery Ventilating Heat Pump Water Heater with Integral Tank and minimum 10 year warranty

This study includes pre-heating domestic water with a heat pump upstream of the hot water tank. Heat pump water heater savings are based on higher recovery efficiency and not standby loss reduction. However, space conditioning interaction is assumed to be equivalent since if the unit is inside the heated space some heat recovery will increase space heating requirements. Typical residential heat pump water heaters use 500 to 1,200 watts at peak load, compared with 3,000 watts for typical 175 litre (40 gallon) electric resistance units, and 4,500 for 270 litre (60 gallon) tanks.. The heat pump gets about two thirds of its heat energy from the air and one third as leftover heat from the compressor motor.

Target Size

2003 stock:
5% of 80 gallon tanks,
New households, annually for the next 10 years:
10% of 80 gallon tanks.

Efficiency Estimate

Exhibit 2-3 shows the residential domestic hot water savings potential.

Exhibit 2-3 Residential Domestic Hot Water Savings Potential (2004-2013)

Domestic Hot Water Efficiency Measure		***Total***
Heat traps, increased insulation, insulated tank bottom	Households	
	Average Annual Savings (kWh/year)	97,135
	2004-2013 Savings (GWh)	1
Heat recovery ventilating heat pump water heater	Households	
	Average Annual Savings (kWh/year)	106,809
	2004-2013 Savings (GWh)	1
Total Domestic Hot Water	Average Annual Savings (kWh/year)	203,944
	2004-2013 Savings (GWh)	2

2.3 Lighting and Appliances

Sales Estimate

All of FortisBC's 124,200 direct and indirect residential customers use electricity for lighting. Estimated annual consumption for lighting is 92 GWh, or 6% of total annual residential consumption in the service area.

Technology Review

Average Interior Compact Fluorescent Bulb

This study has included the deemed savings from 2 CFL bulbs as an estimate for lighting potential savings from the interior of all households. Estimates were based on the replacement of two incandescent bulbs. These estimates are a placeholder for available lighting technologies that are currently available such as certain application for LED lights and high efficiency lighting.

Target Size

2003 stock:
30% of dwellings – 2 CFL bulbs,
New households, annually for the next 10 years:
25% of dwellings – 1 CFL bulb.

Average Exterior Compact Fluorescent Bulb

This study has included the deemed savings from 2 CFL bulbs as an estimate for lighting potential savings from the exterior of single family and row/town households. Estimates were based on the replacement of two incandescent bulbs.

Target Size

2003 single family and row/town house stock:
40% of dwellings – 2 CFL bulbs,
New single family and row/town households, annually for the next 10 years:
40% of dwellings – 1 CFL bulbs.

DRYERBALLS™

This study has identified DRYERBALL™ as an energy saving measure. These are small plastic balls designed with spikes that, when two are added to a dryer load or wet laundry, help to reduce drying time and soften fabric. As the dryer turns, the balls absorb the heat. The spikes on the ball push the hot air evenly throughout each garment, distributing heat and fluffing fabrics. A conservative estimate of reduced dryer time is 15 percent.[9]

Target Size

2003 single family and row/town house stock:
1% of dwellings with electric clothes dryers,
New single family and tow/town households, annually for the next 10 years:
10% of dwellings with electric clothes dryers.

Efficiency Estimate

Exhibit 2-4 shows the residential lighting and appliances savings potential.

[9] Website information corroborated by General Electric.

Exhibit 2-4 Residential Lighting and Appliances Savings Potential (2004-2013)

Lighting and Appliances Efficiency Measures		***Total***
CFL interior fixtures	Average Annual Savings (kWh/year)	432,524
	2004-2013 Savings (GWh)	4
CFL exterior bulbs	Average Annual Savings (kWh/year)	1,269,017
	2004-2013 Savings (GWh)	13
DRYERBALLS™	Average Annual Savings (kWh/year)	37,032
	2004-2013 Savings (GWh)	0.4
Total Lighting and Appliances		
	Average Annual Savings (kWh/year)	1,738,572
	2004-2013 Savings (GWh)	17

2.4 Lifestyle Savings

There are many no cost and low cost energy saving tips that can help the consumer save on energy costs. Typical things that energy users can do at home are:

<u>Heating and Air Conditioning</u>:

1. Lower the thermostat at night.

2. For baseboard heating, turn down the thermostat to 15C (60F) and close doors on unused rooms.

<u>Water Heating</u>:

1. Wash all clothes (and run garbage disposal) with cold water.

2. Use less water.

3. Use the short cycle on the dishwasher, and select the energy saving button (where available).

<u>Lighting and Small Appliances</u>:

1. Turn lights off when not in use. Likewise for computers, TVs and other electronic gear.

2. Use bulbs of lower wattage. Better yet use compact fluorescent bulbs instead of regular incandescent lamps.

3. Boil water in electric kettle, instead of stove-top kettle/pan.

Communication resources, such as web site publications, public awareness campaigns, and school programs can provide the information that people need to change the way they use energy. Lifestyle changes can be minimal, such as using cold water for clothes washing, or they can be dramatic, such as moving to a smaller dwelling or focusing the family's efforts on using less energy. A conservative estimate of 10 percent of efficiency savings potential can be attributed to people choosing to make lifestyle changes.

Reliability of savings through persistent behaviour requires continuous messaging to affirm consumers that are reducing energy use and to attract more participation in energy efficient use behaviour by all consumers. A DSM information and awareness program is needed to provide regular messaging and education packages. The program should include a feedback mechanism to communities to let them know the impact of their choices.

2.5 Conclusions

Exhibit 2-5 shows the residential total potential for efficiency savings.

Exhibit 2-5 Residential Total Potential for Efficiency Savings

2004-2013 Savings	GWh
Residential Total Potential Efficiency Savings	81

3.0 GENERAL SERVICE AND INDUSTRIAL

FortisBC PowerSense has been working with General Service and Industrial customers for over 15 years and success in achieving savings in the last several years can be largely attributed to the pragmatic approach taken by PowerSense: assist customers to lever up efficiency on their approved capital projects. This approach reduces costs and refines utility program research, design, and staff involvement with customers, focusing on the efficient technologies and expertise needed for customer construction projects set to proceed.

3.1 GENERAL SERVICE/COMMERCIAL

The objectives for this section of the study are:

1. Develop an end-use breakdown for each commercial segment based on 2003 billing information and BC Hydro's recent commercial end-use analysis contained in the *2002 Conservation Potential Review Update – Commercial.*
2. Assemble measures
3. Estimate energy efficiency savings for 2004 to 2013 based on deemed savings, case study results, or program evaluation results.

Exhibit 3-1 summarizes the energy efficiency potential for commercial customers.

Exhibit 3-1 Commercial 2003 Energy Use and 2004-2013 Efficiency Potential

Sector/End Use (GWh)	Combined Direct & Indirect 2003 Sales (GWh)	2004 to 2013 Sector Efficiency Potential	General Lighting	Office Equipment & Plugloads	Commercial Food & Refrigeration	Miscellaneous (Elev, Exit Lights)	Space Heat, Cooling, DHW	HVAC Equipment (Fans & Pumps)
Offices	201	23	18	3	-	-	-	2
Hospitals	12	2	1	0.4	-	-	-	0.2
Nursing Homes	9	1	1	-	-	-	-	0.1
University/Colleges	15	2	2	1	-	-	-	0.2
Schools	31	5	4	1	-	-	-	0.4
Accommodation	54	5	5	-	-	-	-	0.5
Restaurants/Taverns	39	3	2	-	-	-	-	0.2
Food Retail	65	7	4	-	3	-	-	0.2
Non-Food Retail	243	38	35	-	1	-	-	2
Warehouse/Wholesale	7	1	1	0.4	-	-	-	0.04
Commercial Laundry		2	-	2	-	-	-	-
Small Commercial	219	31	25	3	2	-	-	2
2004 to 2013 Efficiency Potential (GWh)		*120*	*97*	*9*	*6*	*-*	*-*	*7*
2003 Total End Use (GWh)	*896*		*439*	*91*	*66*	*93*	*65*	*142*

3.1.1 Lighting

Sales Estimate

Estimated annual consumption for lighting for FortisBC's direct and indirect 15,200 commercial customers is 439 GWh, or 49% of total annual commercial consumption in the service area.

Technology Review

High Efficiency Lighting

There is a large body of end use analysis and product information available because the lighting load in the commercial sector represents about 50% of all electricity used by this sector. For this study, the potential savings were calculated based on the deemed savings of new high efficiency fluorescent fixtures operating for 3,500 and for 5,000 hours per year. Annual change out activity is at 70,000 fixtures (35,000 for each 3,500 hours per year with savings of 77 kWh per fixture, and 5,000 hours per year with savings of 110 kWh per year). New installations are also set at 70,000 fixtures per year with savings of 37 kWh per year for 3,500 hours of operation and 53 kWh per year for 5,000 hours of operation. Please refer to Appendix __ for information regarding detail lighting savings measures.

Target Size

2003 stock annual change out:

- 35,000 fixtures at 3,500 hours of annual operation,
- 35,000 fixtures at 5,000 hours of annual operation, and

New Construction:

- 35,000 fixtures at 3,500 hours of annual operation for each year 2004 to 2013,
- 35,000 fixtures at 5,000 hours of annual operation for each year 2004 to 2013.

Efficiency Estimate

Exhibit 3-2 shows the commercial lighting savings potential.

Exhibit 3-2 Commercial Lighting Savings Potential (2004-2013)

Commercial Lighting High Efficiency Fluorescent Fixtures		***Total***
Existing Facilities		
3500 hours/year operation	Average Annual Savings (MWh/year)	2,695
	2004-2013 Savings (GWh)	27
5000 hours/year operation	Average Annual Savings (MWh/year)	3,850
	2004-2013 Savings (GWh)	39
New Construction		
3500 hours/year operation	Average Annual Savings (MWh/year)	1,295
	2004-2013 Savings (GWh)	13
5000 hours/year operation	Average Annual Savings (MWh/year)	1,855
	2004-2013 Savings (GWh)	19
Total Commercial High Efficiency Fluorescent Lighting		
	Average Annual Savings (MWh/year)	9,695
	2004-2013 Savings (GWh)	97

3.1.2 HVAC Equipment, Space Heat, Cooling and Domestic Hot Water

Sales Estimate

Estimated annual consumption for heating, cooling and domestic hot water for FortisBC's direct and indirect 15,200 commercial customers is 142 GWh, or 16% of total annual commercial consumption in the service area.

Technology Review

Improved HVAC Efficiency

Given the diverse size and business use of each of the commercial facilities in the service area, and recognizing that 25 percent of the load serves small businesses, this study has included measures that have broad application for space heat and cooling efficiency across the customer base. An air source heat pump (HSPF 8, SEER 13, 36,000 Btu/hr) saves about 2,400 kWh/a while a more efficient air conditioner (EER 10.8, 10,000 Btu/hr) can provide about 99 kWh/a in savings. Annual change out activity is estimated at 300 heat pumps and 300 air conditioners.

Target Size

2003 stock annual change out:
- 300 heat pumps, and
- 300 air conditioners.

Efficiency Estimate

Exhibit 3-3 shows the commercial space heating and cooling savings potential.

Exhibit 3-3 Commercial Space Heating and Cooling Savings Potential (2004-2013)

Commercial Heat Pump and Air Conditioner		***Total***
Light Commercial Heat Pump	Average Annual Savings (MWh/year)	723
	2004-2013 Savings (GWh)	7.2
Light Commercial Air Conditioner	Average Annual Savings (MWh/year)	11.7
	2004-2013 Savings (GWh)	.01
Total Commercial Heat Pump and Air Conditioner		
	Average Annual Savings (MWh/year)	735
	2004-2013 Savings (GWh)	7.4

3.1.3 Office Equipment and Plug Load

Sales Estimate

Estimated annual consumption for office equipment and plug load for FortisBC's direct and indirect 15,200 commercial customers is 91 GWh, or 10% of total annual commercial consumption in the service area.

Technology Review

Computer/Office Equipment Power Down

Based on the evaluation results of BC Hydro's Computer Power Down project and recognizing the increasing efficiency, yet growing load, of new types of equipment and increased use rates, this study is including the savings that are available from informing, modifying, and enabling the existent software controls in office equipment.

Target Size

2003 stock annual change out in offices, hospitals, universities, schools, and small businesses:

2,900 machines.

<u>Efficiency Estimate</u>

Exhibit 3-4 shows the commercial office equipment savings potential.

Exhibit 3-4 Commercial Office Equipment Savings Potential (2004-2013)

Commercial Office Equipment Power Down		***Total***
Computer and Office Equipment Power Down	Average Annual Savings (MWh/year)	725
	2004-2013 Savings (GWh)	7.3
Total Commercial Office Equipment Power Down		
	Average Annual Savings (MWh/year)	725
	2004-2013 Savings (GWh)	7.3

3.1.4 Commercial Food and Refrigeration

<u>Sales Estimate</u>

Estimated annual consumption for commercial food and refrigeration for FortisBC's direct and indirect 15,200 commercial customers is 66 GWh, or 7% of annual commercial energy consumption, largely by retail food and non-food stores and small business enterprises in the service area.

<u>Technology Review</u>

Improved Refrigeration Efficiency

This study includes the savings from changing out retail food refrigeration equipment, which may be located in large or small outlets, in exchange for efficient units with ECM motors for evaporator fans, high efficiency compressors, and non-electric anti-sweat heating. Savings amounts are based on case study results.

Target Size

2003 stock annual change out:

30 2-Zone Walk-in cooler with 11 heated glass reach-in doors, and

30 Reach-in Cooler with 4 heated glass reach-in doors.

<u>Efficiency Estimate</u>

Exhibit 3-5 shows the commercial retail refrigeration savings potential.

Exhibit 3-5 Commercial Retail Refrigeration Savings Potential (2004-2013)

Commercial Retail Refrigeration Upgrade		***Total***
Refrigeration Upgrade	Average Annual Savings (MWh/year)	630
	2004-2013 Savings (GWh)	6.3
Total Commercial Retail Refrigeration Upgrade		
	Average Annual Savings (MWh/year)	630
	2004-2013 Savings (GWh)	6.3

3.1.5 Commercial Clothes Washers

Sales Estimate

The load for commercial clothes washers, part of the total plug load, is concentrated in multi-unit residential buildings and complexes, and includes similar load in accommodation and commercial laundries.

Technology Review

Efficient Commercial Clothes Washers

Efficient clothes washers with an MEF of 1.8 or higher have been included.

Target Size

2003 stock annual change out:
150 replacement clothes washers.

Efficiency Estimate

Exhibit 3-6 shows the commercial clothes washers savings potential.

Exhibit 3-6 Commercial Clothes Washers Savings Potential (2004-2013)

Commercial Clothes Washers with an MEF 1.8 plus		***Total***
Efficient Commercial Clothes Washer	Average Annual Savings (MWh/year)	177
	2004-2013 Savings (GWh)	1.8
Total Commercial Clothes Washers with an MEF 1.8 Plus		
	Average Annual Savings (MWh/year)	177
	2004-2013 Savings (GWh)	1.8

3.2 INDUSTRIAL

The objectives for this section of the study are:

1. Update the end-use breakdown for each industrial segment in FortisBCs service area from the *1991 Electricity Conservation Potential Review: The West Kootenay Power Serviced Industrial Sector*, with 2003 customer information and BC Hydro's recent industrial end-use analysis contained in the *2002 Conservation Potential Review Update – Industrial.*
2. Assemble measures
3. Estimate energy efficiency savings for 2004 to 2013 are based on NRCan's SME study[10], BC Hydro's *2002 Conservation Potential Review Update – Industrial*, and PNWCC's deemed savings[11].

Exhibit 3-7 summarizes the energy efficiency potential 2004 to 2013 savings for industrial customers.

Exhibit 3-7 Industrial 2003 Energy Use and 2004-2013 Efficiency Potential

Sector/End Use GWh	Combined Direct & Indirect 2003 Sales (GWh)	2004 to 2013 Sector Efficiency Potential	Pumping Systems	Air Displacement	Compression	Conveyance	Other Machines	Process	Space Conditioning & Lighting
Crops, Food, and Beverage	11	1	-	-	-	0.1	-	0.6	0.3
Plant and Fabrication	101	21	4	1	1	0.1	-	14	1.6
Wood Products	191	9	-	3	3	1.1	1.2	-	0.8
Pulp and Paper	75	6	4	1	0.2	0.1	-	-	0.4
Food Storage	10	0.4	-	-	-	-	-	-	0.4
Mining	10	0.4	-	-	-	-	0.2	-	0.2
Street Lighting	10	1	-	-	-	-	-	-	1.0
2004 to 2013 Efficiency Potential (GWh)		*39*	*8*	*5*	*5*	*4.2*	*1.4*	*1*	*5*
2003 Total End Use (GWh)	407		*54*	*34*	*23*	*45*	*169*	*59*	*24*

3.2.1 Pumping Systems

Sales Estimate

Estimated annual consumption by pumping systems by FortisBC's direct and indirect 41 industrial customers and 1,100 irrigation customers, and distributed water supply and waste treatment systems, is 54 GWh, or 13% of total annual industrial consumption in the service area.

Technology Review

Pumping System Improvement

This study includes efficiency savings from improving the mechanical systems used by industry. Components of a pumping system considered for improvement are the drive

[10] Natural Resources Canada. Canadian Industry Program for Energy Conservation. 2002
[11] Pacific Northwest Conservation Council

system, control method, distribution system, pump, and the end-use efficiency of the pumped liquid. Synchronous belts improve drive systems. Variable speed drives and trimmed impellers improve controls. Increased pipe diameter reduces friction and holding tanks can maintain equal flow over a production cycle. Efficient pumps reduce energy requirements. Optimizing design safety margin and practicing water conservation also reduce energy requirements.

This study has averaged the efficiency improvement for 200 hp (large) and 25 hp (small) centrifugal, rotary, and reciprocating pump systems. System savings vary by size of the pumping system. The large systems, 200 hp, are considered to consume 70 percent of the industry sector total pumping load, while the small systems, 25 hp, are assumed to consume 30 percent of the sector pumping load[12].

Target Size

Annual Operations and Maintenance :

One percent per year improved energy use efficiency, and

Capital Projects – Plant & Fabrication and Pump & Paper:

Large pumping systems (200 hp) upgrade projects to 25 percent of 2003 pumping load between 2004 and 2013,

Small pumping systems (25 hp) upgrade projects to 50 percent of 2003 pumping load between 2004 to 2013.

Efficiency Estimate

Savings Potential for Pumping Systems

Exhibit 3-8 shows the industrial pumping system savings potential.

Exhibit 3-8 Industrial Pumping Systems Savings Potential (2004-2013)

Pumping System Improvements		***Total***
Operations & Maintenance Efficiency Improvements GWh (1%p.a.)		
Plant & Fabrication	Average Annual Savings	0.3
	2004-2013 Savings	2.5
Pulp & Paper	Average Annual Savings	0.2
	2004-2013 Savings	2.5
Capital Efficiency Projects GWh		
Large Pumping Systems (200hp)	2004-2008 Savings	0.9
	2009-2013 Savings	0.9
Small Pumping Systems (25hp)	2004-2008 Savings	0.6
	2009-2013 Savings	0.6
Total Pumping System Improvements GWh		
	Average Annual Savings	0.8
	2004-2013 Savings (GWh)	8.0

[12] ISTUM Study

3.2.2 Air Displacement Systems

Sales Estimate

Estimated annual consumption by air displacement systems by FortisBC's direct and indirect 41 industrial customers, and distributed water supply and waste treatment systems, is 34 GWh, or 8% of total annual industrial consumption in the service area.

Technology Review

Air Displacement System Improvement

This study includes efficiency savings from improving the mechanical systems used by industry. Air displacement systems are fans and blowers used to propel a gas. Efficiency improvements for air displacement systems are the same as those for fan blowing systems that are used to convey material such as wood chips. Efficiency improvement potential relies on the design considerations, purpose, and operating conditions of the fan system. Fans are often oversized to accommodate unforeseen conditions, causing the fan to operate in a throttled mode during normal conditions. Fans are required to vary flow levels on a regular basis.

Thus, efficiency improvement can be found in the drive system, control method, distribution system, fan, and the end-use efficiency of the air flow. Synchronous belts improve V-belt drive systems. Variable speed drives adjust the motor drive and throttle as needed, reducing load. Computer control of operating schedules turn off the system during down times. Distribution duct losses can be reduced with elbow vanes, with reduced obstructions in the flow path and, if necessary rerouting of ducting. Efficient sizing of the fan system reduces load requirement and over-air supply, which may mean eliminating over-ventilation and high levels of excess air in combustion processes.

This study has averaged the efficiency improvement for backward inclined, radial, airfoil, and vaneaxial/tubeaxial fan systems. Typical applications for the radial, airfoil, and vaneaxial/tubeaxial systems are the wood products industry (airborne sawdust matter), process related (kiln ventilation), and general ventilation (HVAC), respectively.

Target Size

Annual Operations and Maintenance :

One-and-a-half percent per year improved energy use efficiency, and

Capital Projects – Plant & Fabrication, Wood Products, and Pump & Paper:

Fan systems upgrade projects to 10 percent of 2003 air displacement load between 2004 and 2008.

Efficiency Estimate

Savings Potential for Air Displacement Systems

Exhibit **3-9** shows the industrial air displacement improvements system savings potential.

Exhibit 3-9 Industrial Air Displacement System Improvements Savings Potential (2004-2013)

Air Displacement System Improvements		***Total***
Operations & Maintenance Efficiency Improvements GWh (1.5%p.a.)		
Plant & Fabrication	Average Annual Savings	0.1
	2004-2013 Savings	0.8
Wood Products	Average Annual Savings	0.3
	2004-2013 Savings	2.7
Pulp & Paper	Average Annual Savings	0.1
	2004-2013 Savings	1.4
Capital Efficiency Projects GWh		
Fan Systems (25hp)	2004-2008 Savings	0.3
	2009-2013 Savings	0.0
Total Air Displacement System Improvements GWh		
	Average Annual Savings	0.5
	2004-2013 Savings (GWh)	5.2

3.2.3 Compression Systems

Sales Estimate

Estimated annual consumption by compression systems by FortisBC's direct and indirect 41 industrial customers, and distributed water supply and waste treatment systems, is 23 GWh, or 6% of total annual industrial consumption in the service area.

Technology Review

Compression System Improvement

This study includes efficiency savings from improving the mechanical systems used by industry. Components of a compression system considered for improvement are the drive system, control method, distribution system, compressor, and the end-use efficiency of the compressed air synchronous belts improve V-belt drive systems. Using variable speed drives for compressor modulation will reduce system load requirements.

There are several distribution design features, such as multiple systems, storage in several locations throughout the system, routing to avoid pressure drop, and pipe size, that improve system efficiency. Increasing pipe diameter reduces friction and the storage tanks maintain equal flow over a production cycle. Efficient air dryers and compressors also reduce energy requirements. Utilization of blowers may be a more appropriate than compressors in some instances.

Compression System Maintenance

Not enough can be said about the losses caused by leaks in a compression system. A leakage control program will minimize the impact of any leaks that occur. Efficient size of nozzles for cleaning applications and reduction of system over-pressure help to optimize the system performance and energy use. Maintenance of inlet filters on the distribution system can also to contribute to optimal system performance.

This study has averaged the efficiency improvement for 200 hp (large) and 25 hp (small) centrifugal, double-acting reciprocating, rotary screw, and single-reacting reciprocating compression systems. Savings vary by size of the system. The large systems, 200 hp, are considered to consume 60 percent of the industry sector total pumping load, while the small systems, 25 hp, are assumed to consume 40 percent of the sector pumping load.

Target Size

Annual Operations and Maintenance :

One-and-a-half percent per year improved energy use efficiency, and

Capital Projects – Plant & Fabrication and Pump & Paper:

Large compression systems (200 hp) upgrade projects to 25 percent of 2003 compression load between 2004 and 2013,

Small compression systems (25 hp) upgrade projects to 50 percent of 2003 compression load between 2004 to 2013.

<u>Efficiency Estimate</u>

<u>Savings Potential for Compression Systems</u>

Exhibit 3-10 shows the industrial compressor system improvements savings potential.

Exhibit 3-10 Industrial Compressor System Improvements Savings Potential (2004-2013)

Compressor System Improvements		***Total***
Operations & Maintenance Efficiency Improvements GWh (1.5%p.a.)		
Plant & Fabrication	Average Annual Savings	0.1
	2004-2013 Savings	0.8
Wood Products	Average Annual Savings	0.2
	2004-2013 Savings	2.5
Pulp & Paper	Average Annual Savings	0.02
	2004-2013 Savings	0.2
Capital Efficiency Projects		
Large Compressor Systems	2004-2008 Savings	0.2
	2009-2013 Savings	0.2
Small Compressor Systems (25hp)	2004-2008 Savings	0.18
	2009-2013 Savings	0.18
Total Compressor System Improvements		
	Average Annual Savings	0.4
	2004-2013 Savings	4.2

3.2.4 Conveyance Systems

<u>Sales Estimate</u>

Estimated annual consumption by conveyance systems by FortisBC's direct and indirect 41 industrial customers, and distributed water supply and waste treatment systems, is 45 GWh, or 11% of total annual industrial consumption in the service area.

Technology Review

Conveyance System Improvement

This study includes efficiency savings from improving the mechanical systems used by industry. Conveyance systems move bulk material and comprise a belt or pulley assembly, a speed control, and a motor, making them simpler than pumping or air displacement systems. Conveyance systems are the most efficient amongst the auxiliary systems, including pumping, air displacement, and compression systems. As a result the size of efficiency gains is small, less than 10 percent improvement.

Improving the efficiency of the speed reducing gear drives and reducing friction loss with idlers can reduce load requirement. Selection of less abrasive material for the conveyor can reduce friction loss. Design improvements can shorten the distance and height requiring material conveyance. Adding control systems that schedule shut down during down reduces load requirement.

This study has averaged the efficiency improvement for belt, apron, chain, and screw conveyance systems. The belt system can move thousands of tonnes of material an hour over several kilometers. The apron conveyors are belt containers with raised edges along the belt, creating a container that can hold fine material. Log handling in the wood industry relies on chain conveyor systems to move logs through the milling process. Screw conveyors, with less hauling capacity, transport smaller volumes (less than 500 cubic metres per hour) over short distances; for example wood chips in a pulp mill.

Target Size

Annual Operations and Maintenance :

Two-tenths of one percent per year improved energy use efficiency, and

Capital Projects – Crops, Food, & Beverage, Plant & Fabrication, and Pulp & Paper:

Conveyance systems upgrade projects applied to 50 percent of 2003 conveyance load between 2004 and 2013.

Capital Projects –Wood Products

Conveyance systems upgrade projects to 25 percent of 2003 conveyance load between 2004 and 2013.

Efficiency Estimate

Savings Potential for Conveyance Systems

Exhibit 3-11 shows the industrial conveyance system improvements savings potential.

Exhibit 3-11 Industrial Conveyance Systems Improvements Savings Potential (2004-2013)

Conveyance System Improvements		***Total***
Operations & Maintenance Efficiency Improvements GWh (.2%p.a.)		
Crops, Food, Beverage	Average Annual Savings	0.01
	2004-2013 Savings	0.1
Plant & Fabrication	Average Annual Savings	0.01
	2004-2013 Savings	0.1
Wood Products	Average Annual Savings	0.1
	2004-2013 Savings	0.6

Pulp & Paper	Average Annual Savings	0.01
	2004-2013 Savings	0.1
Capital Efficiency Projects GWh		
Conveyors (25hp)	2004-2008 Savings	0.3
	2009-2013 Savings	0.3
Total Conveyance System Improvements GWh		
	Average Annual Savings	0.1
	2004-2013 Savings (GWh)	1.4

3.2.5 Other Machines Efficiency Upgrades

Sales Estimate

Estimated annual consumption by process equipment by FortisBC's direct and indirect 41 industrial customers, and distributed water supply and waste treatment systems, is 169 GWh, or 41% of total annual industrial consumption in the service area.

Technology Review

Process Equipment Efficiency Upgrade – Wood Products

As reported in the 1991 study[13], the wood products industry predominantly uses equipment such as saws, debarkers, lathes, planers, and sanders. This type of equipment is direct drive and does not offer the opportunity for "system" efficiency improvements that pumping or air displacement systems provide. It also true that the capital cost of new technologies remains high and that energy cost savings contribute little to building a recommended business case. This study has included equipment efficiency upgrades such as premium motors and improved controls.

Recent energy efficiency analysis, comparing wood product manufacturing to automobile manufacturing, has identified opportunities for increased use of variable frequency drive electric motors as suitable replacements for hydraulic mechanical systems.

The push for increased wood recovery and residue processing has increased plant productivity and the demand for electricity. The shift to value-added products is increasing the per-unit electricity demand by wood products. This study's energy savings estimate is the result of considering earlier studies of energy efficiency in the BC wood industry[14], the BC Hydro *2002 CR – Industrial* report, and other industry reports[15]. The replacement of high-efficiency motors, less than 500 hp in size, with premium efficiency motors and increased process controls can provide energy savings.

Wood products are an export commodity, with business cycles that create uncertainty and require quick corporate response. Energy is a relatively small input cost to the end product

[13] 1991 Conservation Potential Review: West Kootenay Powered Serviced Industrial Sector
[14] 1996 Energy Efficiency Opportunities in the solid Wood Industries (COFI, CIPEC, NRCan)
[15] CIPEC

and has little impact on competitiveness. These are identified measures but it is not expected that early market penetration will be significant in BC for the above reasons.

Process Equipment Efficiency Upgrade – Mining
The savings estimate here also relies on the replacement of high-efficiency motors with premium motors and improvement to ore grinders. Also, as producers of internationally traded commodities, it is not expected that the mining industry will move quickly to improve energy use efficiency unless there are significant benefits to productivity or a firm's bottom line.

Target Size
Capital Projects – Wood Products:
Premium motor upgrades for process equipment and increased process control to 1% percent of 2003 process equipment load between 2009 and 2013.
Capital Projects –Mining:
Improved efficiency upgrades to grinders and controls up to 1% percent of 2003 process equipment load between 2004 and 2013.

Efficiency Estimate
Savings Potential for Process Equipment Upgrade
Exhibit 3-12 shows the industrial other machines and equipment upgrade savings potential.

Exhibit 3-12 Industrial Other Machines and Equipment Upgrade Savings Potential (2004-2013)

Other Machines Equipment Upgrade		***Total***
Capital Efficiency Projects GWh		
Wood Products	2004-2008 Savings	-
	2009-2013 Savings	1.2
Mining	2004-2008 Savings	0.1
	2009-2013 Savings	0.1
Total Process Efficient Equipment Upgrade GWh		
	Average Annual Savings	0.1
	2004-2013 Savings (GWh)	1.4

3.2.6 Process Improvement

Sales Estimate
Estimated annual consumption by process equipment by FortisBC's direct and indirect industrial customers involved in the crops, food/ beverage, heat-reliant fabrication industries, and distributed water supply and waste treatment systems, is 59 GWh, or 15% of total annual industrial consumption in the service area.

Technology Review
This study has matched process improvements with FortisBC industrial customer loads. There are several measures suggested as improvements for refrigeration, metal melting, and waste water treatment systems. Since it is not known which measures can address specific

customer facilities, or the specific end use consumption by those facilities, the potential savings reported estimates of percentage improvement. Similarly, no specific cost data has been obtained. But review of other case studies and DSM programs do show these energy users making the investments in these improvements, which must tell us that they are economic in some jurisdictions. Site audits, energy use analysis, and economic analysis of selected measures will be able to provide the data and information for the total resource cost test.

Refrigeration Systems
Measures that can improve efficiency of industrial refrigeration are:

- enhanced computer controls of compressors, condensers, evaporator, and refrigerated area monitoring;
- defrost cycling when temperature drop across the evaporator deteriorates to a low value,
- temperature monitoring to ensure that sufficient, but not excess cooling energy is expended,
- compressor efficiency and type of refrigerant to match facility needs,
- enclosure insulation thickness to avoid heat loss,
- doorway openers and protective devices help to reduce amount of heated doorway air entering refrigerated area,
- waste heat recovery can be used as the heat source for under-slab heating, required to prevent heaving,
- compressor suction pressure increase improves heat removal from refrigerated area, accomplished by piping and valve design for a low-pressure drop or more efficient air coil fins for transferring heat from refrigerated area to refrigerant, and
- adjustable speed drive applications to evaporator fans, compressors and cooling tower fans (see auxiliary systems improvements above), and
- lighting design and controls can reduce lighting load in the refrigerated area and thus reduce the associated cooling load.

The computer controls can be retrofit onto existing equipment and are valuable as an efficiency measure for that reason. With little individual customer information, this study has included refrigeration improvement as Operations and Maintenance since many of the measures listed can be readily installed as part of ongoing maintenance practice and costs of improvements will vary for each customer facility.

Foundries
This study is reporting some of the energy saving opportunities provided from the Foundry Association of Canada on their web site www.foundryassociation.ca.

1. A foundry's furnace energy demand for melting is 78 percent of total demand and the energy consumption is 66 percent of total consumption by the facility. To identify savings opportunities for foundry operations, one must understand the operation's furnace and melting requirements Suggestions from the foundry associations follow.

- By reducing the non-productive idle time in the furnace through reduction of the extra delay in each melting cycle, energy savings can be achieved.
- Installed demand controllers can reduce potential peak requirements for power and result in increased demand during off peak hours.
- If multi-furnaces are in place, their operations can be staggered using new-generation power packs, which can split the power supply amongst the furnaces, controlling demand effectively.
- Also, operations may be able to identify a significant load that can be taken off-line instantly with acceptable impact on operations.

2. Efficient price signals, such as a real-time pricing program, whereby the facility receives the next day's energy price a day ahead and makes production scheduling and storage decisions for the next day according to the peak energy prices and hours of duration.

3. Furnaces need to be inspected for heat losses. Thermographic inspections can detect heat loss and detect electrical hot spots, sources of mechanical losses.

4. Power factor and power quality control provide equipment and power factor bill savings, as well as save energy. In a recent survey[16] it was found that electric induction and arc furnaces, when combined with older power supply systems generated harmonics severe enough to burn out motors, trip fuses, and damage capacitors for one third of those surveyed.

Bioreactor Systems
Waste water treatment facilities improvement have been achieved in the Okanagan with the installation of a bioreactor system which improves the aeration during the waste treatment process and thus reduces the amount of energy and time needed to complete the treatment cycle. The savings per capita due to the improved aeration is 35 kWh/a. The savings potential is estimated at 50 percent of the remaining population, taking into consideration areas that may be served by other types of waste water treatment systems.

Target Size
Annual Operations and Maintenance :
One percent per year improved refrigeration energy use efficiency, and
Capital Projects – Plant & Fabrication:
Bioreactor systems projects to 10 percent of 2003 process load between 2004 and 2013.
Electric furnaces projects to 4 percent of 2003 process load between 2004 and 2008

Efficiency Estimate
Savings Potential for Process Improvement

Exhibit 3-13 shows the industrial process improvements savings potential.

[16] Foundry Association of Canada, 2000

Exhibit 3-13 Industrial Process Improvements Savings Potential (2004-2013)

Process Improvements		***Total***
Refrigeration Efficiency Improvements GWh (1%p.a.)		
Crops, Food, Beverage	Average Annual Savings	0.1
	2004-2013 Savings	0.6
Plant & Fabrication	Average Annual Savings	0.51
	2004-2013 Savings	5.1
Food Storage	Average Annual Savings	0.1
	2004-2013 Savings	0.7
Capital Efficiency Projects GWh		
Bioreactor Efficiency	2004-2008 Savings	3.3
	2009-2013 Savings	3.3
Electric Furnaces	2004-2008 Savings	2.1
	2009-2013 Savings	-
Total Process Improvements GWh		
	Average Annual Savings	1.5
	2004-2013 Savings	15.0

3.2.7 Lighting Efficiency Improvement

Sales Estimate

Estimated annual consumption for lighting, including streetlighting, by FortisBC's direct and indirect 41 industrial customers, and distributed water supply and waste treatment systems, is 19 GWh, or 5% of total annual industrial consumption in the service area.

Technology Review

Lighting design for industrial facilities must consider safety and productivity requirements. Re-design and relamping may improve lighting efficiency but not provide energy use reductions. Efficiency measures for lighting industrial sites include metal-halide to T8s and improved control, conventional metal-halide to pulse-start metal-halide, rewiring and improved controls to match operating hours, and T12 to T8 fluorescent conversions in plant offices. This study includes a 2 percent annual reduction in industrial lighting load.

An increasing issue with street lighting and public area lighting is light pollution at night. Control systems are being designed to dim overhead lighting in residential areas during late evenings and overnight. It is expected that local municipalities will be investigating this technology within the next two years and that controls will be installed due to citizen demands. The study includes a 2 percent annual reduction in street lighting load to capture control systems and other lighting technology improvements.

Target Size
Annual Operations and Maintenance :
Two percent per year lighting energy savings, and
One percent per year for street lighting.
Capital Projects – New Lighting Design:
Six percent energy savings, due to design improvements, to the 2003 lighting load between 2004 and 2013.
Two percent energy savings, due to design improvements, to the 2003 street lighting load between 2004 and 2013.

<u>Efficiency Estimate</u>

<u>Savings Potential for Lighting Efficiency Improvement</u>

Exhibit 3-14 shows the industrial space heating and lighting savings potential.

Exhibit 3-14 Industrial Space Heating and Lighting Savings Potential (2004-2013)

Space Heating & Lighting		***Total***
Efficient Lighting Upgrade GWh (2%p.a.)		
All Sectors	Average Annual Savings	0.28
Street Lighting	Average Annual Savings	0.10
	2004-2013 Savings	3.8
New Lighting Design GWh (5%)		
All Sectors	2004-2008 Savings	0.42
	2009-2013 Savings	0.01
Street Lighting	2004-2008 Savings	0.42
	2009-2013 Savings	0.0
Total Lighting Improvements GWh		
	Average Annual Savings	0.5
	2004-2013 Savings	4.7

4.0 DEMAND REDUCTION

4.1 Peak Demand

The 2003 annual peak demand was 678 MW on the electric system. Currently FortisBC has resources in place to supply approximately 76 percent of peak demand[17], meaning 173 MW of capacity must be purchased from the market. Reliable reduction in peak demand can lead to reduced purchase costs and lower annual average purchase prices. There are also deferred capital costs associated with peak demand reductions.

Exhibit 4-1 is an estimated monthly peak demand for the combined direct and indirect sales in each sector, using the peak and monthly forecast data.

Exhibit 4-1 Estimated FortisBC Monthly Peak Demand

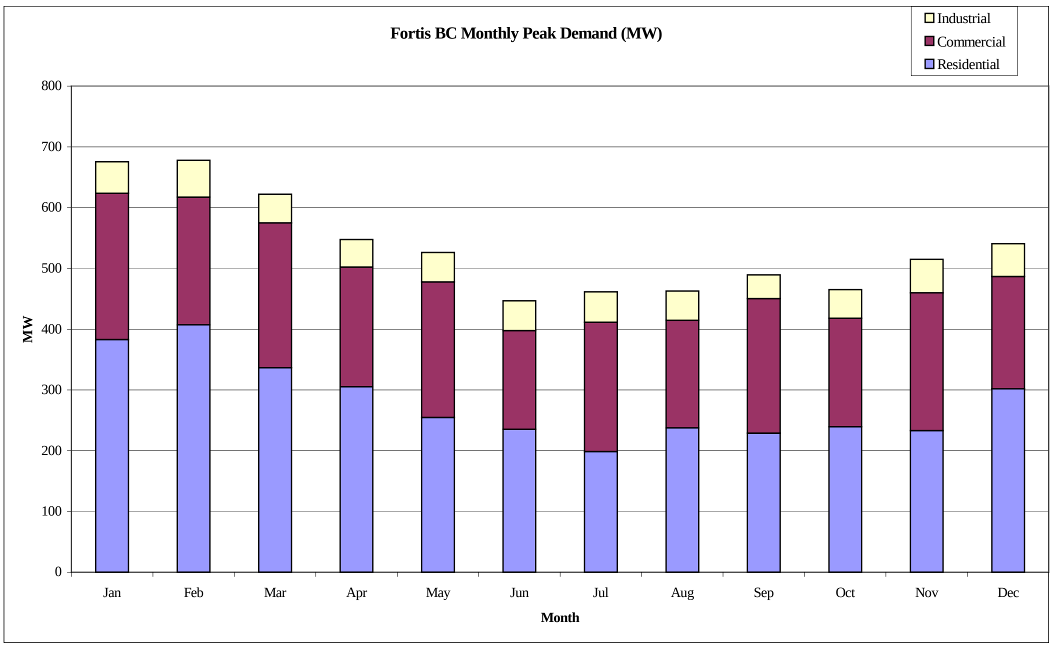


Exhibit 4-1 helps to show that introduction of demand response measures in the FortisBC service area will need to address the residential sector. The nature of large industrial loads and the desire of industry owners to manage costs presents the other customer group on which to focus early demand response programming

For example, the impact of a utility demand reduction program for residential water heaters controlling 10 percent, or 7,400 tanks, reduces residential demand by 7.4 MW, or approximately 2 percent of an illustrative January residential peak demand above. An example of the impact of industrial demand reduction capability, afforded by increasing pumping storage and allowing turn-down of 20 percent of pumping load reduces industrial

[17] FortisBC *2005 Resource Plan*, Executive Summary

demand by 1.4 MW, or approximately 1.5 percent of the estimated January industrial peak demand above.

4.2 Demand Response Program Design

This study is providing a brief introduction to demand response (DR) program design and benefits. DSM planning principles apply because DR programming must address utility, ratepayer and participant costs and benefits, including revenue impact. DR can be considered an insurance product because there are mutual economic benefits to the utility when they do not use DR and to the consumer for being ready to supply DR[18].

Size of the potential response resource is based on price elasticity: consumers will pay to use less high-cost utility-supplied electricity, starting in the short-term. Customer payment may be forgone revenue, increased costs, or down time. For the utility, studies show that as little as a five percent reduction in critical peak demand can result in a 50 percent energy hourly price reduction[19]. In the long-term, electricity rates will remain lower than otherwise would have occurred supplying unresponsive loads with either high price energy purchases, or sufficient capital additions to the electric system..

Fundamental features of DR programs are the load shape objective, the incentive structure and the response approach and measurement technique.

The load shape objective is the basis for the price response that the consumer receives. For example, this objective may involve shifting load from heavy load hours to low load hours, or reduce peak demand at a specified time.

The incentive or price response can be based on the real-time pricing that FortisBC would experience if and when it has to purchase on the spot market. Price response minimums need to be communicated well in advance to customers for them to consider implementing hard-wired direct controls for their equipment.

In order to obtain an appropriate load response, the business needs and technical processes have to be assessed. A joint customer-utility load review to identify critical and non critical loads is necessary. A customer's non-critical load would be targeted for the load response. This approach reduces overall customer risk and can create a low cost pool of DR for the utility. FortisBC's Partners-in Efficiency initiative is well placed to undertake such an initiative.

Automated meter reading and control is the technology solution that will allow the connection of all loads to a system-wide communication, measurement and verification network, enabling the identified loads to respond to the utility's requirement.

[18] Eric Hirst
[19] Demand Response: Principles for Regulatory Guidance Peak Load Management Alliance, February 2002

4.3 Princeton Light and Power DR Program

Since 1999 Princeton Light and Power has offered its residential, small commercial and general service customers the choice between a blended rate and a rate that varies seasonally and by peak/off-peak hours. Features of this successful program are[20]:

- Voluntary customer participation;
- Realistic assessment of benefits for customers;
- Integrated demand-side approach involving education, financing, automated metering and load shifting equipment; and
- A good match between technology and tariffs, considering tariff simplicity, stable rates, ease of use and shared costs of meters.

Princeton Light and Power's experience can provide a fast start to the introduction of DR.

4.4 DR Measures and Reductions

4.4.1 Residential

Automated metering has an important role to play in DR but that analysis is beyond the scope of this study. Regardless of how price communication, measurement, and verification occur, measures that can provide load response for households are listed in Exhibit 4-2 below.

Exhibit 4-2 Load Response Measures

End Use	Installed Equipment	Auxiliary System	DR measure	Households with Controllers	Unit Reduction (kW)
Space Heating	Zonal	None	Turn off scheduled	4,200	2
	Electric FAF	None	Turn off scheduled		
	Electric Hydronic	None	Turn down scheduled		
Space Cooling	CAC		Turn down		
Domestic Hot Water	Electric Tank		Controls/timer	7,400	1
	Electric Tank	Electric Hydronic Heating	Turn down scheduled – direct load control		
	Electric Tank	Larger tank	Increased hot water storage capacity		

[20] CERI – January 2005

4.4.2 General Service and Industrial

DR at large customer sites requires utility assessment of opportunities available based on energy uses. Exhibit 4-3 lists areas of opportunity to shift load or reduce demand as part of a DR program.

Exhibit 4-3 Load Shifting Measures

End Use	Installed Equipment	Auxiliary System	DR measure	End-use Demand (MW)	Reduction Capacity (MW)
Pumping	Pumping Systems	Split system; Add storage	Additional storage capacity to allow shutting pumps off	7.2	1.4
Hot water	Electric Tank	Larger tank for storage	Increased hot water storage capacity; turn off heater		
Hot Water	Electric Tank	Alternate fuel boiler and	Switch to alternate fuel boiler; additional storage		
Process	Process systems	Add capacity and storage	Additional storage capacity to allow shutting some equipment		

Recent experience in the Pacific Northwest by Bonneville Power Administration and Portland General Electric has been a demand response of 200 MW, which is about .8 percent of peak demand. A similar amount of reduction for FortisBC would be about 5.5 MW.

4.5 DR Pricing

The necessary price signal for the first generation of DR programming could, as a suggestion, be developed from averaging the unit costs of real-time or short-term purchases made to supply capacity during November to February peak demand hours. Calculated annually, the price would be set for the coming year, providing notice and price certainty to DR participants.

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GLOSSARY

Coefficient of Performance (COP): A ratio for both the cooling and heating modes calculated by dividing the capacity expressed in watts by the power input in watts, excluding any supplementary heat.

Commercial Sector: The commercial sector is generally defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule.

Conservation: Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Direct Load Control: Refers to program activities that can interrupt consumer load at the time of annual peak load by direct control of the utility system operator by interrupting power supply to individual appliances or equipment on consumer premises. This type of control usually involves residential consumers. Direct Load Control excludes Interruptible Load and Other Load Management effects. Direct Load Control (as defined here) is synonymous with Direct Load Control Management reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411: "Coordinated Regional Bulk Power Supply Program Report". The exception is that annual peak load effects are reported here and seasonal (i.e., summer and winter) peak load effects are reported on the OE-411.)

Direct Utility Cost: A utility cost that is identified with one of the DSM program categories (i.e., Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building).

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British Thermal Units.

Electric Capacity: The maximum electric power that a device or system is capable of producing or transferring. Electric capacity is measured in watts, kilowatts, megawatts, etc.

Electrical Efficiency: The ratio of the useful energy delivered by a system or end-use to the amount of electric energy supplied to it. This ratio measures how well electric energy is translated into another useful form of energy.

Electric Energy: It is the cumulative amount of electricity produced or consumed over a period of time. Electric energy is measured in kilowatthours, megawatthours, gigawatthours, etc..

Electric Power: The instantaneous rate at which electric energy is produced, transmitted or consumed. Electric power is measured in watts, kilowatts, megawatts etc.

Energy Efficiency of Equipment: The percentage of gross energy input that is realized as useful energy output of a piece of equipment.

Energy Efficiency Improvement: Reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting levels per square foot.

Energy Efficiency Investment: An investment that produces a reduction in energy use for a comparable level of service, compared to a specified base case.

Energy Efficiency of a Measure: A measure of the energy used to provide a specific service or to accomplish a specific amount of work (e.g., kWh per cubic meter of a refrigerator, therms per gallon of hot water).

Energy Efficiency Ratio (EER): A ratio calculated by dividing the cooling capacity in Btu per hour by the power input in watts at any given set of rating conditions

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Free Driver: A nonparticipant who adopted a particular efficiency measure or practice as a result of a utility program. See "Spillover Effects" for aggregate impacts.

Free Rider: A program participant (see definition) who would have implemented the program measure or practice in the absence of the program.

Gigawatthour (GWh): One million kilowatthours.

Gross Load Impact: The change in energy consumption and/or demand that results directly from program-related actions taken by participants in the DSM program, regardless of why they participated.

Industrial Sector: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments (Standard Industrial Classification (SIC) codes 01-39). The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Integrated Resource Planning: A planning and selection process used to evaluate a wide range of electricity supply-side and demand-side options to determine the most appropriate mix of resources to reliably meet future electricity requirements. The economic, environmental and social impacts and risks of the resource options may be weighed by public input and ranked for priority selection.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): The amount of energy transferred at a rate of one kilowatt for one hour.

Load: The amount of electricity required by a device, customer or group of customers as measured by an electricity meter. Load may be measured instantaneously in terms of electric capacity in units such as kilowatts. Over time load may be measured in terms in units such as kilowatthours.

Load Building: Fuel substitution and load building share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas or electricity and gas (load building). Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

Load Impact: Changes in electric energy use, electric peak demand, or natural gas use.

Marketing Cost: Expenses directly associated with the preparation and implementation of the strategies designed to encourage participation in a DSM program. The category excludes general market and load research costs.

Measure (Energy Efficiency Measure): A product whose installation and operation at a customer's premises results in a reduction in the customer's on-site energy use, compared to what would have happened otherwise.

Monitoring and Evaluation Cost: The planning, collection, and analysis of data used to assess program operation and effects. It includes the activities such as load metering, customer surveys, new technology testing, and program evaluations that are intended to establish or improve the ability to monitor and evaluate the impacts of DSM programs, collectively or individually.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

Other Load Management: Refers to programs other than Direct Load Control and Interruptible Load that limit or shift peak load from on-peak to off-peak time periods. It includes technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation of equipment from on-peak to off-peak periods through the application of time-differentiated rates.

Participant: An individual, household, business, or other utility customer that received the service or financial assistance offered through a particular aspect of a utility program in a given program year. Participation is determined in the same way as reported by a utility in its Annual DSM Summary.

Peak Demand: The maximum load during a specified period of time.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts.

Residential Sector: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use.

Spillover Effects
Reductions in energy consumption and/or demand in a utility's service area caused by the presence of the DSM program, beyond program related gross savings of participants. These effects could result from: (a) additional energy efficiency actions that program participants take outside the program as a result of having participated; (b) changes in the array of energy-using equipment that manufacturers, dealers, and contractors offer all customers as a result of program availability; and (c) changes in the energy use of non participants as a result of utility programs, whether direct (e.g., utility program advertising) or indirect (e.g., stocking practices such as (b) above, or changes in consumer buying habits).

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Seasonal Energy Efficiency Ratio (SEER): Seasonal energy efficiency ratio – the total cooling of a central air conditioner or heat pump in Btu during its normal annual usage period for cooling, divided by the electric power usage in watt-hours during the same period.

Tariff: The rate and the terms and conditions of sale of electric power and energy between utility and customer. It includes the type of service, delivery point(s), limitations of obligations to serve, minimum charges, etc.

Total Utility Costs: Refers to the sum of the total Direct and Indirect Utility Costs for the year. Utility costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur.

Watt: The basic unit of measurement of electrical of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities.

FORTISBC

DEMAND SIDE MANAGEMENT FIVE YEAR BUSINESS PLAN

2006 – 2010

PREPARED BY:

BRIAN PARENT
MANAGER, ENERGY EFFICIENCY SERVICES

WITH ASSISTANCE FROM:
LIGHTSTREAM BUSINESS SOLUTIONS
WILLIS ENERGY SERVICES

OCTOBER 31, 2005

EXECUTIVE SUMMARY

The 2005 Demand Side Management Five Year Business Plan (the Plan) identifies the Energy Efficiency or Demand Side Management (DSM) market within the company's service area and describes the programs selected to deliver efficiency savings measures to customers over the next five years. The Plan includes the forecast of efficiency savings targets and associated benefits and costs, incorporating the recent 2005 DSM efficiency potential update information.

Since 1989 our customers have saved 226 gigawatt hours (GWh) of energy and have avoided 38 megawatts (MW) of capacity requirements for power. The investment in DSM measures of $26 million by the company and $22 million by FortisBC customers over the last 15 years has been offset by $68 million of avoided power purchase costs. DSM program performance has yielded a benefit-cost ratio of 1.4 since inception.

For the years 2006-2010, the energy efficiency savings target is 81 GWh, with an associated capacity reduction target of 13 MW, plus 1.3 MW of system load reduction measures involving load control. The total utility DSM budget for the five years is set at $10.9 million. Customers are expected to spend $8 million as program participants. The total DSM savings expenditure is $19 million, while the avoided cost of purchases is expected to be $30 million, resulting in an expected benefit cost ratio of 1.6.

The Plan development relied on the customer load and end use information and the review of available efficiency technologies and expected regulation changes presented in the 2005 efficiency potential update. The update estimated 294 GWh of available savings potential for the period 2004 to 2013. The Plan target of 81 GWh is 27 percent of the available potential.

The existing DSM programs are robust and continue to be the foundation of the Plan. Recognizing changing market conditions and the opportunities presented by a growing energy efficiency industry, the Plan has also selected to introduce peak demand reduction measures and to continue to innovate and adapt the design and delivery of energy efficiency programs. Along with the existing programs, the following are included in the Plan and will be delivered with energy auditing and incentives (including rebates and low-cost financing) programs.

- Off-peak water heater control in the residential and general service sectors,
- On-site review of larger customer facilities to catalogue Demand Response opportunities and initiate mutually agreeable arrangements,
- Pilot to promote efficiency upgrade measures for investor-built multi unit housing projects by funding of measures on tenant bills,
- Program design investigation of education and public awareness programs to determine program costs, estimated savings, delivery options and verification processes,
- Efficient commercial clothes washers in multi-unit residential building and complexes,
- Improved hot water insulation for residential water heating,
- Heat pump hot water heaters, and
- A residential appliance program using Dryerballs ™, to reduce clothes drying time.

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INTRODUCTION

Scope

This report outlines the demand side management (DSM) plan for FortisBC and its wholesale customers during the five years 2006 to 2010.

The Plan is based on a market that includes the retail customers of the wholesale utilities served by FortisBC. The forecast of DSM reflects our current business arrangements with these utilities.

This DSM plan is continuation of existing successful programs with the addition of new measures that have been identified as a result of the updated DSM potential and the input of the DSM Incentive Committee (see DSM Incentive Section for the purpose and role of the Committee).

Rationale for DSM

DSM is a low cost resource and this fact is the key driver of the DSM programs described in our plan.

In delivering DSM the resource acquisition must meet an economic test. The cost of DSM must be less than the alternative of buying and delivering power. FortisBC does not have enough hydro generation to meet its customers' needs and must buy power from others. DSM provides the utility with flexible alternatives to meet our customers' needs at less cost.

DSM programs provide a prudent investment for our shareholder. DSM expenditures are rate-based and therefore earn a return similar to distribution and generation assets. In addition, the company can earn a portion of the net benefits from DSM activities under a shared savings mechanism (SSM). The SSM is described in Appendix C.

MARKET POTENTIAL

In 2005, an estimate of the remaining energy efficiency savings and demand reduction potential was developed in conjunction with Willis Energy Services. This study focused on determining the efficiency and demand reduction potential from technical measures that deliver reliable and persistent results. It relied on Deemed Savings, energy savings performance based on regulated equipment and appliance testing by regulatory agencies, in cooperation with manufacturers and utilities and on energy savings measures based on engineering estimates.

The 2005 DSM market potential was an update to the original DSM potential study undertaken in 1991 and the 1999 update. The 2005 study estimated remaining DSM potential for the Residential, General Service and Industrial Sectors.

The cost of electricity and the roster of market ready technologies are consistent with the BC Hydro DSM potential study in 2003. The market potential was based on the availability of "hard-wired" technologies and advancing the adoption rate through the use of rebates and low cost loans. The assumptions for the legislated energy efficiency levels that were used in the potential review were based on recent provincial and federal government information. The company's DSM market potential on which this business plan was developed is detailed in the FortisBC Energy Savings and Demand Reduction Potential Study dated September 15th, 2005.

This plan reflects suggestions from the DSM Incentive Committee including the development of a more extensive education and customer awareness program, the initiation of a municipal and provincial elected representative's information update program, the targeting of reservoir backed district irrigation systems for load control systems and the development of an energy efficiency financing approach for multi unit residential rentals.

See Appendix D.

DSM Market Potential and Business Plan Activity 2006 - 2010

The following table provides a summary of market potential and the amount that will be acquired over the next 5 years as part of this business plan:

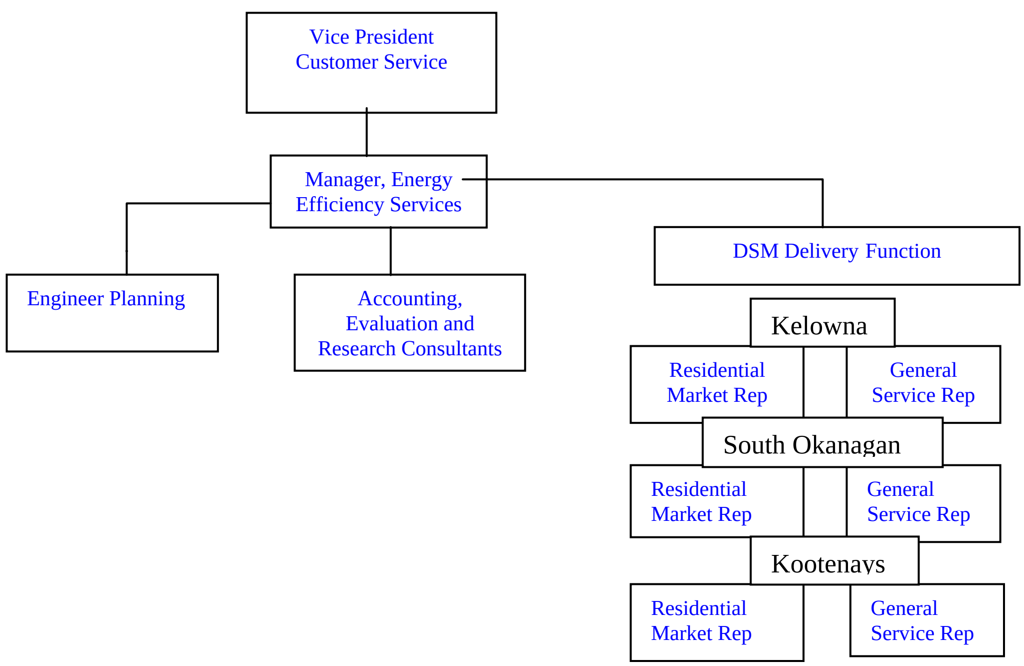
Sector	Market Potential	Plan 2006-2010	% of Potential
Industrial	32.4	8.8	27
General Service	178.5	43.5	24
Residential	83.5	28.2	34
Total	294.4	80.5	27

Our Focus
Our DSM programs are aimed at encouraging our customers to use energy wisely.

Program Design
There is still a significant market potential in all customer sectors. The company will meet its market goals with the current slate of programs. Any enhancements that have been identified as a part of this planning process have been included in the section on Program Review and Plan Strategy. The company plans to keep our programs consistent during the 5-year plan unless changes become warranted by new market conditions or higher legislated efficiency standards. FortisBC will offer a broad range of services including:

- Information through advertising campaigns, group presentations, brochures, and newsletters.
- On-site technical reviews such as home energy audits for residential customers and walk-through audits and comprehensive efficiency studies for non-residential customers.
- Financing that includes loans, grants and product rebates and a review of new billing financing options.

Organization



The five-year plan continues with current organizational structure for PowerSense consisting of two groups: planning and delivery:

- Planning has two staff and an Evaluation Consultant who develops and enhance programs, perform market and engineering research, design advertising and sales campaigns, perform process and impact evaluations and manage the relationship with the regulator and customer interest groups. This group works with engineering, public relations, advertising and operational auditing professionals to augment internal resources. Accounting and financial planning also occurs within this function.

- Delivery has three regional two-person teams who report to the Manager. These teams provide technical and administrative services and coordinate program implementation with customers. Each team works with trade allies that include engineering and architectural firms, local building, electrical and heating contractors, and retail building supply stores and other energy services providers to deliver the programs.

Trade Allies
Our relationship with trade allies and energy service providers is fundamental to the success of our programs. Trade allies receive advertising and technical assistance from us. They can offer their customers our financing and grants for energy efficiency projects. This helps them create business and it helps us meet our goals.

PROGRAM REVIEW AND PLAN STRATEGY - RESIDENTIAL SECTOR

Home Improvements and New Home Program

These programs consist of efficiency measures like building envelope improvements, heat pumps for heating and cooling, compact fluorescent lighting (CFL) systems and hot water heater controls.

Existing Programs
1. Under the Home Improvements Program (HIP) an electric heat customer can receive a free Energy Audit or a $50 credit towards NRCan’s EnerGuide for Homes audit and a free hot water kit. To finance efficiency improvements to the home, the customer is eligible for a grant of 5 cents per kW.h saved.
2. To promote heat pump technology, there is a grant of 5 cents/kW.h saved or a loan of up to $5000 at 4.9% for 10 years on qualifying units.
3. For efficient lighting, there are product rebates of $5 or 50% of the cost of compact fluorescent lights (CFL) or a grant of 5cents/kW.h saved with a 2 year minimum payback.
4. The New Home program provides high E window upgrade rebates of up to $2.50 per SF and a CFL demonstration package of 10 lights valued at $100.

Challenges
- To make our customers more informed about wise energy use.
- To influence customers switching to electric space heating because of rising natural gas commodity prices, so that the most efficient electric technology (heat pumps) is chosen instead of the cheapest (baseboards)
- To increase market penetration of energy efficiency new residential construction especially in the multi unit residential rental market.
- To assist in creating and nurturing a healthy geo-exchange infrastructure so that this technology has a fair chance of being chosen in large scale applications.
- To demonstrate that hot water load controllers can provide an acceptable peak clipping measure.
- To sustain and increase public awareness about the performance of CFL’s with respect to design, colour rendition, starting characteristics and cost effectiveness.
- To increase the volumes in HIP.

Opportunities

School education and public awareness campaigns can yield immediate energy savings and are an important factor in consumer adoption of the "hard-wired" measures.

With the rising cost of oil and natural gas commodity prices, there will trend to switch to electric heating. In our potential study, the company has already identified a space heating plug load in 10% -20% of gas heated homes. Anecdotal information indicates that some people may remove their gas furnace and install baseboard heaters. Based on a comparison of current rates there is only a 10% saving by using baseboard heaters. With the current NRCan EnerGuide for homes rebate program and our financial support of heat pump technology, there is an opportunity to have fuel switching customers choose heat pumps over baseboards. The payback for customers would be 5 years. And as an additional benefit, customers could reduce their exposure to changing fuel prices by having access to 2 fuel sources.

Electric space heating has its highest market penetration (75%) in the multi-unit residential housing sector. This market has potential for improvements in space heating efficiency and envelops upgrades because each project involves a large number of housing units under the control of a single developer. In addition, other efficiency upgrades can be introduced for appliances and plug-in loads. However, when efficiency upgrades benefit future owners or tenants and not the developer, an intervention that helps "purchase" efficiency at the time of construction through the introduction of a long-term efficiency financing option for ultimate occupants should work.

Large scale multi-unit residential housing projects in excess of 75 units also present a cost effective opportunity for geo-exchange systems. The Life Cycle cost of geo-exchange is less than other alternatives, but the adoption of this technology requires a disciplined infrastructure to make it attractive to investors. Effective engineering design, proper installation and commissioning, attention to operational detail, appropriate financing and a conventional utility billing process is necessary.

Multi-unit residential housing projects like condos and apartments are built by developers on speculation. There may be opportunities to invest in load control measures that will reduce the capital and operating costs for the developer and provide a practical demand reduction resource. The Big White residential and ski area is a seasonal peaking load that is scheduled for supply side upgrades. The key residential loads are space heating and water heating. Hot water controls can shift existing loads and can reduce the load impact of residential growth in the area.

CFL - screw-in lights are a cost effective and educational component of the new home program. This aspect of the new home program could become a part of the EnerGuide For Homes audit and could be provided to residential customers to familiarize them with the advantages of the CFL technology.

Homeowners are interested in upgrading the appearance and functionality of their homes. New windows and doors are usually an important part of the design. The company can provide information in cooperation with EnerGuide for Homes about how easily a home renovation can save money through energy efficiency as well as make the home look and feel better. Additionally, during 2006/2007 the federal and provincial governments will fund the installation of Energy Star windows and doors. A rebate of $1.50 per sf. of window will be provided to customers.

Strategy and Program Enhancements

1. During 2006, Fortis will investigate the introduction of an education and customer awareness program by issuing a request for proposal that will include the definition of a process to verify savings derived through this initiative. Once a proposal has been accepted, the Business plan will be updated for costs and savings.
2. Fortis will develop and implement an approach to inform municipal and provincial elected representatives about energy efficiency issues and initiatives in our service area.
3. HIP: FortisBC will contact the top 200 residential energy consumers to reduce their energy costs; by recommending an EnerGuide audit to learn what action should be taken and how to obtain federal and utility upgrade incentives; providing a 2 pack CFL demo package; initiating a quarterly billing insert that highlights

heat pump, window or lighting retail specials; and providing periodic mass market advertising.

4. HIP: FortisBC is working to complete arrangements with the province to offer existing electric heat customers with a high efficiency window incentive of $1.50 per SF in 2006 and 2007.
5. HIP: FortisBC will coordinate activities with the EnerGuide for Homes initiative so that owners and renters living in mobile home parks have information about energy efficiency upgrades and available financial incentives.
6. ASHP: The top 200 energy consuming residential customers will be informed about this technology and encouraged to have an EnerGuide audit.
7. ASHP: FortisBC will investigate the cold climate air source heat pump technology; confirm its effectiveness and if proven, then incorporate it into our programs. It has the capability to operate at – 20 F without resistance heating backup.
8. Geo-Exchange: FortisBC will enter into an agreement with a developer of a multi-unit residential project to acquire and operate a geo-exchange heating and cooling system that meets our TRC.
9. Hot Water Controls: FortisBC will develop a load shifting pilot project by paying the full cost of replacement or new hot water tanks with a controller for apartments, condos and other appropriate projects where water heating is done electrically and the facility is maintained by a property manager. FortisBC will meet with the landlord or owners to provide information on reducing costs through a load shifting technology and simple lifestyle changes. The prime focus for this pilot will be at a Big White or new multi-unit residential facilities. Based on the 2006 results, a new program will be added to the capital plan in 2007.
10. New Home Program: The company will continue our incentives and our focus on electrically heated single-family and multi-unit residential housing. In situations where developers are building speculative homes or apartments, FortisBC pays the incremental cost for window upgrades and provide 7 complimentary CFL's for each unit. For electrically heated owner occupied single family units, FortisBC will pay $1.50 per SF for window upgrades and arrange for a complimentary demonstration 10 pack of CFL's.
11. New Home Program: The reps will work with developers and BC Housing multi-unit housing societies to act as an energy efficiency advisor during any new projects. Life cycle leasing options for energy efficiency equipment upgrades will be identified and developed for each project and offered through a billing option.
12. CFL: FortisBC will promote the use of CFL's as an outdoor residential light option.

PROGRAM REVIEW AND PLAN STRATEGY - GENERAL SERVICE SECTOR

Building Improvements Program and New Facility Program

The Building Improvements Program (BIP) and the New Facility Program (NFP) consist of energy efficiency measures for building envelopes, heating, ventilation and air conditioning (HVAC), lighting, municipal water and sewer process, and pump load management.

Existing Program

1. Free walk-through audit or 50% of comprehensive efficiency study to a maximum of $5000 subject to funding availability
2. Incentives for efficiency measures are based on the lesser of:
   - 50% of cost for existing facilities or 100% for incremental cost of new facilities
   - 5 cents per kW.h saved
   - amount required for a 2 year payback
3. Loans at cost of funds + 2% are available
4. Optional energy efficiency services are available for all general service customers. These services include a review of design and product specifications; project management; short term project financing and performance guarantees

Challenges

- To sustain program participation by gaining knowledge about customer planning and decision-making criteria and identifying key customer projects that are most likely to proceed.

- To identify and demonstrate a variety of technologies and approaches that can provide an acceptable peak clipping measures.
- To promote business relations with key trades contractors and developers

Opportunities
Large developers and key businesses need to know how they can profit from investments in energy efficiency and working with FortisBC.

The school and health care sectors will continue to invest in retrofit and new facilities in our service area over the next five years. Decision-makers need information about technology options and FortisBC financial assistance that supports lifecycle economics.

Based on our review of municipal water and sewer treatment plants and implemented recommendations, there is a significant savings potential. There is also an opportunity to implement load management of municipal water pumps and district irrigation systems with reservoir capabilities.

Strategy and Program Enhancements
1. FortisBC will increase its “Partners-in-Efficiency (PIE)” arrangement to include its top 200 energy customers. Under this arrangement, the company are directly involved with the customer’s annual capital budget process to identify potential efficiency improvements and develop funding for these. Utility cost tracking will be offered for a fee and a performance awards system will be offered.
2. For PIE customers, the company will undertake a review of facilities to identify Demand Reductions opportunities and develop technical options, related financial arrangements and establish a dispatch protocol for drawing these resources.
3. Efficiency awareness will be promoted through recognition press releases and quarterly updates to our website covering new projects, technologies or program offerings.
4. For all municipal customers and selected district irrigation districts, water and sewage treatment process reviews will be completed through on-site visits. FortisBC will arrange training for local engineering firms to perform subcontract process audits for water and sewage treatment operations in our service area. Water distribution operators will be contacted for reservoir capabilities and demand response opportunities.
5. The company will offer “full cost recovery” energy services related to heating, cooling, outdoor lighting and water handling equipment to municipal, university, school and hospital. In cases where an E/E system meets our TRC but does not meet governmental payback criteria, FortisBC may purchase EM equipment and may enter into a sale and leaseback arrangement with a third party.
6. The company will hold information sessions with lighting and HVAC contractors to update them about our programs and services and obtain their input on growing the energy efficiency business.

PROGRAM REVIEW AND PLAN STRATEGY - INDUSTRIAL SECTOR

Efficiency Improvements and New Design
Efficiency improvements and New Design Programs include measures like adjustable speed drives, correct motor sizing and replacement of underutilized motors, matching pump size to load, improving heating and cooling systems and compressed air system sequencing and maintenance.

Existing Programs
1. 50% of comprehensive on-site efficiency study, free air leak test in the case of compressed air
2. Incentives for efficiency measures are based on the lesser of:
   - 50% of cost for existing facilities or 100% for incremental cost of new facilities
   - 5 cents per kWh saved
   - amount required for a 2 year payback
3. Loans at cost of funds + 2% are available

3. Optional energy efficiency services are available for all industrial customers. These services include a review of design and product specifications; project management; short term project financing and performance guarantees

Challenges

- The company has to sustain program participation by keeping informed about our customers' capital planning activities.
- This sector has very short payback criteria of less than 2 years for energy efficiency upgrades.
- Compressed air systems need to be updated for variable speed drives improvements and follow up with customers to ensure maintenance of leak reduction savings

Opportunities

This sector comprises a relatively small number of customers with large facilities. Site potential for energy efficiency and demand reduction is larger than for other customer sectors. These customers are interested in opportunities to reduce costs and improve operations. However, decision-makers normally use a payback criterion that is two years or less. Shaping financial arrangements to meet this payback hurdle will encourage more projects.

Strategy and Program Enhancements

1. FortisBC will continue the Partners-in-Efficiency arrangement with these customers. The company will be directly involved with the customer's annual capital budget process to identify potential efficiency improvements and develop funding for these. Utility cost tracking will be offered for a fee and a performance awards system will be established.
2. The company will undertake a review of facilities to identify Demand Reductions opportunities and develop technical options, related financial arrangements and establish a protocol for dispatching these resources.
3. FortisBC will arrange contracting services with compressed air specialists to perform annual maintenance of compressed air systems on a contingency fee basis for 25% of energy savings from the review to a maximum of our cost plus $500.
4. Efficiency awareness will be promoted through a series of press releases, periodic updates on our website covering new projects, technologies or program offerings for this sector. The company will sponsor customer site visits of any unique efficiency projects that have been implemented. This will be of interest to FortisBC staff, local engineering firms and customers in the same business.

WHOLESALE CUSTOMERS PROGRAM DELIVERY

Delivering DSM services for the Wholesale utilities that FortisBC serves requires a commitment to regular communication and a consistent demonstration of our openness to do what is necessary for our customers to satisfy their customers. The priorities and DSM objectives of each utility will vary based on its needs. Program delivery will be flexible enough to accommodate the different interests.

FortisBC will work with each utility to establish:

- An annual action plan to address current interests
- A prioritized list of issues with the DSM service,
- Notification of large incentives payable to their customers

During this plan the company will continue our full slate of DSM programs for Wholesale utilities.

DSM INCENTIVES

DSM Incentive Committee

Since 2000, a new incentive approach has been operational that provides FortisBC with a share of the net benefits from its DSM activities. This mechanism sends the signal to maximize the resource savings per dollar spent on energy efficiency measures. The SSM will provide for a small share of the life-cycle benefits as a potential reward to the shareholders. More details are contained in Appendix C.

As part the mechanism arrangement, a DSM Incentive Committee was established. The purpose of the DSM Incentive Committee is to:

- Establish the structure of the company's incentive mechanism and review its effectiveness;
- Review DSM operating results for DSM incentive purposes;
- Provide advice and comments on operating results and plans and
- Approve the DSM incentive calculation and report to the NSP Annual Review.

The committee represents a broad range of stakeholders:

- All customer sectors including Residential, General Service and Wholesale
- Environmental groups and non-utility energy service groups and
- FortisBC

The incentive mechanism creates a high profile and stimulus for DSM activities because it recognizes and rewards the company for superior DSM performance.

PLANNING AND EVALUATION

Planning and evaluation activities and annual budgets are described in Appendix B.

FINANCIAL PLAN

Plan Development

The financial plan is based on the Market Potential review and supports the actions that have been identified in the Program Review and Plan Strategy. It provides for an appropriate level of funding to deliver continuing programs and to investigate, plan, test and evaluate the proposed changes to the program portfolio.

Annual DSM Targets

Plan Years Program	2005	2006	2007	2008	2009	2010	Total
Total Energy Efficiency (GWh)	***19.0***	***20.400***	***16.200***	***16.100***	***13.900***	***13.900***	***80.50***
Total Demand Reduction (MW)	***0***	***0.050***	***0.150***	***0.250***	***0.350***	***0.450***	***1.25***

The plan targets are derived from program experience and take into consideration the results of the market potential study. The targets reflect a very robust residential market in 2006 with a return to early 2000 levels during the remainder of the plan, and a reduction in the general service and industrial sectors during the last two years of the plan.

Annual DSM Program Savings by Sector

Plan Years / Program	2005	2006	2007	2008	2009	2010	Total
New Home	4.9	7.2	3.3	3.3	2.9	2.9	19.6
Home Improvements	3.3	2.4	1.6	1.6	1.5	1.5	8.6
Residential Sector	*8.2*	*9.6*	*4.9*	*4.9*	*4.4*	*4.4*	*28.2*
New Facilities	2.7	2.7	2.7	2.7	2.3	2.3	12.7
Building Improvements	6.4	6.4	6.6	6.5	5.6	5.6	30.7
General Service Sector	*9.1*	*9.1*	*9.3*	*9.2*	*7.9*	*7.9*	*43.4*
New Design	0.3	0.3	0.3	0.3	0.3	0.3	1.5
Industrial Efficiency	1.4	1.4	1.7	1.7	1.3	1.3	7.4
Industrial Sector	1.7	1.7	2.0	2.0	1.6	1.6	8.9
Total Energy Efficiency (GWh)	**19.0**	**20.40**	**16.300**	**16.100**	**13.900**	**13.900**	**80.50**
Residential Sector	0	0.050	0.100	0.150	0.200	0.250	0.75
General Service	0	0	0.050	0.100	0.150	0.200	0.50
Industrial	0	0	0	0	0	0	0
Total Demand Reduction (MW)	**0**	**0.050**	**0.150**	**0.250**	**0.350**	**0.450**	**1.25**

- Residential Sector. The Residential sector will see a continuation of programs and targets that are based on the strength of the market. But overall, the company expects to see a tapering off in the market activity and corresponding activity in our programs.
- General Service Sector. The targets are based on a continuation of our existing programs with the recognition that a decrease in target will result in the latter years of this plan from the market penetration of more efficient lighting technologies and the diminishing returns from this technology.
- Industrial Sector. Savings identification and delivery will continue through energy management committees for large customers. Energy savings will decline marginally over the five-year period from the plan of 1.7 GWh in 2005 to 1.6 GWh by 2010.

Annual Costs
The following table details expenditure categories over the plan period with comparative costs for the 2005 plan year:

Plan Years / Costs in $000	2005	2006	2007	2008	2009	2010	Total (2006-10)
Labour	739	795	778	787	796	805	3,961
Incentives	661	1,005	864	931	899	960	4,659
Advertising	105	111	113	116	118	120	578
Administration	328	325	340	350	358	362	1,735
Total Costs	**1,833**	**2,236**	**2,095**	**2,184**	**2,171**	**2,247**	**10,933**

Benefit Cost Ratio

The benefit cost ratio indicates the robustness of our DSM programs. The benefits of energy and capacity savings and the value of deferred transmission and distribution expenditures are compared to the cost of delivering the DSM programs. The following table summarizes plan savings, benefits and costs:

Plan - Annual Savings, Benefits and Costs

	Actual	Results	Plan	Plan					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
Energy Efficiency (GWh)	18.50	21.30	19.00	20.40	16.20	16.10	13.90	13.9	80.5
Capacity savings (MW)	3.00	3.70	3.00	3.55	2.55	2.55	2.25	2.25	13.15
Demand reduction (MW)	0	0	0	0.05	0.15	0.25	0.35	0.45	1.25
Gross Benefits ($000)	5,419	6,182	6,262	7,247	5,856	5976	5,307	5,424	29,810
Fortis Costs ($000)	1,705	1,989	1,833	2,236	2,095	2,184	2,171	2,247	10,933
TRC Benefit/Cost Ratio	1.60	1.50	1.80	1.70	1.60	1.60	1.50	1.50	1.60

The gross benefits from DSM over the next five years will be $29.8 million. The DSM budget for the same period will be $10.9 million. FortisBC will save $18.9 million as a result of the DSM activities described in this plan.

The benefit cost ratio from DSM activities including customer costs is projected at approximately 1.6.

Other Information

The DSM Capital Budget Summary is included in Appendix A

.

APPENDIX A

DSM CAPITAL BUDGET SUMMARY 2006 - 2010

Energy Management Financial Plan
Year 2006

	Financia Incentive	Admin	Custome Cos	Tota Resourc Cos	Annua Energ Saving (kWh	Annua Capacit Saving (kw	Benefit	TR Benefit Cost	Utilit Benefit Cost
Home Improvements	123	106	89	318	2,388,200	866	617	1.9	
New Home	488	281	872	1,641	7,230,300	1,049	2,777	1.7	
Total	611	387	961	1,959	9,618,500	1,915	3,394	1.7	3.4
Building Improvement	263	268	507	1,038	6,450,000	1,101	2,308	2.2	
New Facilities	89	69	361	519	2,700,000	402	1,045	2.0	
Total General	352	337	868	1,557	9,150,000	1,503	3,353	2.2	4.9
Industrial	98	64	81	243	1,400,100	138	409	1.7	
New	11	9	32	52	249,900	30	91	1.8	
Total	109	73	113	295	1,650,000	168	500	1.7	2.7
All	1072	797	1942	3,811	20,418,500	3,586	7,247	1.7	3.2
Planning and		367							
Total		2,236							

FortisBC

Energy Management Financial Plan
Year 2007

	Financia Incentive	Admin	Custome Cos	Tota Resourc Cos	Annua Energ Saving (kWh	Annua Capacit Saving (kW)	Benefit	TR Benefit Cost	Utilit Benefit Cost
Home Improvements	139	102	120	361	1,574,700	526	496	1.4	
New Home	279	273	350	902	3,287,200	418	1,238	1.4	
Total	418	375	470	1,263	4,861,900	943	1,734	1.4	2.2
Building Improvement	297	274	571	1,142	6,559,000	1,113	2,427	2.3	
New Facilities	89	69	361	519	2,700,000	402	1,081	2.1	
Total General	386	343	932	1,661	9,259,000	1,515	3,508	2.2	4.9
Industrial	113	63	98	274	1,700,000	190	491	1.8	
New	15	9	45	69	350,000	42	132	1.9	
Total	128	72	143	343	2,050,000	233	623	1.8	3.1
All	932	790	1545	3,267	16,170,900	2,691	5,865	1.6	2.8
Planning and		373							
Total		2,095							

Energy Management Financial Plan
Year 2008

	Financia Incentive	Admin	Custome Cos	Tota Resourc Cos	Annua Energ Saving (kWh	Annua Capacit Saving (kW)	Benefit	TR Benefit Cost	Utilit Benefit Cost
Home Improvements	170	105	120	395	1,574,200	576	537	1.4	
New Home	291	278	351	920	3,350,800	431	1,292	1.4	
Total	461	383	471	1,315	4,925,000	1,007	1,829	1.4	2.2
Building Improvement	327	277	604	1,208	6,490,000	1,102	2,439	2.3	
New Facilities	89	69	361	519	2,700,000	402	1,099	2.1	
Total General	416	346	965	1,727	9,190,000	1,504	3,538	2.2	4.7
Industrial	114	64	98	276	1,700,000	190	499	1.8	
New	13	9	36	58	285,100	35	110	1.9	
Total	127	73	134	334	1,985,100	225	609	1.8	3.0
All	1004	802	1570	3,376	16,100,100	2,735	5,976	1.6	2.8
Planning and		378							
Total		2,184							

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Energy Management Financial Plan
Year 2009

	Financia Incentive	Admin	Custome Cos	Tota Resourc Cos	Annua Energ Saving (kWh	Annua Capacit Saving (kW)	Benefit	TR Benefit Cost	Utilit Benefit Cost
Home Improvements	197	107	118	422	1,474,200	591	556	1.3	
New Home	267	283	308	858	2,928,800	389	1,166	1.4	
Total	464	390	426	1,280	4,403,000	980	1,722	1.3	2.0
Building Improvement	323	282	605	1,210	5,583,000	950	2,121	2.2	
New Facilities	79	70	313	462	2,350,000	350	973	2.1	
Total General	402	352	918	1,672	7,933,000	1,299	3,094	2.1	4.1
Industrial	96	65	74	235	1,300,200	142	393	1.7	
New	11	9	32	52	249,900	30	98	1.9	
Total	107	74	106	287	1,550,100	172	491	1.7	2.7
All	973	816	1450	3,239	13,886,100	2,451	5,307	1.5	2.5
Planning and		382							
Total		2,171							

FORTISBC

Energy Management Financial Plan
Year 2010

	Financia Incentive	Admin	Custome Cos	Tota Resourc Cos	Annua Energ Saving (kWh	Annua Capacit Saving (kW)	Benefit	TR Benefit Cost	Utilit Benefit Cost
Home Improvements	229	108	118	455	1,474,200	641	600	1.3	
New Home	267	289	308	864	2,928,800	389	1,184	1.4	
Total	496	397	426	1,319	4,403,000	1,030	1,784	1.4	2.0
Building Improvement	353	284	637	1,274	5,583,000	950	2,155	2.2	
New Facilities	79	71	313	463	2,350,000	350	988	2.1	
Total General	432	355	950	1,737	7,933,000	1,299	3,143	2.1	4.2
Industrial	96	65	74	235	1,300,200	142	398	1.7	
New	11	9	32	52	249,900	30	99	1.9	
Total	107	74	106	287	1,550,100	172	497	1.7	2.7
All	1035	826	1482	3,343	13,886,100	2,501	5,424	1.5	2.5
Planning and		386							
Total		2,247							

FORTISBC

APPENDIX B

PLANNING AND EVALUATION

PLANNING AND EVALUATION REVIEW

The monitoring and evaluation review covers three broad categories: Process Evaluation, Market Evaluation and Impact Evaluation. The Process aspect will consider the delivery, the Market, its market effect and Impact, its cost and savings achievement. This work is performed by ongoing and special contracts arrangements the cost of which is noted in the Planning and Evaluation Budget.

The points noted below provide an over view of the nature and scope of work related to monitoring and evaluation.

Process Evaluation:

- System design & control - flowchart process
  - look for internal control weaknesses
  - look for streamlining opportunities
  - consider effectiveness as a customer service

- Published Costs & Savings - confirm support from data base
  - confirm cost integrity from accounting system
  - supporting documentation

- Staff Resources - How are staff organized to implement the program?
  - What changes are needed to achieve objectives?
  - What inhibitors exist that might frustrate the delivery process?

Market Evaluation

- Industry Relations - Liaison of Power Sense personnel with manufacturers, wholesalers and distributors
  - M&E discussion with trade allies
  - M&E discussion with customers

- Marketing Delivery - marketing approach e.g. proactive, reactive
  - advertising and promotion
  - unique marketing efforts and effectiveness

- Marketing Intensity - How long should the program be active?
  - How much of the market has been captured?
  - What investment level is appropriate?
  - What uncertainties exist?

Impact Evaluation

- Baselines for assessment - What are the standards for measuring effectiveness?
  - Compare on a unit basis
  - How does it compare to the findings of other utilities?

- Cost Effectiveness - Review & recalculate key indicators
  - Identify cost savings and efficiency opportunities
  - Incremental cost and incentives (program volatility)

- Program specifics - What peculiarities influence program success e.g. Hours of use, peak capacity impact, financing & incentive packages etc.

- Risk assessment - What threats to persistence?
  - How reliable is the measure?
  - Are projected savings being achieved?

- Societal impacts - Any special environmental benefits & how measured?
  - How has the program impacted on customers?
  - Any improvement opportunities or greater awareness possibilities?

- Generic issues - emerging issues from AESP, EPRI, & other utilities

- Cost indicators - Total Resource Cost Test
  - Avoided Cost
  - Ratepayers Impact Test
  - Levelized Cost, Benefit Cost Ratio

PLANNING AND EVALUATION BUDGET

Category	2006	2007	2008	2009	2010
Labour	$221,199	$224,517	$228,000	$231,000	234,000
Travel	14,000	14,200	14,400	14,600	14,800
Telephone	6,100	6,200	6,300	6,400	6,500
Training	8,000	8,000	8,000	8,000	8,000
Office/Administration	1,780	1,900	2,000	2,100	2,200
Ongoing Contracts	93,800	95,700	97,000	98,000	99,000
Special Contracts	21,900	22,080	22,300	21,900	21,500
Total	**$366,779**	**$372,597**	**$378,000**	**$382,000**	**$386,000**

Commentary

The Labour category contains the loaded salaries for the manager and the engineer.

Travel, telephone, training and office and administration are associated costs for managerial and engineering activities.

There are three types of ongoing contracts. The first is for routine capital planning and budgeting, accounting, financial statement preparation, regulatory filings, internal control reviews, and database management. The second contract is an ad hoc contract to provide assistance with long term planning, research, with providing facilitation services for the DSM incentive committee and for performing project management for special contract activities. The last type of contract is for specialized engineering project impact reviews for more complex energy efficiency projects.

Special contract services are required for the following activities:

2006:	Market survey Education and customer awareness programs	$10,000	
	Website development and support	$ 4,900	
	Development of Geo-exchange financing support program	$ 5,000	
	Development of Multi-unit financing programs	$ 2,000	$21,900
2007:	Evaluation – Geo-exchange support review	$ 5,000	
	Evaluation and metering – Residential DWH peak demand reduction	$12,080	
	Review of Government support program	$ 5,000	$22,080
2008:	Evaluation – Commercial Clothes dryer /water heaters	$ 5,000	
	Evaluation – Residential / Appliance (Dryer ball^{TM}) programs	$ 5,000	
	Website survey and updating	$ 2,000	
	Evaluation Demand Response programs	$10,300	$22,300
2009:	Evaluation – Commercial Lighting program	$ 5,000	
	Review delivery and marketing issues related to public sector	$ 5,000	
	Market Survey and Financing program effectiveness review	$11,900	$ 21,900
2010:	Update market potential for all sectors.	$19,000	
	Review of education and public awareness campaigns		$ 2,300
	$21,300		

APPENDIX C

PROPOSED DSM INCENTIVE MECHANISM

PROPOSED DEMAND SIDE MANAGEMENT INCENTIVE MECHANISM FOR 2006 - 2010

For the 2006 – 2010 timeframe, the company proposes a continuation DSM incentive mechanism based on the existing shared savings mechanism (SSM). The mechanism provides the company with an effective yet moderate performance incentive for meeting its DSM targets. At this time, the company is working with the Committee to secure the continuation of the existing mechanism.

The SSM is the most commonly used shareholder incentive over the last decade. This approach will provide FortisBC with a share of the net benefits from its DSM activities. Benefits are defined as the value of avoided energy and capacity costs and deferred capital expenditures. All utility program costs and the customer costs of energy efficiency are deducted from the benefits to arrive at the net benefits. This mechanism sends the signal to maximize the resource savings per dollar spent on energy efficiency measures. The SSM will provide for a small share of the life-cycle benefits as a potential reward to the shareholders. It also introduces a penalty for not achieving a threshold level of net benefits.

The SSM approach requires both the power savings and the resource benefits flowing from those savings to be quantified. The benefits are calculated over the lifetimes of the DSM measures put into place. FortisBC will receive a share of the total net present value of these life-cycle benefits.

Gross Benefit Values
Under the existing mechanism, the benefits are valued at 2.6¢ for each kW.h (energy savings) and $28 for each annual KW (capacity savings) and $36 for each annual KW saved from peak (deferred capital expenditures). The lifetimes of DSM measures range from 5 years to 30 years.

SSM Incentive or Penalty Rates
Incentives for the sectors are calculated for performances of 100% to 150% of the plan net benefits. There is no calculation for performance between 90% and 100% of plan net benefits for the residential sector and 95% and 100% for the general service and industrial sectors. The determination of incentives for performances of less than 90% and less than 95% for residential and the general service and industrial sectors respectively result in negative amounts. Maximum penalty is applied to performances of less than 50% of plan net benefits. If the sum of the sector results is greater than zero, then the sum is the DSM incentive for FortisBC for the year. If the sum is less than zero, then there is no DSM incentive for FortisBC for the year and no penalty is charged.

APPENDIX D

EFFICIENCY AND DEMAND REDUCTION POTENTIAL UPDATE

Residential Update
In order to update remaining potential, the 2003 residential load was categorized by housing type and electric or non- electric space heating. Consumption by end use was determined based on housing type and typical use rates. They were compared to efficient technologies for each end-use. During this process, the company considered potential load shifting technologies and introduced hot water controllers for apartment and multi-unit housing types. The reduction in load or improvement in load distribution through load shifting was multiplied by our estimate of the market penetration for the more efficient technology. This product was the market potential. In determining the load impact of the more efficient technology, the company used the deemed savings for efficient equipment or processes.

The efficient technology measures that are included in the residential market potential are summarized for each end-use:

- Space Heating: Envelope, Heat Pumps and Efficient Furnace Fans
- Space Cooling: Heat Pumps
- Clothes Dryers: Dryerballs ™
- Hot Water: Showerheads, aerators and hot water heater controls
- Lighting: Compact Fluorescent Screw-ins

The market potential is summarized in the table below:

2013 Residential Market Potential by End-Use and Housing Type							
Housing Type	Residential End-Uses						
	Envelope	Ht Pumps	Lighting	Water Heating	Efficient Fans	Appliances	Total
Single Family	4.7	13.8	12.7	2.1	1.7	0.2	35.2
Multi-Unit	6.1	1.7	4.3	0	0	0.2	12.3
Apartments	32.1	3.9	0	0	0	0	36.0
Market Potential - GWh	42.9	19.4	17.0	2.1	1.7	0.4	83.5
5 Yr Acquisition Plan	5.8	14.7	6.0	0.8	0.7	0.2	28.2
Market Potential – MW				7.4			7.4
5 Yr Acquisition Plan				0.8			0.8

This market potential of 83.5 GWh represents about 5% of the annual residential load of 1,571 GWh

General Service Update
This plan reviewed the technology profiles that were noted in the Deemed Savings documentation, the federal small and medium sized business enterprise database, and California commercial program plans to determine the measures and initiatives with significant. After preparing the 2003 consumption for the General Service customers by building and facility types within the standard industrial classification (SIC) for commercial facilities, estimates of end-use consumption were made. With reference to deemed savings documentation, the life of existing facilities,

program experience and BC Hydro's 2002 DSM potential update, FortisBC determined the DSM potential for each end use within each of its SIC categories. The company specifically reviewed its experience with HVAC measures like geo-exchange and heat pump technologies to broaden the scope of DSM potential.

The efficient technology measures that are included in the general service market potential are summarized for each end-use:

- Lighting: T8's, electronic ballasts, occupancy sensors, compact fluorescent lamps and daylight optimization, and light switching options
- Heating, Ventilation & Air Conditioning (HVAC): central chillers with SEER > 20, Ground or Air source heat pumps, economizers, water cooled condensers, variable air volume systems and building automation systems, and Low –E windows
- Commercial Clothes Dryers: This new measure targets multi-unit residential building and complexes, and includes similar load in accommodation and commercial laundries.
- Hot water Heater Controls: This off-peak program will be an extension of the technologies used in the Residential sector.
- Other: Refrigeration with compressor bank controls, desiccant dehumidifiers and brine pump speed controls; Sewage treatment facilities process improvements: Water distribution systems pump sizing and optimization.

The market potential is summarized in the table below:

2013 General Service Market Potential By Sector and End-Use				
Sector	End-Use			
	Lighting	HVAC	Other	Total
Non-Food Retail	35.0	13.0	1.0	49.0
Small Commercial	25.0	14.0	5.0	44.0
Offices	18.0	16.0	3.0	37.0
Food Retail	4.0	1.7	3.0	8.7
Hospitality	7.0	5.3	-	12.3
Hospitals	2.0	2.4	0.4	4.8
Schools	6.0	4.4		12.4
			2.0	
Other	1.0	0.3	2.4	3.7
Water Handling Systems	-	-	6.6	6.6
Market Potential GWh	98.0	57.1	23.4	178.5
5 Yr Acquisition Plan	19.5	12.7	11.3	43.5
Market Potential – MW			1.4	1.4
5 Yr Acquisition Plan			0.5	0.5

This market potential of 178.5 GWh represents 21.5% of the annual general service load of 827 GWh.

Industrial Update

The Plan is based on the potential of savings opportunities available in industrial auxiliary systems and processes. The update reviewed BC Hydro's potential update for the industrial sector completed in 2002, along with energy use information for specific customers in the service area. Savings are based on system improvements. The industrial energy use for 2003 consumption was broken out by standard industrial classification (SIC) and then by end uses for each of the SICs. The federal small and medium size business data base for industrial activity was also used to identify savings activities and opportunities.

The efficient technology measures that are included in the industrial market potential are summarized for each end-use:

- Pumps and Fans: reduce overall system requirements by use of holding tanks, eliminate bypass loops, and increase pipe diameter; match pump size to load by installing parallel systems for highly variable loads, and control pump speed by use of adjustable speed drives in place of throttling valves
- Compressed Air: fix air leaks, install sequencers, and controls, replace with conveyance belt systems
- Other: install controlled atmosphere systems, improve heating and cooling systems

The market potential is summarized in the table below:

2013 Industrial Market Potential (GWh) By End-Use						
	Space Conditioning & Lighting	Process	Pumps & Fans	Compressed Air	Other	Total
Market Potential	5.0	7.4	13.0	5.0	2.0	32.4
5 Yr Acquisition Plan	1.1	1.4	2.3	2.8	1.2	8.8

This market potential represents about 8% of the annual industrial load of 407 GWh

Backgrounder
Demand Side Management Incentive Mechanism

Shared Savings Mechanism
A commonly applied shareholder incentive for utility DSM investments has been the shared savings mechanism. It is designed to send a signal to maximize the resource savings acquisition per dollar spent on energy efficiency measures. A minimum threshold (Base) is established annually for each sector. The sector performance is the acquired net savings over the Base, as a percentage. If the threshold is exceeded, meaning that acquired savings are greater than the Base, the mechanism applies an incentive amount to the sector. Sector performance in excess of 150 percent of the threshold is not considered. If the 90 percent threshold is not met, then a penalty amount is applied to the sector. Sector performance between 90 and 100 percent of the threshold results in neither an incentive nor a penalty. The sum of the sector incentive and/or penalty is the incentive amount available for shareholders. If the sum is less than zero, the incentive is zero.

DSM Gross Benefits
Life-cycle benefits are the value of the utility's avoided energy and capacity costs and deferred capital expenditures. The benefits are calculated over the lifetime of each DSM measure installed. The lifetimes of DSM measures range from 5 years to 30 years.

Total Resource Cost
The sum of the utility program costs and the equipment and installation costs for the energy efficiency measures is known as the Total Resource Cost (TRC). Annual costs for planning, evaluation, and public awareness expenditures are not included in the program costs for the DSM performance determination.

TRC Net Benefits
The Total Resource Cost is deducted from the DSM Gross Benefits to arrive at the TRC Net Benefits.

Base Net Benefits
Base Net Benefits are the average of the previous three year's actual TRC Net Benefits for each sector, adjusted for the present year's avoided costs and inflation.

Annual DSM Performance
For determination of the annual DSM performance, expenditures are capped at 110 percent of the planned annual expenditure for DSM program delivery. Total acquired savings are prorated to the 110 percent spending level.

For each sector the achieved TRC Net Benefits are recorded as a percentage of the Base Net Benefits.

Incentive Calculations
Those sectors with an annual DSM performance of greater than 100 percent attract an incentive at the rates shown in Table A. Incentives are available to a maximum DSM performance of 150 percent.

Neutral Zone
There is no calculation for any sector for annual DSM performances between 90 percent and 100 percent.

Penalty Calculations
DSM performances of less than 90 percent for any sector result in a negative amount, or penalty. Maximum penalty is applied to performances of less than 50 percent.

Results
If the sum of the sector incentives or penalties is greater than zero, then that sum is the DSM incentive amount for the year. If the sum is less than zero, then the DSM incentive amount is zero. There are no penalty charges.

TABLE A Rates for Incentive (+) or Penalty (-) Amounts at Selected DSM Performance Levels

DSM Performance Level % of Base Net Benefits	<50%	<70%	<90%	90-100%	100.1-110%	110.1-120%	>120.1 – 150%	>150%
Customer Sector	**Penalty**			**Neutral**	**Incentive**			**N/A**
Residential	-6.0%	-4.5%	-3.0%	0.0%	3.0%	4.5%	6.0%	
General Service	-4.0%	-3.0%	-2.0%	0.0%	2.0%	3.0%	4.0%	
Industrial	-3.0%	-2.0%	-1.0%	0.0%	1.0%	2.0%	3.0%	

Project No. 3698519: 2009-2010 Capital Expenditure Plan
Requestor Name: Alan Wait
Information Request No: 1
To: FortisBC Inc.
Request Date: August 28, 2008
Response Date: September 11, 2008

Q1 Ref. pages 21-22, Plant #3

Has FortisBC been able to increase the flow rate at the South Slocan Plant to the full water license that it holds on that Plant with the completion of the upgrade to all 3 units? If not, why not?

A1 FortisBC currently has the capability to use the full water license held at South Slocan. The completion of the upgrades at South Slocan will replace one of the remaining two turbines. The capability to use the full water license will be maintained.

Q2 Ref. pages 28 & 32 Spare Transformers

Will these spare transformers be depreciated as any other piece of operating equipment once in storage, even though the transformers will not likely be in service for some time?

A2 Based on the "Uniform System of Accounts for Electric Utilities for the Province of BC, Section 105: Utility Plant Held for Future Use", plant included in this account shall be classified according to the detailed accounts prescribed for utility plant in service and the account shall be maintained in such detail as though the plant were in service.

Therefore these spare parts will be depreciated as any other piece of operating equipment once in storage, even though the transformers will not likely be in service for some time.

Q3 Ref. pages 50-51, Tarry's Substation

What has been the rate of load growth on the Tarry's substation for the last 4 years and how long are the cooling fans and voltage regulation expected to delay the need for a larger transformer?

A3 The peak load values recorded for Tarrys over the last four years have indicated a negative load growth since the peak recorded value of 3,360 kVA in 2004/05. The load is dependent on the Kalesnikoff Sawmill. The current five year forecast does not project an increase in load demand for Tarrys Substation. Based on the current load forecast, the cooling fans will delay the need for a transformer at least for that period.

Q4 Ref. pages 50-51, Tarry's Substation

Has the Kalesnikoff Sawmill participated in any of the DSM programs to reduce its peak load in the last five years? If not, might an assessment of the potential savings be a wise move first?

A4 The Kalesnikoff Sawmill has participated in the PowerSense program since 1991. They have completed energy efficient upgrades to their motors, compressors, kilns, bandsaw and chipper lines. In 2008 the mill put in a new planer line with premium efficiency motors and variable frequency drives that were reviewed through PowerSense.

Over the last five years PowerSense has made biannual visits to the mill in order to assess the potential for further energy/load reduction. While opportunity exists for energy savings from their compressor operation, there is not substantial opportunity for peak demand reduction without fuel switching (there is about 250 kVA of electric heat scattered throughout the mill). Due to the fact the mill quite often runs two shifts, there is no load shifting opportunity.

PowerSense will continue to consult the mill regarding their capital expansion plan.

Q5 Ref. pages 51-52, Huth Substation

What will be the situation at the Huth Substation during the OTR construction, when 76 line is out of service and supply to Penticton from 73 line is unexpectedly lost? How long with power be delayed in being restored though Huth?

A5 No work will be conducted at the Huth Substation during the OTR construction. Contingency plans will be developed to ensure that both 41 Line and 42 Line are available to supply the Penticton area from the Oliver Terminal. The 75 Line / 76 Line construction will be scheduled for the shoulder months to ensure that the combined capacity of 41 Line / 42 Line is sufficient to meet the Penticton load. The system will be configured to allow remote restoration of the load from the 41 Line / 42 Line source. As well, when practical, measures will be taken to ensure that 76 Line can be restored to service as quickly as possible.

Q6 Ref. page 83, Christina Lake Feeder #1

Planning studies indicate a voltage problem. Has FortisBC any direct measurement of voltage problems at the end of the Feeder #1 on the east side of Christina Lake during winter or summer high load times?

A6 Yes. Measurements during the summer peak season have supported the results of the planning studies.

Q7 Ref. page 83, Christina Lake Feeder #1

What has been the maintenance experience of the lines planned for replacement, specifically because they are older copper conductor and not newer lines?

A7 The Christina Lake Feeder is a part of the distribution condition assessment and rehabilitation program. The feeder is scheduled for a detailed condition assessment in 2008 and rehabilitation in 2009. Results of the condition assessment with respect to the copper conductor are not currently available.

Q8 Ref. page 83, Christina Lake Feeder #1

Why is extending 3-phase power further along Feeder #1 not considered, along with rebalancing the loads instead of replacing the conductors?

A8 The proposed project does include a short extension of the three phase distribution, rebalancing the loads as well as replacing the conductor along Highway 3. Extending the three phase distribution further as a part of this project was not considered due to the current load levels and narrow corridors for the existing single phase sections.

Q9 Ref. page 83, Christina Lake Feeder #1

How much longer could the portion of Feeder #! to be replaced, be expected to last, before the major replacement of poles or conductor is required, assuming the voltage problem is corrected another way.?

A9 A replacement of any poles identified in Condition Assessment will be completed in 2009 as a part of the Distribution Rehabilitation program. The copper conductor replacement would be completed as a part of the Copper Conductor Replacement program within the next five years.

Q10 Ref. page 83, Christina Lake Feeder #1

Why is the addition of voltage regulation not considered?

A10 Please refer to the response to BCUC IR No. 2 Q146.1.

Q11 Will the West Boundary Substation and 25 KV distribution lines be completed in 2008?

A11 The Kettle Valley (West Boundary) Substation and 25 kV distribution lines will be substantially complete from Rock Creek to Midway by the end of 2008. The remaining work from Midway to Greenwood will be completed in the most cost effective manner which may require delay until 2009.

My general impression of Fortis' approach to capital is that they find the most expensive way to complete any upgrade or expansion. I have seen no evidence that they rigorously brainstorm alternatives and bring forward the lowest cost alternatives. Please see below for some detailed examples.

Information requests to Fortis as a result of the workshop in August.

Q1 GENERATION

Q1.1 Fortis stated that the seals in the generator are being replaced to stop oil loss to the river, but have no evidence that the seals were faulty. On what basis was this expenditure justified?

A1.1 FortisBC is replacing the generator's greased bronze bushing that are past their useful life and do not have seals to prevent grease from being lost into the river. The replacement is a "greaseless" bushing of a composite material that requires no lubrication which eliminates the possibility of grease entering the river and also reduces maintenance costs. The cost of the greaseless bushing material is comparable to the greased bronze bushing material.

Q1.2 What alternatives were considered and evaluated, and how did their economics compare with replacing the seals? Please provide all analysis prepared before the decision was implemented.

A1.2 There were no alternatives considered as the seals are not being replaced.

Q2 DISTRIBUTION PROJECTS

AIRPORT WAY UPGRADE

Q2.1 What alternatives have been considered and evaluated for this upgrade?

A2.1 For this upgrade only one other alternative was considered. It involved the construction of a new circuit to feed the south part of Airport Way. The upgrade to the existing underground circuit was selected as the most cost effective means of providing the necessary capacity to accommodate the forecasted load growth.

Q2.2 Page 82, Lines 13-14: how are these alternatives evaluated?

A2.2 The alternatives are evaluated in terms of what would provide the most cost effective long term solution.

Q2.3 Why does the line have to be underground?

A2.3 This is a well established commercial/industrial corridor where the feeder was originally installed underground. Construction of an overhead system will make it difficult to maintain safe limits of approach.

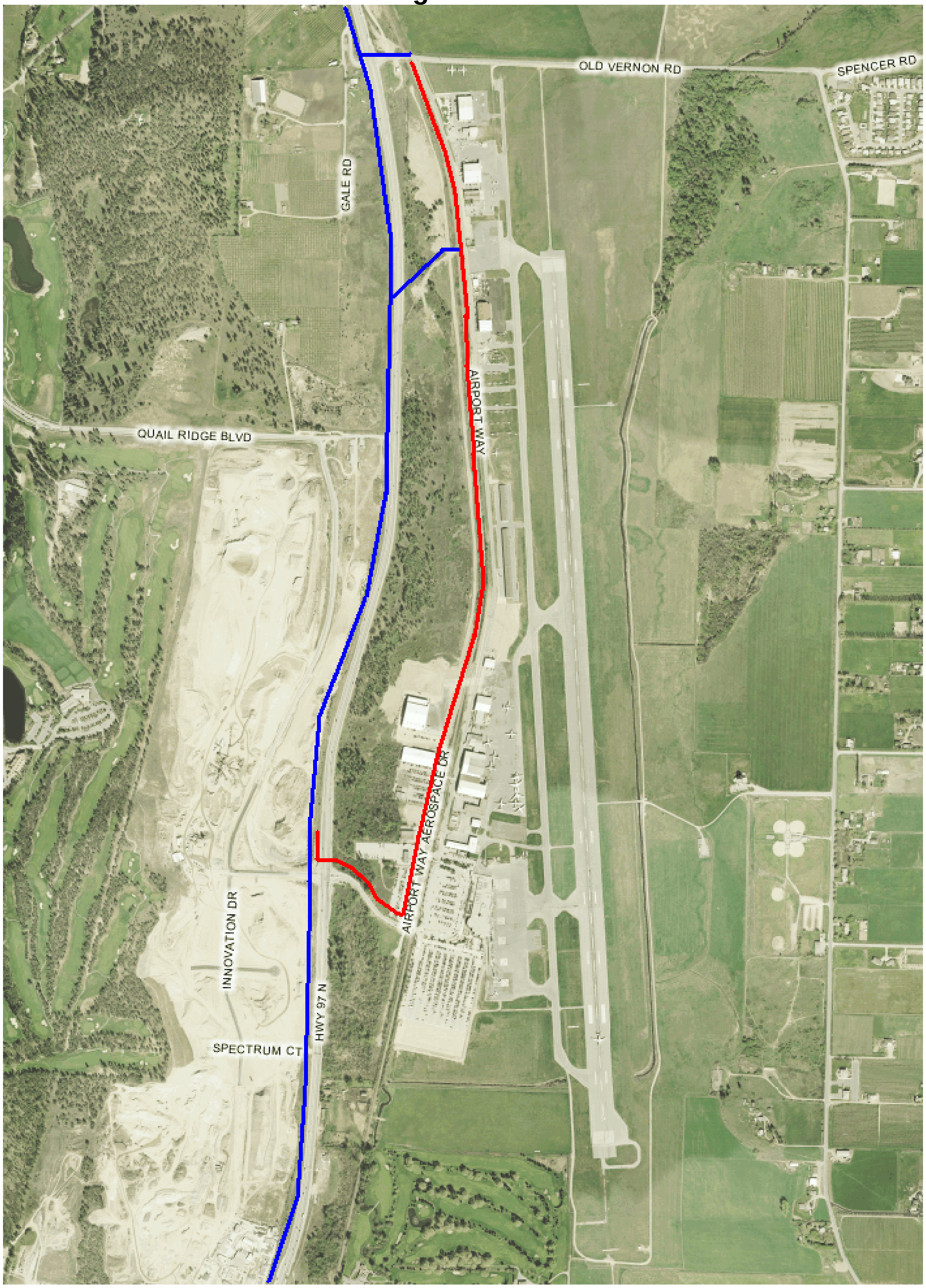
Q2.4 Can the existing line be split and fed independently so the demand will be equal both ways? Could this double the existing line's capacity?

A2.4 No, the current and anticipated load is not split evenly along the length of Airport Way. Furthermore, this proposal would make it impossible to provide backup in the event of a cable failure.

Q2.5 Are there any other power lines on the left side of picture #7 and if so, they need to be shown.

A2.5 Please see Figure A2.5 below. The blue line represents the existing 13 kV overhead distribution primarily along the west side of Highway 97.

Figure A2.5


OLD VERNON RD
SPENCER RD
GALE RD
QUAIL RIDGE BLVD
AIRPORT WAY
AEROSPACE DR
AIRPORT WAY
INNOVATION DR
HWY 97 N
SPECTRUM CT

1

Q2.6 Where is(are) the source(s) for the existing line?

A2.6 The existing line is currently fed from the Sexsmith Substation, with the alternate feed from the Duck Lake Substation. The line will be fed from the Ellison Substation following completion of that project in 2009.

Q3 CHRISTINA LAKE

Q3.1 What is the duration of the low voltage and overload shown on the graph?

A3.1 As stated in response to BCUC IR No. 1 Q62.2 the voltage issues are expected during peak periods in the morning and late afternoons from June thru August and December thru February.

Q3.2 With few if any building lots available beyond 3,000 meters north of the sub, on either side of the lake, what portion of the line on the east and west side can meet a 10 year projected demand?

A3.2 Currently there are no voltage issue projects on the west side of the lake due to the proximity to the substation and the existing conductor size. Based on the current load forecast for 2009, voltage issues are expected approximately around 7 kilometres east of the Christina Lake Substation. This is attributed to overall growth, as well as upgrades to existing services and subdivision development on the east side of the lake.

Q4 DISTRIBUTION LINE REHABILITATION.

PAGE 8 PICTURE 16

Q4.1 What type of material is the large wire shown in the picture?

A4.1 The wire shown in the picture is 2/0 Aluminum Wire with a Steel Core (ACSR).

Q4.2 What type of material is the clamp?

A4.2 The clamp is aluminum alloy.

Q4.3 What percentage of the clamp is in contact with the large wire?

A4.3 The clamp jaw is designed for 100 percent contact with the wire.

During the meeting in Kelowna, Fortis stated hot taps had to be replaced to eliminate hot lines falling to the ground.

Q4.4 What alternatives have been considered and evaluated? Please provide all analysis completed before the recommendation was made..

A4.4 The Company did not evaluate any other solution for this problem as stirrups have been shown to be the least cost utility standard to address this concern.

Q4.5 If all hot taps were installed on the down stream side of the poles, would a cold line fall to the ground? The attached pictures show about 50% of hot taps are installed in this manner. This entire subject needs a major policy review.

A4.5 The Company reviewed and changed its policy with respect to installing Hot

Tap Connectors in the 1990s. This project will remove those that were installed prior to the standards change.

Q4.6 Picture 346 – if the wire that loops the insulator was longer, can the hot tap be connected to it rather than to the main line, and would that eliminate the possibility of a hot line falling to the ground? Where lines dead end, could a pig tail be left at the insulator with the hot tap being connected to it? On corners where a wire bridges between two insulators, can a hot tap be attached, rather than the wire from the pole?

A4.6 The utility industry has determined that the best solution to avoid attaching Hot Tap Connectors directly to the line is to install a stirrup and attach the Hot Tap connector to the stirrup. While the suggested alternative may be appropriate for new construction, it is not a cost effective solution for in-service connections which this program is intended to address.

Q5 PAGE 9 PICTURE 18

Q5.1 What is the age of this structure?

A5.1 The structure is approximately 30 years old.

Q5.2 Does O&M budget for this type of work?

A5.2 No, urgent repairs involving units of property are capitalized. Please also see the response to BCUC IR No 2, Q114.1.

Q6 GENERAL PLANT

Q6.1 How many vehicles has Fortis owned in each of the last 5 years?

A6.1 Inventory levels (including owned and leased units) for the past five years are as follows:

2003 - 264;

2004 - 265;

2005 - 288;

2006 - 293; and

2007 - 354

Q6.2 What is the total value of all vehicles owned by fortis in each year?

A6.2 The vehicle net book value per year for the past five years is as follows:

2003 - $1.69 million

2004 - $1.58 million

2005 - $4.21 million

2006 - $7.51 million; and

2007 - $12.1 million

Q6.3 How many insurance claims were filed and their value in each year?

A6.3 Please see Table A6.3 below.

Table A6.3

Year	No. of Claims	Total Value of Claims
		($000s)
2003	47	26.3
2004	42	36.6
2005	51	66.5
2006	59	30.7
2007	71	93.0

Q6.4 How does Fortis charge out vehicle hours? For example, the in house construction of the Big White line. Does corporate charge construction for use of Fortis-owned equipment?

A6.4 FortisBC charges out its vehicles based on an hourly rate that is a function of the type of vehicle. If a vehicle operator is working on a specific project, the individual charges out their time and the vehicle to the project for each hour worked on the project.

Q7 DEMAND SIDE MANAGEMENT

Q7.1 Please supply actual expenditures and budgets for the last 5 years.

A7.1 Please see Table A7.1 below

Table A7.1
Cumulative FortisBC DSM Costs

Year	Plan	Actual	% of Plan Expenditures
	($000s)		(%)
2002	1,661	1,555	94
2003	1,840	1,706	93
2004	1,814	1,989	110
2005	1,835	2,350	128
2006	2,234	2,241	100
2007	2,474	2,549	103

Q7.2 How many Fortis customers participated in this program and what % of total power sold did they consume?

A7.2 Please see Table A7.2 below. The Company does not tally the consumption of its customers who participate in DSM programs.

Table A7.2
DSM Participation

DSM Program: 2003-2007	Wholesale	FortisBC
Residential Lighting	260	679
New Home Construction	324	1,447
Home Improvement	75	242
Ground Source Heat Pump	37	305
Air Source Heat Pump	798	2,439
New Process Design	0	1
Pumps & Fans	2	7
Motors	2	2
Fortis Property	0	2
Water Savers	27	100
Building Improvement New	61	91
Building Improvement Retrofit	64	113
Industrial Efficiency	5	18
Commercial/Industrial Lighting	178	373
Compressors	14	3
Destination Conservation	0	0
Provincial Gov't New Home Construction	26	263
Provincial Gov't Home Improvement	201	558
Total No. of database entries:	2,074	6,643
Percentage:	24%	76%

Q7.3 How many wholesale customers participated in this program and what % of total power sold did they consume?

A7.3 Please refer to the response to Q7.2 above. The Company does not have access to the billing records of indirect customers served by wholesalers.

Q7.4 Are there any losses on monies that are to be returned to the Company?

A7.4 Under the Terms and Conditions of Schedule 90 of the FortisBC Electrical Tariff, unamortized balances of incentives paid are subject to repayment if the customer ceases operations. The Company has successfully collected such monies in the past. Residential loans that have defaulted are subject to the Company's collections process, which results in a portion of those losses being collected.

Q8 COPPER CONDUCTOR REPLACEMENT

Page 5

Q8.1 Sign of annealing. How does this affect the wire and to what degree has annealing taken place and has it reduced the tensile strength of the samples tested?

A8.1 Annealing negatively affects the strength of the conductor. The report did not provide a specific degree to which annealing has taken place. The report concluded that annealing has reduced the strength of the samples tested.

Q8.2 How does the below spec affect the wire?

A8.2 It reduces the strength of the conductor.

Q8.3 Please provide a copy of the analysis report.

A8.3 A copy of the report is included as Gabana Appendix A8.3.

Q8.4 Does the joint in Picture 343 affect the role of the wire in service?

A8.4 No, however in certain situations corrosion within the splice (connector) can lead to increased contact resistance and conductor burn off.

Q8.5 It was stated at the work shop that 50 years is the life of copper wire. How was the number 50 established?

A8.5 Fifty years is generally recognized by the utility industry as the life of the smaller copper conductor. This has been substantiated at FortisBC by the increasing failures of copper conductor of that vintage.

Q8.6 Who pays the costs to move or relocate other utility wires when lines are upgraded or moved?

A8.6 In general, the utility initiating the move or relocation pays the other utility's cost.

Q9 GENERAL QUESTION

Q9.1 With significant reductions to federal and provincial corporate income tax rates in the last few years, what are Fortis' actual and projected savings?

A9.1 FortisBC will not realize any savings as a result of changes to federal or provincial corporate income tax rates. For rate setting purposes, income tax expense is forecast based on known income tax rates for the test year. Any known income tax reductions are therefore included as a reduction to revenue requirements and serve to reduce rates. Under the Company's current PBR mechanism, any subsequent reduction to income tax rates are regarded as "Z" factor adjustments and the entire benefit is flowed through as a reduction to customer rates in the following year.

Q9.2 Typically, expenditures can be classified as either capital or maintenance. Capital expenditures would be added to the balance sheet and depreciated over their useful life, while maintenance expenditures would be expensed. Does Fortis follow this procedure or do maintenance expenditures get added to the capital base for purposes of calculating power rates?

A9.2 Please refer to the response to BCUC IR No. 2 Q114.1.

Attachment Picture 343

Attachment Picture 346

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POWERTECH LABS, INC.

Project Report

FAILURE INVESTIGATION OF COPPER CONDUCTOR AND MATERIAL PROPERTIES ASSESMENT

Project: 17518-34

January 24, 2008

Prepared for:

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3.5 CONCLUSIONS ______ **13**

1.0 SUMMARY

Solid copper conductors used in the south central British Columbia region of Fortis BC's electrical distribution system are failing with increasing frequency. The failures are occurring primarily at hot tap and splice type connections. A recently failed conductor within a hot tap connection was subjected to a root cause failure analysis. The analysis showed annealing (softening) of the copper conductor leading to ductile overload failure under normal operating stresses. Annealing of the copper conductor occurred due to elevated service temperatures from high contact resistance within the connection. Over time, the elevated service temperature caused recrystallization and grain growth in the copper microstructure, leading to a reduction in the tensile properties. The increase in contact resistance was from large-scale buildup of corrosion product within the connection. Given the current average service age of 50 years for the conductor and components within the system, similar conditions likely exist in the majority of hot tap connections and additional failures will be expected. Additional splice connections relying on contact resistance were examined and also showed a reduction in hardness as well as increasing grain size. A material properties assessment was performed on randomly selected samples of various sizes of copper conductor, both solid and stranded, used in the system outside of hardware connections. The conductor sizes tested showed mechanical property values below that specified for hard drawn copper wire by ASTM B1 "Standard Specification for Hard-Drawn Copper Wire". The lower values may be attributable to softening of the copper over its long service life. Metallographic examination indicated the presence of some recrystallized grains within the hard drawn microstructure. The lower values may also be attributable to historical standards at the time of installation, which may not have had as stringent requirements for tensile properties.

2.0 FAILURE INVESTIGATION OF COPPER CONDUCTOR IN HOT CLAMP

2.1 INTRODUCTION

Powertech Labs Inc. was contracted to investigate the failure of a copper conductor in a hot tap electrical connection. The conductor failed while in service, resulting in a downed energized line. Solid copper wire is used extensively within the south central British Columbia distribution system of Fortis BC, with various sizes from #3 to #10 AWG (American Wire Gauge size) employed. These copper conductors were predominantly installed in the 1940s to 1960s, giving the conductor and associated hardware an average service life of 50 years A number of incident reports were provided to Powertech Labs Inc. for the investigation, the majority of which dealt with conductor failures at hot tap or splice connections. Failures at these types of connections have been occurring regularly over the last few years, with an increase in frequency noted within the previous year.

A hot tap refers both to the piece of hardware utilized as well as the method of connection. In most instances, a feeder conductor is tapped to provide electrical service to a nearby application. Both the feeder and secondary conductor are mechanically attached to the hot tap hardware in a saddle type compression fitting. The electrical connection occurs between the outer surface of the conductor and the surface of the clamps, with the entire hot tap hardware energized. Dependent on its service configuration, some level of tensile stress will be present on the conductor.

2.2 VISUAL EXAMINATION

Upon receipt, the hot tap containing the failed conductor was photographed for documentation purposes, dissected, and examined with the aid of a low power stereomicroscope. Following are observations noted during the examination:

- The hot tap in which the failure occurred consists of a cast aluminum body which is tin coated to prevent galvanic corrosion between aluminum and copper (Figure 1). The conductor failed in the approximate center of the clamp portion of the hot tap (Figure 2).
- Disassembling of the hot tap revealed a very thick layer of corrosion and contaminant debris. The thick layer of debris was present around the entire circumference of the conductor (Figures 3 and 4). The conductor required substantial force to be removed from the encasing corrosion layer and was bent in the process (Figure 5).
- The fracture surface and outer surface of the conductor were coated in a sooty black dust likely from arcing in the vicinity of the failure (Figures 2 and 5). The conductor was subsequently cleaned with a corrosion inhibited acid solution to facilitate examination.
- The fracture surface of the conductor was fibrous and dimpled in topography, consistent with macro scale features of a ductile overload failure (Figure 6).
- The outer surface of the failed conductor in the portion within the hot tap clamp was pitted heavily from corrosion attack (Figure 7).
- The diameter of the wire just below the fracture surface was measured with a micrometer to be 3.96 mm. The diameter of the wire at the opposite end of the sample was 5.15 mm (#4 AWG size). The measurements show a 41% reduction in the cross sectional area of the conductor at fracture. The large scale elongation and necking down of the diameter is typical of ductile overload in annealed copper.

Figure 1: Hot tap and failed #4 AWG conductor received for examination

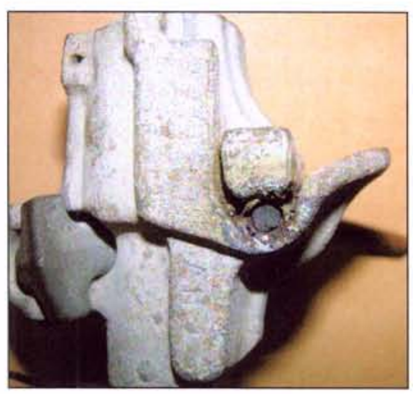


Figure 2: View of fractured conductor in hot tap saddle

Figure 3: Hot tap disassembled for examination

Figure 4: Buildup of contamination on clamping surface of hot tap in contact with copper conductor

Figure 5: Section of failed #4 AWG conductor removed from hot tap

Figure 6: Macro image of fracture surface of copper conductor

Figure 7: Macro image of surface condition of failed copper conductor

2.3 SCANNING ELECTRON MICROSCOPY

The cleaned fracture surface of the failed conductor was sectioned approximately half an inch below the fracture and examined in a Hitachi S-2500 Scanning Electron Microscope. Microscale features of the fracture consisted of rupture dimples formed by microvoid coalescence, characteristic of a ductile overload fracture (Figures 8 and 9).

Figure 8: Low magnification scanning electron micrograph of fracture surface of copper conductor.

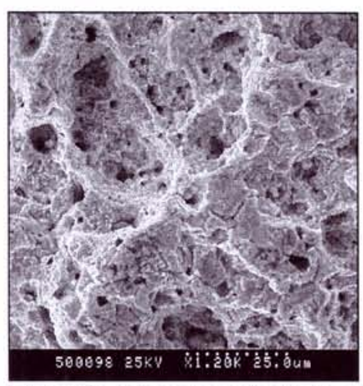


Figure 9: High magnification scanning electron micrograph of fracture surface of copper conductor.

A portion of the adherent contaminant layer was removed from the clamp surface and analyzed by Energy Dispersive X-Ray Spectroscopy (EDS) using Quartz X-One Microanalysis Software. The spectrum obtained from the analysis (Figure 10) showed an elemental composition high in aluminum (Al), copper (Cu), tin (Sn), zinc (Zn) and oxygen (O), indicating the majority of the contaminant is corrosion (oxide) product from the tin coating, the aluminum alloy body of the clamp, and the copper conductor itself. Minor traces of silicon (Si) and chlorine (Cl) are attributable to general environmental contamination.

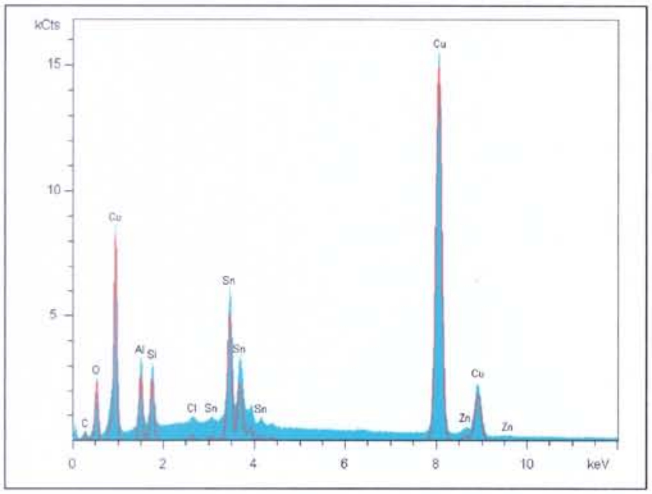


Figure 10: EDS spectrum obtained from the analysis of corrosion product within hot tap connection.

2.4 METALLOGRAPHY

The failed conductor was subjected to a metallographic examination. The fracture surface section previously removed for electron microscopy, as well as the remaining length, were mounted in acrylic, ground and polished to a 0.05 μm finish, and etched to examine their microstrucutral properties. The microstructure of the failed conductor varied considerably along its length. Within 0.5 inches of the fracture (corresponding to the length of conductor within the hot tap), the microstructure of the copper consisted of large equiaxed and twinned grains of copper, characteristic of copper in the annealed condition. Between 0.5 inches to 2.5 inches from the fracture the microstructure consisted of progressively finer equiaxed grains and a mixture of fine equiaxed grains and elongated grains. At 3 inches away from the fracture area the microstructure consists of predominantly elongated grains, characteristic of a hard drawn structure.

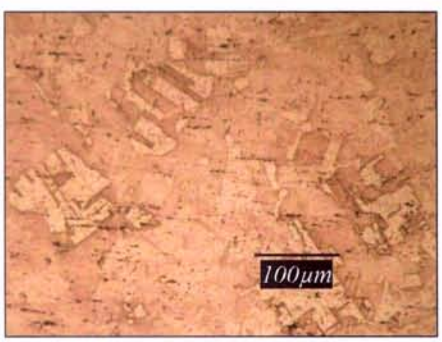


Figure 11: Microstructure 0.025 inches below fracture surface Hardness 57 HV Mag: 200X

Figure 12: Microstructure 0.500 inches away from fracture surface Hardness 60 HV Mag: 200X

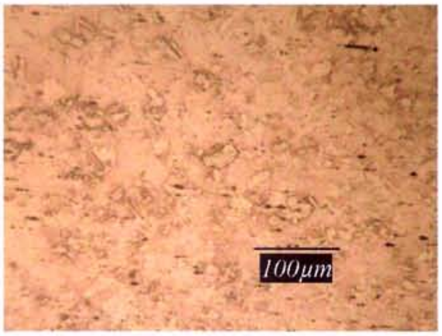


Figure 13: Microstructure 1.00 inches away from fracture surface Hardness 63 HV Mag: 200X

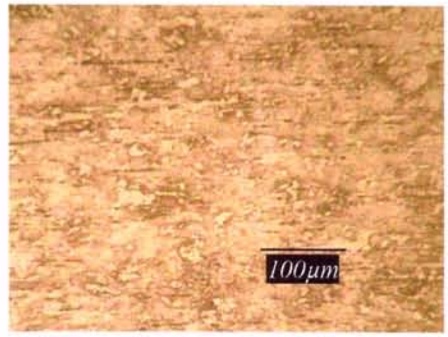


Figure 14: Microstructure 2.00 inches away from fracture surface Hardness 80 HV Mag: 200X

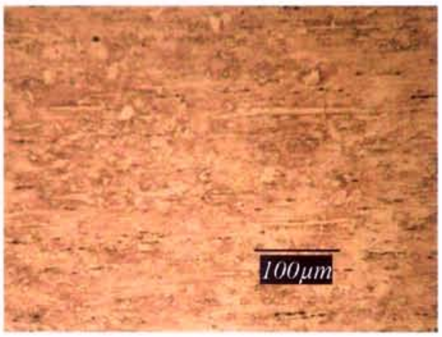


Figure 15: Microstructure 2.50 inches away from fracture surface Hardness 91 HV Mag: 200X

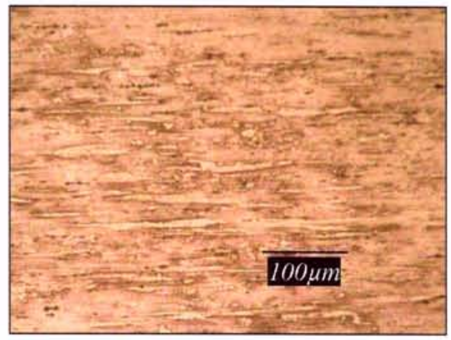


Figure 16: Microstructure 3.00 inches away from fracture surface Hardness 104 HV Mag: 200X

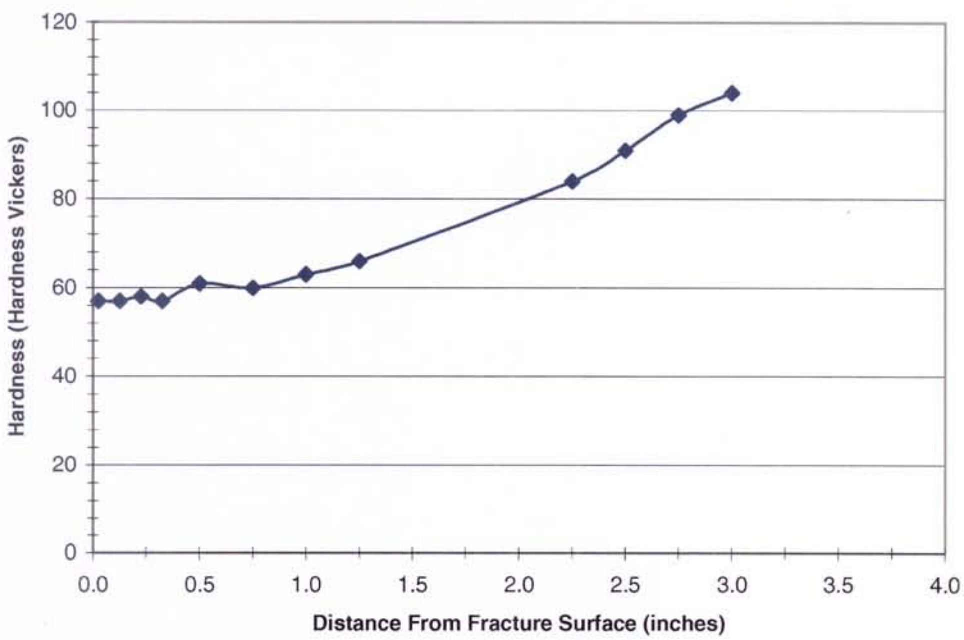
2.5 MICROHARDNESS TESTING

A microhardness survey was performed on the polished metallographic sample in accordance with ASTM E 92 "Test Method for Vickers Hardness of Metallic Materials". Testing was performed on a Tukon-Wilson Microhardness Tester with a load of 200 grams. Microhardness readings were taken linearly along the center of the cross section, from 0.025 inches below the fracture surface to 3.00 inches away.

Table 1: Microhardness Survey, Failed Copper Conductor

Distance From Fracture Surface (inches)	**Microhardness Value (Hardness Vickers)**
0.025	57
0.125	57
0.225	58
0.325	57
0.500	61
0.750	60
1.000	63
1.250	66
2.250	84
2.500	91
2.750	99
3.000	104

Figure 17: Hardness vs. Distance From Fracture Surface



The hardness values obtained from the survey show that the conductor within the clamping area of the connection had softened considerably, consistent with copper in the annealed condition. Outside of the connection area, the hardness returns to values closer to that expected for the hard drawn condition.

2.6 CONCLUSIONS

The copper conductor failed in the hot tap connection by ductile overload, from normal operating tensile stresses on the wire. Corrosion of the tin coating of the aluminum hot tap hardware likely occurred slowly over its long service life. As the tin oxide formed, the coating deteriorated to the point were contact between the aluminum body and copper conductor occurred, leading to galvanic corrosion of both materials. The buildup of all three corrosion products resulted in increased contact resistance within the hot tap junction. As the contact resistance increased, the service temperature for any given current load also increased. The elevated service temperature, over the long duration of the connections service life, led to the annealing of the copper from its original hard drawn condition. The tensile strength of the copper conductor is significantly decreased in the annealed condition, leading to ductile overload failure at the tensile stress present in its normal configuration. Corrosion attack also reduced the cross sectional area of the conductor and introduced stress concentrators in the form of pits that may also have contributed to the failure. Away from the failure area the hardness value of the conductor and its microstructure indicate it was originally in the hard drawn condition and likely would have been close to its expected strength.

Given the long average service life of the conductors and connection hardware, varying levels of corrosion attack within hot tap connections and splice connections will be present. In these connections the service temperature will be elevated, and similar conductor failures are likely to occur.

3.0 MATERIAL PROPERTIES ASSESMENT OF COPPER CONDUCTOR SAMPLES

3.1 INTRODUCTION

In addition to the repeated failures occurring in hot tap connections, concern was expressed over the condition of other common connections used with the solid copper conductor, as well as the general material properties of copper conductors away from any connections. Random selections of copper conductor (solid and stranded, varying sizes some containing splice connections) were forwarded to Powertech Labs Inc. for examination. Samples were received at staggered dates, and subsequently ascribed identification tags by Powertech Labs. The examination consisted of tensile testing, metallographic examination and hardness testing. Following is a list of sample types received for examination (seen in Figures 18-25).

Table 2: Sample Description and Identification

Sample ID	Sample Description
6a	Large coil (>20') of #6 AWG solid conductor
6b	46" length of #6 AWG solid conductor
6c	18" length of #6 AWG solid conductor
8a	56" length of #8 AWG solid conductor
8b	56" length of #8 AWG solid conductor
3a	50" length of #3 AWG solid conductor containing spring loaded tapered barrel splice connection near one end
3b	50" length of #3 AWG solid conductor
3c	12" length of #3 AWG solid conductor
4a	4 – 24" lengths of #4 AWG solid conductor
4b	30" length of #4 AWG solid conductor containing compression splice in approximate center
90	18" length of 90 MCM – hemp core stranded conductor (6 strands with individual strand diameter equivalent to #8 AWG)
2s	12" length of #2 stranded copper conductor (7 strands with individual strand diameter equivalent to #10 AWG)

Figure 18: Coil of #6 AWG copper conductor received for examination, identified as sample 6A

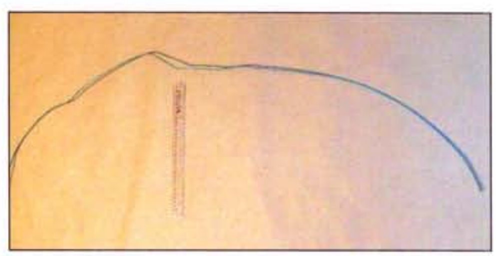


Figure 19: Length of #8 AWG wire received for examination, identified as sample 8A

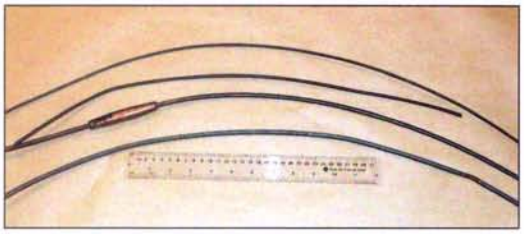


Figure 20: Single pieces of copper conductor samples received for examination. Conductor sizes were #8, #6, #3 containing a spring loaded tapered barrel splice, and #3 (top to bottom). Samples identified as: 8b, 6b, 3a and 3b (top to bottom)

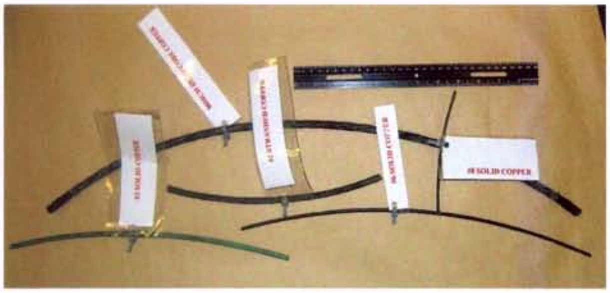


Figure 21: Single pieces of both stranded and solid copper conductor samples with identification. Stranded conductors were a 90 MCM hemp core (6 strands), and a #2 stranded conductor (7 strands), solid conductors were #8, #6 (6c), #3 (3c) and #2

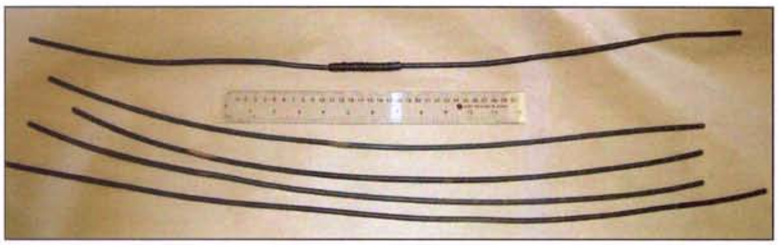


Figure 22: Single pieces of #4 AWG solid copper conductor (grouped as 4a), and #4 solid copper conductor containing a compression splice (4b)

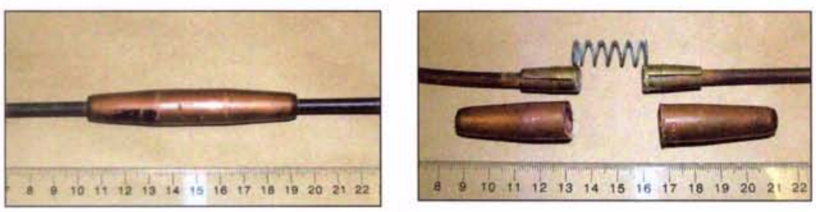


Figure 23: Macro image of spring loaded tapered barrel splice on sample 3b, before and after dissection. Note corrosion product on surface of conductor and on jaw inserts

Figure 24: Macro image of compression splice on sample 4b. Note corrosion product on surface of conductor and splice

3.2 APPLICABLE SPECIFICATIONS

Specifications for copper wire used for electrical purposes are governed by ASTM B1-01 "Standard Specification for Hard-Drawn Copper Wire". Section 5 of the standard details the tensile strength and elongation requirements of the copper wire.

Table 3: Standard Tensile Properties for Hard-Drawn Copper Wire, ASTM B1

Conductor Size	Nominal Diameter (mm)	Nominal Tensile Strength (Mpa)	Nominal Elongation %
#10	2.59	445	1.2
#8	3.26	440	1.3
#6	4.12	430	1.5
#4	5.19	415	1.7
#3	5.83	405	1.8

3.2 TENSILE TESTING

Tensile strength and elongation were determined simultaneously, in accordance with section 6 of ASTM B1. Testing was performed on a Sintech 20 G/T Universal Test Frame with a crosshead extension rate of 5 mm/min. Tensile strength was calculated by dividing the peak load by the cross sectional area of the strand. Elongation was calculated using a gage length of 250 mm. The maximum number of tensile specimens available was tested, based on the length of sample provided. Values for the tensile specimens, which fractured in the jaws of the test machine, were discarded and the values not reported, as dictated by ASTM B1. For the large coil, sample 6a, testing was performed until ten valid tensile test results were obtained, in accordance with a lot average dictated by ASTM B1.

Table 4: Tensile Test Results, Sample 6a

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
6a-1	4.12	5,625	422	2.2
6a-2	4.12	5,617	421	2.4
6a-3	4.13	5,604	420	1.9
6a-4	4.12	5,620	422	1.8
6a-5	4.10	5,579	423	2.1
6a-6	4.11	5,641	427	1.6
6a-7	4.12	5,449	409	2.0
6a-8	4.12	5,559	417	2.0
6a-9	4.11	5,608	425	1.9
6a-10	4.11	5,653	426	1.7
	Averages	**5,596**	**421**	**2.0**

Table 5: Tensile Test Results, Sample 6b and 6c

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
6b-1	4.14	5,662	421	2.1
6c-1	4.13	5,821	436	2.0
6c-2	4.13	5,682	425	2.2
6c-3	4.13	5,788	433	2.0
	Averages	**5,738**	**429**	**2.1**

Table 6: Tensile Test Results, Sample 8a

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
8a-1	3.25	3,219	388	2.2
8a-2	3.24	3,193	387	1.7
8a-3	3.24	3,191	387	2.5
8a-4	3.23	3,258	398	2.6
	Averages	**3,215**	**390**	**2.2**

Table 7: Tensile Test Results, Samples 3a, 3b and 3c

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
3a-1	5.84	10,400	388	2.3
3a-2	5.85	9,425	353	2.2
3b-1	5.85	10,311	388	2.2
3c-1	5.82	10,271	384	2.3
	Averages	**10,102**	**378**	**2.3**

Table 8: Tensile Test Results, Sample 4a

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
4a-1	5.19	8,213	388	3.0
4a-2	5.19	8,511	402	2.2
4a-3	5.16	8,634	413	2.0
4a-4	5.16	8,527	408	2.1
4a-5	5.18	8,509	404	2.1
4a-6	5.18	8,740	415	1.8
	Averages	**8,522**	**405**	**2.2**

Table 9: Tensile Test Results, Sample #2 Stranded Conductor

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
2s-1	2.54	2,128	422	1.9
2s-2	2.54	2,116	419	2.0
2s-3	2.56	2,178	423	2.0
2s-4	2.55	2,110	413	2.1
2s-5	2.56	2,095	407	2.2
2s-6	2.57	2,142	413	2.2
	Averages	**2,131**	**414**	**2.1**

Table 10: Tensile Test Results, 90 MCM Stranded Conductor

Sample ID	Diameter (mm)	Peak Load (N)	Tensile Strength (Mpa)	% Elongation
90-1	3.25	3,060	369	2.6
90-2	3.25	3,087	372	2.4
90-3	3.25	3,008	363	2.6
90-4	3.25	3,052	368	2.6
90-5	3.25	3,074	371	2.4
90-6	3.25	3,112	375	2.2
	Averages	**3,062**	**369**	**2.5**

For all conductor wire sizes tested, the tensile strength was below that of the nominal values required by ASTM B1. Elongation requirements of the samples were exceeded. The elongation requirements of the standard are a minimum requirement, however large positive variances would indicate that the copper has softened, or was not originally in the hard drawn condition. Of the samples the #8 AWG size showed the largest variance in both tensile and elongation properties, with an average tensile strength 12% below that of the nominal requirement.

3.3 METALLOGRAPHY

Metallographic specimens were prepared from samples 6a, 8a, 90, and 2s. Specimens were also prepared from sections of conductor within the splices of samples 3a and 4b, as well as approximately 2" outside the splice area. Sections of the conductor were prepared in the transverse and longitudinal cross section. Micrographs taken of the microstructure of samples 6a, 8a, 2s show elongated grains consistent with hard drawn copper (Figures 25-27). In sample 8a some fine equiaxed grains are seen, indicating some recrystallization and grain growth may be occurring. The microstructure of sample 90 shows elongated grains are not as compacted as the other samples, indicating the conductor may have been in the medium drawn condition, or some grain growth has occurred (Figure 28). Both the microstructures seen in sample 8a and 90 are consistent with the lower tensile strengths seen.

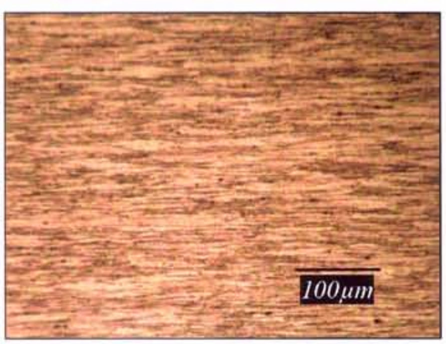


Figure 25: Microstructure seen in sample 6a Magnification: 200X

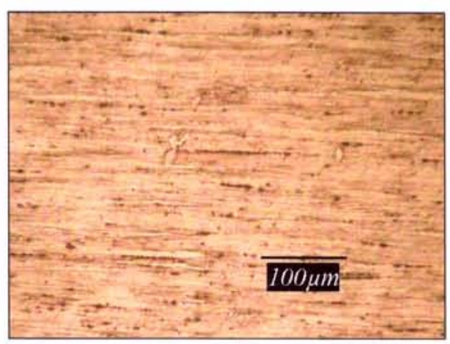


Figure 26: Microstructure seen in sample 8a Magnification: 200X

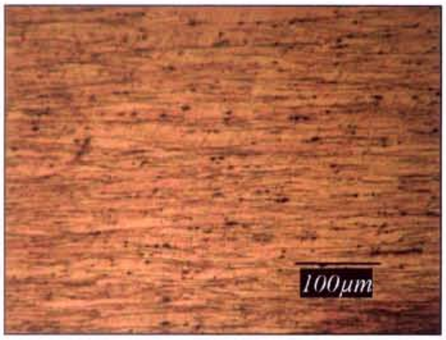


Figure 27: Microstructure seen in sample 2s Magnification: 200X

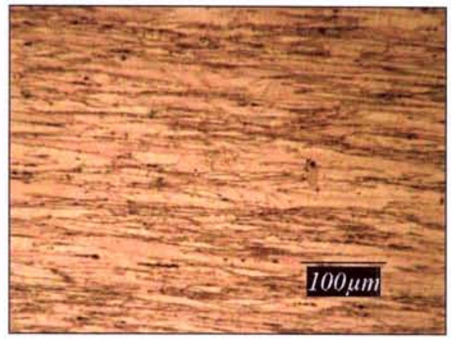


Figure 28: Microstructure seen in sample 90 Magnification: 200X

In samples 3a and 4b, the microstructure of the conductor outside the splice area consisted of elongated grains typical of hard drawn copper, with some recrystallization seen in 3a (Figures 29 and 31). In both samples the area within the splice showed markedly larger grain sizing, indicating some annealing has occurred within the splice connections (Figures 30 and 32).

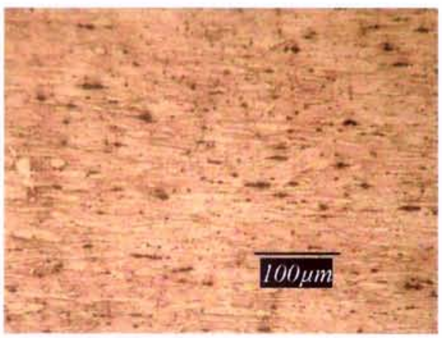


Figure 29: Microstructure seen in sample 3a, outside of splice area Magnification: 200X

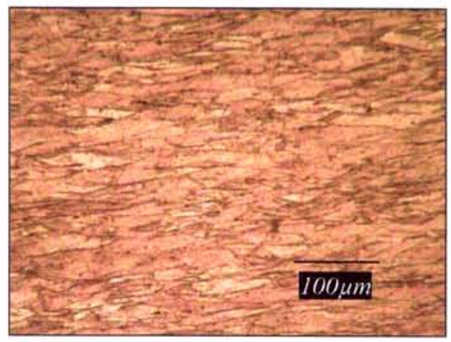


Figure 30: Microstructure seen in sample 3a within splice area Magnification: 200X

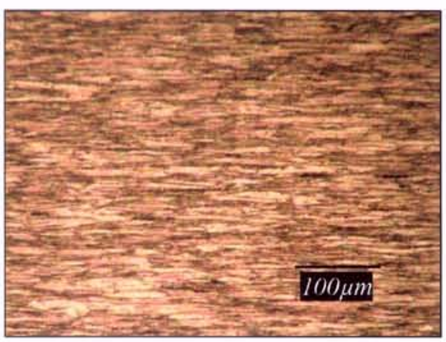


Figure 31: Microstructure seen in sample 4b outside splice area. Magnification: 200X

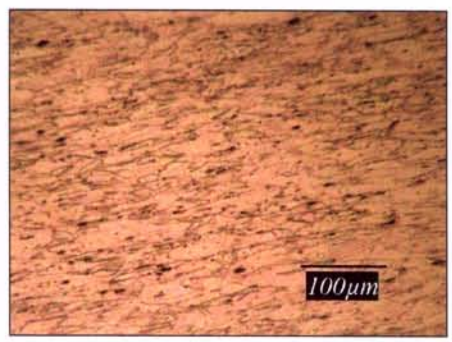


Figure 32: Microstructure seen in sample 4b within splice area. Magnification: 200X

3.4 MICROHARDNESS TESTING

Microhardness testing was performed on the polished metallographic samples in accordance with ASTM E 92, on a Tukon-Wilson Microhardness Tester with a load of 200 grams. Five microhardness readings were taken on each sample and averaged.

Table 11: Microhardness Values, Samples 6a and 8a

Sample ID	Average Microhardness (Hardness Vickers)
6a	102
8a	96
3a outside of splice area	100
3a within splice area	90
4b outside of splice area	99
4b within splice area	92
2s	99
90	98

The hardness values of sample 6a and the conductor from sample 3a outside the splice are consistent with the approximate hardness expected of hard drawn copper. The hardness values of samples 8a, 4b outside the splice area, 2s, and 90 are lower, consistent with the lower tensile strengths and microstructures seen. The conductor within the splice area of samples 3a and 4b is significantly lower than that of hard drawn copper, consistent with the larger grain size seen in those samples.

3.5 CONCLUSIONS

The tensile properties of the copper conductors provided for examination are below that of the nominal values dictated by the current standard. Examination of the microstructure and hardness would indicate that the conductors are slightly outside the expected parameters for copper wire in the hard drawn condition. The condition of the conductors may be attributable to one of two principle causes:

- The copper conductors present in the system may be undergoing a slow softening process from the combination of service temperature and their prolonged service life. Given the extended time in service of the conductor, it is possible that recrsytallization and grain growth is occurring in the microstructure, leading to a reduction in the hardness and tensile properties of the conductor.
- At the time of installation it is uncertain what the historical specifications of hard drawn copper wire were. Historical specifications or standards for hard drawn copper may have had lower strength requirements.

The hardness of the conductor within the splices is significantly lower than outside of the splice. The microstructure of the conductor within the splice has a larger grain size, similar to the trend seen in the failed hot tap examined. Both splice types examined rely on contact resistance between the two ends of the conductor and the splice body to transfer the current. Contact resistance within the splices has likely increased over time due to the buildup of corrosion product and external contamination. The increased resistance within the splices has led to elevated service temperatures, which over the long duration of their service life have caused grain growth.