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September 9, 2011

Via Email
Original via mail

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. (FortisBC) Application for 2012 -2013 Revenue Requirements and Review of 2012 Integrated System Plan Responses to British Columbia Utilities Commission Information Request No. 1

Please find attached FortisBC's responses to Information Request No. 1 from the British Columbia Utilities Commission (BCUC or the Commission).

If further information is required, please contact the undersigned at (250) 717- 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

SYSTEM LOSSES AND PEAK

1.0 Reference: 2012 and 2013 Forecast

Exhibit B-1, Tab 3, Section 3.0, pp. 1-2;

Figure 3.0 - Normalized Gross Load Composition

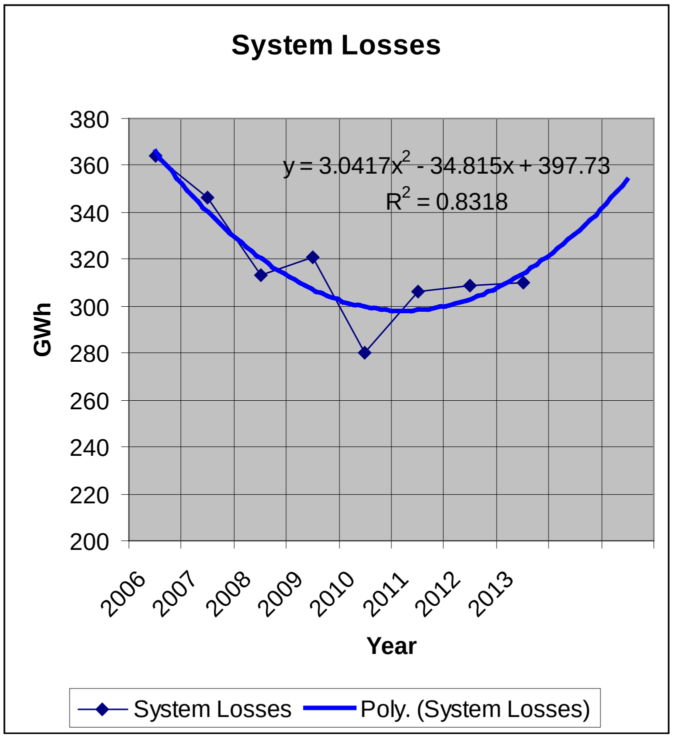
FortisBC states "For 2012 and 2013 gross system losses are forecast at 8.82 and 8.76 percent, using a two year rolling average from actual system loss calculation and forecast loss reduction in 2013 because of Advanced Metering Infrastructure (AMI) based programs." (Tab 3, p. 1)

1.1 The graph below has been developed from the data in Figure 3.0. Please explain the relatively constant decrease in losses between 2006 and 2010 and the marked increase between 2010 and 2011? Are there any non-recurring activities that explain the increased losses in 2009 and 2011?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

1.2 Please explain how FortisBC intends to mitigate the increasing losses being forecasted to 2013 and beyond by the trend-line.



Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

1.3 The losses shown in Exhibit B-1, Table 3.0 (Tab 3, p. 2) are the same values quoted in the reference above, which are calculated on a two year rolling average. Please provide the actual system loss calculations for 2011, 2012 and 2013, and explain how the OTR Project has affected losses.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

1.4 Please also explain the specific changes made to the loss analysis to compensate for the loss reduction anticipated from the AMI Project.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

2.0 Reference: Losses

Exhibit B-1, Tab 3, Section 3.5, p. 11

System Loss Composition

2.1 Please provide the composition of these actual and forecast system losses (calculated, not rolling average), in GWh by year, in the table below complete with a mitigation plan to reduce the system losses by type of loss?

	Type of System Loss	2006	2007	2008	2009	2010	2012	2013	Total
1	Losses in the transmission and distribution system								
2	Company use								
3	Losses due to wheeling through the BC Hydro system								
4	Unaccounted-for energy (meter inaccuracies)								
5	Unaccounted-for energy (theft)								
	Total	364	346	313	321	280	306	309	

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

2.2 Please provide the value of these system losses, in dollars by year using BC Hydro's RS 3808 to convert the GWh to dollars assuming firm power (capacity included), in the table below.

	Type of System Loss	2006	2007	2008	2009	2010	2012	2013	Total
1	Losses in the transmission and distribution system								
2	Company use								
3	Losses due to wheeling through the BC Hydro system								
4	Unaccounted-for energy (meter inaccuracies)								
5	Unaccounted-for energy (theft)								
	Total								

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

3.0 Reference: System Loss Composition

Exhibit B-1, Tab 3, Appendix 3C, p. 3C-2

Residential (Energy Forecast)

FortisBC states "A sale increase by the AMI-based revenue protection programs will be offset by a reduction in losses so that the total impact of the AMI-based programs on the gross load is zero" (Tab 3, p. 3C-2)

3.1 Please explain this statement and how the expected reduction in losses (2 GWh) will be realized and tracked.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

4.0 Reference: Peak Demand

Exhibit B-1, Tab 3, Section 3.6, Table 3A2, p. 12

System Winter peak

4.1 Please explain the reasons behind the very large increase (approximately 7 percent) in the 2011 winter peak demand as compared to the average in 2006 through 2010? Why is this increase expected to be sustained in 2012 and 2013?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

5.0 Reference: System Planning Forecasts

Exhibit B-1, Tab 3, Appendix 3F, Section F.3, p. 3F-4

Transmission Planning Forecast

"The transmission planning group derives data from both the resource planning forecast and the Distribution Load Forecasts to develop forecast loads allocated to FortisBC busses on the Western Electricity Coordinating Council (WECC) power flow model. This data is submitted to the WECC annually for application in regional and system-wide transmission planning studies."

5.1 Please provide the latest set of data submitted to the WECC and the most recent results from the associated transmission planning studies.

Response:

The actual and forecast FortisBC system peak load and energy data is submitted in an excel file template that is provided by WECC. The FortisBC system includes Teck Metals (Trail/Warfield Operations) and Zellstoff Celgar load information. The latest data submitted to WECC is provided in Tables BCUC IR1 5.1a and BCUC IR1 5.1b below.

Table BCUC IR1 5.1a

	FortisBC Peak Data											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
	(MW)											
2009	900	758	809	672	634	636	731	706	680	672	755	914
2010	831	737	697	688	659	625	746	755	655	691	956	896
2011	904	921	791	732	648	673	823	799	708	783	870	975
2012	937	880	837	762	724	769	835	810	717	793	882	990
2013	952	893	849	772	734	780	847	822	727	805	896	1005
2014	965	905	860	782	743	790	858	833	736	815	908	1018
2015	978	917	871	791	751	799	869	843	744	825	919	1030
2016	986	925	878	798	758	806	876	850	750	832	927	1040
2017	995	933	886	804	764	813	884	857	756	839	935	1049
2018	1005	942	894	812	770	820	892	865	762	847	945	1060
2019	1015	951	903	819	777	827	900	873	769	854	954	1070
2020	1025	960	911	826	784	835	909	881	775	862	963	1081
2021	1035	969	920	834	791	843	917	890	782	870	972	1092

Table BCUC IR1 5.1b

	FortisBC Energy Load											
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
	(GWH)											
2009	508	431	444	371	367	369	402	387	364	408	436	532
2010	488	414	430	388	392	373	423	393	376	372	443	513
2011	522	467	456	410	382	374	457	436	405	439	484	553
2012	545	489	483	432	422	416	461	440	408	445	488	559
2013	553	496	490	438	428	421	467	446	413	451	495	567
2014	560	502	496	443	433	426	473	452	418	456	501	575
2015	567	508	502	448	438	430	478	456	422	461	507	583
2016	572	512	506	452	441	433	482	460	425	465	511	588
2017	578	517	510	455	444	437	486	463	428	468	516	594
2018	583	521	515	459	448	440	490	467	431	472	520	600
2019	589	526	520	463	451	444	495	471	435	476	525	606
2020	595	531	524	466	455	447	499	475	438	480	530	612
2021	601	536	529	470	459	451	503	479	441	484	535	618

The WECC uses the load forecast data submitted by its members to update its computer models of the interconnected power system. These models are used by members, consultants and other parties in their own regional and system-wide studies. An example of a study is provided as BCUC IR1 Appendix 5.1.

6.0 Reference: System Planning Forecasts

Exhibit B-1, Tab 3, Appendix 3F, Section F.4, pp. 3F-4, 3F-5

1-in-20 Peak Forecast

> "This provides a peak forecast for transmission planning studies that has a quantitative risk index, as is necessary to achieve consistency with industry practice and established reliability standards."

6.1 Please provide the relevant industry and reliability standards that specify the approach used in the 1-in-20 peak forecast.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

6.2 Please provide a summary table of the 1-in-20 peak forecast annual results, showing escalated projected loads for each year, and identify which year sets the peak.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

6.3 Please describe whether the data from the year which defined the 1-in-20 peak has been examined for any outlier conditions which may have influenced the peak in the peak month or months.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

POWER PURCHASES AND WATER FEES

7.0 Reference: Power Purchases
Exhibit B-1, Tab 4, p. 1

FortisBC states "This section includes an estimate of 2011 Power Purchases based on FortisBC's actual results to April 30, 2011…." (Tab 4, p. 1)

7.1 Please update Table 4.1-1 to include 2011 actuals through July 31, 2011.

<u>Response:</u>

Please see the following table.

Table BCUC IR1 7.1

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Brilliant	33,216	32,249	35,601	36,785
2	BC Hydro	29,544	34,882	52,519	57,965
3	Independent Power Producers	914	175	155	158
4	Capacity Block Purchases	2,080	2,664	2,475	2,808
5	Market Purchases	8,222	4,835	214	545
6	Surplus Revenues	(1,000)	(63)	(284)	(267)
7	Capital Projects	(398)	(467)	-	-
8	Special and Accounting Adjustments	421	(139)	(750)	(750)
9	Balancing Pool	(1,036)	498	(156)	-
10	Planning Reserve Margin	-	-	-	311
11	Department Budget	-	-	1,211	1,266
12	TOTAL	71,964	74,635	90,984	98,821

On August 11, 2011, BC Hydro announced that it will be filing a revised rate application reducing its proposed rate increases by approximately 50 percent for F2012 to F2014. At this time BC Hydro has not confirmed the timing of its RRA update.

FortisBC intends to revise its forecast Power Purchase Expense for 2012 and 2013 once BC Hydro updates its RRA.

8.0 Reference: Power Purchases

Exhibit B-1, Tab 4, Section 4.1.1, p. 2

Review of 2011

8.1 Has the cooler and wetter weather since this Application was prepared led to additional benefits to 2011 power purchases? Please explain and quantify the impact on 2011 expected Power purchases compared to approved.

Response:

The reduction to Power Purchase Expense identified in the response to BCUC IR1 Q7.1 includes the impact of weather.

8.2 With the continuing improvements to BC Hydro reservoirs, would it not be expected that in 2012 market opportunities to purchase power at costs less than rate schedule 3808 should be anticipated? Please explain your views.

Response:

FortisBC does not have information as to how BC Hydro will manage its reservoirs in 2011 and into 2012, nor how this would impact market opportunities. Market opportunities are subject to a number of different factors including hydrological conditions, fuel prices, weather, economic conditions, as well as other supply and demand conditions. FortisBC will continue to monitor the market in order to mitigate its power purchase costs by purchasing power at costs less than BC Hydro Rate Schedule 3808 when the opportunity arises.

8.3 Please reconcile the statement “FortisBC annual gross load is forecast to be 29 GWh above approved 2011 (net of Demand Side Management (DSM) savings)” (Exhibit B-1, Tab 4, p. 2) with the forecast of 2011 annual gross load of 7 GWh less than approved as shown in Exhibit B-1, Tab 3, Table 3.0, p. 2.

Response:

The statement “FortisBC annual gross load is forecast to be 29 GWh above approved 2011 (net of Demand Side Management (DSM) savings)”, refers to actual loads while Exhibit B-1, Tab 3, Table 3.0, page 2 refers to weather normalized loads.

8.4 Please provide an annual history of capitalized power purchases (volume and cost) resulting from the ULE program and please describe how these power purchases should be viewed under US GAAP accounting procedures.

Response:

Data is only readily available for the ULE project from 2003 onwards. Table BCUC IR1 8.4a shows the capitalized power purchases as a result of the ULE project from 2003 to 2011.

Table BCUC IR1 8.4a

Capitalized Power Purchases ($)	P1U1 ULE Unit Outage Costs	P1U3 LE Unit Outage Costs	P2U5 Outage Costs	P2U6 LE Outage Costs	P3U1 LE Unit Outage Costs	P3U3 ULE Unit Outage Costs	P4U1 ULE Unit Outage Costs	**Total**
2003			$ 276,600					**$ 276,600**
2004			$ 720,391	$ 205,223				**$ 925,614**
2005	$ 178,390							**$ 178,390**
2006	$ 173,458	$ 2,886						**$ 176,343**
2007	$ 12,034	$ 533,204						**$ 545,238**
2008						$ 67,513		**$ 67,513**
2009					$ 95,544	$ 215,080	$ 4,265	**$ 314,889**
2010					$ 190,476		$ 215,877	**$ 406,353**
2011							$ 171,454	**$ 171,454**
Total	**$ 363,881**	**$ 536,090**	**$ 996,991**	**$ 205,223**	**$ 286,021**	**$ 282,593**	**$ 391,595**	**$ 3,062,393**

Table BCUC IR1 8.4b shows the amount of energy lost as a result of the ULE project. Following the renegotiation of the Canal Plant Agreement in 2005, the energy loss for planned outages was reduced significantly. The majority of the costs after 2005 are due to the capacity entitlement reductions as a result of the ULE project.

Table BCUC IR1 8.4b

Energy Loss (MWh)	P1U1 ULE Unit Outage Costs	P1U3 LE Unit Outage Costs	P2U5 Outage Costs	P2U6 LE Outage Costs	P3U1 LE Unit Outage Costs	P3U3 ULE Unit Outage Costs	P4U1 ULE Unit Outage Costs	**Total**
2003			7,903					**7,903**
2004			19,295	32,335				**51,630**
2005	36,055							**36,055**
2006	2,308							**2,308**
2007		17,219						**17,219**
2008						256		**256**
2009					870	170		**1,040**
2010					184		681	**865**
2011							973	**973**
Total	**38,362**	**17,219**	**27,198**	**32,335**	**1,054**	**426**	**1,654**	**118,247**

The historical capitalized power purchase costs resulting from the ULE program have been previously approved for recovery in rates, therefore this accounting treatment is permissible under US GAAP.

FortisBC has previously capitalized ULE power purchases as shown in Table BCUC IR1 8.4a. Pursuant to Commission Order G-184-10, the stakeholders recognized that these incremental power purchase costs have been capitalized in the past and during the PBR term. The parties agreed that such costs should be expensed beginning in 2012. The Company has prepared its 2012-13 RRA and 2012-13 CEP by expensing the incremental power purchase costs associated with the ULE program in accordance with BCUC Order G-184-10.

9.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 5

CPA Exchange accounts

FortisBC states "In 2011 the Company forecasts that it will use 17 GWh of storage energy from the CPA Exchange accounts (balancing pool), and in 2012 it will store 4 GWh of energy." (Tab 4, p. 5)

9.1 Please provide further explanation to this statement and update it for recent events. What impact will this updated information have on the Power Purchase forecasts for 2011, 2012, and 2013?

Response:

The forecast use of the balancing pool has not changed since the 2012-13 RRA was filed and results in no change to the Power Purchase forecasts for 2011, 2012, and 2013.

Normal Company operations are to ensure that energy reserves (storage) will always be full at the beginning of winter and will always be drawn down to close to empty by the end of winter. The balancing pool puts a dollar value on these transfers of energy from one time period to another based on the BC Hydro RS 3808 rate prevalent at the end of the year.

9.2 Please explain the application of the 4.45 percent for reserves on CPA capacity entitlements and discuss why or why this does not form an appropriate level of planning reserves instead of FortisBC's proposed approach to planning reserve margin.

Response:

FortisBC is part of the Northwest Power Pool (NWPP) Reserve Sharing Group, and is required to hold reserves according to the NWPP Reserve Sharing Program, which is based on WECC Standard BAL-STD-002-0 and NERC Standard BAL-002-0. This requires that a utility holds 5 percent of its hydro generation for contingency reserve, at least half of which is spinning, and 2 percent for regulating reserve. Therefore, FortisBC holds 2.5 percent of its entitlement as spinning contingency reserve and 2 percent of its entitlement as regulating reserve, as required. This is equal to 4.45 percent of total entitlement.

This is called operating reserve and it is intended to allow the reliable operation of the system on a real-time basis. The more spinning reserve the system holds, the better the chances of the electric system surviving the loss of a generator. Regulating reserves account for the fact that generation must follow demand on a real-time basis, not just the average for the hour. Utility experience has shown that in general the actual peak demand for any hour will be up to 2 percent higher than the average demand for the hour. For example, if the peak hourly load was 700 MW, it is likely that the actual peak demand on a real-time basis was about 700 * 1.02 = 714 MW.

Therefore, operating reserve is completely different from planning reserve since operating reserves deal with the real-time operation of the system. One of the main functions of the planning reserve margin is to ensure that there is sufficient generation such that firm load shedding or blackouts are not required to preserve the operating margin. The operating margin must be maintained even at the expense of blackouts. In other words, a utility that chooses to enter the hour with only operating reserve essentially has no reserves at all as any increase in load from what was expected should result in load shedding. Prudent utility operations require that a planning margin or planning reserve be held in addition to the operating reserve.

10.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 6;

Brilliant Energy Purchases

10.1 Please explain the derivation of the $39.14/MWh for 2012 forecast in Table 4.1.2.2-3?

<u>Response:</u>

The $39.14/MWh is calculated based on the estimates of the operating cost of the Brilliant facility provided by Columbia Power Corporation (CPC), calculated as a unit cost. Any variance between the forecast provided by CPC and the actual costs, will be trued up in a rate adjustment to a future year.

For 2012, the forecast costs at Brilliant (from CPC) are:

Original Plant Capital Charges: $15,999,000

Sustaining Capacity Charge: $7,313,000

Operation and Maintenance Expense: $10,400,000

Total Cost ($) = $33,712,000

True up from Previous Year = ($78,000)

Net Cost ($) = $33,634,000

Total Entitlement = 859.380 GWh

Unit cost (33,634,000/(859.38 x 1000)) = $39.1375/MWh

11.0 Reference: Power purchases

Exhibit B-1, Tab 4, p. 8

Table 4.1.2.2-5

11.1 Why is the BC Hydro 3808 cost/MWh increasing by 9.0% in 2011?

<u>Response:</u>

The 9 percent increase in BC Hydro cost between 2010 and 2011 is the increase in the average cost of BC Hydro energy. This will vary from the actual rate increase of 8 percent due to the timing of the rate increase, and the inclusion of excess energy costs. Since the rate increases begin partially through the year, the average cost per MWh can vary from the 8 percent depending on how much was purchased in each year before the rate increase, and how much was purchased after the rate increase. Additionally, the average rate is affected by the amount of excess energy the Company purchases. The cost of BC Hydro excess energy is 15 percent greater than the pre-scheduled energy. Changes to the amount of excess energy purchased will create changes to the average cost of BC Hydro energy. Currently FortisBC forecasts excess energy based on the average amount taken over the last two years (for the 2012-13 RRA the 2012 and 2013 forecasts were based on the average of 2009 and 2010). In 2011, FortisBC is forecasting the purchase of 34 GWh of excess energy, compared to only 18 GWh in 2010, making the 2011 cost higher on average.

12.0 Reference: Independent Power Producers

Exhibit B-1, Tab 4, p. 8

Table 4.1.2.2-6

12.1 Please explain the reason for the large sustained reduction in energy volumes after 2010 shown in Table 4.1.2.2-6 and provide a table showing actual quantities back to 2006.

<u>Response:</u>

The reduction in IPP purchases after 2010 is due to Zellstoff Celgar Limited Partnership's (Celgar) Energy Purchase Agreement with BC Hydro, which came into effect in the second half of 2010. Prior to this agreement, FortisBC purchased the majority of Celgar's output beyond their mill load. FortisBC's forecast IPP purchases in 2011, 2012, and 2013 are based on the average IPP generation in the FortisBC system from 2007 to 2010, excluding Celgar. The forecast for 2011 includes actuals up to April 30, 2011.

Table BCUC IR1 12.1

	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
IPP (GWh)	16	18	29	38	37	5	4	4

13.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 9

Market Capacity Purchases

13.1 Please compare the cost /MW of the Powerex capacity blocks in 2012 and 2013 with the cost of the Teck capacity blocks in recent years.

Response:

Please refer to Tables BCUC IR1 13.1a and 13.1b below.

Table BCUC IR1 13.1a Teck and Powerex Capacity Block Cost in Nominal Dollars

Capacity Block Cost ($CDN/MW/Month)	2008	2009	2010	2011	2012	2013
Teck	$ 5,625	$ 4,581	$ 3,792	N/A	N/A	N/A
Powerex	N/A	N/A	$ 5,825	$ 5,728	$ 6,186	$ 7,019

Table BCUC IR1 13.1 Teck and Powerex Capacity Block Cost in Real Dollars (2011 Dollars, assuming 2% inflation)

Capacity Block Cost ($CDN/MW/Month)	2008	2009	2010	2011	2012	2013
Teck	$ 5,970	$ 4,766	$ 3,867	N/A	N/A	N/A
Powerex	N/A	N/A	$ 5,941	$ 5,728	$ 6,065	$ 6,746

The cost of the Powerex capacity blocks are higher than the cost of the Teck capacity blocks due to different market conditions at the time the contracts were entered into. However, the Powerex capacity blocks are a better product, and have more capacity coverage than the Teck capacity blocks, including 6 light load days, and 16 additional hours of light load coverage.

14.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 10

2010 Capacity Deficit in November

14.1 In the past 10 years, how often has FortisBC faced a capacity deficit in November?

Response:

Between 2001 and 2010, FortisBC has faced a November capacity deficit in 6 years: 2002, 2004, 2005, 2006, 2007 and 2010. In addition, in both 2006 and 2010 the Company experienced the peak load for the year in November with loads of 718 MW in 2006 and 707 MW in 2010.

15.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 10

Forecast Market Prices

FortisBC states: "The forecast market prices are based on a variety of sources, including an April 29, 2011 Argus Media Publication titled "Argus US Electricity," and consultations with both Shell Energy North America and Powerex. These sources are used to derive a monthly Mid-Columbia (Mid-C) price forecast, and using the methodology described in Section 4.1.2.3 to extrapolate an hourly price forecast. The hourly forecast is used to estimate the cost of meeting the Company's peak demand shortfall, and the cost to meet the Company's energy deficit."

15.1 Please provide any updates that FortisBC has for forecast market prices through the test period.

Response:

Please refer to Tables BCUC IR1 15.1a and 15.1b below.

Table BCUC IR1 15.1a

Market Energy

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
As filed	$ 53.84	$ 50.94	$ 48.05	$ 42.15	$ 34.51	$ 23.20	$ 41.68	$ 63.39	$ 62.88	$ 64.66	$ 66.02	$ 70.14
Updated August 15, 2011	$ 46.80	$ 45.70	$ 41.68	$ 40.62	$ 34.60	$ 29.46	$ 48.13	$ 54.05	$ 52.55	$ 51.48	$ 52.97	$ 58.75
2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
As filed	$ 63.94	$ 60.50	$ 57.07	$ 49.33	$ 40.39	$ 27.16	$ 48.38	$ 73.58	$ 72.99	$ 74.60	$ 76.17	$ 80.93
Updated August 15, 2011	$ 56.92	$ 55.59	$ 50.69	$ 48.69	$ 41.47	$ 35.31	$ 57.21	$ 64.25	$ 62.47	$ 60.83	$ 62.58	$ 69.42

Table BCUC IR1 15.1b

Market Capacity - Energy

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
As filed	$ 39.00	$ 37.07	$ 34.42	$ 21.91	$ 12.97	$ 8.26	$ 19.87	$ 36.74	$ 40.86	$ 46.31	$ 50.30	$ 53.04
Updated August 15, 2011	$ 32.95	$ 31.26	$ 28.00	$ 21.12	$ 14.51	$ 11.25	$ 27.60	$ 34.47	$ 33.59	$ 35.79	$ 37.61	$ 41.70
2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
As filed	$ 45.48	$ 43.23	$ 40.13	$ 25.17	$ 14.91	$ 9.49	$ 22.65	$ 41.87	$ 46.57	$ 52.46	$ 56.97	$ 60.08
Updated August 15, 2011	$ 39.91	$ 37.87	$ 33.92	$ 25.22	$ 17.33	$ 13.43	$ 32.68	$ 40.81	$ 39.77	$ 42.11	$ 44.26	$ 49.07

The updated market price forecast is lower in most months than the forecast at the time of submitting the application.

In this application, the Company is proposing that any variance in power purchase expense from forecast, including market prices variances, will flow through to the ratepayer.

16.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 12

Market Prices

FortisBC states: "In order to get the energy from the MID-C to the FortisBC service territory, the Company applies a cost of $4 USD/MWh to the forecast Mid-C price as a transmission charge. The Company escalates this forecast based on annual forecasts from the sources above, in order to extrapolate a 5 year market price forecast." And "The Company adds a conservative 20 percent premium to the block forecast of heavy load energy to account for the peak hour premium."

16.1 Please demonstrate the validity of this practice by showing the transmission and peak hour premium charges experienced in recent years.

Response:

FortisBC does not receive a breakdown of transmission charges that are paid to move energy from the Mid-C to the FortisBC service territory. FortisBC purchases energy only from marketers and the price paid is the "all-in" price, which includes energy, transmission, losses and any other tariff, such as greenhouse gas offsets. The estimate of $4 USD/MWh is based on consultations with Shell Energy North America, and verified by a review of Bonneville Power Administration's (BPA) "2010-2011 Transmission and Ancillary Service Rates" posted on the BPA website at http://transmission.bpa.gov/Business/Rates/default.cfm?page=cur. BPA's stated rates for Hourly Firm and Non-Firm transmission service is 3.74 mils per kilowatt hour, equivalent to $3.74/MWh.

A review of MID-C Market prices shows that the relationship between average daily MID-C prices and peak hour prices, with data from January 1, 2006 up to August 7, 2011, is 19 percent. This is calculated by taking the average MID-C price for each day between hour ending 7 and hour ending 22, and comparing to the peak hourly price for that day. This is calculated for each day, and averaged to determine annual numbers. The Mid-C data is based on Hourly Electricity Index provided by Dow Jones. Table BCUC IR1 16.1 below summarizes the data.

Table BCUC IR1 16.1

Year	Average of Daily Mid-C Price (HE 7 to HE 22) ($/MWh)	Average of Maximum Daily Price ($/MWh)	Average Premium of Daily Peak Hour versus Monthly Average (%)
2006 Total	46.62	54.50	20%
2007 Total	52.69	61.09	17%
2008 Total	59.47	67.36	16%
2009 Total	33.20	38.93	19%
2010 Total	33.87	39.62	19%
2011 Total	23.03	37.61	63%
Grand Total	**42.80**	**50.73**	**19%**

17.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 13

Planning Reserve Margin (PRM)

FortisBC has relied on the BC Hydro 3808 agreement to meet its PRM needs.

17.1 Why does FortisBC not expect that the 3808 renewal in 2013 will continue to provide PRM benefits?

Response:

The current PPA expires in October 2013 and FortisBC and BC Hydro are currently in detailed discussions regarding the terms of any renewal of the PPA, and therefore the Company respectfully declines to provide a detailed response to the question at this time. The Company notes however, that the discussions are limited to the terms under which FortisBC would continue to have access to the 200 MW of firm capacity and associated energy available under the current 3808 agreement to meet load requirements. Additional capacity for PRM is outside the scope of these discussions.

17.2 Please provide details of the 2013 forecast PRM expense of $0.311 million. Since this forecast is speculative, would it not be better to use a $0 forecast and then true up any actual cost in the Power Purchase deferral account? Please explain.

Response:

The Company's best estimate at this time of the 2013 PRM expense is $0.311 million and therefore it is the Company's view that it is appropriate to include this amount in the current forecast of total Power Purchase expense costs. Any variations from this amount, including if the cost were to be avoided completely, would be trued up through the Power Purchase deferral account.

17.3 Please provide a forecast for potential PRM costs for 2014 to 2018.

Response:

In the 2012-13 RRA, FortisBC forecasts a PRM cost for 2012 of $0 and 2013 of $311,000. The PRM cost for 2013 is based on the assumption that the Company will need to acquire resources to meet PRM requirements following the expiry of the current BC Hydro PPA at the end of Q3 2013. It also assumes a phase-in of the PRM requirement.

The following table provides an estimate for PRM costs for 2014 to 2020. Note that the PRM cost to Procure listed here does not assume a phase-in of the PRM requirements.

Table BCUC IR1 17.3 PRM Cost to Procure: 2014 to 2018

Year	Total Cost (2010$)
2014	$2,238,000
2015	$2,238,000
2016	$2,238,000
2017	$2,506,000
2018	$2,769,000
2019	$3,030,000
2020	$3,303,000

These cost estimates are based upon the following assumptions:

- All prices are in 2010 dollars;
- The cost of procuring capacity is based on 80% of the UCC price estimate for the lowest cost UCC resource – a simple cycle gas turbine @ $10,163 per MW-Mo, as per the FortisBC 2010 Resource Option Report by Midgard Consulting Inc. The discount is applied because this capacity product is expected to be supplied from existing and operating facilities;
- The cost of capacity is expected to vary by month based upon the availability of surplus regional market supply. This variability is approximated using the BC Hydro monthly super-peak delivery factor table from the 2008 Clean Power Call (shown in Table 4);
- The capacity price will not vary by year due to the assumption that the capacity is linked to BC based resources, and therefore transmission constraints between BC and neighbouring jurisdictions will not materially impact the price; and

- This PRM Cost to Procure forecast has been done on a high level, and FortisBC PRM requirements, potential sources and contractual instruments have not been optimized. FortisBC will look at minimizing potential PRM costs for its ratepayers.

For more detail on the calculation of PRM costs, please see the response to BCUC IR1 Q258.1.

18.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 16

Surplus Sales

18.1 Please update the 2011 forecast Summer Sales in Table 4.1.3.

Response:

Table BCUC IR1 18.1 below shows the actual 2011 surplus sales to the end of July 2011. The volume of surplus sales in 2011 was well below forecast, since market prices were too low for the Company to benefit from additional sales.

Table BCUC IR1 18.1 Summer Surplus Sales

		Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
1	Volume (GWh)	49	10	19	16
2	Change (%)		-79%	86%	-16%
3	$/MWh	18.60	6.24	15.16	16.92
4	Change (%)		-66%	143%	12%

19.0 Reference: Total Power Purchase Expenses

Exhibit B-1, Tab 4, Section 4.1.4, Tables 4.1.4-1, 4.1.4-2, and 4.1.4-3, pp. 16-22

Planning Reserve Margin (PRM)

19.1 Please explain how the cost of the PRM shown in 2012 and 2013 is addressed in the expense summary, and show a breakout table of how this expense is derived. Please provide the corresponding expense summary table assuming no PRM in 2012 or 2013.

Response:

The cost of the PRM for 2012 is addressed in the expense summary in line 72 of Table 4.1.4-2 (Tab 4, page 20 of the 2012-13 RRA) and there are no costs associated with the PRM in 2012.

For 2013 the expected cost of the PRM is $0.311 million and is addressed on line 68 of Table 4.1.4-3 (Tab 4, page 22 of the 2012-13 RRA).

The PRM cost used in the Application was calculated by Midgard Consulting as detailed in the response to BCUC IR1 Q17.3.

Tables BCUC IR1 19.1a and 19.1b below show a breakout of the Power Purchase expense summaries for 2012 and 2013 assuming no PRM.

Table BCUC IR1 19.1a 2012 Forecast Power Purchase Expense (No PRM)

	2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
1	**Energy (GWh)**													
2	FortisBC Resources	156	131	132	128	117	100	178	118	113	121	115	170	**1,581**
3	Turbine Upgrades	2	2	2	2	2	2	2	2	2	2	2	2	**20**
4	Brilliant Base Plant	82	63	57	82	79	72	79	85	66	62	63	65	**856**
5	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**
6	Total BCH 3808 Energy	131	120	116	38	37	55	32	48	52	84	132	146	**991**
7	Net IPP Generation	0	0	1	0	0	0	0	0	0	0	0	0	**4**
8	Market Energy	0	0	0	0	0	0	0	0	0	0	0	0	**0**
9	Market Capacity - Energy	0	0	3	0	0	0	1	0	0	0	0	0	**4**
10	DSM and Other Customer Savings	3	4	4	4	4	4	4	5	5	5	6	6	**53**
11	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	**-**
12	WEPAS Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	**-**
13	FBC Surplus Sales	0	0	0	0	0	0	-19	0	0	0	0	0	**(19)**
14														**-**
15	**Total Gross Load (GWh)**	**375**	**319**	**314**	**263**	**253**	**246**	**292**	**271**	**238**	**275**	**319**	**390**	**3,555**
16	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
17														
18	**Capacity (MW)**													**Total**
19	FortisBC Resources	210	192	186	180	176	178	188	202	206	192	213	213	**2,335**
20	Turbine Upgrades	2	2	2	2	2	2	2	2	4	4	4	4	**27**
21	Brilliant Base Plant	123	123	87	117	106	100	106	81	119	119	123	123	**1,325**
22	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	**238**
23	Brilliant Tailrace	0	3	1	3	6	6	6	4	1	1	3	5	**38**
24	BCH Billing Capacity	180	200	200	175	150	198	200	200	150	190	200	200	**2,243**
25	BCH Peak Usage	180	200	200	175	149	198	200	200	99	190	200	200	**2,191**
26	Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125	**400**
27	Market Purchases - Real Time	0	1	76	0	0	0	47	33	0	0	0	32	**189**
28	DSM and Other Customer Savings	5	6	5	6	6	7	7	8	8	8	9	9	**83**
29	**FBC Peak Load (MW)**	**677**	**620**	**577**	**502**	**464**	**509**	**575**	**550**	**457**	**533**	**622**	**730**	**6,816**
30	Planning Reserve Margin	52	49	47	42	38	38	43	44	40	43	49	54	**537**
31	**Total Capacity Planning Load (MW)**	**729**	**669**	**623**	**543**	**502**	**548**	**617**	**594**	**496**	**577**	**671**	**783**	**7,353**

Table BCUC IR1 19.1a 2012 Forecast Power Purchase Expense (No PRM) (cont'd)

	2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
32	**Energy Rates (CDN$/MWh)**													**Average**
33	Brilliant Base Plant	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	**39.14**
34	Brilliant Upgrade	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	**27.87**
35	BCH 3808	36.21	36.21	36.21	39.11	39.11	39.11	39.11	39.11	39.11	39.11	39.11	39.11	**38.38**
36	IPP Rate	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	**34.64**
37	Market Energy	39.00	37.07	34.42	21.91	12.97	8.26	19.87	36.74	40.86	46.31	50.30	53.04	**53.04**
38	Market Capacity - Energy	53.84	50.94	48.05	42.15	34.51	23.20	41.68	63.39	62.88	64.66	66.02	70.14	**48.76**
39	Surplus Rate	33.49	31.69	29.21	17.20	8.99	4.65	15.16	30.54	34.29	38.99	42.60	45.08	**15.16**
40														
41	**Capacity Rates (CDN$/MW/month)**													
42	BRD Tailrace Capacity Rate	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	**4041**
43	BCH 3808 Capacity Rate	6,178	6,178	6,178	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	**6549**
44	Powerex Capacity Rate	5,786	5,786	-	-	-	-	-	-	-	-	6,701	6,701	**2081**
45														
46	**Exchange Rate (CDN$/USD$)**	0.96	0.96	0.96	0.98	0.98	0.98	0.99	0.99	0.99	0.99	0.99	0.99	**0.98**
47														
48	**Energy Expense ($000s)**													
49	Brilliant Base Plant	3,207	2,468	2,309	3,203	3,104	2,828	3,105	3,371	2,588	2,438	2,465	2,548	**33,634**
50	Brilliant Upgrade	20	(18)	(12)	273	387	361	387	355	27	17	8	9	**1,814**
51	BCH 3808	4,740	4,363	4,208	1,490	1,434	2,133	1,242	1,890	2,033	3,273	5,177	5,705	**37,688**
52	BCH 3808 Excess	-	-	0	12	32	29	33	27	11	0	5	0	**152**
53	IPP Costs	12	17	19	7	17	14	13	10	10	16	12	8	**155**
54	Market Energy	-	-	-	-	-	-	-	-	-	-	-	10	**10**
55	Market Capacity - Energy	-	1	132	-	-	0	38	17	-	1	1	14	**204**
56														
57	**Total Energy Expense ($000s)**	**7,979**	**6,831**	**6,655**	**4,985**	**4,975**	**5,365**	**4,819**	**5,671**	**4,670**	**5,744**	**7,669**	**8,295**	73,657
58														
59	**Capacity Expense ($000s)**													
60	BRD Tailrace Capacity	-	12	4	10	24	24	23	15	4	4	14	19	**153**
61	BCH 3808 Capacity	1,112	1,236	1,236	1,168	1,001	1,321	1,334	1,334	1,001	1,268	1,334	1,334	**14,680**
62	Powerex Capacity	868	434	-	-	-	-	-	-	-	-	335	838	**2,475**
63														
64	**Total Capacity Expense ($000s)**	**1,980**	**1,682**	**1,240**	**1,178**	**1,025**	**1,345**	**1,358**	**1,349**	**1,004**	**1,271**	**1,683**	**2,192**	17,307
65														
66	**Other Expenses ($000s)**													
67	Surplus Revenue	-	-	-	-	-	-	(284)	-	-	-	-	-	**(284)**
68	Capital Project Recovery													**-**
69	Special & Accounting Adjustments													
70	Market Adjustment	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	**(750)**
71	Balancing Pool Adjustments	313	274	602	(368)	(704)	(899)	1,603	(1,173)	(782)	(196)	(313)	1,486	**(156)**
72	Planning Reserve Margin	-	-	-	-	-	-	-	-	-	-	-	-	**-**
73	Management Expense	101	101	101	101	101	101	101	101	101	101	101	101	**1,211**
74														
75	**Total Other Expense ($000s)**	**351**	**312**	**641**	**(329)**	**(665)**	**(861)**	**1,357**	**(1,135)**	**(744)**	**(157)**	**(274)**	**1,524**	20
76														
77	**Total Power Purchase Expense**	**10,310**	**8,824**	**8,535**	**5,833**	**5,334**	**5,849**	**7,534**	**5,886**	**4,930**	**6,859**	**9,077**	**12,011**	**90,984**

Table BCUC IR1 19.1b 2013 Forecast Power Purchase Expense (No PRM)

	2013	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
1	**Energy (GWh)**													
2	FortisBC Resources	156	131	132	132	117	100	178	118	113	121	115	170	**1,585**
3	Turbine Upgrades	2	2	2	2	2	2	2	2	2	2	2	2	**20**
4	Brilliant Base Plant	82	63	57	82	79	72	79	85	66	62	63	65	**856**
5	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**
6	Total BCH 3808 Energy	136	124	121	37	39	57	32	51	54	87	136	146	**1,020**
7	Net IPP Generation	0	0	1	0	0	0	0	0	0	0	0	0	**4**
8	Market Energy	0	0	0	0	0	0	0	0	0	0	0	5	**5**
9	Market Capacity - Energy	0	0	2	0	0	0	1	0	0	0	0	0	**4**
10	DSM and Other Customer Savings	7	7	7	7	7	7	7	8	8	8	9	9	**89**
11	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	**-**
12	WEPAS Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	**-**
13	FBC Surplus Sales	0	0	0	0	0	0	-16	0	0	0	0	0	**(16)**
14														**-**
15	**Total Gross Load (GWh)**	**383**	**326**	**321**	**269**	**259**	**252**	**298**	**277**	**244**	**281**	**325**	**398**	**3,632**
16	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
17														
18	**Capacity (MW)**													**Total**
19	FortisBC Resources	210	192	199	191	187	178	188	202	206	191	213	213	**2,370**
20	Turbine Upgrades	4	4	4	4	4	4	4	4	4	4	4	4	**43**
21	Brilliant Base Plant	123	123	87	117	106	100	106	81	119	119	123	123	**1,325**
22	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	**238**
23	Brilliant Tailrace	0	3	1	2.5	6	6	5.7	3.6	0.9	0.9	3.4	4.8	**38**
24	BCH Billing Capacity	186	200	200	168	150	200	200	200	150	198	200	200	**2,252**
25	BCH Peak Usage	186	200	200	168	142	200	200	200	105	198	200	200	**2,199**
26	Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125	**400**
27	Market Purchases - Real Time	0	7	69	0	0	2	53	39	0	0	10	43	**222**
28	DSM and Other Customer Savings	9	10	10	10	10	11	11	12	13	12	13	13	**135**
29	**FBC Peak Load (MW)**	**692**	**633**	**589**	**512**	**474**	**520**	**587**	**562**	**467**	**545**	**636**	**745**	**6,961**
30	Planning Reserve Margin	52	49	47	42	38	39	43	44	40	44	49	54	**542**
31	**Total Capacity Planning Load (MW)**	**744**	**682**	**636**	**554**	**512**	**559**	**630**	**606**	**506**	**589**	**685**	**799**	**7,503**

Table BCUC IR1 19.1b 2013 Forecast Power Purchase Expense (No PRM) (cont'd)

	2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
32	**Energy Rates (CDN$/MWh)**													**Average**
33	Brilliant Base Plant	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	**40.46**
34	Brilliant Upgrade	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	**28.56**
35	BCH 3808	39.11	39.11	39.11	42.24	42.24	42.24	42.24	42.24	42.24	42.24	42.24	42.24	**41.45**
36	IPP Rate	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	**35.33**
37	Market Energy	45.48	43.23	40.13	25.17	14.91	9.49	22.65	41.87	46.57	52.46	56.97	60.08	**60.08**
38	Market Capacity - Energy	63.94	60.50	57.07	49.33	40.39	27.16	48.38	73.58	72.99	74.60	76.17	80.93	**58.60**
39	Surplus Rate	37.07	35.08	32.35	19.15	10.09	5.31	16.92	33.89	38.03	43.23	47.21	49.95	**16.92**
40														
41	**Capacity Rates (CDN$/MW/month)**													
42	BRD Tailrace Capacity Rate	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	**4115**
43	BCH 3808 Capacity Rate	6,672	6,672	6,672	7,206	7,206	7,206	7,206	7,206	7,206	7,206	7,206	7,206	**7073**
44	Powerex Capacity Rate	6,882	6,882	-	-	-	-	-	-	-	-	7,195	7,195	**2346**
45														
46	**Exchange Rate (CDN$/USD$)**	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	**1.02**
47														
48	**Energy Expense ($000s)**													
49	Brilliant Base Plant	3,315	2,552	2,387	3,311	3,209	2,923	3,210	3,485	2,675	2,520	2,549	2,634	**34,770**
50	Brilliant Upgrade	20	(18)	(13)	280	397	369	397	364	28	17	8	9	**1,859**
51	BCH 3808	5,303	4,858	4,715	1,562	1,665	2,414	1,342	2,156	2,293	3,663	5,754	6,162	**41,886**
52	BCH 3808 Excess	-	-	0	13	35	32	36	30	12	0	6	0	**164**
53	IPP Costs	12	17	19	7	17	14	13	11	10	16	12	8	**158**
54	Market Energy	-	-	-	-	-	-	-	-	-	-	-	304	**304**
55	Market Capacity - Energy	-	2	118	-	-	0	57	27	-	-	3	34	**241**
56														
57	**Total Energy Expense ($000s)**	**8,650**	**7,411**	**7,226**	**5,173**	**5,323**	**5,753**	**5,055**	**6,072**	**5,019**	**6,217**	**8,331**	**9,151**	**79,381**
58														
59	**Capacity Expense ($000s)**													
60	BRD Tailrace Capacity	-	12	4	10	25	25	23	15	4	4	14	20	**155.547**
61	BCH 3808 Capacity	1,241	1,334	1,334	1,211	1,081	1,441	1,441	1,441	1,081	1,427	1,441	1,441	**15,916**
62	Powerex Capacity	1,032	516	-	-	-	-	-	-	-	-	360	899	**2,808**
63														
64	**Total Capacity Expense ($000s)**	**2,273**	**1,863**	**1,339**	**1,221**	**1,106**	**1,466**	**1,465**	**1,456**	**1,085**	**1,431**	**1,815**	**2,360**	**18,879**
65														
66	**Other Expenses ($000s)**													
67	Surplus Revenue	-	-	-	-	-	-	(267)	-	-	-	-	-	**(267)**
68	Planning Reserve Margin													**-**
69	Capital Project Recovery													**-**
70	Special & Accounting Adjustments													
71	Market Adjustment	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	**(750)**
72	Balancing Pool Adjustments	338	296	650	(228)	(760)	(971)	1,732	(1,267)	(845)	(211)	(338)	1,605	**-**
73	Previous Year True-up													
74	Management Expense	106	106	106	106	106	106	106	106	106	106	106	106	**1,266**
75														
76	**Total Other Expense ($000s)**	381	339	693	(185)	(717)	(928)	1,508	(1,224)	(802)	(168)	(295)	1,648	**250**
77														
78	**Total Power Purchase Expense**	**11,305**	**9,612**	**9,258**	**6,209**	**5,711**	**6,291**	**8,028**	**6,304**	**5,302**	**7,479**	**9,851**	**13,160**	**98,510**

19.2 What amount of reserves from CPA entitlement is considered to form part of PRM?

Response:

As described on page 3 of the FortisBC Planning Reserve Margin Study (Appendix E to the 2012 Long Term Resource Plan), the PRM requirement is reduced by the 2.5 percent spinning reserve that is held on the Company's CPA capacity entitlement. This amount is subtracted from the potential PRM deficit.

20.0 Reference: Power Purchases

Exhibit B-1, Tab 4, p. 23

Power Purchase Expense Variance Deferral Account

20.1 Please update Table 4.1.5-1 for 2011 forecast based on most recent market information?

Response:

The updated table is provided below.

Table BCUC IR1 20.1

	2007	2008	2009	2010	2011F	Total
			Over/(Under) Approved			
Sales Load variance in GWh	13	-	50	(153)	(8)	
Sales Load variance in %	0.4%	-	1.6%	(4.8%)	(0.3%)	
Power Purchase Expense variance	$ (2,631)	$ (2,528)	$ (168)	$ (8,444)	$ (7,013)	$ (20,784)
Power Purchase Expense variance %	(3.8%)	(3.7%)	(0.2%)	(10.5%)	(8.6%)	

20.2 Since 2007, FortisBC has underspent Power Purchase Expense approvals by approximately $4 million/year, mostly due to favourable market purchases compared to the approved expenditures. Would it not be appropriate to reduce the current forecasts in 2012 and 2013 by $4 million/year to reflect those market opportunities? The variance would flow to the deferral account.

Response:

Please see the response to BCMEU IR1 Q12b.

20.3 Does the Company expect that any variance in the Power Purchase Management Expense would flow to the Power Purchase Expense Variance Deferral Account? Why?

Response:

Yes, the Company expects that any variance in the Power Purchase Management Expenses will be included as part of the deferral account. The Company believes this is appropriate given that the purpose of including the Power Purchase Management Expense with Power Purchase Expense is to ensure that the costs are directly linked to the function.

21.0 Reference: Wheeling Expense

Exhibit B-1, Tab 4, Section 4.1.6, p. 26

General Wheeling Agreement (GWA)

21.1 Please provide the total costs and volumes under the GWA since 2006.

Response:

The table below shows the actual cost and volumes under the GWA since 2006.

Table BCUC IR1 21.1

	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1 GWA Wheeling Nomination				(MW)				
2 Okanagan	1,920	1,920	1,965	2,115	2,160	2,220	2,475	2,715
3 Creston	396	396	402	420	420	420	420	420
4 GWA Wheeling Expense				($000s)				
5 Okanagan	3,072	3,052	3,189	3,500	3,550	3,723	4,233	4,732
6 Creston	409	410	425	453	450	459	468	477
7 Total GWA Expense	3,480	3,462	3,614	3,953	4,050	4,181	4,701	5,209

22.0 Reference: Water Fees

Exhibit B-1, Tab 4, p. 28

22.1 Will the variances in water fees due to differences in CPI or generation flow to the Power Purchase Expense Variance Deferral Account? Please explain.

Response:

FortisBC has not proposed including variances in Water Fees in the Power Purchase Expense Deferral Account. Variances in Water Fees could result from either volume variances in

FortisBC generation in the prior year or from rate variances due to differences in water rental rates, which are escalated annually by the BC Consumer Price Index.

The Company would not object to including Water Fees in the proposed Deferral Account. Variances from 2007 to 2011 forecast are shown in the following table.

Table BCUC IR1 22.1 Water Fee Variances 2007 – 2011

	2007	2008	2009	2010	2011F	Total
			Over/(Under) Approved			
Forecast	7,976	7,858	8,480	9,068	9,381	
Actual	7,918	7,878	8,656	9,256	8,977	
Difference	(58)	20	176	188	(404)	(78)

23.0 Reference: Power Purchase Expenses

Exhibit B-1-2, Appendix D, pp. 2, 7

Planning Reserve Margin

23.1 In Table 1-A of the Midgard report the monthly PRM in Jan., Nov., and Dec. reached as high as 21%. Is this not unreasonably high? What percentages are carried by BC Hydro and other utilities in the Pacific Northwest in those months?

<u>Response:</u>

The Company does not believe that the planned PRM in January, November and December is unreasonably high. The table below (a modified version of Table 5.2.1.1-C on page 58 of the 2012 Long Term Resource Plan) shows PRM percentages held by other utilities as well as a description of how the PRM was calculated.

Table BCUC IR1 23.1a Nearby Planning Reserve Margins

Utility	PRM (%)	How PRM is Calculated
Avista	15	Summer & Winter Peaks
BC Hydro[1]	14	Average Annual
Idaho Power	10	Annual Peak
Northwestern Energy[2]	0	N/A
PacifiCorp	12	Annual Peak
Portland General Electric	12	Annual Peak
Puget Sound Energy	15	Annual Peak

All of the utilities in Table BCUC IR1 23.1a (with the exception of BC Hydro) report PRM against their respective annual peak load obligations. These PRM percentages effectively represent the lowest available margin in a given year. The following example reveals that actual PRM carried during non-peak months can significantly exceed the PRM carried during peak months:

Peak Month Load Obligation = 1000 MW

Supply Stack = 1000 MW

PRM (calculated against peak load) = 10% or 100 MW

Total Supply Stack + PRM = 1100 MW

Non-peak Month Load Obligation = 700 MW

Effective Non-Peak Month PRM = (1100 – 700)/700 MW = 57%

The example above shows that utilities that plan PRM solely against the peak month subsequently carry large unneeded reserves during non-peak months.

FortisBC plans its long-term capacity/load resource balance on a monthly basis, therefore allowing the appropriate amount of PRM to be allocated in each month of a given year. This method significantly reduces the amount of un-needed reserves during non-peak months. Since FortisBC's single largest unit varies month-by-month it follows that FortisBC's PRM will be larger in certain months to comply with the WECC's PRM recommendations.

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[1] BC Hydro's 14 percent PRM is calculated after allowing for reserves required to meet a 1 day in 10 year Loss of Load Expectation, so the actual reserve level being carried by BC Hydro is substantially higher than 14 percent; see BC Hydro 2008 Long Term Acquisition Plan Appendix F10: Calculation of Capacity Planning Reserves

[2] Northwestern Energy (NWE) does not carry Planning Reserves, relying instead on the market to provide required real time reserves or to cover unit contingencies. However, NWE recognizes that its market access is being impacted by an erosion of excess capacity in the Pacific Northwest area, as identified in its 2009 Electric Supply Resource Procurement Plan: "In the past few years the market for ancillary services, such as operating reserves, has tightened which has caused prices to increase substantially. In order to avoid paying steep prices in the market for operating reserves, Northwestern at times has self-provided the reserves by utilizing the capacity from the Basin Creek facility."

Table BCUC IR1 23.1b (Exhibit B-1-2, Section 5.2.1.1, page 57) below shows that on an average annual basis, FortisBC's PRM percentages are lower than BC Hydro's 14 percent average annual PRM.

Table BCUC IR1 23.1b Monthly PRM in 2020, 2030 and 2040 (%)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2020	12	9	8	7	8	8	7	5	5	6	7	14	**8**
2030	15	12	12	7	8	8	11	6	5	6	11	18	**10**
2040	18	15	15	7	8	8	12	9	5	9	14	17	**11**

This table shows that on an annual average basis, FortisBC's PRM requirements are equivalent or lower than what most other utilities in the Pacific Northwest report (on an annual peak basis) for two reasons:

1. As described earlier, FortisBC has planned for the appropriate amount of PRM on a monthly basis rather than an annual basis. This significantly reduces reserves in non-peak months (the same months that other utilities carry much greater reserves than required); and
2. The single largest unit in the FortisBC system represents a greater proportion of its load than is typical for larger utilities. A single Waneta Expansion unit is 165 MW, which represents 21% of FortisBC's 2020 forecast peak load of 778 MW. In contrast, BC Hydro's 2020 peak demand forecast is approximately 9,000 MW and its single largest unit is a 500 MW Revelstoke unit, which represents approximately 6 percent of BC Hydro's peak load.

Please note that the methodology recommended by Midgard for the calculation of PRM (Appendix D of the 2012 Long Term Resource Plan) would produce a larger monthly PRM requirement than is being proposed by FortisBC, due to a modified approach in accounting for the Single Largest Utilized Contingency. Please refer to the response to BCUC IR1 Q257.1.1 for detailed examples.

23.2 Footnote 5 on page 7 of the Midgard report discusses why Northwestern Energy does not carry any PRM. Please compare the circumstances of FortisBC with Northwestern Energy.

Response:

FortisBC is in different circumstances than NorthWestern Energy and as a result FortisBC must carry a prudent level of PRM.

In its 2009 Electrical Supply Resource Plan (Volume 1, pp. 105), NorthWestern Energy states the following:

> "Because of its efficient use of market purchases, exchanges and the availability of short-term purchase products, NorthWestern has not needed to acquire and maintain reserve margin or excess capacity to meet peak demand and provide reliability. … This condition exists for NorthWestern because of excess generation on the Montana system and in the Northwest."

In summary, NorthWestern Energy believes it can continue to rely on the spot market to meet any capacity shortfalls going forward.

However, the Company believes this is an imprudent planning approach for FortisBC for the following reasons:

- The market that FortisBC buys power from does not have, as NorthWestern Energy suggests, excess generation. Whether or not this is true of NorthWestern is beyond the scope of the FortisBC Resource Plan. As outlined in Section 5.3 (Exhibit B-1-2, Appendix D, pp. 12 – 15), various factors are contributing to decreasing capacity margins in the northwest WECC region, including:
    - Capacity resources being reserved to firm intermittent resources such as wind;
    - Shrinking capacity margins in the Canadian WECC region;
    - The possibility of economic recovery, which could spur the return of large industrial loads that would further erode capacity margins; and
    - Aggressive DSM targets that may not be achieved and would have the effect of removing "capacity resources" (which is how DSM targets are accounted for in utility planning) from utility resource stacks.
- Unlike NorthWestern Energy, whose resources are mainly thermal (coal and natural gas), FortisBC and its neighbours are largely dependent on hydroelectric resources. Periods of poor precipitation levels would force FortisBC into a capacity-poor market. Although NorthWestern takes part in the same market, its thermal resources would not force it into the market to the same extent as FortisBC.

24.0 Reference: FortisBC Operating Statistics

Exhibit B-1, Appendix G, p. 1

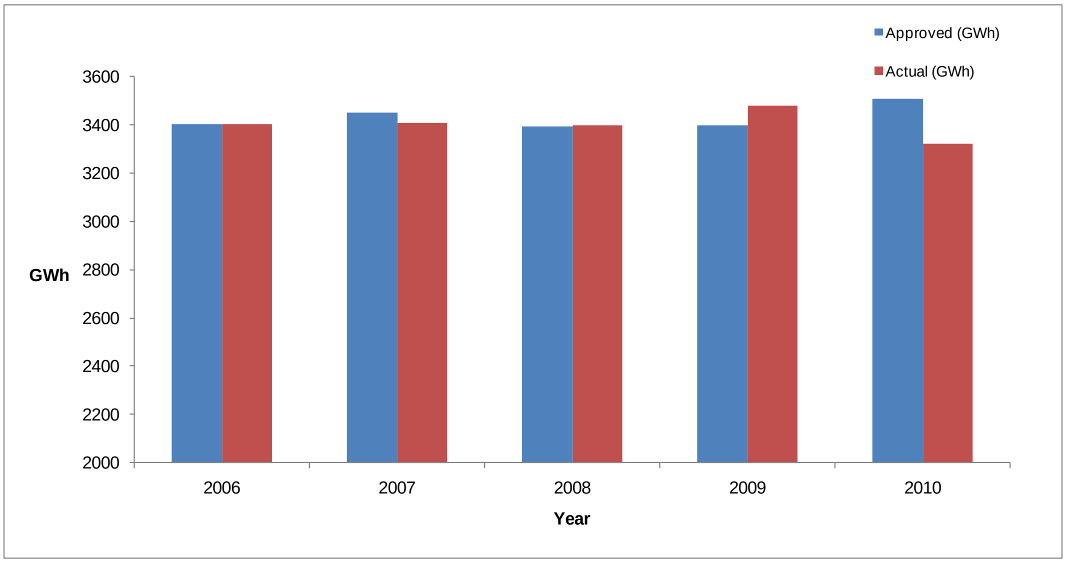
Power Purchases

24.1 Total power purchases approved and actuals track closely from 2006 to 2009, but the approved level in 2010 is much higher than either the trend or the actual. Please explain why.

Response:

The approved 2010 power purchase expense was higher than the previous period mainly due to increased loads, and an increase in BC Hydro rates that went into effect April 1, 2010. The 2010 actual power purchase expense was below the 2010 approved amount mainly due to actual gross loads being substantially below plan in contrast to previous years as shown in the following graph:

Figure BCUC IR1 24.1 FortisBC Gross Load (GWh)



The 2010 approved power purchase expense was based on the load forecast using normal weather conditions. The 2010 actual load was below forecast partially due to weather being different than what was forecast. Weather that was warmer than normal in winter, and weather that was cooler than normal in the summer, resulted in decreased loads in both seasons. Furthermore, economic recovery did not occur as quickly as had been forecasted. This resulted in actual loads across many classes, including industrial and commercial, to be below forecast. (It should be recognized that reduced load results in both avoided power purchases and decreased revenues from customers).

In addition to reduced load requirements, the Company was also able to mitigate 2010 power purchase expense by taking advantage of market opportunities through continuing to actively manage the daily power supply operations.

24.2 In 2011, the approved level is also much higher than the forecast. What is the current forecast and why did the FortisBC insist on such a high approved level at last year's Annual Review?

Response:

Please refer to BCUC IR1 Q7.1 for the updated forecast of 2011 and a discussion of the variance between the updated forecast and the forecast that was filed in the Application.

The Company's forecast for 2011 at last year's Annual Review was based on the best information that was available at that time on forecast loads and power purchase costs. Since that review, although actual loads are fairly close to plan, the Company has been able to take advantage of 2011 market opportunities that were not expected to be available late in 2010.

For 2012 and 2013, FortisBC proposes that any variance in power purchase expense, including those that arise from changes in market conditions, will flow through to the ratepayer through the Power Purchase Expense Variance Deferral Account.

OPERATION AND MAINTENANCE

25.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.1.2.6, pp. 13-15

Purchased Power Management Expense (PPME)

25.1 Please explain the cost drivers for purchase power management expense and what is included in the "non labour" component of the expense?

Response:

The main cost driver for Power Purchase Management Expense is Labour costs. For 2012 out of a total expected cost of $1.211 million, $0.923 million is Labour Expense. These Labour Expenses are required to cover costs associated with the Company's annual load forecast (1 .5 FTEs), certain resource planning functions (2.5 FTEs), Power Supply (1 FTE for 2011, 2 FTEs for 2012) and overall departmental management (1 FTE). Of the 2.5 Resource Planning FTEs for 2012, only 1.5 FTE is being recovered through Resource Planning Departmental charges with the remaining FTE charged to the Resource Plan project. The increase to 7 FTEs in 2012 from 6 FTEs in 2011 will add an additional FTE to concentrate on managing power purchase costs.

Non-Labour 2012 expenses of $0.288 million include the following:

- the 1938 International Joint Commission order annual payments to United States farmers to compensate them for higher pumping costs due to Kootenay Lake operations;

- Gray Creek snow surveys to assist in forecasting annual freshet run-off in the Kootenay basin;
- Training expenses;
- Industry subscriptions;
- Telephone costs;
- Travel costs;
- Consultant costs; and
- Cross charges for labour required for services provided by FEI, FortisBC's Gas Supply group.

The increase of $0.085 million in Non-Labour expenses for 2012 is related to increased consultant and FEI charges. These are required to address the critical contract negotiations and renewals that will set the direction of the Company's Power Supply portfolio for the next 20 to 40 years. In addition, FEI will also provide enhanced capabilities to the electric power supply group through activities like contract administration, regulatory and policy compliance, business planning and load forecasting. These FEI services will provide an opportunity to enhance current work practices through the provision of cost effective services in support and administrative areas while allowing critical employees to focus more on negotiating contractual arrangements and managing and mitigating power supply costs.

25.2 During 2010 and 2011 while the number of FTE remained constant at 6, labour costs have increased 15%. Please explain why.

Response:

Labour costs have increased by 15 percent in 2011 compared to 2010 due to salary adjustments, timing differences due to one of the 2010 FTE increases not occurring at the start of 2010 and differences in the charge out rate to the Resource Plan.

25.3 The labour cost increase in 2012F is 30% over 2011, which appears to be substantially high. After accounting for the additional FTE and a 3% wage inflation, total labour costs appeared to be 6% higher than expected in 2012. Please explain why? (supporting calculations shown in the interactive excel insert below)

Response:

The 30 percent increase in labour costs in 2012 compared to 2011 is mainly driven by the increase in 1 FTE at a forecast fully loaded cost of approximately $0.145 million. The remaining increase of approximately $0.055 million is due to salary increases for existing employees and changes to the charge out rate to the Resource Plan.

25.4 Since FortisBC has a capacity block with Powerex, Waneta capacity in the future, and likely smaller summer surpluses to sell, why have the FTEs of this group risen from 3 in 2008 to 7 expected in 2012/13?

Response:

As detailed in response to BCUC IR1 Q25.1 there is currently only one FTE (plus management support) in the group fully engaged in the daily Power Supply activities. The additional FTE in 2012 will be to raise this number to two.

The Company agrees that portions of the work in managing Power Supply, such as the capacity blocks are stable. Also, the addition of the Waneta Expansion capacity in the future will not reduce the workload from current levels as that additional capacity will have to be optimized along with existing energy resources and surplus sold to the market. In addition many other issues continue to increase in complexity at a rapid pace. Tab 4, Section 4.1.2.6, page 14, rows 7 to 20 lists the following issues:

1. Regional environment that is becoming more constrained;
2. Tighter regulation;
3. Critical contract negotiations and renewals;
4. Increasingly complex environment to manage and optimize generation and contractual resources;
5. Significant increase in regional working group participation;
6. Further optimization of Power Purchase Expense through increased market activity;
7. Transmission becoming more constrained; and
8. Better price forecasting.

Since the time of filing the 2012-13 RRA, an example of a new potential requirement has come to the attention of the Company. Currently, the smallest unit of time that is scheduled is 60 minutes. This means that load resource balances are run every hour and additional supply is obtained as needed on an hourly basis. In the future, it is expected that the basic scheduling time will be every 30 minutes or even 15 minutes. If adopted by the Company, this transition will require additional resources on a long-term basis.

It is expected that new issues will continue to arise over the next few years as utilities retool long standing procedures and practices to adapt to intermittent renewable generation in the face of ever tightening transmission resources. These issues will require significant analysis to determine what the Company's position should be and the Company will have to be much more active in the Regional Power groups to ensure customer interests are represented.

25.5 What services is FEI planning to provide to the PPME group in 2012 and how did FortisBC obtain similar services in the past?

Response:

Please see the response to BCUC IR1 Q25.1.

26.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.1.2.6, pp. 13-15;

Power Purchases Management Expenses

FortisBC states that "The Company notes that if the inclusion of the PPME costs in Power Purchase Expense is not approved by the Commission, the costs must be reclassified as Operating and Maintenance Expense" …. (Tab 4, p. 15)

26.1 If the PPME costs are not approved, to what department's O&M expense will they be assigned?

Response:

The PPME costs will be included, as at present, in the Resource Planning department (See Line 1 in Table 4.3.1 at page 31 of Tab 4 of the 2012-13 RRA.

26.2 As FortisBC is considering pursuing AMI/Smart Grid, would it consider delaying the establishment of a PPME group as a management expense savings measure? Please explain.

Response:

The PPME is an existing group whose costs are currently approved as part of overall O& M. As part of this Application, the Company is proposing to include these costs in the Power Purchase Expense instead of O&M. There is no relation to the AMI/Smart Grid initiative and therefore no opportunity for management expense savings.

26.3 Please identify other vertically integrated utilities where the cost for coordinating power supply is included as part of the power purchase expense and not as an O&M expense.

Response:

FortisBC has reviewed the most recent regulatory filings of several integrated electric utilities in Canada and the United States, but the level of publicly available detail does not enable determination of whether or not any of these utilities directly include PPME costs in their Power Purchase Expenses.

BC Hydro includes the cost of power purchases acquired from its subsidiary Powerex in its Power Purchase Expenses. It is assumed that Powerex includes the cost of its Power Purchase Management Expenses in the cost of energy it sells to all parties, since those costs are not recoverable through regulated rates. BC Hydro would therefore be recovering the variable cost of managing power purchases as part of its Power Purchase Expense.

27.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.1, p. 31

O&M Budgets, Table 4.3.1

27.1 Please explain what is included in the “other” column of expense budgets shown in Table 4.3.1.

Response:

Other Items in Tab 4, Table 4.3.1, page 31, show the 2012 and 2013 budgeted change (increases and decreases) as compared to the prior year for the following Operating and Maintenance Expenses:

a) Contractors and Consultants;
b) Lease costs;
c) Materials;
d) Staff training;
e) Business travel;
f) Office costs;
g) Bad debt;
h) Insurance;
i) Bank fees;
j) Board of Director costs;

k) Fortis Inc. Corporate Service Charges; and

l) Corporate Other expenses (forecast to be nil in both 2012 and 2013).

28.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3, pp. 31-100; Tab 7, Table 2-A-3

O&M Budgets

Commission staff have prepared the following excel attachment to compare the O&M figures for the period of 2007A to 2013F. Cost data is based on information provided in Tab 4 and Tab 7 of the Application. Historical customer count information is obtained from previous RRAs (double-click in spreadsheet below to enter excel format).

				$'000							% Change			
O&M Departments	2007A	2008A	2009A	2010A	2011F	2012F	2013F		2008A	2009A	2010A	2011F	2012F	2013F
Generation	1,908	1,894	2,152	2,217	2,187	2,287	2,497		-0.70%	13.60%	3.00%	-1.40%	4.60%	9.20%
Utility Operations	12,655	12,856	13,100	13,155	**17,412**	18,503	18,964		1.60%	1.90%	0.40%	**32.40%**	6.30%	2.50%
Mandatory Reliability Standards	-	-	-	-	955	**1,179**	1,187						**23.50%**	0.70%
Cominco Facility Charge	46	46	46	46	46	46	46		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Brilliant Terminal Station	3,222	3,206	3,054	3,069	2,987	3,160	3,192		-0.50%	-4.70%	0.50%	-2.70%	5.80%	1.00%
Internal Audit	364	334	348	360	348	396	393		-8.20%	4.20%	3.40%	-3.30%	13.80%	-0.80%
Legal & Regulatory	1,181	1,293	1,292	1,451	1,502	1,520	1,548		9.50%	-0.10%	12.30%	3.50%	1.20%	1.80%
Customer Service	6,154	6,272	5,835	5,975	6,412	6,737	6,806		1.90%	-7.00%	2.40%	7.30%	5.10%	1.00%
Community & Aboriginal Affairs	143	**186**	153	**571**	594	674	689		**30.10%**	-17.70%	**273.20%**	4.00%	13.50%	2.20%
Communications	860	893	997	1,067	903	923	952		3.80%	11.60%	7.00%	-15.40%	2.20%	3.10%
Human Resources	1,701	1,539	1,558	1,638	1,789	1,840	1,874		-9.50%	1.20%	5.10%	9.20%	2.90%	1.80%
Information Technology	2,865	2,834	2,938	2,824	2,815	2,841	2,846		-1.10%	3.70%	-3.90%	-0.30%	0.90%	0.20%
Health, Safety & Environment	645	616	645	727	**907**	925	953		-4.50%	4.70%	12.70%	**24.80%**	2.00%	3.00%
Facilities Management	2,718	2,834	**3,537**	3,700	3,620	3,685	3,716		4.30%	**24.80%**	4.60%	-2.20%	1.80%	0.80%
Finance & Accounting	2,869	2,482	2,469	2,617	3,092	3,275	3,360		-13.50%	-0.50%	6.00%	18.20%	5.90%	2.60%
Transportation Services	696	**987**	**644**	**377**	**766**	**573**	593		**41.80%**	**-34.80%**	**-41.50%**	**103.20%**	**-25.20%**	3.50%
Supply Chain Management	524	**664**	**384**	**478**	**550**	498	505		**26.70%**	**-42.20%**	**24.50%**	**15.10%**	-9.50%	1.40%
Corporate & Executive Management	**4,447**	**5,244**	**6,126**	**5,049**	6,072	5,112	5,674		**17.90%**	**16.80%**	**-17.60%**	**20.30%**	-15.80%	11.00%
TOTAL O&M EXPENDITURE	42,998	44,180	45,278	45,321	**52,957**	54,174	55,795		2.7%	2.5%	0.1%	**16.8%**	2.3%	3.0%
Power Purchase Management Expense		546	**739**	827	927	**1,211**	1,286			**35.3%**	11.9%	12.1%	**30.6%**	6.2%
Y/E Number of Custo	107,724	109,719	110,853	112,250	113,977	116,105	118,357		1.90%	1.00%	1.30%	1.50%	1.90%	1.90%
O&M per Customer (not incl PPME)	$399	$403	$408	$404	**$465**	$467	$471		0.90%	1.40%	-1.20%	**15.10%**	0.40%	1.00%

28.1 FortisBC's customer growth has been averaging 1.6% for the period of 2007A – 2013F. The nominal O&M rate per customer has remained steady for 2007-2010 but soared to a 15% increase in 2011, in the last year of the PBR. Although the nominal O&M per customer rate remains steady for the test period, the significant increase in 2011 is concerning and is significantly different than the real O&M per customer data presented by FortisBC in Table 4.3.1 of the Application. Please explain these observations.

<u>Response:</u>

The costs per customer do increase in 2011 by 15.1 percent excluding the Power Purchase Management Expenses. Some reallocation between various departments may occur each year to account for the fact that demands are placed on various areas of the Company differently in different years. In addition to labour escalation and inflationary pressures, the following items make up the bulk of the increase in 2011 over 2010 in O&M costs per customer:

a) The Commission's decisions on the Company's 2011 Capital Expenditure Plan (Order G-195-10) directed that certain capital expenditures were more appropriately classified as operating expenses. These included the Right-of-way Reclamation, the Hot Tap Connector Replacement, and the Pine Beetle Hazard Tree Removal. This accounts for approximately $3.8 million;

b) Increases associated with the implementation of the BC Mandatory Reliability Standards (Order G-27-10). This accounts for approximately $1.0 million;

c) During 2010 Corporate Other costs included approximately $0.4 million of recoveries related to one-time non-regulated work; and

d) Pension and other post employment benefits increased O & M costs in 2011 over 2010 by approximately $1.0 million. This increase was primarily due to a decrease in the discount rate and lower investment returns.

Table BCUC IR1 28.1

		2011 Expenditure Increases	Cost per Customer
		($000s)	
a.	Right-of-way Reclamation	1,112	9.76
	Hot Tap Connector Replacement	500	4.39
	Pine Beetle Hazard Tree Removal	2,155	18.91
b.	Mandatory Reliability Standards	955	8.38
c.	Corporate Other Costs	400	3.51
d.	Increased Pension Load	1,000	8.77
Total		6,122	53.71

These items make up for 13.3 percent of 15.1 percent increase showing in 2011. The remaining increase of 1.8 percent is reasonable compared to other years in the test period.

Real O&M per customer normalized out the items that were previously defined as Extraordinary O&M items (Trail Office Lease & Pension and Post Employment Benefits) during the PBR period as well as items that were defined as Z-factors (Mandatory Reliability Standards (Order G-27-100) and Sustaining Capital transferred to O&M Expense (Order G-195-10)) during the PBR period.

28.2 Please discuss the efficiencies that were gained during the early part of the PBR period and how these have transpired into cost savings or efficiencies for each O&M department.

Response:

The PBR mechanism included a PIF (Performance Incentive Factor) in the calculation of O&M Expense in order to embed efficiencies. Amounts over or under the PIF were shared with the customer through the PBR sharing mechanism. 10.4 percent is the (compounded) sum of PIFs over the term of the PBR plan, as shown below.

Table BCUC IR1 28.2

Year	PIF	Compounding Effect	Total
2007	2.0%		2.00%
2008	2.0%	x 2007	4.04%
2009	3.0%	x 2008	7.16%
2010	1.5%	x 2009	8.77%
2011	1.5%	x 2010	10.40%

Each year during PBR, a PIF factor was built into the O&M budget and therefore the approved rate increases. The savings are embedded throughout all areas of O&M in order to hold to the approved budget.

The savings can be seen in some departments as a reduction of costs, and in other departments as added efficiency. Added efficiencies make it possible to handle more tasks as the company grows while mitigating some of the increases in costs to handle the extra tasks.

Some of these efficiencies are described below.

Generation:

Generation undertook a maintenance rationalization project. This focused on maintaining existing reliability at the facilities in a more efficient and reliable manner. The project was an initial step away from a strictly time based maintenance system towards a condition based maintenance approach. The result of this project showed a 10 percent drop in routine repetitive maintenance tasks that will be ongoing. This will have no projected impact to the existing reliability statistics.

In order to more efficiently utilize its workforce, Generation introduced the operator role in 2010, and reorganized its labour force to provide a greater focus on operations. The Operator role provides support to day to day operations and improves the ability of the Company to respond to issues that arise within the facilities. In addition, a Major Maintenance group was developed which provide manpower support for major maintenance outages and minor and major capital projects. Overall, this reorganization will result in more efficient use of resources as manpower planning has been simplified and the available resources are being trained for more specific work.

In 2007, Utility Operations assumed responsibility for the maintenance and operation of the switchyards at the Generation Plants. By shifting this responsibility to Utility Operations, the Company was able to realize efficiencies in maintenance activities by reducing the costs of on-call coverage, as well as an overall reduction in administration, management and planning hours.

Utility Operations:

During the PBR period Operations implemented a number of productivity improvements in the areas of line operations, substation construction and maintenance, system control center, as well as vegetation management. In general, there has been significant improvements in the overall work scheduling and worker dispatch processes. Improved visibility, through collaborative work reviews, of the field work has allowed the operating and capital crews to be better coordinated to reduce windshield time as well as optimizing tool and equipment utilization.

- In the line operations group initiatives were focused on reducing the lower value work done by internal crews by utilizing contractors. Some examples of work being contracted out are underground locates, streetlight maintenance, and field exchanges of revenue meters;

- The substation construction and maintenance crews have been utilizing a more cost effective work week schedule where they will work the equivalent of five days in four days. This reduces unproductive time by eliminating one start up and shut down cycle each week. Improvements were gained when the crews moved to data collection for the field equipment from a paper based system to a tablet based system. While this system reduces the time it takes to collect the data, it also ensures, through prompts, that the technician enters all the necessary data while in the field. Substation equipment data collection has moved from a monthly cycle to a bi-monthly or even a quarterly inspection cycle based on the equipment type. History as well as industry experience have proven that equipment reliability is not adversely impacted by these longer inspection cycles;

- In 2010 the distribution Person In Control (PIC) project was completed. This project was the transfer of the distribution system operating authority from seven districts to the System Control Center (SCC). This move transferred the distribution control for the individual operating areas, with individual power line technicians managing the control, to one operator at SCC.
- The substation and communications capital program during the PBR system has significantly increased the field equipment that can be operated as well as monitored from SCC. These enhancements have reduced the number of physical field visits personnel are required to make which allows them to focus on more important tasks. One example of this is the field tagging of equipment before workers can work on or near the high voltage power system. In most cases this required a twice daily substation visit to operate equipment for crews working in each of the geographic operating areas. Today, it is a simple task performed remotely by an operator at SCC.
- A competitive bid process was used to firm up longer term contracts with our vegetation management contractors in 2010. These contracts will provide improved efficiencies through; realignment of contract areas, coordinating aerial surveys with operation's line patrols, surgical use of herbicides, as well as individual reporting of performance metrics.

Internal Audit:

O&M costs in Internal Audit have increased by approximately eight percent over the five years from 2007 to 2013 despite the addition of two staff. Additional auditing projects and responsibilities have, over time, resulted in the need for increased resources to address the workload.

Efficiencies have been gained through the use of in-house Internal Audit staff and reducing the reliance on higher cost of external consultants.

Legal and Regulatory:

The Legal and Regulatory department has experienced increased demands primarily resulting from increased complexity and participation of regulatory processes, increased influence of government policy and increased complexity of legal activities and risk mitigation. Despite these increased demands, the Legal and Regulatory department has demonstrated efficiencies by maintaining its total head count and associated costs at the levels it did for all years other than 2008 and 2010. During 2008 a Director of Regulatory was added to address the increased regulatory priorities of the Company. During 2009 there was a vacancy that was not backfilled with a contractor until 2010, which caused an increase in 2010 that outpaced inflation.

Customer Service:

Customer Service has mitigated potential cost increases by improving efficiencies in numerous ways. Specific actions that have created efficiencies include:

- Reduced postage and printing costs due to eBilling;
- Improved collections processes and reduced write-off period;
- Automation of various billing and collection processes;
- Automated planned outage and collections calls;
- Improving utilization of the existing Customer Service Representatives;
- Increased third party revenues from pole contracts; and
- Improved user interface for Customer Information System.

These efficiencies have created more time for existing staff to absorb the continual customer growth.

Aboriginal Affairs:

The Aboriginal Affairs group has undertaken a number of initiatives in order to reduce costs:

- Established positive corporate relationships with many of the Company's First Nations. FortisBC has been able to construct major infrastructure on Band land in preferred locations, resulting in lower capital construction costs including new customer extensions, and ultimately lower operating expense;

- Recognizing the cultural and historic land variances between the Ktunaxa and Okanagan Nations and considering the geographic requirements FortisBC realigned the Aboriginal Affairs group to expand the role of an existing qualified employee to engage First Nation communities within the Ktunaxa Nation. This local resource resulted in lower operating costs as the existing employee in the Okanagan no longer is required to travel to the Creston / Cranbrook area on a regular basis;

- Established blanket distribution permits which have a direct positive impact to operating costs as FortisBC no longer has to wait for Band Council Resolutions prior to commencing O&M work;

- Negotiated protocol agreements or permitting process with First Nations that do not have blanket distribution permit. Once again these initiatives result in lower costs by referencing established fee or permit schedules. The turnaround time between initial requests and permit approval has been significantly reduced; and

- Focused the First Nations Community Investment program to parallel O&M and capital projects that may involve First Nations reserve or traditional land. This approach helps to solidify relationships and goodwill that have developed into mutually beneficial arrangements. FortisBC has been able to access local knowledge and expertise resulting in reduction of operation costs.

Human Resources:

Human Resources has taken on the employee events budget causing a slight increase in costs. Within the Human Resources department there are pressures to attract, train and retain quality employees. With an aging workforce and a shrinking global talent pool the time and costs to achieve desired results have increased. Turnover due to increased retirements impacts recruitment and training volumes. Increased volume has been managed with minimal if any additional cost. Costs have been mitigated and productivity efficiencies achieved through:

- Competency based hiring and the introduction of a new employee orientation program;
- Efficiencies in administration of the defined contribution pension plan have been achieved by transitioning to a service delivery model and service provider; and
- Efficiencies in benefits administration have been achieved by moving to a new systems platform which has increased service at no additional cost.

Information Technology:

Information Systems has been able to mitigate budget increases despite increasing wages and maintenance costs. This has been accomplished by:

- Longer term, lower cost vendor agreements; and
- Re-negotiating lower telecommunication costs and using technologies such as described on page 73 and 74 in Tab 4 of the 2012-13 RRA and FortisBC's responses to BCUC IR1 Q55.5 and Q60.6.

Health, Safety & Environment:

With increased compliance requirements for all areas of the business becoming more complex the demand for support for compliance measuring and monitoring has increased costs. Health and Safety has focused its efforts on reducing injury, illness and accidents that may cause unnecessary costs to FortisBC and its customers. The cost savings from a reduction in injury, illness and accidents is reflected in every department of the Company.

Facilities:

The changes in costs continue to be driven by contractual inflation and required service levels for operating and maintaining building assets. To mitigate these costs the Facilities department has:

- Implemented Cyclical Maintenance. This is a preventative maintenance service to keep facility assets in good condition, improving equipment utilization and reliability and ensuring the health, safety and welfare of employees; and
- All service contracts are competitively tendered and negotiated over a fixed term.

Finance and Accounting:

The Finance and Accounting department has achieved efficiencies as is evident by keeping a consistent number of FTEs since 2007, while at the same time, the accounting and finance environment has become much more complex during this time period. Examples of the challenges that have been absorbed by this department are described in section 4.3.4.15 inn Tab 4 of the 2012-13 RRA and include the increasingly complex accounting guidance issued under Canadian GAAP, the transition efforts to US GAAP and IFRS, increased internal control requirements, changes in audit requirements, changes to provincial sales taxes, increased regulatory filings requiring financial support and increased financing requirements, including rating upgrades that impact the cost of debt for the Company. The Finance and Accounting department has managed these business challenges over the last several years and has obtained efficiencies by embedding much of this knowledge and related skill set with existing employees and through increased documentation and improved processes.

Scanning of accounts payables documents to reduce manual routing, approvals and filing has also created efficiencies and extra time for staff to handle larger workloads.

Transportation Services:

In order to reduce revenue requirements, the Company applied for and received approval from the Commission to buyout the majority of leased vehicles in its 2006 Capital Expenditure Plan and Revenue Requirements application.

FortisBC continues to evaluate and monitor new green vehicle technologies. In concert with FEI, FortisBC is also currently investigating the economics of using natural gas powered vehicles. To counter rising fuel costs and in support of the BC Energy Plan, FortisBC currently has eight low emission hybrid vehicles (six passenger vehicles, one half-ton truck, and one line truck).

Supply Chain Management:

The Supply Chain group has undertaken a number of initiatives in order to reduce cost:

- Using consignment inventory the Company has been able to enter into an agreement with a transformer vendor where the vendor supplies the Company with 50 “safety stock” transformers that are inventoried at FortisBC sites, but are not paid for until the Company uses the transformer;
- In 2008 the Company moved to in house sourcing of freight. The in house use has reduced costs and dependence of outside contractors and increased efficiency in the delivery of materials to the Districts; and
- Fortis Inc. companies have entered into national tendering for the purchase of common equipment such as conductors and transformers.

Corporate and Executive Management:

FortisBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP) were updated in 2009 and approved by the Commission in Order G-5-10A as part of the Commission's review of the Subcontractor Agreement between FortisBC Inc. and FortisBC Pacific Holdings Inc. (FPHI).

There are significant positive benefits of contracting FortisBC personnel to FPHI under the provisions of the COC and TPP, both in terms of incremental revenue to the regulated utility and labour force enrichment.

In the summer of 2010, FortisBC and FEI began sharing a common executive management team. This structure allows for sharing of specialized resources and economies of scale for customers

Insurance:

FortisBC's customers have benefited from lower insurance premiums partially due to the economies of scale obtained with the consolidated Fortis group of companies (the Fortis Group). The specific cost savings cannot be reasonably quantified without going to all the various markets with a complete underwriting submission specifically prepared for FortisBC on a standalone basis, however it should be recognized that such savings are embedded in the historical and forecast insurance premium expense. The benefits of participation in the Fortis Group insurance program include pooling of a geographically spread risk, access to specialized markets, reduced broker fees, reduced administration and reduced insurance premiums. Beginning in 2008, FortisBC Holdings Inc., the parent company of FortisBC filled the role of providing certain specialized advisory services to FortisBC on more complicated insurance matters that FortisBC did not have available in house. These services are similar to those provided to FEI and are another example of sharing specialized resources and achieving economies of scale for customers. With insurance expertise available from FortisBC Holdings, the Company can access these advisory services on an as needed basis, rather than incurring the annual costs for full time insurance staff.

Board of Directors:

Prior to July 1, 2010 FortisBC had a separate Board and Committee and incurred 100 percent of the costs. Effective July 01, 2010 the Board of Directors is a joint Board that is shared amongst FortisBC and the FEU. All costs incurred for compensation and certain other Board and Committee expenses are shared between FortisBC and the FEU on a Massachusetts Formula applied to revenue, payroll, and net tangible assets. The decrease in costs in 2010 was due to the sharing of Board fees and certain other Board costs amongst the FortisBC group of Companies effective July 01, 2010. The number of executive was held at six for the period 2007 through to June 30, 2010 and was increased to ten effective July 01, 2010. This structure allows for the sharing of more specialized resources and economies of scale for customers. The Company benefits from the expertise of a broader depth of experience of ten officers for less than the cost of six officers employed previously. Although the decrease in costs due to the sharing has been partially offset by increased travel costs for both Board and executive attending the Board meetings and related functions, the costs in 2012 and 2013 are forecast to be less that those incurred in each of the years 2007 through 2010.

Corporate Service Costs:

The Company shares certain specialized services that reside in Fortis Inc. and provide expertise to Fortis Inc. subsidiaries including FortisBC. These services are shared amongst the Fortis Group, thereby providing economies of scale to FortisBC. The services provided by Fortis Inc are listed in Tab 4, pages 96-97 of the 2012-13 RRA. In 2008 Fortis Inc. began allocating its recoverable costs to FortisBC based on the relative assets by subsidiary as it is closely correlated to the net investment by Fortis Inc. in the respective subsidiaries. FortisBC customers benefit from the efficiencies realized by allocating appropriate Fortis Inc. costs across its subsidiaries. The cost to FortisBC for the services received from Fortis Inc. would be higher on a stand-alone basis. In addition, FortisBC and its customers benefit from the level of expertise at Fortis Inc. that would not be available on a stand-alone basis for the same or similar cost.

Power Purchase Management Expense:

In 2008 the Power Purchase Management group for financial budgeting and reporting purposes was broken out from the Company's System Control center, which is part of Utility Operations. Since 2008, the Power Purchase Management group has added staff in order to assist with the Resource Planning function which includes development and on-going management of the overall Resource Plan, assisting with contract negotiations and determination of overall Power Supply direction. These additions resulted in the Company being able to accomplish most of the analytical and overall management of the Resource Plan in-house rather than through external consultants. In addition, responsibility for the Company's load forecast was transferred from the Finance department to the Resource Planning department. This has allowed Resource Planning staff to support the load forecast through the creation of a load forecasting model and upgraded forecasting methodologies.

In 2010 additional staff was hired to support the Company's Power Supply functions. This has assisted in allowing the Company to take advantage of favorable market conditions in 2010 and 2011 to significantly reduce Power Supply Costs to the benefit of customers. For 2012 the Company plans to hire an additional FTE to further support and assist the Power Supply function to successfully manage the increasingly complex environment in Power Supply operations.

28.3 Please explain why similar efficiencies were not achievable in the last year of the PBR? How can ratepayers be assured that these O&M increases are necessary and why are they observed only in the final PBR year?

Response:

The final year of the PBR saw similar efficiencies to earlier years within areas that were under the control of the Company. As indicated in the response to BCUC IR1 Q28.2, the PIF (Productivity Improvement Factor) built into the approved rate for 2011 was -1.5% and the O&M budgets were set to meet the calculated amount. The majority of the 2011 increase ($4.7 million out of the total $7.6 million increase) relates to, as explained in response to BCUC IR1 Q28.1, items that were ordered by the Commission to either be transferred from Capital to O&M or relate to the BC Mandatory Reliability Standards (BC MRS).

a) The Commission's Decision on the Company's 2011 Capital Expenditure Plan (Order G-195-10) directed that certain capital expenditures were more appropriately classified as operating expenses. These included the Right-of-Way Reclamation, the Hot Tap Connector Replacement, and the Pine Beetle Hazard Tree Removal; and

b) Mandatory Reliability Standards (Order G-27-10).

Table BCUC IR1 28.3

		2011 Expenditure
		($000s)
a.	Right-of-Way Reclamation	1,112
	Hot Tap Connector Replacement	500
	Pine Beetle Hazard Tree Removal	2,155
b.	Mandatory Reliability Standards	955
Total		4,722

28.4 For every $1M of O&M increase, what does this relate to in terms of rate impact? Similarly, what dollar amount of O&M increase would account for a 0.5% increase in rates?

Response:

For a $1 million increase in O&M Expense (before Capitalized Overhead), the 2012 rate impact would increase by 0.2 percent, and the 2013 rate impact would decrease by 0.1 percent.

The corresponding increase in Capitalized Overheads is 20 percent of Gross O&M Expense, or $0.2 million, which would result in an increase to capital expenditures in each year. A summary of the rate impacts is shown in Table BCUC IR1 28.4a below.

Table BCUC IR1 28.4a

		2012	**2013**
1	Base Case O&M	54,172	55,794
2	Additional O&M	1,000	1,000
3	Total Revised O&M	**55,172**	**56,794**
4	Base Case Rate Impact	4.0%	6.9%
5	Revised Rate Impact	4.2%	6.8%
6	Rate Impact Variance	**0.2%**	**-0.1%**

A customer rate impact of 0.5 percent in each of 2012 and 2013 would result in an increase in O&M Expense by $1.9 million in 2012, and a further increase of $2.075 million in 2013.

The corresponding increase in Capitalized Overheads would be $0.4 million and $0.8 million in 2012 and 2013 respectively.

A summary of the rate impacts is shown in Table BCUC IR1 28.4b below.

Table BCUC IR1 28.4b

		2012	**2013**
1	Base Case O&M	54,172	55,794
2	Revised o&M	56,072	59,769
3	Total Additional O&M	**1,900**	**3,975**
4	Base Case Rate Impact	4.0%	6.9%
5	Revised Rate Impact	4.5%	7.4%
6	Rate Impact Variance	**0.5%**	**0.5%**

29.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.1, p. 31

O&M Budgets

"Through the PBR period, from 2007 to 2011, the Company has achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors." (Tab 4, p. 31)

29.1 Please provide supporting calculations for the 10.4 percent mentioned above. Explain where these efficiencies can be quantified in the organization.

Response:

Please refer to the response to BCUC IR1 Q28.2.

29.2 Discuss whether these efficiencies are long or short term and why.

Response:

The Productivity Improvement Factor (PIF) efficiencies achieved are long term embedded efficiencies. In many cases they represent permanent process improvements. Examples of these efficiencies are provided in the response to BCUC IR1 Q28.2. The efficiencies have mitigated costs in the test period and are expected to remain in place beyond the test period.

On page 31-32, FortisBC states "The achievements in managing O&M have been made despite substantial number of changes affecting FortisBC over this period. Some examples of these changes include:

- Increased requirements for most segments of FortisBC operations;"

29.3 Please further explain what increased requirements are implied in the above statement. Provide examples.

Response:

As discussed in Tab 4, page 31, there are many factors both internal and external that affect the operations of FortisBC. "Increased requirements for most segments of FortisBC operations" includes items that are common to all departments as well as items that affect a single department.

For example:

a) With an aging workforce, half of the employees of FortisBC are eligible to retire within the next five years. The requirements to attract, train and retain a suitable workforce have an important impact on all of the departments of the Company;

b) Increased arbitration costs have increased legal costs;

c) Species at risk have changed some operations in generation to include more consideration of the species, resulting in increased operating costs;

d) Mandatory Reliability Standards are evolving requirements that must be met;

e) Auditing and accounting standards are changing and becoming more complex;

f) The increased complexity of the regulatory process together with a greater interest from the general public and more interveners has increased requirements for all departments involved in the regulatory process;

g) Customer growth has created the need for customer service to find more efficient ways to handle current business while creating room to take on more customers;

h) Increased complexities in dealing with First Nations and municipal governments have increased the work requirements for Community and Aboriginal Affairs;

i) New and evolving technology has increased usage of technology. Training of the users and support personnel has increased as a direct result;

j) Health and Safety practices are always evolving to align practices with new industry best practices;

k) Environmental issues are at the forefront of all the work that FortisBC does;

l) Changes in financial reporting requirements have increased the need for training and time allotment to implement changes and meet reporting deadlines; and

m) Fuel, Commodity Prices, and globally driven insurance costs also create uncertainty with costs and availability. These items require extra planning.

30.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.2.3, p. 39

Demographics, Comparable Turnover Rates, Table 4.3.2.3-2

30.1 During 2008 and 2009, FortisBC's turnover rate compared to other sectors was the lowest. During this same period, all of the other sectors' turnover rate (as presented in the table) has declined whereas FortisBC's turnover rate declined in 2009 followed by an increase in 2010. Please explain why.

Response:

FortisBC's turnover in all years is below the experience of all sectors. Generally FortisBC turnover has been very low. The Company does not know with certainty why the 2010 turnover rate trends differently.

30.1.1 What is FortisBC's opinion its business operations in 2010 that would cause an inverse relationship to all comparative sectors? Please discuss.

Response:

Please refer to the response to BCUC IR1 Q30.1

31.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.2.3, pp. 40-41

Demographics, Workforce Strategies

31.1 Pleased explain which department manages, organizes, and facilitates these programs (i.e. apprenticeship, educational programs, Power Engineering, EIT, scholarships, co-op). Where are these costs captured in the organization?

Response:

Often several departments work in partnership to administer a program. The administration charges associated with program oversight are shared by the Human Resources and the operating department(s) affected. The below table clarifies how the costs for the various programs are assigned:

Program Description	Administration (indirect cost)	Operating and Maintenance (direct cost)
Apprenticeship, Engineer in Training (EIT) and Co-op Student	Program oversight is performed by Steering Committees with representation from Human Resources and the operating department(s); the home department for each committee member is responsible for the labour charges for its members' time	The apprentice/EIT/Co-op student hours and associated employment costs are assigned to the department where the work is performed
Education and/or Training Programs	Program oversight is performed by the HR department; these costs are assigned to HR	The cost of the training program and the attendees labour charges for the time spent participating in the program are assigned to the employee's home department
Electrical Engineering Scholarship available to third or fourth year students. Final scholarships were for the 2011/2012 academic year.	Corporate sponsorship for these Programs is drawn from a corporate account	

32.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.2.3, p. 41

Workforce Strategies, EIT Program

"To address this gap FortisBC developed an Engineer-in-Training program…"

"The program has been a successful component of the Company's overall workforce strategy."

32.1 When was the EIT Program developed and how many years has it been running?

Response:

The employment of EITs has been in practice by FortisBC since 2005. In 2008, the EIT Program was enhanced to include various business unit rotations thereby providing for a more complete exposure to the various business functions and enhancing the training.

32.2 How many EITs are currently in the program?

Response:

Presently there are two EITs in assigned work rotations (6 months in duration). In 2010, four EITs completed the Program and were appointed to permanent engineering positions.

32.3 How does FortisBC measure / track the success of this program?

Response:

Of FortisBC's 23 engineers, 8 have been recruited from the EIT Program. One third of FortisBC's engineers have come through the program, which speaks to the program's success. The program provides opportunities for new engineers to gain the fundamentals of working within a utility. The labour market for power and utility engineers in Canada is very competitive, and this program has proven effective.

The success of the program is defined by:

1. satisfactory performance of the participant (as determined by a Steering Committee who evaluate each work rotation);
2. participants' ability to meet the requirements of the Association of the Professional Engineers of British Columbia to become professional engineers at the end of the program; and
3. placement of program participants into permanent engineering positions within the Company once the program requirements are complete. No EITs, upon completion of the program, have left the Company to pursue employment elsewhere.

FortisBC has been able to place graduates of the EIT program into core engineering vacancies. The costs associated with recruitment are minimized as a result of the ability to retain these employees upon completion of the program.

33.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.2.3, p. 42

Workforce Strategies, Supervisory Skills Development Program

33.1 Was this program developed in-house? Is it delivered / facilitated as an internal training program?

Response:

The Human Resources (HR) department together with the operating departments and senior management team identify leadership development opportunities and/or needs. The learning objectives are then defined and the most cost effective delivery method for achieving the learning outcomes is researched by HR. The majority of programs are developed by external suppliers; however where unique or specific needs are identified, FortisBC uses internal content specialists to research and prepare the material.

1. How to manage in a unionized environment;
2. Respect in the workplace;
3. URM incident management module training;
4. Corporate orientation for leaders;
5. Progressive discipline; and
6. Recruitment

Where facilitation is deemed to be most cost effective through an external service provider, an external service provider is retained. Examples of course offerings through external service providers include:

1. Time/priority management;
2. Teambuilding;
3. Effective coaching;
4. Managing conflict – facing the tiger;
5. Leadership Toolbox;
6. Microsoft Office Suite of Products; and
7. Train the trainer

33.2 Is it mandatory for all supervisory positions?

Response:

For exiting leaders, participation is encouraged but is not mandatory unless there is a performance concern. For new leaders participation is mandatory.

33.3 Does this program consist of a single course/session or a program of multiple courses/sessions similar to a management trainee program?

Response:

Please refer to the response to BCUC IR1 Q33.1 for examples of the program components. The program has a number of core components which provide a shared/common corporate leadership foundation. After the foundational competencies are established focus on employee specific learning development areas occurs.

34.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.3.2, p. 44

Executive Compensation

> "The Company's executive compensation program involves four main elements (base pay, short term and long term incentive pay, and benefits), which comprise a Total Rewards package."

34.1 Please explain and provide examples of a long term incentive pay.

<u>Response:</u>

Long term incentives are generally accepted as a standard element in executive compensation. They are designed to balance the longer term interests of the Company and customers. Long term incentives may be provided in several forms. FortisBC provides its long term incentive through participation in a stock option plan. The stock option plans provide the opportunity for executive members to be provided a grant of shares. The grant size is dependent upon several factors, including the executive's position, salary, share price and share holdings.

Participation in this long term incentive program serves the interests of the customers by incenting delivery on long term strategies. Focusing on short term business strategies only can have adverse effects on system reliability and ultimately customer satisfaction. The intent of the long term incentive program is to balance short term and long term Company and customer interests. Please note that stock option expense is funded by the shareholder and is not included in revenue requirements.

> "FortisBC establishes base and incentive compensation targets so as to compensate executives at a median level of a broad reference group of Canadian commercial industrial companies."

34.2 Who are the primary companies that make up the Canadian reference group? Have any of the companies in the reference group changed in the last 5 years, and why? Has FortisBC studied a similar reference group but on the provincial level? If not, why not?

Response:

The broad reference group of Canadian commercial industrial companies is made up of nearly 300 companies. A list of the companies is included in Appendix BCUC IR1 34.2.

The following table shows the number of Commercial Industrial participants in the Company's database from 2006 to 2010.

Table BCUC IR1 34.2

	2006	2007	2008	2009	2010
No. of Commercial Industrial Organizations	255	263	272	284	295

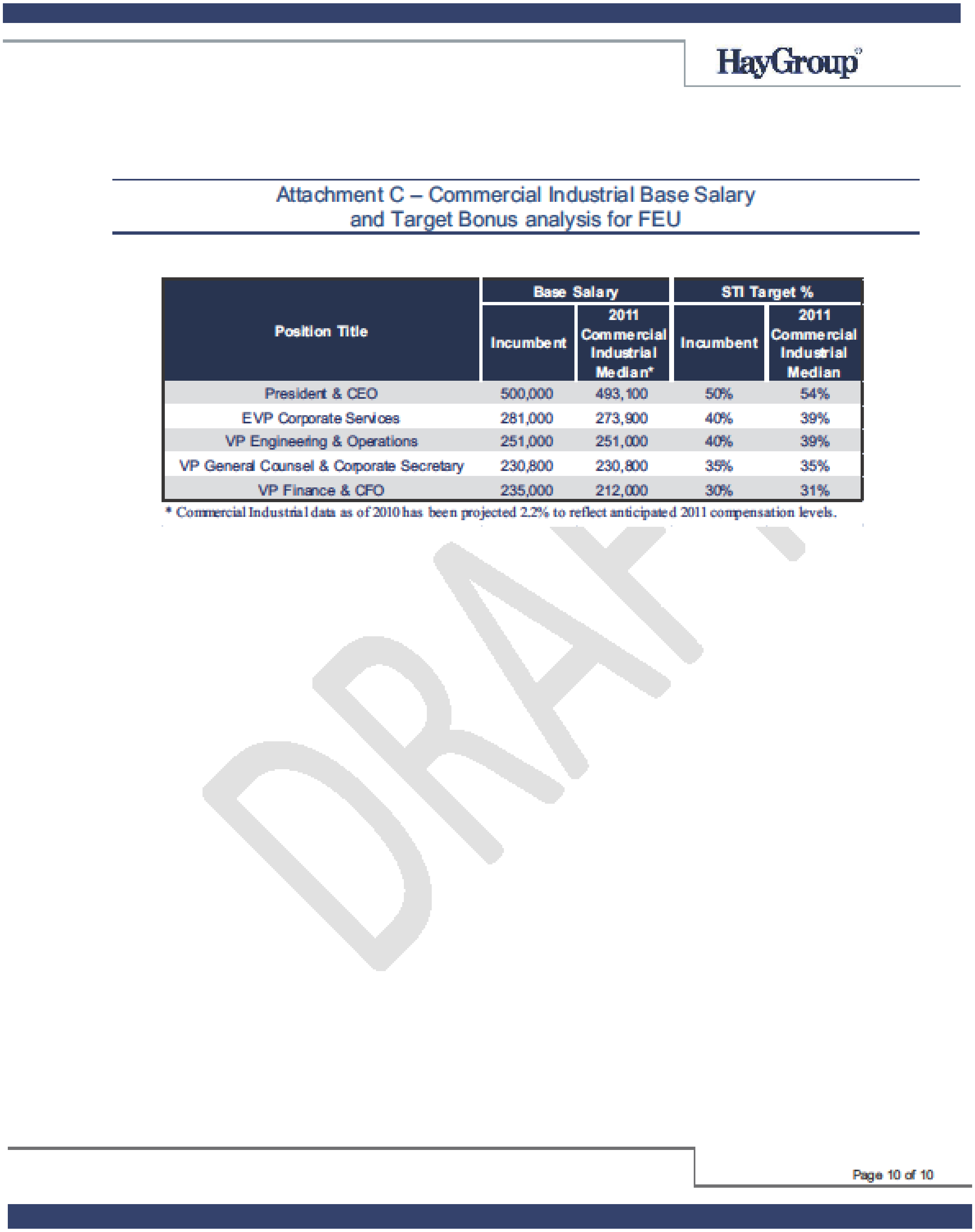
It is evident that the number of Commercial Industrial organizations has been growing every year and this makes the database more representative of the general Canadian industrial environment. While Hay strives to increase the coverage of the database, some companies will inevitably choose not to participate and others may cease to operate as a result of mergers and acquisitions. On a yearly basis, about 80 percent of the participants have remained constant. Despite these changes in participants, Hay believes the size of the Commercial Industrial database will provide a valid and stable reference market, representing a broad spectrum of Canadian industrial organizations with which FortisBC competes for executive talent.

FortisBC has not studied a similar reference group on the provincial level, for reasons explained in the response to BCUC IR1 Q34.4 below.

34.3 Please provide supporting evidence for the above statement. Show in a table format the comparative findings of the reference group compared to FortisBC's executive compensations for base and incentive pay.

Response:

Please see the table reproduced below for a summary of the Base Salary and Target Bonus analysis.



Attachment C – Commercial Industrial Base Salary and Target Bonus analysis for FEU

Position Title	Base Salary		STI Target %	
	Incumbent	2011 Commercial Industrial Median*	Incumbent	2011 Commercial Industrial Median
President & CEO	500,000	493,100	50%	54%
EVP Corporate Services	281,000	273,900	40%	39%
VP Engineering & Operations	251,000	251,000	40%	39%
VP General Counsel & Corporate Secretary	230,800	230,800	35%	35%
VP Finance & CFO	235,000	212,000	30%	31%

* Commercial Industrial data as of 2010 has been projected 2.2% to reflect anticipated 2011 compensation levels.

34.4 Show in a table format the comparative findings of a provincial reference group compared to FortisBC's executive compensations for base and incentive pay.

Response:

As stated in response to BCUC IR1 Q34.2, FortisBC has not studied a similar reference group on the provincial level. The comparator group that the Company uses reflects a broad range of firms from Hay's compensation database, representing industrial commercial entities from across Canada. The broad national database is not heavily weighted in one province or another and ensures that FortisBC has representation from the type of companies against which the Company typically competes for talent. FortisBC's current executives have come from a variety of industries, including financial consulting, properties, energy and utilities.

"The Company makes notional contributions in excess of the RRSP maximum limit equal to 13 percent of earnings to a Supplemental Executive Retirement Plan (SERP)."

34.5 Please further explain the SERP. Is this incentive linked to individual or corporate performance objectives? Is it funded from ratepayers or shareholders?

Response:

The Supplemental Retirement Plan (SERP) provides an accrual of 13 percent of base salary and annual incentive (earnings) in excess of the Canada Revenue Agency limit. At retirement, the SERP may be paid in one lump sum or in equal payments over 15 years.

The SERP calculation of 13 percent is on base and incentive earnings and therefore is linked to corporate and individual performance objectives. The inclusion of SERP in executive total compensation is industry standard and permits FortisBC to compete for quality talent to lead the company and drive business results both in the short and long term.

The SERP is funded by the ratepayer, similar to all other regular compensation amounts.

34.6 Is this a matching contribution by both the employee and employer or is it strictly an employer contribution.

Response:

No, this is not a matching contribution it is an employer contribution.

34.7 Please explain "notional" in context of the statement.

Response:

The contributions are called notional because they are not deposited to an account in the employees' name. The notional account is tracked as a deferred liability.

34.8 Provide in a table format the total balance in the SERP for the past 5 years.

Response:

Below are the balances in the SERP account for the last five years (2006-2010).

Table BCUC IR1 34.8 Supplemental Executive Retirement Plan (SERP)

Balance in SERP Account, Years Ended 2006-2010	
2006	302,490
2007	620,004
2008	827,892
2009	1,044,892
2010	1,293,258

34.9 What is the amount paid out from the SERP for the top 5 executives over the past 2 years?

Response:

There have been no payouts to the executives from the SERP plan over the past 2 years. Payouts from the SERP may be deferred for up to five years but must be paid within fifteen years post retirement.

35.0 Reference: Operating and Maintenance Budgets

Exhibit B-1, Tab 4, Section 4.3.4, Table 4.3.4, p. 45

Employee Turnover

"Between 2008 and 2010, 181 new employees were recruited, which includes all levels of positions within FortisBC." (Exhibit B-1, Tab 4, p. 40)

35.1 The referenced table shows that FTE levels have remained somewhat constant since 2007. Is it implied that the new recruitments were a result of employee turnover? If so, please discuss the reasons for the turnover rate of approximately one-third of all employees in the three-year period between 2008 and 2010, and comment on the incremental costs to ratepayers associated with this turnover rate.

Response:

FTE levels for FortisBC have remained constant since 2007. Recruitment was, for the most part, as a result of backfilling turnover. The backfills often cause a cascading effect when filled with internal candidates. The backfill positions were budgeted and therefore had zero to minimal impact on the ratepayer. FortisBC's records show that employees left for a variety of personal reasons. The cost of turnover can vary by position and are not specifically tracked.

36.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.1, pp. 45-50

Generation

"Generation faces a number of issues of note as it moves into 2012 and 2013, which are listed in greater detail below:" (Tab 4, p. 46)

36.1 Is it implied by the above statement that the issues discussed on pages 46-47 contribute to the cost increases in the Generation department?

Response:

The issues described on pages 46-47 of Tab 4 of the 2012-13 RRA (Exhibit B-1) are contributing to an increased scope of work at Generation and by extension increased operating costs. The one exception is the potential listing of the Umatilla Dace and White Sculpin under the Species at Risk Act. At this time no additional monies have been budgeted for this issue, but if these species become listed there may be a need for expenditures prior to the end of this forecast period.

> "With the completion of the ULE program, the Company will return to its full maintenance program at all facilities…" (Tab 4, p. 46)

36.2 What year did the ULE program start? How long has it been running?

Response:

Construction of the first ULE was completed in 1998. The program has been running for approximately 14 years.

> "…there are two new species of fish which could potentially be listed under the SARA… there may be a requirement to conduct fish stranding studies and modify operating plans at the existing facilities if these fish do become listed under SARA legislation;" (Tab 4, p. 47)

36.3 What is FortisBC's estimate of the likelihood of listing these 2 species under SARA? When will this be known?

Response:

Umatilla dace is a fish species that is presently listed as "special concern" and may be listed as "threatened" on Schedule 1 of the Species at Risk Act (SARA) as early as September 2, 2011, which marks the end of the legislated consultation period of nine (9) months. There are a number of studies presently underway that would contribute additional scientific data to the listing decision; FortisBC considers it likely that this species will be listed as threatened, triggering the prohibitions under SARA and thus increasing species management expectations for FortisBC.

The short-headed sculpin is already listed as "threatened" on Schedule 1 of SARA and has recently been recommended for down-listing to "special concern". It is likely that this species will be down-listed removing the prohibition triggers under SARA and thus reducing species management expectations for FortisBC.

36.4 What is the order of magnitude for increased operating costs related to this issue?

Response:

It is difficult to predict what impact this may have on Generation operational budgets at this time. FortisBC's experience with the listing of the white sturgeon indicates that the primary impact to operations is increased observation and monitoring during routine maintenance outages as well as a requirement for fish stranding inspections during any event requiring fluctuating water levels. The impact to operating costs will be highly dependent on the outcome of a recovery strategy and its requirements to protect the habitat of the listed species.

Subject to the species being listed and a clear understanding of recovery strategy initiatives, FortisBC estimates that operating costs may increase from $0.01 to $0.10 million per year to provide mitigation for this issue. Additionally, the Company may incur costs through participation in working groups and on technical committees formed to promote the recovery of these species. FortisBC has not made any specific allocation in 2012 or 2013 for these costs.

36.5 Please explain why these activities are captured under the generation department instead of Health, Safety and Environment department.

Response:

Activities such as fish stranding studies are usually initiated by a component of Generation operations (such as fluctuating forebay or tailrace levels). Since the requirement for fish stranding assessments and other monitoring activities are a direct result of operations, the costs to conduct these activities are borne by the Generation operational budget. The Health, Safety and Environment department are actively involved with Generation to ensure that all operational activities are in compliance with legislation and regulations, and assist where required to complete assessment and studies.

> “Recent changes to legislation targeted at improving workplace safety have had an impact on operating costs over the past five years. For instance, changes to confined space legislation and working alone legislation… The recognition of silica dust…”

36.6 Please explain why these activities are captured under the generation department instead of Health, Safety and Environment department.

Response:

These activities are discussed in the Generation section because the changes to the legislation have had a direct impact on the cost of conducting operations. For example, changes to the confined space regulations require minimum staff levels and access to a rescue team for certain confined space workspaces. Since Generation has numerous areas classified as confined space under the legislation (for example sump pits and draft tubes) there are numerous examples where additional labour hours are required to complete a maintenance task in these areas.

The Health, Safety and Environment department is actively involved in interpreting changes to legislation to ensure that the Generation group complies with all relevant workplace rules. It assists in developing safe work plans and assessing hazards to ensure work methods are adequate to provide a safe work environment.

37.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.1, p. 48

Generation O&M Cost Summary, Table 4.3.4.1

37.1 Please split line 2.2 Non-Labour costs in this table to separately show contracted labour costs and material costs.

<u>Response:</u>

A breakdown of Non-Labour costs is provided below. Table 4.3.4.1 has been corrected in Errata 2.

Table BCUC IR1 37.1

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
	($000s)						
Contracted Labour	274	143	139	143	240	287	287
Material	177	212	144	105	150	150	150
Other/Recoveries and O/H	302	195	634	640	549	476	525
Total Non Labour	753	550	917	888	939	913	962

37.1.1 If contracted labour costs have changed +/- 10% in any year, please provide explanations.

<u>Response:</u>

Table BCUC IR1 37.1.1

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
Contracted Labour	274	143	139	143	240	287	287

In 2007 contracted labour was required to repair the Lower Bonnington Unit 2 transformer failure. The increases in 2011, 2012 and 2013 are related to Dam Safety reviews that are a statutory requirement.

37.2 Please confirm that line 1 Full-time Equivalents do not include contract labour. Please confirm that this is the same assumption for each department's O&M cost summary for the remainder of this section in the Application.

Response:

Full Time Equivalents appearing in the Generation cost summary do not include contracted labour.

38.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.1, pp. 49-50

Generation, Routine Maintenance

"Plant labour is forecast to increase from 2011 to 2013 by approximately $0.24 million primarily as a result of labour increases and increased routine and non-routine maintenance work." (p. 49) [emphasis added]

"…reduction in planned routine repetitive maintenance tasks helped offset the additional costs expected in future years for the introduction of non-routine maintenance and planned maintenance from ULE projects.." (p. 50) [emphasis added]

38.1 Please clarify the contradictory messages in the 2 statements above.

Response:

Although the two statements appear contradictory, they are in fact an accurate reflection of what has occurred within Generation operations. The reduction in planned routine repetitive maintenance tasks occurred as a result of the maintenance rationalization efforts which reviewed each planned repetitive routine maintenance task, its frequency and the effort required to complete it balanced against safety, reliability, manufacturers suggested maintenance frequency and other factors such as legislative requirements and insurance requirements. By extending the time interval between certain tasks and finding more economical methods to complete other tasks, Generation was able to reduce the overall scope of work included in its planned routine repetitive maintenance (Tab 4, pp 49-50, 2012-2013 Revenue Requirements). This is the reference to "…reduction in planned routine repetitive maintenance" noted in the question above.

On the other hand, the Company has also seen an increase in the total number of labour hours required to complete the revised scope of work described above primarily as a result of changes to legislation such as working alone and confined space (Tab 4, pp 47, 2012-2013 Revenue Requirements). This is the reference to "increased routine…" noted in the question above. The impact of these legislative changes typically results in more labour hours required to complete the same scope of work as in the past.

Over the past two years, Generation has been able to reduce some planned maintenance activities, and associated costs, but not to the extent required to fully offset the increased costs, leaving an overall incremental increase of $0.24 million.

39.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.1, pp. 49-50

Generation, Maintenance Rationalization Project

> "FortisBC undertook a maintenance rationalization project which focused on maintaining existing reliability at the facilities in an efficient and productive manner while addressing the maintenance needs of the new equipment… to ensure that the time interval between maintenance cycles was consistent with current industry practice."

39.1 Please explain how FortisBC has utilized the information gathered in this project? Is this data fed into a capital maintenance program / software? Will there be reports generated through queries to identify maintenance schedules? Will there be flags / warnings to indicate upcoming maintenance to specific equipment?

Response:

The information gathered by the Maintenance Rationalization Project (MRP) was fed in to Generation's maintenance scheduling system (GenJO). The information translated to adjustments to a number of existing maintenance intervals within GenJO.

Reports can be generated by GenJO to identify maintenance schedules. GenJO automatically generates job orders when upcoming maintenance is required to specific equipment.

39.2 How is this project parallel to the Computerized Maintenance Management System (CMMS), described on page 53 of Tab 4? Is there any duplication of the maintenance rationalization project with the CMMS? Please discuss.

Response

CMMS and the Maintenance Rationalization Project (MRP) are not related. CMMS is a software system employed by the Utility Operations group to manage its maintenance work. The MRP was a project completed by the Generation group in 2010 as described in the 2012-13 RRA.

39.3 What was the cost to develop, implement, and maintain the maintenance rationalization project?

Response:

The maintenance rationalization project was completed by internal staff as part of their ongoing responsibility to ensure safe, reliable and low cost operations. FortisBC estimates the total cost to develop and implement the project was approximately $50,000. No costs are specifically assigned to maintain the project, rather it is expected that the Generation group will continually refine maintenance activities. It is expected that a transition to an asset management program will help further rationalize maintenance activities at Generation.

> "As a result of this project, the overall budgeted labour hours for planned routine repetitive maintenance tasks at the river plants was reduced by nearly 10 percent for 2011…"

39.4 What is FortisBC's estimate of the dollar value associated with the 10 percent reduction in routine repetitive maintenance? Is there any expectation that this will be an annual cost reduction?

Response:

FortisBC estimates that the maintenance rationalization project reduced annual labour costs associated with routine planned maintenance by approximately $110,000 per year. It is expected that this reduction is an annual reduction, however as noted previously the introduction of non-routine work as well as the increased labour requirement of some remaining routine tasks continue to place pressure on yearly operating budgets.

40.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.1, p. 50

Generation, Workforce Reorganization

> "…the Company has introduced an operator role which is aligned with existing utility practice and provides employees dedicated to operating and maintenance functions with the appropriate level of training and experience required to perform their jobs."

40.1 Is FortisBC implying that this is a new role for the organization or only for the department? Is there currently a similar role in the Human Resources department?

Response:

No, this is not a new role. The Floorman job description previously existed in the FortisBC IBEW collective agreement. The job description was dated and hadn't been used or reviewed for some time. In May 2010, the Company and the union agreed to revise the outdated job description and update the title to Operator, which more closely aligns with current utility industry practice.

The duties of an Operator include the day to day monitoring, inspection and cleaning of power plants and minor maintenance tasks within the power plants as well as switching operations on electrical equipment and manual operation of generating units.

There is no position in the Human Resources Department that provides Generation-specific training.

41.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.2, pp. 50-54

Utility Operations O&M Cost Summary, Table 4.3.4.2

41.1 Table 4.3.4.2 shows that the number of FTE's in this department decreased annually between the PBR years of 2007 – 2010, then increases in 2011 during the last year of the PBR and continues to increase into the test period of 2012-2013. Please discuss the observation of the trend and why.

Response:

In 2007, FortisBC did have a large number of PLTs which were part of the overall succession plan to compensate for the ageing workforce and anticipated retirements. Recently it has been difficult to attract and retain suitably experienced PLTs and this has contributed to the steady decline of the PLT workforce. The slowdown in the Company's capital program has also contributed to this reduction in FTEs.

The numbers in 2007 to 2010 represent actual FTEs on the roles, less vacancies, whereas 2011 to 2013 represents the forecast numbers, inclusive of vacancies, which have been budgeted for.

41.2 Please discuss and identify the maintenance programs that were reduced during 2007-2010 that would contribute to the downward trend in FTE over the same period. Please include a discussion on the essential nature of each of these programs.

Response:

Maintenance programs were not reduced during this time period, but rather the programs were reviewed to gain operational efficiencies and certain activities were contracted out.

41.3 There does not appear to be any rational relationship between the number of FTE's and the total O&M cost in this department for the period 2007 – 2013. Please discuss why (even in consideration of labour increases).

Response:

The number of FTEs listed on line 1.0 of Table 4.3.4.2 in Tab 4 of the 2012-13 RRA represents all employees in the Utility Operations group. These employees perform capital, O&M, or third party related activities.

42.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.2, Table 4.3.4.2, p. 52

Utility Operations

"The Commission's decision on the Company's 2011 Capital Expenditure Plan (Order G-195-10) directed that certain capital expenditures (totaling $3.78 million) were more appropriately classified as operating expenses. These expenditures have been included in the 2012-13 operational budgets and relate to:

- Right-of-way reclamation (transmission and distribution);
- Pine beetle kill hazard tree removal (transmission and distribution); and
- Hot tap connector replacement."

42.1 Please provide an explanation for the sustained $3.7 million increase in 2011 over 2010 in non-labour expenses shown in Table 4.3.4.2, and show a breakout by activity in tabular format.

Response:

The increase in non-labour expenses relates to the three programs mentioned above.

Table BCUC IR1 42.1

	2011
	($000s)
Right-of-Way Reclamation	1,112
Pine Beetle Kill Hazard Tree Removal	2,155
Hot Tap Connector Replacement	500

42.2 Please identify the number of hot tap failures and number of hot tap replacements in 2010 and year to date in 2011.

Response:

Please refer to Table BCUC IR1 42.2 below.

Table BCUC IR1 42.2

	2010	2011
Hot tap connector failures	2	1
Hot tap connectors replaced	4946[1]	1670[2]

[1] The majority of hot tap connector replacements identified in the 2 year 2009/2010 capital plan were replaced in 2010

[2] This number is the forecast number of hot tap connectors to be replaced in 2011; actual replacement numbers are unavailable at this time.

42.3 Please identify the quantity of labour involved or number of trees removed associated with pine beetle kill along transmission and distribution lines in 2010 and year to date in 2011.

Response:

The number of trees removed associated with pine beetle kill along transmission and distribution lines in 2010 including assessment, identification, removal and associated debris disposal was approximately 12,350. In 2011, FortisBC is planning to remove approximately 16,600 trees associated with pine beetle kill along transmission and distribution lines. This work is approximately 55 percent complete year to date.

43.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.2, pp. 52-53

Utility Operations

43.1 Provide the operating budgets for each program (Line Maintenance, Vegetation Management, Substation Maintenance) for the period 2007 – 2013.

Response:

Please refer to the below table.

Table BCUC IR1 43.1

Year	Line Maintenance		Vegetation Management				Substation Maintenance
	Hot Taps	Total	Cyclical Brushing	Right of Way Reclamation	Pine Beetle Kill	Total	
	($000s)						
2007		4,075	2,166	1,950[1]		4,116	2,638
2008		4,521	2,133	959[1]	1,730[1]	4,822	2,627
2009		4,469	2,213	979[1]	1,939[1]	5,131	2,990
2010		4,304	2,417	1,018[1]	1,235[1]	4,670	2,675
2011	500	5,042[3]	2,234	1,112[2]	2,155[2]	5,501	2,805
2012	410	5,839[3]	2,627	1,010[2]	1,727[2]	5,364	3,060
2013	411	5,993[3]	2,702	1,009[2]	1,732[2]	5,443	3,120

[1] RoW Reclamation & Pine Beetle kill - Capital Expenditure
[2] RoW Reclamation & Pine Beetle kill - Operating Expenditure
[3] Hot Tap connector replacement included in Line Maintenance Total

43.2 Please explain whether Vegetation Management now includes 1) cyclical brushing, 2) Right-of-Way Reclamation, and 3) Pine Beetle Kill hazard tree removal?

Response:

The FortisBC Vegetation Management program does include: 1) cyclical brushing, 2) Right of Way Reclamation, and 3) Pine Beetle Kill hazard tree removal.

43.2.1 Provide a table which separately shows the 3 programs in the above question for the period 2007 – 2013. Include costs and FTEs which would have transferred from capital to O&M.

Response:

There has been no change in FTEs. The same FTE compliment manages the consolidated O&M as it did the separate Capital and O&M budgets.

Table BCUC IR1 43.2.1

Year	Cyclical Brushing	Right of Way Reclamation	Pine Beetle Hazard Tree Removal	Total
	($)			
2007 (1)	2,166,000	1,950,170		4,116,170
2008 (1)	2,133,000	958,791	1,730,053	4,821,844
2009 (1)	2,213,000	979,213	1,938,952	5,131,165
2010 (1)	2,417,000	1,018,049	1,235,121	4,670,170
2011 (2)	2,234,367	1,112,000	2,155,000	5,501,367
2012 (2)	2,627,090	1,010,000	1,727,297	5,364,387
2013 (2)	2,701,782	1,009,000	1,732,445	5,443,227

[1] *Reclamation & Pine Beetle Hazard - Capital Expenditure*

[2] *Reclamation & Pine Beetle Hazard - Operating Expenditure*

Order G-195-10 for FortisBC's 2011 Capital Expenditure Plan directed 3 specific programs to be reclassified as operating expenses, totaling $3.78M.

43.3 In 2012F, there is a 4.6% FTE increase which accounts for 9% of labour cost increases. Please explain whether these increases are the result of the 3 capital programs now classified as capital or for other reasons. Provide details.

Response:

No, the increases are not as a result of the three capital programs now classified as operating. For increases in FTEs please refer to the response to BCUC IR1 Q41.1.

43.4 Given that the FortisBC 2011 Capital Expenditure Plan Decision denied the capitalization of the Hot Taps connector replacement program, please provide the operating budgets for this program for 2012 and 2013.

Response:

The operating budget for this program is $0.5 million in each of 2012 and 2013.

44.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.2, p. 53-54

Utility Operations, Substation Maintenance

"The (CMMS) system is…being used to generate corrective maintenance work, and tasks and repair orders have been based on four year historical averages. Maintenance expenditures for 2012 and 2013 have increased over previous years based on a historical workload and a task driven budget through the CMMS."

44.1 Please explain the use of the task driven budgeting process. Is this a forward-looking process based on required tasks in the upcoming years?

Response:

The CMMS software is configured with preventative maintenance procedures for most of the tasks that can be planned in advance. The fundamentals of the system design are for each procedure to have a standard duration assigned and a combination of time and/or condition based trigger applied. The procedure will then be initiated based on these triggers. The forecast process will compare time based triggers and condition results from inspections or diagnostics; the CMMS then extrapolates a trend and attempts to determine when one of the triggers will reach its threshold. This allows work to be forecast for future years and provides a foundation for determining the resources required.

44.2 Please explain how this budget was developed as it appears that the two budgeting techniques (4-year historical averages versus task driven budget) appear to be two very different approaches.

Response:

This budget consists of estimates for two related, but distinct, components: preventative and corrective maintenance.

Preventative tasks make up the work that can be forecast for future years based on time and condition-based parameters. Wherever possible planned actives are developed into procedures and forecast as a preventative task to determine the resources required.

Corrective tasks are issues that arise throughout the year that must be dealt with but are not planned activities. As there is no way to know how many of these events will occur, a four year historical average is used for the purposes of assigning resources for corrective tasks.

In general, the budget is developed by combining the results from the preventative and corrective components.

On page 50 of Tab 4 (Line 20-25), FortisBC states that "In 2011, additional monitoring equipment is being installed at South Slocan to permit the Company to collect and monitor condition data of equipment installed during the ULE program. Over time, this monitoring will permit the Company to further rationalize its maintenance activities by conducting maintenance on equipment <u>based on actual need rather than on a time based interval</u>."

44.3 Please explain why some generation maintenance activities are based on actual needs while some operational programs are based on historical averages? Should there be a consistency with regards to budgeting processes within difference departments? Please discuss.

<u>Response:</u>

Page 50 of Tab 4 (Line 20-25) above states that FortisBC would like to transition to a condition based approach which permits maintenance on equipment based on condition and need rather than strictly a time based interval. Generation maintenance activities are predominately time based at this time.

Operational programs are based on historical averages since, in the absence of actual condition data, this often provides the best indicator of future expenditures.

The Company intends to move towards consistency in budgeting processes with a transition to Asset Management. As discussed on page 3 of the 2012 Long Term Capital Plan: "A fully developed Asset Management solution will improve the ability of the Company to present objective and prudent investment decisions for the benefit of customers."

45.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.3, pp. 54-55

Mandatory Reliability Standards (MRS)

In accordance with Order G-27-10, the date for filing of mitigation plans was June 30, 2010. FortisBC states it "…filed mitigation plans to become compliant. Ongoing effort is required to remain within auditable compliance with all standards and to evaluate the impacts and implement changes to existing and new standards."

45.1 Please explain in detail the ongoing efforts that are required to maintain compliance to MRS. How often does FortisBC expect these changes to existing and new standards to occur? How does this account for maintaining the 5 FTEs during the test period (a reduction of only 1 FTE even after the filing of the mitigation plan?)

<u>Response:</u>

The above questions are answered separately below.

a) ***<u>Please explain in detail the ongoing efforts that are required to maintain compliance to MRS</u>***

The standards that are applicable to FortisBC have over 550 requirements that must be met. These requirements vary in task and effort. Below is a list of some functions that need to be performed as an entity registered for the reliability functions such as FortisBC.

- Maintain and submit compliance records and related documentation for compliance activities as requested internally or by WECC/BCUC;
- Maintain framework for compliance records and information repository;
- Document and file telephone conversation recordings, email or other equivalent evidence that can be used to confirm that reporting procedures demonstrating compliance with requirements have been followed (ensure an auditable trail);
- Perform internal investigations for potential utility exposure to new Reliability Standards requirements associated with new or modified utility activities, processes, procedures, agreements or contractual arrangements;
- Perform routine checks on processes and procedures to ensure compliance is adhered to. If a gap is found, formalization of the violation, and subsequent mitigation plans will need to be submitted to WECC/BCUC;
- Perform annual internal audits and complete self-certifications;
- Participate in WECC/BCUC audits;
- Ongoing reviews of personnel access lists with physical and cyber access to critical assets. Lists need to be reviewed quarterly and any changes completed within the specific requirement timelines;

- Ensure personnel with physical and cyber access to critical assets have proper documentation in place such as criminal record checks, training, and proper authorization. This information is to be verified by the various departments on a quarterly basis;
- Provide training on an annual basis for MRS related activities such as cyber and physical security awareness, compliance awareness, operation of protection systems and operating personnel. Records are to be kept for what training was received and when. Annual review and signoff of the various training programs is also required;
- Annual review and signoff of procedures, policies and processes related to the requirements identified in the Mandatory Reliability Standards. These include such documents as facility rating methodology, critical asset and cyber asset list, cyber security policy, physical security plan, sabotage reporting, risk based assessment methodology for all assets, protection system maintenance program, physical and cyber security maintenance plans, vegetation management program, emergency response plan;
- Test and document software changes/upgrades prior to implementation to ensure that there is no impact on MRS. This would include such tools as antivirus software, software service packs, vendor software upgrades, operating system upgrades, and database platforms on cyber assets. Typically this implementation process is expected in quarterly timeframes;
- Conduct field maintenance on systems identified in the MRS requirements such as protection systems, physical security systems, cyber security systems and electronic security perimeters on a regular basis. Correct any shortfalls identified in testing; and
- Ongoing participation in the review of NERC/WECC standards and regional criteria revisions/additions;

FortisBC is tentatively scheduled for an audit with BCUC/WECC during the summer of 2012. The results of the audit will determine if the Company's interpretation to meet the requirements of the standards is accepted by WECC and the Commission.

b) ***<u>How often does FortisBC expect these changes to existing and new standards to occur?</u>***

Changes to the standards are ongoing. FortisBC cannot speculate to potential volume as the changes are driven by WECC/FERC and subsequently BCUC. However, since the standards were implemented, BC Hydro has submitted three assessment reports to the BCUC which are summarized as follows:

Table BCUC IR1 45.1a

BC Hydro (formerly BCTC) Assessment Report	Quantity of Standards Changed	Quantity of New Standards	Status with BCUC
Report #2	22	1	Approved (Order G-167-10)

Report #3	19 (8 of which are going through 2 revisions)	1	Pending
Report #4	0	6	Pending

NOTE: Assessment Report #1 resulted in the adoption of BC MRS.

The changes and additions thus far have not required an adjustment to FortisBC operating costs. However, future changes and additions may affect the budget and will be identified through the assessment process.

Changes/additions to standards in the United States can subsequently impact BC through the assessment process. In the interest of FortisBC customers, the Company is taking an increasing active role in reviewing, providing comments to changes, and voting for or against acceptance of changes to standards through its WECC membership. WECC's process is to issue members an alert or position paper on pending changes. For the period of January 1, 2011 to July 31, 2011, FortisBC has reviewed (and provided comments if required) on 50 WECC alerts and 12 WECC position papers. These include standards for which FortisBC is not currently subject to but still require review for potential impact.

c) How does this account for maintaining the 5 FTEs during the test period (a reduction of only 1 FTE even after the filing of the mitigation plan?)

The FTE quantity identified in Table 4.3.4.3 is the total count for the department. Following is the table with the number of FTEs within the department and estimates of time charged to O&M. FortisBC has estimated that 4.5 FTEs need to be dedicated to maintain compliance in addition to incremental costs to the various departments in the organization. The departments with incremental costs include Planning, Information Systems, Generation, Internal Audit, Human Resources, Vegetation Management, and Station Maintenance. The reduction of one FTE to the department correlates to the completion of the capital effort and the FTE being redeployed to another area within the organization and tasked with other capital efforts.

1 **Table BCUC IR1 45.1b**

	General Assumptions	2010	2011F	2012F	2013F
1.0	**Full Time Equivalents (FTE):**	6	6	5	5
	Full Time Equivalents Budgeted to Operating Expenses	0	3.6	4.5	4.5
		($000s)			
2.0	**Expenses**				
2.1	Labour		752	905	914
2.2	Non-Labour		203	274	273
TOTAL O&M EXPENDITURE:			**955**	**1,179**	**1,187**

2 The costs identified above are incremental to previous operating costs incurred prior to the
3 adoption of the Mandatory Reliability Standards in British Columbia.

45.2 Please provide a table by assessment report of BC Hydro's costs versus FortisBC's costs required to comply with MRS.

Response:

Below is a table of costs by assessment report as submitted to the BCUC.

Table BCUC IR1 45.2a

Report	BCTC		BC Hydro		FortisBC	
	One-time	Ongoing	One-time	Ongoing	One-time	Ongoing
No. 1	$301,200	$420,000	5,399,500	938,500	3,510,000	625,000
No. 2	-	2,000	-	-	-	-
No. 3	-	-	-		-	-
No. 4	-	-	$35,000	-	-	-
Totals	$301,200	$422,000	$5,434,500	$938,500	$3,510,000	$625,000

FortisBC assessed 104 NERC reliability standards and WECC regional standards that are listed in Attachment A to Order G-67-09 and registered for the following functions:

1	TO	Transmission Owner
2	TOP	Transmission Operator
3	GO	Generation Owner
4	GOP	Generation Operator
5	DP	Distribution Provider
6	TP	Transmission Planner
7	RP	Resource Planner
8	TSP	Transmission Service Provider
9	LSE	Load Serving Entity
10	PSE	Purchase-Selling Entity

Based on the assessment, FortisBC determined that of the 80 standards potentially applicable to the registered functions, 55 standards applied to the Company. Finally, it is the opinion of the Company that the remaining 25 standards are not applicable due to the fact that the tasks and functions referenced in the standard are not currently performed by FortisBC.

The following table is a summary listing of the applicable standards by area:

Table BCUC IR1 45.2b

Category	**Description**	**Standards Applicable to FortisBC**	**Standards Applicable to Function**[1]	**Total BC Standards**[2]	**Pending Approval**
BAL	Resource and Demand Balancing	1	1	8	
CIP	Critical Infrastructure Protection	9	9	9	
COM	Communications	2	2	2	
EOP	Emergency Preparedness and Operations	6	7	8	
FAC	Facilities Design, Connections and Maintenance	5	6	9	
INT	Interchange Scheduling and Coordination	1	3	9	
IRO	Interconnection Reliability Operations and Coordination	1	5	10	
MOD	Modeling, Data, and Analysis	5	9	10	6[3]
NUC	Nuclear	0	1	1	
PER	Personnel Performance, Training, and Qualifications	3	3	4	
PRC	Protection and Control	7	17	17	1[4]
TOP	Transmission Operations	7	9	9	
TPL	Transmission Planning	4	4	4	
VAR	Voltage and Reactive	4	4	4	
	Total Standards	55	80	104	7

1 TO, TOP, GO, GOP, DP, TP, RP, TSP, LSE, PSE

2 As of January 1, 2011

3 BC Hydro Assessment Report #4 submitted to BCUC July 15, 2011 – Pending approval

4 BC Hydro Assessment Report #3 submitted to BCUC March 3, 2011 – Pending approval

An assessment for compliance was then conducted and it was determined that the Company was potentially non-compliant with 40 of the 55 reliability standards. By June 30, 2010, FortisBC was compliant with 35 standards and 20 mitigation plans had been filed with WECC. By the end of 2010, the number of mitigation plans was reduced to 13. The following table is a summary of those plans:

Table BCUC IR1 45.2c

Category	Description	Number of Standards in Non-Compliance January 1, 2010	Number of Standards in Non-Compliance June 30, 2010	Number of Standards in Non-Compliance December 31, 2010
CIP	Critical Infrastructure Protection	9	5	5
COM	Communications	2		
EOP	Emergency Preparedness and Operations	5	5	2
FAC	Facilities Design, Connections and Maintenance	4		
IRO	Interconnection Reliability Operations and Coordination	2		
PER	Personnel Performance, Training, and Qualifications	1	1	1
PRC	Protection and Control	7	6	3
TOP	Transmission Operations	6	3	2
VAR	Voltage and Reactive	4		

The focus in 2010 was to come into compliance and consequently all work was considered one-time setup costs (no operating expenditures were incurred). In 2011, the Company focus is transitioning from initial assessment and development of compliance plans to monitoring and maintenance of compliance with the standards. The original budget for 2011 was $853,000 and is currently forecast at $955,000. The increase in expenditures is due to the requirement to be auditably compliant with the following two standards:

PRC-005-1	“Transmission and Generation Protection System Maintenance and Testing”
PRC-008-0	“Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program”

In 2011, this increase has been mitigated by operating cost savings in other departments.

The transition to maintenance is anticipated to be complete by 2012. However, WECC and BCUC are in the process of reviewing the remaining mitigation plans. Through the review, interpretation of the standard is clarified and any adjustments required will be identified as a variance to the submitted budget. The CIP standards are complex and are particularly at risk.

Commission Order G-171-10 issued November 26, 2010 approves the 2011 Implementation Plan for Monitoring Compliance with the BC Mandatory Reliability Standards. The plan identified FortisBC, as a registered Transmission Operator (TOP), will be audited by BCUC/WECC every three years. It also identified the requirements for entities to self-certify annually. The 2011 Actively Monitored Standards List for BC identifies 70 standards that are to be considered. FortisBC is not scheduled to be audited by BCUC/WECC in 2011 but is required to self-certify 61 standards. FortisBC is tentatively scheduled to be audited in summer 2012.

The effort required to self-certify and be audited by BCUC/WECC is difficult to quantify at this time as FortisBC has no formal experience with either process. FortisBC originally budgeted for an annual audit of 10 standards and not the minimum of 40 standards as referenced in Commission Order G-171-10. In discussions with entities in the United States during user group meetings it has become apparent that the level of effort is significant. In addition, FERC issued Docket No. IC11-725B-001 on May 31, 2011 (attached as Appendix BCUC IR1 45.2) which indicates that 3,840 man-hours is the average time spent for new US entities that have to come into compliance with the CIP standards. FortisBC is not aware of any official documentation related to other standards.

As indicated, FortisBC did not previously anticipate or fully budget for this level of effort. Therefore, the Company plans to track the costs of self-certification requirements over the next two years and report it as a variance if required. Also, the Company intends to track the costs of BCUC/WECC audits, which will occur every three years. The results of these audits will determine if the Company’s interpretation to meet the requirements of the standards is satisfactory to the WECC and the Commission. Adjustments to processes and efforts may be required based on the results of the audits and may require adjustments to operating and/or capital costs.

There are five risks FortisBC has identified to date that could affect the budget for Mandatory Reliability:

1. Effort required to annually self-certify;
2. Effort required for a BCUC/WECC audit;
3. Adjustments required as a result of the audit;
4. Final Interpretation of CIP standards; and
5. Changes to standards and additions of new standards.

FortisBC will continue to manage the costs associated with Mandatory Reliability Standards compliance to minimize impact on customer rates while maintaining compliance to the satisfaction of BCUC/WECC.

45.3 Given the 2 FTE reduction in 2012, why is there a 20% increase in labour costs and the 35% increase in the non-labour costs?

Response:

FortisBC is unable to identify the BCUC reference to a 2 FTE reduction. However, the labour cost increase is due to incremental costs associated with compliance to the standards. 2011 is a transition year, in which work is still ongoing to become compliant under mitigation plans. The change from 3.6 FTE to 4.5 FTE (as shown in the Table BCUC IR1 45.1b of the response to BCUC IR1 Q45.1) represents the transition to maintenance of the standards.

In addition, incremental general operating expense costs from other departments such as Information Systems, Internal Audit, Human Resources, Vegetation Management, and Station Maintenance are included in this budget and contribute to the increase in Non-Labour costs.

45.4 What is included in non-labour costs? Show breakdown.

Response:

Included in Non-Labour are consultant costs and general operating expenses. A breakdown is provided in the below table.

Table BCUC IR1 45.4

Category	2011	2012	2013
	($000s)		
Consultant/Contractor	68	116	116
General Operating Expenses	135	158	158

Consultant/Contractor costs include those to provide support in specific areas of expertise required by FortisBC to maintain compliance. They include specialized support that may be required for any of the standards, particularly the CIP standards due to their complex requirements.

General Operating Expenses include costs for routine expenses for the department (telephones, travel, participation in user groups, etc.), training expenses and incremental operating expenses from other departments.

46.0 Reference: Operation and Maintenance Mandatory Reliability Standards (MRS)

Exhibit B-1, Tab 4, Section 4.3.4.3, pp. 54-56

Mandatory Reliability Standards (MRS) Costs

FortisBC states that “The O&M expenses include the costs to maintain full and auditable compliance with the BC MRS. This includes efforts on monitoring and maintaining security systems, field maintenance, ongoing reporting requirements for the various standards, documentation and records, conducting self audits, participating in BCUC audits, ongoing training and participation in user groups, and evaluating impacts on changes to existing standards and adoption of new standards.” (Tab 4, p. 55)

46.1 What were the costs to maintain FortisBC’s best practices prior to the MRS program?

Response:

The cost to maintain best practices were part of the Company’s overall O&M costs. This effort was not specifically tracked and cannot be separated from other expenditures in previous years.

46.2 Are these costs to maintain FortisBC’s best practices prior to the MRS program replaced by the MRS program costs? If so, please explain; and if not, why not?

Response:

The costs to maintain full and auditable compliance with the BC Mandatory Reliability Standards are incremental to the organization. They are required in addition to the existing effort of best practices. As stated in Section 4.3.4.3 of Tab 4, the previously voluntary WECC Reliability Management System (RMS) had limited scope and focused primarily on operational concerns. The costs associated with participation in the RMS were low and were included within previous budgets.

46.3 Please provide FortisBC’s estimate of incremental costs associated with MRS as reported to BC Hydro (BCTC) and the Commission in BCTC’s initial MRS assessment report, and provide in a comparison table with actual and forecast annual costs.

Response:

As seen in the table in response to BCUC IR1 Q45.2, FortisBC reported an estimate of $625,000 in incremental operating costs due to the implementation of the BC MRS. This value was included in the BC Hydro (BCTC) initial MRS assessment report.

Following is a summary of the currently forecast MRS incremental operating costs from Table 4.3.4.3, page 55 of Tab 4 of the 2012-13 RRA.

Table BCUC IR1 46.3

2011 Forecast	2012 Forecast	2013 Forecast
$955,000	$1,179,000	$1,187,000

Please refer to the response to BCUC IR1 Q45.2 for a discussion of the increased forecast costs compared to the 2008 initial assessment. Note that no incremental operating costs due to the BC MRS have been incurred prior to 2011 as the program was still under development and implementation within FortisBC at that time.

46.4 Is FortisBC providing MRS assistance to any other entities, and if so, is it charging for such assistance, and where is any such income reported?

Response:

Yes, FortisBC does provide assistance to other entities. All associated costs are recovered as per the agreements established between the parties and is reported in ‘Other Income’.

47.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.4, p. 56

Cominco Facility Charge

47.1 Please provide the terms of the Facility Sharing Agreement and explain whether this is an on-going agreement or whether there it is subject to expiration?

Response:

In exchange for the annual rental fee that is based on a combination of annual capital carrying costs and O&M expenses, FortisBC Inc can nominate for the use of a portion of certain Teck Resources Ltd. (Teck, formerly Cominco) facilities. The facilities used by FortisBC are mainly switch positions of the Waneta and Emerald terminal owned by Teck. Conversely, Teck can nominate to use FortisBC facilities but does not currently use any of FortisBC facilities.

There is no termination date in the agreement. However any party to the agreement can opt out by providing at least five years written notice.

48.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.5, p. 56

Brilliant Terminal Lease

48.1 Please explain the terms of the long term lease at BTS and when this would expire.

Response:

The Brilliant Terminal Station (BTS) Facilities Interconnection and Investment Agreement gives FortisBC exclusive license to use the BTS, and the BTS equipment and to operate, maintain and repair the BTS facilities during the term of the agreement. The BTS enables FortisBC to interconnect its 77 and 79 transmission lines.

The agreement expires in May 2056. There are also early termination provisions that allow FortisBC to terminate after the anniversary date of the agreement in 2029 subject to certain conditions.

49.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.6, pp. 57-58

Internal Audit

49.1 Please explain why labour costs are forecast to reduce by 11% in 2011F when there is an increase to FTEs, then labour costs are forecast to increase 28% for 2012F when there is no change in FTE.

Response:

The reasons are primarily:

1.) A portion of the Director's salary (at fully loaded Transfer Price) is being charged to FortisBC Holdings Inc. starting 2010 (November and December) and for the budget years 2011 through 2013 due to the Director's management responsibilities with FortisBC Holdings Inc.'s audit group;

2.) A portion of Internal Audit salaries are budgeted to be charged to the Mandatory Reliability Standards (MRS) project during 2011;

3.) These cost transfers create credits in salary expense (reducing the expense) for 2011 as compared to 2010 in spite of the increase in FTEs. The new FTE hire was delayed until mid-year which results in an actual FTE of approximately 2.5 for the year 2011; and

4.) Labour expense for 2012 includes a full year salary for the new FTE; therefore the 28 percent increase reflects a comparison of 3 FTEs with the 2.5 FTEs for 2011.

49.2 What is included in the non-labour costs?

Response:

The following items are included in the Non-Labour costs for Internal Audit:

1. Contractor expense;
2. Employee Travel;
3. Professional Dues;
4. Training (Professional Development);
5. Telephone; and
6. Audit Software update expense.

49.3 Given the increase in FTEs in the Internal Audit department in mid-year 2011F, shouldn't there be corresponding decrease in the use of external contractors (hence decrease in the "non-labour" costs)?

Response:

The department has reduced the budgeted expense for external contractors over the three year period (**2011**: $50,000; **2012**: $41,500; **2013**: $30,000) but there are still some external contractors that will be needed for specialized expertise in projects such as IT Penetration Testing, Enterprise Risk Management consulting, and IT General Controls testing.

50.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.7, pp. 59-61

Legal and Regulatory

50.1 Please provide a breakdown of FTE and expenses separately for each functional area (Legal and Regulatory) for the years 2007A – 2013F.

Response:

The revised table below shows the breakdown of FTEs and expenses between Legal and Regulatory functions.

Table BCUC IR1 50.1 Legal and Regulatory O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	Full Time Equivalents							
1.1	Legal	3	2	1.25	1.5	2	2	2
1.2	Regulatory	4	6	5.75	5.5	6	6	6
1.3	Total	7	8	7	7	8	8	8
		($000s)						
2.0	Legal Expenses							
2.1	Labour	294	227	220	205	321	329	345
2.2	Non-Labour	218	152	142	270	158	158	158
2.3	Total Legal	511	379	362	475	479	487	503
	Regulatory Expenses							
2.4	Labour	475	788	667	598	801	801	813
2.5	Non-Labour	195	126	263	378	222	232	232
2.2	Total Regulatory	670	914	930	976	1023	1033	1045
TOTAL O&M EXPENDITURE		1,181	1,293	1,292	1,451	1,502	1,520	1,548

51.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.8, pp. 61-63

Customer Service

51.1 Please provide a breakdown of Table 4.3.4.8 to show the number of FTEs and costs separately for each functional area for the years 2007A – 2013F (Billing and customer Systems, Meter Reading, Customer Contacts Center, Key Account Management, DSM, AMI).

Response:

Please refer to Table BCUC IR1 51.1 below.

Table BCUC IR1 51.1

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
Billing	13.0	13.0	12.0	13.0	17.0	15.3	14.3
Contact Centre	19.0	19.0	22.3	23.7	22.1	22.1	23.0
Energy Management	8.0	9.0	9.0	8.0	11.0	12.8	11.0
Meter Reading	19.9	18.9	20.0	22.0	19.8	20.2	19.4
Revenue Protection	1.0	1.0	1.0	1.0	1.0	1.0	1.0
TOTAL	61	61	64	68	71	71	69

"Some readings are obtained by wireless drive-by devices or remote interrogation…" (p. 61)

51.2 Is it implied that FortisBC has some form of AMI or SMI (pilot project) in its service area?

Response:

No. There is no form of AMI or SMI pilot project underway at this time. However, FortisBC does have the ability to remotely interrogate 22 of the larger Commercial and Industrial customers. FortisBC also has approximately 3,600 'drive-by' meters installed at customer request or on 'hard to read' premises. The 'drive by' meters are wirelessly read by the handheld device that the meter reader carries.

51.2.1 What is the ratio of conventional versus AMI/SMI meters?

Response:

As stated in the response to BCUC IR1 Q51.2, FortisBC has not installed any AMI/SMI meters.

"This (DSM) activity has been included in the department narrative for completeness as it is a function of the Customer Service department, <u>but is not included in O&M Expense.</u>" (p. 62) [emphasis added]

51.3 Please clarify the above statement relating to DSM expenses. Is this because the operational costs for DSM activity are all included in the DSM deferral account?

Response:

Confirmed, all DSM costs are included in the DSM deferral account.

FortisBC then states that "four additional employees in the PowerSense department to coordinate, manage and monitor the increased DSM program expenditures." (p. 63)

51.4 Please explain why the 4 additional employees in PowerSense are not accrued to the DSM deferral account but included in the O&M costs? Please confirm whether or not operational expenses relating to PowerSense / DSM are included in O&M.

Response:

The DSM FTE count is included in the Customer Service FTE count shown in Tab 4, Table 4.3.4.8 however, as was stated in the response to BCUC IR1 Q51.3, the entire DSM expenditure, including the 4 additional employees, are included in the DSM deferral account.

FortisBC states "This (AMI) activity has been included in the department narrative for completeness as it is a function of the Customer Service department, but is not included in O&M Expense." (p. 62) [emphasis added]

51.5 Please clarify the above statement relating to AMI expenses. Is this because the operational costs for AMI activity are included in a deferral account?

Response:

Confirmed. Operational costs for AMI activity are recorded in a deferral account.

51.6 FortisBC then states that there are "two additional employees for the Advanced Metering Infrastructure project team (fully capitalized)." (p. 63) If AMI costs are fully capitalized, why are they included in the O&M FTE count?

Response:

AMI personnel are included in the Customer Service department. Table 4.3.4.8 (page 62 of Tab 4) describes changes, over time, to the total FTE count to the department. The bullet in question (page 63 of Tab 4) is part of the explanation for the departmental FTE growth between 2009 and 2011. However, as otherwise noted in the bullet and in the answer to BCUC IR Q56.5, the AMI-related FTE are recorded in an AMI deferral account, and not included in departmental O&M.

51.6.1 Please provide the total number of FTE's solely working on PowerSmart / DSM.

Response:

The PowerSmart/DSM (Energy Management) FTE count is provided in response to BCUC IR1 Q51.1.

On page 59 of Tab 4, FortisBC states that "The Company's rate increases, which have been magnified by slow customer load growth,…"

51.7 Please explain why there a need to increase DSM program expenditures if customer growth has slowed.

Response:

FortisBC has not requested an increase in the level of DSM program expenditures, but proposes to maintain them at the level established in 2011. The Company believes that a long-term, stable DSM offering gives the market time to respond most effectively to programs. Nevertheless, the Company believes that if the level of customer growth is materially below forecast levels over time, the total amount of DSM will have to be re-evaluated.

FortisBC explains that "The cost savings from most of the above items (aside from eBilling) is manifested in improved efficiency which creates more time for existing staff to absorb customer growth." (p. 63)

51.8 Given that customer growth has slowed, please explain where these efficiencies / cost savings can be seen. Provide evidence and calculations to support this claim.

Response:

As explained in the 2012-13 RRA in the referenced section, the efficiencies and cost savings are "… demonstrated by the fact that the customer service budget is forecast to rise at an annual growth rate of 1.7 percent over the period 2007-2013, while unit labour costs have seen an annual growth rate of approximately 3.3 percent over the same period." The fact that total Customer Service labour costs are rising more slowly than wage inflation provides evidence that efficiencies are being realized.

52.0 Reference: Operation and Maintenance
Exhibit B-1, Tab 4, Section 4.3.4.9, pp. 64-66
Community & Aboriginal Affairs

52.1 Please provide a breakdown of Table 4.3.4.9 to show the number FTEs and costs in each of the 3 primary areas of responsibility (Aboriginal Relations, Community Relations, and Community Investment) for the years 2007A – 2013F.

Response:

The breakdown of FTEs is as follows:

- 2007 – 2010: 1 FTE responsible for Aboriginal Relations and Community Relations; and
- 2011 – 2013: 3 FTEs responsible for Aboriginal Relations, Community Relations and Community Investment.

There are no FTEs dedicated to a singular function. Each employee's position is cross functional.

FortisBC states that "A significant portion of FortisBC's facilities are located on First Nations land, both reserve and traditional…"

52.2 What percentage of FortisBC facilities is referenced in the above?

Response:

Twenty percent of transmission facilities and 18 percent of distribution facilities are located on reserve or traditional First Nations lands.

52.3 Please explain whether the expenses relating to Community Investment are the cost involved in supporting and running the programs or do they relate to the actual cost of donations and sponsorships.

Response:

The expenses relate to the actual costs of donations and sponsorships undertaken to bring value in accepting projects more readily, reduction of long run operations costs driven by stronger relationships and productive resolutions of local issues.

52.4 Please explain how sponsorships and donations should be solely a ratepayer borne costs when there are clear benefits to increasing shareholders value through goodwill and branding.

Response:

As noted in the Application (Exhibit B-1), FortisBC's Community Investment program is designed to help the Company connect with customers and contribute to the economic and social fabric of the communities FortisBC serves. Community investment is increasingly used by municipalities, First Nations, and ratepayers at large, to gauge a company's performance and reputation. Permissions, approvals, licenses, and/or cooperation required to provide prompt and reliable service to customers can be delayed or accelerated as a result of the relationships developed by way of the Company's Community Investment program.

Ownership of the corporate name and goodwill, similar to ownership of other assets, is not determinative as to who should pay for costs associated with benefits or values received from the asset. As the sponsorships and donations provided through the Community Investment program enhance the relationship between the utility and the communities FortisBC serves, they can affect the expenses associated with the activities discussed above that are a necessary part of the Company's operation. It is appropriate that ratepayers fund the costs for community investment programs that ultimately have a beneficial effect on their rates. Because community investment is required for the successful operation of the utility for the benefit of customers, these costs have, and should continue to be, borne by customers.

52.5 Please discuss FortisBC's views on sharing in this cost with ratepayers.

Response:

Please refer to the response provided to BCUC IR1 Q52.4 above.

52.6 Please provide a table which lists all the programs / donations / sponsorships that FortisBC provided for (forecast to provide for) in the period 2007A to 2013F.

Response:

The attached list for 2012 and 2013 identifies some community investment opportunities that will materialize, however the majority of requests originate from communities and customer groups in the respective calendar year and decisions as to which particular initiatives to pursue are made at that time.

2007	
Beaver Valley May Days	Kelowna Civic Awards
Castlegar Chamber Golf	Penticton Chamber Awards
Castlegar Sunfest	Oliver AgriSpirit Pavilion (community tent)
Castlegar Sunrise Rotary	Osoyoos Seniors Centre Association (repair of seniors' pool table)
Travis Green Community Golf Tournament (Castlegar)	Princeton Posse Hockey Club
Kootenay Lake Dominion Day (Crawford Bay)	Summerland Minor Hockey
Creston Valley Rotary Club (Golf Tournament)	South Okanagan Concert Society
Creston Valley Fest	Tuc-el-nuit Elementary School (Oliver)
Rossland Winter Carnival	Penticton Historic Automobile Society
Squirt C Provincials - Salmo	Okanagan Similkameen Conservation Alliance - Meadowlark Festival Sponsorship
Silver City Days - Trail Festival Society	Kaleden Volunteer Fire Department - Jaws of Life
Trail CIB Memorial park	Summerland Chamber of Economic Dev & Tourism
Trail Lions	First Nations Golf Tournament
Trail Santa Parade	Lower Kootenay Band Pow Wow
Warfield Sports Day	Lower Similkameen Indian Band
BC River Days	Okanagan Nation Alliance (salmon feast)
KBRH Health Foundation	Okanagan Nation Ambassador - Ethan Baptiste
Kokanee Genetics Work	Penticton Indian Band Elders
Kootenay Lake Hospital Foundation Golf Tournament sponsorship	Upper Similkameen Indian Band
Kootenay South Soccer - Second year of commitment to retire WKP Jerseys	Lower Kootenay Band (Ktunaxa Language DVD)
Riondel Centennial Celebration	Okanagan Indian Band - Territorial Stewardship
Trail Historical Society	Spotted Lake (ONA)
Trail Library - Let's Read Festival	Aboriginal Tourism BC - BC Aboriginal Awards
Destination Imagination (Science Alive Camps)	Association of Kootenay Boundary Municipalities
Castlegar Nordic Club	Union of British Columbia Municipalities
Nelson Rod & Gun Club - Environmental fundraiser	Beaver Valley Pee Wee Rep
Nelson Fine Arts Society (Environmental Arts Program for Youth)	Beaver Valley Midget Rep
2007 Columbia River Brigade	Beaver Valley Pee Wee Rep
Destination Imagination (Brent Kennedy Elementary)	Creston Midgets Hockey Team
Castlegar Business Awards	Kelowna Select U18 Girl's Soccer Team
Scotties Tournament of Hearts (Trail) - Curling	Kelowna Ringette Association
Trail Business Awards	Rutland Minor Baseball Association
World Junior "A" Challenge (Trail & Nelson)	WinterQuest (Kootenays) - Single entry
West Kootenay Local Gov't Mgmt Association Luncheon	JCI Urban Adventure Challenge
Rotary Club of Grand Forks	Kootenay Youth Soccer
Greenwood Demolition Derby	Kootenay Ice Major Midget
Kaslo Ladies Rainbow Golf Tournament	WinterQuest (Kootenays)

Nelson Minor Hockey - Pee Wee AA	South Okanagan Minor Baseball Association
Trail Chamber Golf	BC Senior Games
Trail Curling Club rink board renewal	Okanagan Easter Seals 24 Hour Relay
Trail Hospital Auxiliary Conference	West Kootenay Wildcats
ALS Society (Selkirk Paving)	High schools in service territory (23) - $500 ea.
Glacier Gymnastics Club (Tumbl Trak)	UBCO Scholarship
Mel Simister Memorial (Kootenay Boundary Regional Hosp Found)	Grand Forks Hockey Game
WE Graham Community Services Society	Kelowna Chamber Golf Sponsorship
West Kootenay Big Game - Environmental enhancement fund	Kelowna Dragonboat Festival
Castlegar & District Wildlife Assn	Rotary Pro-Am Charity Golf Tournament (Kelowna)
Wildcat Bantam AAA Provincials	Al Horning & Friends Golf Classic (Liberals)
Provincial Curling Championships	Cops for Kids
West Kootenay Eco Society Conference	Crimestoppers (Central Okanagan)
Kelowna FortisBC Flames	Rick Thorpe Golf Tournament (Liberals)
Naramata Centennial	Networking Engineering Women @ UBC - Symposium
City of Penticton	UBC Power Engineering Option
Princeton & District Agricultural Fair	Have a Heart Radiothon (Kelowna General Hospital)
Princeton Ladies Curling Bonspiel	BC Hospital Jeans Day
Princeton Minor Football	Burger Flip for Cancer
Summerland Fall Fair	Kelowna Apple Triatlon
Similkameen Sizzle	Nelson Hydroelectric Museum
Kelowna Women's Soccer League The FortisBC Stiyotes	FortisBC Wild Festival for Youth
Mayor's Youth Forum - Kelowna	West Kootenay Ecosociety
Sizzling Summer Science Camp	Lieutenant Governor's Awards for Public Safety 2007
Okanagan Partnership - Okanagan Sustainability Week	
2008	
2009 Western Pond Hockey Championship - Rossland	Royal Canadian legion Branch 227
ALS Society of BC	Similkameen Country Community Kitchen
BC Amateur Midget A Provincials hockey championships	Similkameen Sizzle
Castlegar and District Heritage Society	South Columbia Search & Rescue Society (SCSAR)
Castlegar Community Ducks unlimited	South Okanagan Concert Society
Castlegar Festival Society	South Okanagan Sylx Environment Committee
Castlegar Rotary Club	Southern Okanagan Sportsmen's Association
Communities in Bloom Annual Conference	Summerland Chamber of Commerce - Festival of lights
Creston Valley Blossom Festival Association	Summerland Chamber of Economic Dev & Tourism
Creston Valley Rotary	Summerland Economic Development and Tourism Excellence Awards
Golden City Days-Rossland	Summerland Exhibition Association
Kaslo & Area Community Consultation Group 08/09 Tree/shrub plant	Telus Community Fundraising Golf Tournament

Kaslo Ladies Golf Tournament	Town of Osoyoos
Kaslo Logger Sports 2008	Variety - The Children's Charity
KBRH Health Foundation	Aboriginal Tourism BC - BC Aboriginal Awards
KBRH Health Foundation Annual Golf Classic	Cayoose Creek Band
Kootenay Association for Science & Technology (KAST)	Chopaka Rodeo Committee
Kootenay Boundary Regional Fire & Rescue	LKB Pow Wow Committee
Kootenay Employment Services	Lower Similkameen Indian Band
Kootenay Lake Hospital Foundation	Metis Nation British Columbia
Kootenay South Youth Soccer Association	Okanagan Elders Gathering
Men's Night Sponsor at Castlegar Golf Club	Okanagan Indian Band - Okanagan Dream Makers Society
Nelson District Rod and Gun Club	Okanagan Nation Alliance
Ohana Foundation	Penticton Indian Band
Phoenix Foundation - Rotary Golf Tournament	The Krew
Rossland Mountain Film Festival	Association of Kootenay Boundary Local Government
Rossland Winter Carnival	BC Safety Authority
Rotary Disrict 5080 Conference 2008	BC Widlife Federation
The Nelson History Theatre Society	IEEE Vancouver Section - PES banquet
Trail & District Public Library	Kelowna Rockets
Travis Green Community Golf Tournament	Princeton Posse Junior Hockey Club
Village of Midway	South Interior Local Government Association (SILGA)
Village of Montrose, Family Fun Day	Trail Smokeeaters
Warfield Recreation Commission	Union of British Columbia Municipalities Convention
West Kootenay All Star BC Baseball Provincials	Beaver Valley Midget Rep Hockey Team
West Kootenay Big Game Trophy Association	Beaver Valley PeeWee Rep "Hawks" Hockey Team
West Kootenay Brain Injury Assn.	Boat for Hope, Children Variety Charity
West Kootenay Branch APEGBC - Community Science Fair	Boundary Minor Hockey
West Kootenay Regional Science Fair	Kelowna Minor Football Association
Zone 6 Sr. Games Guys & Gals Calendar Fundraiser	Kootenay Avalanche 1999
2008 Kelowna Chamber of Commerce Business Excellence Awards	Kootenay South Youth Soccer Association
2008 Kelowna Chamber of Commerce Presidents Dinner	Major Midget Kootenay Ice Team
Friends of Rick and Yasmin Thorpe dinner - Okan. College	Mel Simister 27 Hole Mountain Classic
33rd Annual Kelowna Civic & Community Awards	Miss Kelowna Lady of the Lake Program
BC Liberal Sindi Hawkins & friends Annual Charity Golf Classic	Penticton Pony Club
BC Liberals 3rd annual Al Horning & Friends Golf Classic	Rossland/Trail Bantam B rep team
Boat for Hope, Children Variety Charity	Select Soccer 1995
CIBC Wood Gundy Annual RCMP Golf Tournament-Cops for Kids	South Okanagan Minor Baseball Tigers
Federation of BC Naturalists - South Okanagan Naturalists Club	South Okanagan Minor Hockey Association Pre-novice Team
Fresh Outlook Foundation Conference	St. Joseph's Catholic Elementary School

GGC - 1st Knox Mountain Pathfinders	Stanley Humphries Sr. Sec. Reach for the Top Team
Kars under the K Show & Shine	Trail Girls Softball
Kelowan Museums Society	Vernon Minor Fastball Association
Kelowna Chamber of Commerce	West Kootenay All Star Baseball Provincials
Kelowna Fire Department	West Kootenay Pee Wee Wildcats
Kelowna Minor Fastball Association - FortisBC Kelowna Flames	West Kootenay Wolf Pack Junior B Lacrosse Association
Kelowna Pops Orchestra Canada Day Spectacular	Westside Mixed Softball League (WMSL)
Ladies night - Fairview Mountain Club	Westside Warriors Age 10
Life & Arts Illuminarts Festival	High schools in service territory (23)
Mayor's Youth Forum - Kelowna	UBCO Scholarship
Naramata Centennial Legacy Project	Brad Hiscock Trust Fund
Okanagan Environmental Industry Conference & Trade show	Rotary Pro-Am Charity Golf Tournament
Okanagan Similkameen Conservation Alliance - Meadowlark Festival	UBC Okanagan - Engineer Mentoring Luncheon
Oliver Fire Department	UBC Okanagan - MSA Distinguished Leadership Gala
Penticton & Wine Country Chamber of Commerce	UBC Power Engineering Option
Penticton and District Jaycees	BC Hospital Jeans Day
Penticton Historical Automobile Society	Community Energy Association
Penticton Peach Festival Society	Crawford Bay Hall and Park Board - community light display
Princeton Basketball Team	Okanagan Surf n Turf
Princeton Ladies Curling Bonspiel	Scotties Tournament of Hearts (Trail) - Curling
Princeton Special Olympics	Stiyotes Soccer Team
Rick Thorpe Okanagan - Westside BC Liberals Golf Tourney	Whillis Harding Golf Tournament
2009	
2009 FortisBC Rotary Club of Kelowna Charity Golf Tournament	Central Okanagan Economic Dev. Commission (Youth Ent. Program)
Bats for a Cause	Kars under the K Show & Shine
Union of British Columbia Municipalities Convention booth	Desert Sun Counseling and Resource Centre
BC Widlife Federation	Osoyoos Desert Society
BC Safety Authority	South Interior Local Government Association
EPICC Planning Forum	City of Kelowna 34th annual Civic & Community Awards
Crescent Valley Volunteer Fire Dept	2009 Kelowna Chamber of Commerce Business Excellence Awards
Friends of the Trail & District Public Library	2009 Penticton & Wine Country Chamber of Commerce Excellence Awards
KAST Luminous Sponsor	Summerland Chamber of Commerce and Economic Development Excellence Awards
The Nelson History Theatre Society	GeoExchange 2009
LV Junior Girls Basketball - Provincial Championships	Summerland Action Fest
Creston & District Museum & Archives	2009 Kelowna Chamber of Commerce State of the City lunch
Garrett Horbul Scholarship Golf Tournament	Summerland Exhibition Association

Beaver Valley May Days Society	British Columbia Sustainable Energy Association
Greenwood Demolition Derby	UBC Women in Engineering
Goat Style Mountain Bike Society	Chamber of Commerce - 24th Annual Golf Tournament
Kootenay Lake Hospital Foundation	Penticton & Wine Country Chamber of Commerce
Warfield Recreation	Kelowna Rockets
Village of Montrose	Princeton Posse Junior Hockey Club
Special Olympics - Trail Local	Princeton Curling Bonspiel
Generation to Generation Society	Princeton Minor Fastball Association
KBRH Health Foundation Golf Classic	Kelowna 2010 Major Midget Tournament
Slocan River Streamkeepers	Osoyoos Indian Band
Castlegar Committee Ducks Unlimited	Lower Similkameen Indian Band - Sylix Girls Bball team
Sandman Classic Golf Tournament (formerly known as Travis Green)	Osoyoos Indian Band
Rossland Mountain Film Festival	Penticton Indian Band
Greenwood Improvement Society	Lower Similkameen Indian Band
KIJHL All Star Game	Osoyoos Indian Band
Western Screech Owl	Upper Similkameen Indian Band
Trail Lions Club	Aboriginal Tourism BC - BC Aboriginal Awards
KAST Luminous Sponsor	LKB 18th Annual Pow Wow
Association of Kooteney Boundary Local Government	PIB Peachfest Aboriginal Cultural Village
Trail Smokeeaters	Okanagan Nation Alliance
Castlegar Festival Society	Ethan Baptiste – Tradtional Hunt
Castlegar Rotary Club	Okanagan Nation Alliance
Trails Jays Baseball - Butler Park sign	Boat for Hope, Children Variety Charity
Creston Valley Blossom Festival Association	West Kootenay Wildcats Bantam female hockey team
Kaslo Loggers Sports	West Kootenay Wildcats Major Midget female hockey team
Rossland Golden City Days	Penticton Academy of Music
Creston Valley Rotary Club	Westside Mixed Softball League
Village of Midway	Princeton Figure Skating Club
West Kootenay Brain Injury Assn.	Rutland Minor Baseball Association
Castlegar and District Chamber of Commerce	FortisBC Slopitch Team
AKBLG - City of Castlegar	Trail Girls Softball
Boat for Hope, Children Variety Charity	Vernon Minor Fastball
Economic Development Commission (Youth Ent. Program)	Trail Youth Soccer Association
Okanagan Similkameen Conservation Alliance - Meadowlark Festival	Kelowna Red Heat Spring Hockey Club
Penticton Peach Festival Society	Nelson Neptune Swim Club
UBC Okanagan - Distinguished Leadership Gala	White Water Ski Team
YMCA Healthy Kids Day	Select Soccer 1995
Kelowna Minor Hockey Association	Westside Youth Soccer Association
Princeton Basketball Association	Rossland Radio Cooperative

Town of Princeton	Grand Forks Pianha Swim Club
Kelowna Canada Day Concerts Society	Beaver Valley Junior Girls Softball
BC Cancer Foundation	Rossland Trail Country Club (Mel Simister Golf Classic)
Princeton Rotary Golf Tournament	W.K. Babe Ruth All Stars
Fairview Mountain Ladies Golf Night	Warm Wishes Workshop, BC Children's Hospital
Kelowna Cop for Kids (Golf Tournament)	Stanley Humphries Sr. Sec. Reach for the Top Team
Inn From the cold - Kelowna	West Kootenay Wildcats PeeWee female hockey team
Society for Ecological Restoration	Westside Warriors
Similkameen Sizzle	Beaver Valley Bantam Rep
Kelowna Museums Society	Scouts Canada 1st Beaver Valley Group
Kettle Valley Steam Railway	Taril Midget Rep
Osoyoos Museum	South Okanagan Sportsman Association
South Okanagan Concert Society	BC Hospital Jeans Day
Osoyoos Desert Society	Heat in the Street
Learning Through the Arts	High School Scholarships
Summerland Chamber of Commerce - Festival of lights	UBC Okanagan - FortisBC Scholarship in Engineering
Literacy Now	President's Scholarship
2010	
2010 FortisBC Rotary Club of Kelowna Charity Golf Tournament	Oliver Fire Department
City of Trail/Lower Columbia Community Development Team	South Okanagan Rehabilitation Centre for Owls
Okanagan College Foundation	Osoyoos Desert Society
BC Safety Authority	City of Kelowna 35th annual Civic & Community Awards
"The Fairmont Hotel Vancouver" - Canadian Veterans of the Afghan Conflict	Penticton & Wine Country Chamber of Commerce
KIJHL All Star Game	South Interior Local Government Association- District of Barriere
Western Screech Owl	Kelowna Chamber of Commerce President's dinner
Trail Lions Club	Summerland Exhibition Association
KAST Luminous Sponsor	Summerland Chamber of Commerce and Economic Development Excellence Awards
Beaver Valley May Days Society	Summerland Action Festival Society
Greenwood Demolition Derby	Chamber of Commerce - 25th Annual Golf Tournament
Village of Montrose	Fat Cat Children's Festival Sponsorship
KBRH Health Foundation Golf Classic	Kelowna Lake Country Riding Association
Castlegar Committee Ducks Unlimited	BC Liberal Party Boundary Similkameen & Penticton Riding
Creston Rotary Club	Penticton & Wine Country Chamber of Commerce
Steps Dance Company	Kelowna Skating Club
BC Senior Games -Zone 6	2010 Kelowna Chamber of Commerce Business Excellence Awards
Creston Valley Wildlife Management Area	Okanagan Sun
Nelson District Rod & Gun Club	2010 Kelowna Chamber of Commerce Go Green Business challenge

The Nelson History Theatre Society	Kelowna 2011 Major Midget Tournament
School District No 8	Kelowna 2010 Major Midget Tournament
Slocan Park Pump Track Group	Kelowna Rockets
Passmore Fire Department	Princeton Posse Junior Hockey Club
Sandman Classic Golf Tournament (formerly known as Travis Green)	Princeton Curling Bonspiel
Slocan City Loggers	Princeton Basketball Association 09/10 season
Kootenay Lake Independent School Society	Princeton Minor Fastball Association
Wildsight	Oliver Curling Club
Community Harvest Food Bank	Kelowna Chiefs Hockey Club
Brandon Salviulo Scholarship Memorial Fund	Okanagan Nation Alliance - Jr. Syilx Girls Bball Team
Castlegar and District Chamber of Commerce	Okanagan Dreammakers Society
Kootenay Family Place	ntamtqen snma?maya?tn (school in Cawston)
Rossland Winter Carnival	Tuc-el-nuit Xeriscape Garden Project
Kinnaird Elementary	St. Eugene Golf Resort and Casino
BC Cancer Foundation - Ride to conquer cancer	Penticton Indian Band
Association of Kootenay Boundary Local Government - City of Castlegar	Lower Similkameen Indian Band
West Kootenay Big Game Trophy Association	Upper Nicola Indian Band
Castlegar Festival Society	Upper Similkameen Indian Band
Castlegar Rotary Club	British Columbia Achievement Foundation
Trails Jays Baseball - Butler Park sign	Ktunaxa Nation Council
Creston Valley Blossom Festival Association	Osoyoos Indian Band - Four Host Nation Pavilion
Creston Valley Rotary Club	LKB 19th Annual Pow Wow
Village of Midway	National Aboriginal Business opportunities conference
Castlegar and District Chamber of Commerce	Okanagan Nation Alliance
Garrett Horbul Scholarship Golf Tournament	West Kootenay Wildcats Bantam female hockey team
Rossland Golden City Days	Kelowna Blackhawks Minor Hockey team
West Kootenay Branch of APEGBC	Campuinesse (FC) Soccer Club
Kaslo Loggers Sports	Kootenay Wildcats female major midget hockey team
Goat Style Mountain Bike Society	Nelson Neptune Swim Club
Bill Bennett Open	JL Crowe Grad 2010 class
Rossland Mountain Film Festival	Sunrise Rotary Club of Kelowna
Kootenay Robusters Dragon Boat Team	JL Crowe debate Club
Rossland Trail Minor Hockey	FortisBC dragon boat team
Trail Smokeeaters	West Kootenay Girls Softball
Salmo Minor Softball	Trail Girls Senior softball
Castlegar Hockey Society - Rebels	Kelowna Track & Field Club
Literacy Now	Beaver Valley Minor Baseball
Central Okanagan Economic Dev. Commission (Youth Ent. Program)	BC Girls softball Association
Kars under the K Show & Shine	Rossland Trail Country Club (Mel Simister Golf Classic)

Desert Sun Counselling and Resource Centre	Kelowna Minor Fastball Society
Osoyoos Desert Society	Trail Curling Association
Okanagan Similkameen Conservation Alliance - Meadowlark Festival	Boat for Hope, Children Variety Charity
Similkameen Sizzle	Trail Midget Rep
UBC Okanagan - Distinguished Leadership Gala	Osoyoos Lake Paddling Club
Naramata Community Garden	Habitat for Humanity - Kelowna
BC Cancer Foundation	Kootenay South Youth Soccer Association
Fairview Mountain Ladies Golf Night	White Water ski Team
Cops for kids bike ride	Scouts Canada 1st Beaver Valley Group
YMCA of the Central Okanagan	Castlegar Hospice Society
South Okanagan Concert Society	Rossland - Trail Peewee rep hockey team
Central Okanagan Heritage Society	Swingers Squash Club
Princeton & District Agricultural Fall Fair	West Kootenay Wildcats PeeWee female hockey team
Heavy Metal Rocks	BC Hospital Jeans Day
Kinsmen Club of Kelowna	BC Pond Hockey team
Town of Osoyoos	High School Scholarships
Rotary Club of Kelowna	UBC Okanagan - FortisBC Scholarship in Engineering
Central Okanagan Search & Rescue Society	President's Scholarship
City of Kelowna 36th annual Civic & Community Awards	Nelson & District Museum
Princeton Ground Search & Rescue Society	Village of Slocan
Princeton figure skating club	Central Okanagan Crime Stoppers
Central Okanagan Economic Dev. Commission (Youth Ent. Program)	Summerland Steam Hockey Club
2011	
2011 FortisBC Rotary Club of Kelowna Charity Golf Tournament	City of Kelowna 36th annual Civic & Community Awards
Okanagan College Foundation - Annual golf tournament	Penticton & Wine Country Chamber of Commerce
Wildsight	UBC O Student Association
Kootenay Family Place	Summerland Chamber of Commerce and Economic Development Excellence Awards
Rossland Winter Carnival	Fat Cat Children’s Festival Sponsorship
BC Cancer Foundation - Ride to conquer cancer	Kelowna Chamber of Commerce
Partners in Parenting	UBC Okanagan
KAST Luminous Sponsor	Kelowna Chamber of Commerce
West Kootenay Big Game Trophy Association	Kelowna Rockets
Beaver Valley May Days Society	Princeton Posse Junior Hockey Club
Lower Columbia Community Development Team	Princeton Curling Bonspiel
Village of Montrose	Osoyoos Coyotes Jr Hockey Club
Kaslo Trailblazers Society	Osoyoos Indian Band
Deer Park & Area Communication Society	Okanagan Nation Alliance
Greenwood Demolition Derby	Splatsin Community - Sturgeon Gathering

Rotary Club of Nelson	Penticton Indian Band
Kootenay Lake Hospital Foundation	Ktunaxa Nation Council
Monica Nissen - education program to Yaqan Nukiy School	Cayoose Creek Indian Band
Goat Style Mountain Bike Society	Princeton Community Arts Council
Castlegar & District Rec Dept - Kootenay Festival	Okanagan Indian Band
Garrett Horbul Scholarship Golf Tournament	LKB 20th Annual Pow Wow
LGMA - West Kootenay Chapter	Scouts Canada
Castlegar Rotary Club	Campuinesse (FC) Soccer Club
Creston Valley Blossom Festival Association	Kootenay Wildcats female major midget hockey team
Central Kootenay Invasive Plant Committee	Princess Margaret Secondary School
Rossland Golden City Days	Princeton Highland Dancers
West Kootenay Branch of APEGBC	S.O.M.H.A Team 2
Kaslo Loggers Sports	Westside Mixed Softball League
Columbia Brewery	Penticton Minor Baseball
KBRH Health Foundation Annual Golf Classic	Greater Trail Street Hockey League
South Okanagan Rehabilitation Centre for Owls	Trail Curling Association
Osoyoos Desert Society	Rutland Youth Soccer Association
Kars under the K Show & Shine	Trail Girls Senior softball
Kelowna 2011 Major Midget Tournament	Trail Girls Softball
Okanagan Similkameen Conservation Alliance - Meadowlark Festival	JL Crowe Dry Grad
Central Okanagan Economic Dev. Commission (Youth Ent. Program)	Rossland Trail Country Club (Mel Simister Golf Classic)
Osoyoos Elementary Green Team	West Kootenay Minor Lacrosse
Kabau Park, Cawston	Nelson Cycling Club - Fat Tire Festival
Similkameen Sizzle	Canadian Mental Health Association
South Okanagan Naturalists' Club	Penticton Golden Dragons
Oliver Communities in Bloom	BC Hospital Jeans Day
Fairview Mountain Ladies Golf Night	Vancouver Sun Run
Cops for kids bike ride	BC Pond Hockey team
Oliver Curling Club	BC Children's Hospital
Central Okanagan Search & Rescue Society	High School Scholarships
Princeton Ground Search & Rescue Society	President's Scholarship
UBCO Athletics Scholarship Breakfast	UBC Okanagan - FortisBC Scholarship in Engineering
Central Okanagan Crime Stoppers	
Forecast for 2012 and 2013	
Okanagan College Foundation - Annual golf tournament	Summerland Chamber of Commerce
Wildsight	Princeton Posse
Kootenay Family Place	Trail Smoke Eaters
Rossland Winter Carnival	Kelowna Rockets
KAST Luminous Sponsor	Kelowna YMCA

Beaver Valley May Days Society	Kars under the K Show & Shine
Lower Columbia Community Development Team	Okanagan Similkameen Conservation Alliance - Meadowlark Festival
Village of Montrose	Similkameen Sizzle
Kaslo Trailblazers Society	South Okanagan Naturalists' Club
Greenwood Demolition Derby	Oliver Communities in Bloom
Rotary Club of Nelson	Osoyoos Indian Band
Kootenay Lake Hospital Foundation	Okanagan Nation Alliance
Association of the Kootenay Boundary Local Government	Splatsin Community - Sturgeon Gathering
Southern Interior Local Government Association	Penticton Indian Band
Castlegar & District Rec Dept - Kootenay Festival	Ktunaxa Nation Council
LGMA - West Kootenay Chapter	Cayoose Creek Indian Band
Princeton Agricultural Fall Fair	Upper Similkameen Indian Band
Castlegar Rotary Club	Lower Similkameen Indian Band
Creston Valley Blossom Festival Association	Okanagan Indian Band
Central Kootenay Invasive Plant Committee	Lower Kootenay Band Annual Pow Wow
Summerland Exhibition Association	BC Hospital Jeans Day
Summerland Chamber of Commerce and Economic Development Excellence Awards	BC Children's Hospital
Rossland Golden City Days	High School Scholarships
West Kootenay Branch of APEGBC	President's Scholarship
Kaslo Loggers Sports	Fat Cat Children’s Festival Sponsorship
KBRH Health Foundation Annual Golf Classic	City of Kelowna annual Civic & Community Awards
South Okanagan Rehabilitation Centre for Owls	South Okanagan Concert Society
Kelowna Chamber of Commerce	Kelowna Rotary

FortisBC states that “the Community Investment Program was transitioned from the communications department to this department during 2010.”

52.7 Is the above statement intended to explain the FTE increase in 2011F or the non-labour increase in 2010? Provide the reconciliation to show the reduction of FTEs and associated costs in the Communications department and subsequent increase in FTEs and associated costs in the Community and Aboriginal Affairs department, as a result of this transition.

Response:

The statement is intended to explain a portion of the FTE increase, a budget adjustment was not made until 2011. The increase in 2010 was required to support First Nation capacity funding driven in part by BCUC consultation guidelines.

52.8 If not already identified in the response to the previous questions, explain why there is a substantial increase in non-labour costs in 2010? Is this related to the use of contractors, a result of the transition of the Community Investment Program or some other factor?

Response:

Please refer to the response to BCUC IR1 Q52.7 above.

52.9 How is this program different than the "community outreach initiatives" which is under the responsibility of the Communications department? Why is the Community Investment Program transitioned to the Community and Aboriginal Affairs department?

Response:

Community outreach initiatives refers to communication support for participation by various departments at corporate and community events. Community investment refers to the company's donations and sponsorship program.

Community Investment was transitioned to the Community and Aboriginal Affair department as its employees have direct interaction with the Aboriginal and non native communities.

53.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.10, pp. 66-68

Communications

53.1 Please provide general position descriptions for the 5 FTEs in this department.

Response:

The five FTEs in the department are responsible for work as follows:

- One manager FTE leads and manages the Company's Communications department, including personnel management (recruitment, performance management, coaching, termination), and strategic communications planning for employee communications, customer communications, advertising, public education and social marketing, media relations, website, social media, and community outreach initiatives.
- The four communications generalist FTEs are responsible for the following functions:

- Two FTEs for internal and external communications planning and delivery for projects and initiatives for all aspects of the business including new projects, power outage and emergency situations, operations and maintenance activities, rates and regulatory initiatives, safety, and environment; media relations, including serving as an emergency response communications contacts and media spokespeople; communications materials writing and production including newsletters, brochures, bill inserts, website/intranet content, annual report, advertising and other public materials to support key business communications needs.

- Two FTEs for internal and external communications planning and delivery for the PowerSense program; PowerSense media relations; PowerSense communications materials writing and production including newsletters, brochures, bill inserts, website/intranet content, annual report, advertising and other public materials to support key business communications needs.

53.2 Please explain why the 1.5FTE increase relating to PowerSense DSM is not charged to the DSM deferral account?

Response:

All costs related to the 1.5 FTE increase are charged to the DSM deferral account.

During 2011, the community investment program was transitioned from the communications department to the community and aboriginal affairs department, and the budget associated with employee events was transitioned to the human resources department." (pp. 67-68) [emphasis added]

53.3 On page 66 of Tab 4, FortisBC says that the community investment program was transitioned in 2010. Please confirm whether the transition took place in 2010 or 2011?

Response:

A portion of the labour component was transitioned in 2010. The community investment budget was transferred in 2011.

53.3.1 Why did the budget associated with the transition go to the human resources department and not into the community and aboriginal affairs department? Please clearly identify how many FTEs and its associated costs were transitioned from which department to which.

Response:

The budget associated with the community investment program transition went to the community and aboriginal affairs department. The 0.5 FTE and associated costs for the community investment program were transitioned from communications to community and aboriginal affairs.

The budget transitioned to the Human Resources department was the budget associated with employee events, with the exception of the communication materials budget for these events, which remained with Communications. A total of $88,000 was transferred from Corporate Communications to Human Resources to fund employee events which include: employee long service awards, surf and turf events and the annual holiday celebration – revenue from ticket sales for these two events is given to local charities annually. There were no FTEs associated with the transition of employee events to human resources.

53.4 Please explain the significant reduction in non-labour costs in the Communications department for 2011F.

Response:

The reduction in non-labour costs is due to the transfer of $88,000 to Human Resources for employee events and the transfer of $200,000 to Community and Aboriginal Affairs for community investment and sponsorship.

54.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.11, pp. 68-71

Human Resources

"Upgrades to the ADP Payroll system to ensure compliance with collective agreements and pension plans will be completed during 2011 resulting in an increase to O&M Expense in 2012."

54.1 Please explain the relevance of the above while the significant increase in 2012F is under "labour." Is it suggested that the increased personnel would be required to run this new system?

<u>Response:</u>

No increase in personnel is required to run the upgraded ADP payroll system. The following summarizes the drivers for the changes in Human Resources Department O&M 2011 to 2012 year over year:

- In 2012, there is $30,000 less in labour expenses charged to capital (credited to HR O&M), due to reduced capital project work requiring HR labour time in 2012; and
- In addition, the shared service charges associated with the Chief Human Resources Officer position (gas/electric) which was created in late 2010 amounts to approximately $80,000 per annum and was classified as consulting services (Non-Labour) in error in 2011. This error is corrected by assigning the $80,000 shared service charge to "labour" in the 2012 budget forecast. This is why there appears to be a substantial difference in labour from 2011-2012; it is due to a classification change only (the total O&M expenditure as indicated by the HR O&M Cost Summary Chart increases by a total of $50,000 from 2011 to 2012).

The below table provides the details in thousands with comments:

Table BCUC IR1 54.1 HR O&M Summary

	2011	2012	Change	Comments
	($000s)			
Regular (gross loaded)	1,494	1,518	24	Mainly due to 3 precent salary increase
Labour to capital/labour charged out	(197)	(107)	90	$30,000 reduction is due to less labour charged to capital in 2012 as the ADP upgrade should be complete by the end of 2011; the CHRO cross charge is applied here in 2012
TOTAL LABOUR	1,297	1,411	114	Due to Chief Human Resources Officer (CHRO for Gas/Electric) cross charge into electric which is noted as a labour expense in 2012, but was noted as non-labour in 2011 (in error). The remaining gross labour differential is mainly due to the forecast 3 percent salary increase
Professional fees (legal)	50	50	-	
Consultants	82	9	(73)	Mainly due to the CHRO salary applied here in 2011 in error
Contractors	51	62	11	Difference in ADP licensing as a result of the upgrade
Materials	1	1	-	
Staff Expenses	57	52	(5)	
Vehicle	2	2	-	
Office	34	34	-	
Training	271	272	1	
Employee Recognition	90	93	3	
HR allocation	(25)	(26)	(1)	
Admin Absorption Loading	(124)	(124)	-	
Other	3	4	1	
TOTAL NON LABOUR	492	429	(63)	Mainly due to the CHRO salary being included in labour in 2012, non-labour in 2011
TOTAL O&M VARIANCE	1,789	1,840	51	

54.2 Please explain the 50% increase in non-labour costs for 2011F?

Response:

Please refer to the response to BCUC IR1 Q54.1.

FortisBC says "…1.5 FTEs were transferred in from Health, Safety and Environment to focus on compliance training."

54.3 Please explain why there isn't a corresponding decrease of 1.5 FTEs in the HS&E department between 2007 and 2008.

Response:

Costs for Compliance Training had been allocated to a separate cost centre prior to the transfer of this function to HR. The compliance training cost centre became part of the roll up of HR costs after the transfer. This is why there was no corresponding reduction in Health, Safety and Environment of either FTEs and/or costs associated with the transfer.

55.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.12, pp. 71-74

Information Systems

55.1 Table 4.3.4.12 indicates an increase of 6 FTEs between 2007 to 2013F, yet the Labour and non-labour costs are relatively at the same level. Please explain these observations. (Has there been a large increase of in personnel or replacement with staff at the junior level?)

Response:

The FTE count in Table 4.3.4.12 (Tab 4, page 72 of the 2012-13 RRA) for 2012 and 2013 mistakenly included vacant positions, and are not intended to be filled in those years. The actual headcount for 2012 and 2013 is 26 FTEs. Overtime is also expected to be lower due to more mature systems and processes. The vacant positions were left in the system and showed up on the resulting report included in the 2012-13 Revenue Requirements. Please refer to Errata 2 for a corrected Table 4.3.4.12.

55.2 Provide a breakdown of costs that are included in the non-labour category.

Response:

Table BCUC IR1 55.2

Expense Description	2007A	2008A	2009A	2010A	2011F	2012F	2013F
Staff Expenses - primarily travel other than training	128	99	82	48	38	31	34
Telecom - including Telus managed network costs	434	383	387	407	423	420	426
Training Expenses - includes all associated costs for training	62	63	97	64	87	82	82
Printing Costs	118	154	152	176	129	138	139
Vendor Support and Maintenance	652	594	609	555	614	639	678
IT Allocation - transfer from capital	-53	-53	-54	-53	-52	-53	-54
Administrative Absorption - Third party compensation	-103	-76	-73	-75	-81	-80	-80
Total Non-Labour Expenses	**$1,238**	**$1,164**	**$1,200**	**$1,122**	**$1,158**	**$1,177**	**$1,225**

**Note that in 2009 employee expenses specific to training began being tracked separately and are included in Training Expenses from 2009 forward.*

55.3 There appears to have been some FTE fluctuations in the IT department during the past 5 years. Please explain the 4 FTE increase between 2007 and 2009 then the 3 FTE decrease in 2010 only to have another 2 FTE increase from 2010 onwards. Describe the activities and changes in department responsibilities during this period which would contribute to the fluctuation of staff.

Response:

The fluctuation from 2007 to 2009 was due to the increased requirements to support the organization technology requirements. This included increased technical support and the addition of Business Analysts in the group. The business analyst role is to link business areas to technologies to help ensure that business needs are represented and value and efficiency is realized from technology.

In 2010 the Business Analyst roles were transitioned into their respective business areas. This included customer service and operations.

Please refer to the response to BCUC IR1 Q55.1 for 2012 and 2013.

On page 73-74, FortisBC describes various cost controls and initiatives observed in the IT department. For example:

- $0.023 million was saved annually on the total cellular costs
- printing costs have been reduced by over 50 percent
- New technologies…Remote control and management tools…reducing travel time
- reduced physical server requirements by approximately 10 to 1,… reduced and mitigated annual energy consumption by approximately 150 kW, or approximately $0.1 million annually, consequently reducing cooling requirements
- Desktop virtualization…reduces processing requirements at the desktop level, thus extending the life of older units and reducing the costs of replacement laptops and desktops…

55.4 Can it be assumed that these savings are permanent, annual cost savings to various areas of business?

Response:

Yes, the savings identified are permanent and have been embedded in the operating budget.

55.5 Please identify the projects and related cost savings and business areas that FortisBC anticipates during 2012 and 2013 that would result from IT influenced efficiencies.

Response:

Please refer to the responses to BCUC IR1 Q166.1 and Q167.1

Desktop virtualization and improved mobility capabilities is delivering more information and systems to field workers. Enhancements to mobile tools enable field employees to collect and update electronic information while in the field, which in turn increases their field working time. This allows the Company to deliver a continued high level of service to a growing number of customers while mitigating staffing increases. It also improves the access to equipment and procedural information benefiting safety in the field.

Upgrades to applications, programming languages, databases and infrastructure have mitigated the need to fill 2 vacant positions in the Information Systems department (see response BCUC IR1 Q55.1) due to the more efficient environments.

56.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.12, p. 71

Information Systems - Business Responsibilities

FortisBC states that "The total value of all assets that the IS department is responsible for is approximately $62 million, which also includes operational technology such as System Control and Data Acquisition (SCADA), data historian and maintenance management systems." (Tab 4, p. 71)

56.1 Please provide a list of all operational technology that the IS department is responsible for.

Response:

The IS department has responsibility for the following operational Technologies:

Table BCUC IR1 56.1

Infrastructure Description	**Qty**
VHF Radio Recording System	1
Cisco Catalyst 3560 switches	4
Firewalls	44
ICCP Router	1
HP G series servers	5
Operator workstations	9
HMI systems – ruggedized PCs	40
Application Description	
Survalent Worldview SCADA	
CROW - Permit Requesting Software	
Power Purchase Interchange Log Sheet	
Quality Training Systems - Tracking SCC training requirements	
Digital Inspections Cascade - Computerized Maintenance Management System	
Schneider Electric ION Enterprise Power Monitoring	
Aspen Oneliner Network Modeling	
Aspen Relay Database	
Schweitzer Relay Software	
InStep eDNA Data Historian	

This does not include some Mandatory Reliability Standards specific equipment, such as intrusion detection equipment.

56.2 Is the IS department responsible for off-line simulation technology? If so, please explain the safeguards in place to prevent live system operation of equipment when using off-line simulation technology and the safeguards to prevent non-operations staff from accessing on-line modes of operation.

Response:

FortisBC does not have any off-line simulation technology in regard to SCADA or any other electrical network control technology.

56.3 Provide a separate cost breakout for the operation technology costs similar to table 4.3.4.12.

Response:

Costs to support operational technologies is not tracked separately, as it would be time consuming and difficult to manage. Operation technologies integrate with corporate technologies at many points and trying to discern what technology is specifically being supported is not practical.

57.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.13, pp. 74-78

Health Safety and Environment

FortisBC states that “Increasing resources are continually required to measure, monitor, and reporting PCB removal or releases.”

57.1 What are the resources, namely, # FTEs and associated costs, that are required to measure, monitor and report on PCB issues.

Response:

The existing PCB activities are overseen by several departments in the Company. The Environmental group’s activities with respect to PCB issues are managed by the two existing Environmental Affairs staff members; the requirements of the Amended PCB Regulation require that a further resource be retained to assist in this area. This resource would assist the Operations and Projects departments in the ongoing testing, monitoring and reporting that is related to oil filled equipment or assets.

57.2 Are there any efficiencies or tools in the IT department that could assist with PCB identification and measurement?

Response:

Currently the ESRI ArcFM GIS technology is being used to support the planning, inventory, tracking and reporting of all equipment with regard to PCB related information. The mobile GIS tool has been used to capture detailed information on the equipment during PCB sampling programs. The GIS system contains a large amount of information from the PCB sampling program, as well as information captured from operations. This includes equipment nameplate data, as it relates to PCB information, PCB sampling information, such as when sampling occurred and what equipment has been sampled, the results of laboratory PCB test results and the equipment that poses no PCB risk.

This information is made available throughout the organization through a variety of technologies and reports both in the office and in the field. Users throughout the organization may look at any in-service equipment and determine the PCB content and related detail for a wide variety of operational needs. This includes planning around management of equipment as it relates to PCB management, such as planning and coordination for the management of equipment, reporting on the PCB information and sample results for specific equipment for purposes of transportation or spill response and locations of equipment.

“Wages have increased an average of three percent annually over the past five years.”

57.3 Between 2007 and 2009, when the number of FTE stayed constant at 6, labour costs increased 8% in 2008 then another 5% in 2008. These figures appear to be substantially higher than the 3.5% average labour inflation shown in Table 4.3.2.1 for the same period. Please explain why.

Response:

Health, Safety and Environment labour rates appear higher than the average 3.5 percent increase due to individual changes in personnel job position and their pay rates. A student position transitioned to a permanent position at a higher wage rate and continued to increase with collective agreement salary progression between 2007 and 2009.

57.4 Between 2011F and 2013F, the number of FTEs is forecast to be constant at 8, but labour costs are forecast to increase 4.2% and another 4.8%. These figures appear to be higher than the average labour inflation forecast for the same period. Please explain why.

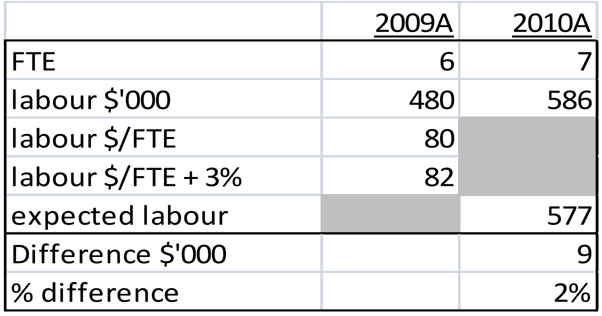
Response:

The increased labour costs forecast between 2011 and 2013 are influenced by:

- the average labour rate increase
- additional increase due to a reduction in Health, Safety and Environment department labour charged to capital works.

The nature of capital work in the Health, Safety and Environment section is expected to change and the labour charged by the Health, Safety and Environment department to capital works is projected to decrease. The reduction of direct Health, Safety and Environment department charges to capital works will appear as an increment in operational spending.

57.5 With the incremental increase of 1 FTE in each of 2010 and 2011 and factoring in a 3% wage inflation, total labour costs appeared to be 2% higher than expected in 2010. Please explain why? (supporting calculations shown in the interactive excel insert below)



	2009A	2010A
FTE	6	7
labour $'000	480	586
labour $/FTE	80	▨
labour $/FTE + 3%	82	▨
expected labour	▨	577
Difference $'000		9
% difference		2%

Response:

In 2010, the wages noted in the above table appear to be slightly higher than the average increase as a result of costs paid due to the person in the junior environment position leaving the Company and the hiring of a senior environment position at a higher wage.

57.6 Previously, on page71, FortisBC says "…1.5 FTEs were transferred in from Health, Safety and Environment to focus on compliance training" during 2007 and 2008. However, Table 4.3.4.13 shows that the number of FTEs remained constant in the HS&E department during the same period. Please explain why.

Response:

The Training Department resources were budgeted separate from the HS&E department. The transfer from HS&E was a reporting function only.

58.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.14, pp. 78-80

Facilities Management

58.1 Provide a breakdown of the non-labour costs shown in Table 4.3.4.14 (contractor costs, lease costs, other?)

Response:

Listed below is the breakdown of the Non-Labour costs show in Table 4.3.4.14. The 2013F for rent has been revised to reflect the O&M cost savings for the expiry of the Kelowna Enterprise Lease.

Table BCUC IR1 58.1

Facilities Management O&M Cost Summary (2011 - 2013)

2011	2012	2013	Expense Type
408,000	408,000	416,000	Contractor Services
530,000	530,000	542,000	Cleaning & Security
60,000	60,000	60,000	Material
13,421	22,500	20,200	Empl Exp Site Travel, Training
110,000	105,000	100,000	Off Exp: Stationery
45,000	45,000	45,000	Off Exp: Postage
206,000	199,000	209,000	Off Exp: Building Operations
25,000	25,000	25,000	Office Expense: Telecom
45,000	45,000	45,000	Other Expense: Freight
1,755,000	1,755,000	1,505,000	Other Expense: Rent
3,197,421	**3,194,500**	**2,967,200**	**Total**

58.2 The labour cost increase in 2012F is approximately 16%, please explain how much of this is related to increased cyclical maintenance work and how much is related to labour inflation?

Response:

The labour rate is escalated by 3 percent in 2012. The remainder of this increase is related to increased cyclical maintenance work.

58.3 Please explain the FTE increase from 4.5 to 7 from 2008 to 2009. Similarly, please explain the FTE decrease from 7 to 5 from 2010 to 2012.

Response:

The FTE increases in 2008 to 2009 from 4.5 to 7 were a result of the following:

- Facilities Management initially had a 0.5 FTE position to complete mail services for the Trail Office. This 0.5 was increased to 1 FTE as a result of first aid attendant duties added to this role. Previously, first aid attendant coverage was being provided by a contractor. First Aid coverage is mandatory to comply with WorkSafe BC OHS Regulation 3.16. By providing this function internally, it has reduced the requirement and cost for a full time contractor to be on the site; and
- The 2 FTE positions of Reception/Mail Service for the Springfield location were transferred from Finance to Facilities.

The FTE decreases in 2010 to 2012 from 7 to 5 were a result of the following:

- The 2 FTE position of Reception/Mail Service for the Springfield location were transferred from Facilities to Customer Service.

58.4 Please explain Service Contracts. Who are they for and for what kind of work?

Response:

Service Contracts are formal agreements covering services rendered based on a defined scope and at an agreed price for a specific amount of time. Facilities requires service contracts with various vendors to provide services not provided by FortisBC employees. Examples of services contracted for FortisBC buildings are security, janitorial, window washing, HVAC, snow removal, roof maintenance and equipment services. These services are required to deliver a suitable work environment for the Company's employees in safe and efficient buildings.

59.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.15, pp. 80-85

Finance and Accounting

59.1 Please provide a breakdown of Table 4.3.4.15 showing separate FTEs and associated costs for each of 3 areas of responsibility (Budgeting and Forecasting, Financial Reporting and Treasury, Accounting and Financial Systems). Also show a breakdown of the non-labour cost (consulting, contractor, bank charges).

Response:

Please refer to Table BCUC IR1 59.1.

Table BCUC IR1 59.1

		2007A	2008A	2009A	2010A	2011F	2012F	2013F
	Budgeting and Forecasting							
1.0	Full Time Equivalents	4	4	3	3	3	3	3
2.0	Expenses							
2.1	Labour	525	340	407	422	445	434	450
2.2	Contracted Manpower	(52)	-	-	2	2	37	46
	Other	22	(43)	(22)	(37)	(20)	(21)	(24)
2.2	Non-Labour	(30)	(43)	(22)	(35)	(18)	16	22
	Subtotal O&M Expenditure	495	297	385	387	427	450	472
	Financial Reporting and Treasury							
1.0	Full Time Equivalents	4	4	4	4	5	5	5
2.0	Expenses							
2.1	Labour	574	569	536	499	735	773	787
2.2	Consultants	309	299	333	365	401	513	532
	Bank Charges	140	139	104	131	108	111	115
	Other	47	34	40	92	62	47	48
2.2	Non-Labour	496	472	478	589	571	672	695
	Subtotal O&M Expenditure	1,070	1,042	1,014	1,087	1,305	1,444	1,482
	Accounting and Financial Systems							
1.0	Full Time Equivalents	12	11	11	11	11	11	11
2.0	Expenses							
2.1	Labour	967	989	922	1,038	1,126	1,137	1,161
2.2	Contracted Manpower	424	263	264	271	290	422	431
	Other	(87)	(109)	(117)	(167)	(57)	(178)	(186)
2.2	Non-Labour	337	154	147	104	233	244	245
	Subtotal O&M Expenditure	1,304	1,143	1,069	1,142	1,359	1,381	1,406
	TOTAL FULL TIME EQUIVALENTS	20	19	18	18	19	19	19
	TOTAL LABOUR	2,066	1,899	1,866	1,959	2,305	2,343	2,398
	TOTAL NON LABOUR	803	583	603	658	787	932	962
	TOTAL O&M EXPENDITURE	2,869	2,482	2,469	2,617	3,092	3,275	3,360

59.2 What area of responsibility does internal audit/control fall under?

Response:

Internal Audit reports administratively to the Vice President, General Counsel and Corporate Secretary and functionally to the Audit Committee of the Board of Directors.

59.3 What additional internal control and reporting is required under the adoption to US GAAP? Has this been factored into the departments forecast cost for the test period?

Response:

Under the adoption of US GAAP, the Company's Finance and Accounting departments will be required to update and maintain additional internal control narratives and financial accounting reconciliations relating to the new accounting differences under US GAAP that did not previously exist under pre-changeover Canadian GAAP. The incremental time and effort to update the internal control processes and financial reporting reconciliations, including the changes associated with employee future benefits and the Brilliant Power Purchase Agreement capital lease, have been considered as part of the process for forecasting 2012 and 2013 Finance and Accounting O&M Expenses.

Beyond the incremental internal control and reporting requirements, the forecast 2012 and 2013 Finance and Accounting O&M expenses include the annual audit and quarterly review fees to be conducted by external auditors.

It should also be noted that if a Canadian entity adopts US GAAP by way of becoming a Securities and Exchange Commission Issuer ("SEC Issuer" as defined under the Canadian reporting rules), it would be necessary to incur costs related to SOX 404 attestation. These ongoing costs would be incurred by the entity to engage an external independent audit firm to provide an opinion on internal controls over financial reporting. Upon adoption of US GAAP, FortisBC is not required to incur the SOX 404 attestation expenses in 2012 and 2013 because on June 9, 2011, the Ontario Securities Commission (OSC) issued its Decision on the Company's Exemption application, granting the relief sought for the financial years commencing on or after January 1, 2012 but before January 1, 2015. As a result of receiving the OSC exemption, the forecast 2012 and 2013 Finance and Accounting O&M expenses have appropriately excluded any expenses related to SOX 404 attestation expenses. Should the Company ever be required or choose to become an SEC issuer, it would be necessary to incur SOX 404 attestation expenses at that time.

59.4 The number of FTE's show in the years shown in Table 4.3.4.15 have been relatively stable yet the labour costs have increase approximately 16% from 2007 to 2013F. Is this an indication that the staff in this department are receiving significant wage increases or working substantial overtime? What other reasons are there for this observation?

Response:

The geometric mean of the increase in labour costs is 2.5 percent per year, which is a reasonable cost escalation over a six-year period.

The Finance and Accounting department does work substantial overtime, however this overtime is worked primarily by those employees who are paid an annual salary and are not compensated for overtime.

The overtime that is paid to hourly employees is relatively consistent from year to year and is primarily related to month-end, quarter-end and year-end reporting deadlines.

59.5 There appears to be a substantial increase in labour costs from 2010 to 2011A, even factoring the 1 FTE increase. Please describe the activities in this area that would contribute to the increase during this period.

Response:

The Increase in labour costs between 2010A and 2011F is primarily due to the following:

1. increases in employee future benefit costs;
2. inflation of labour costs;
3. reorganization of one position that had been shared 50 percent with another department became 100 percent in Finance; and
4. labour costs associated with one FTE, which was previously charged out to a project as part of the transition to IFRS (International Financial Reporting Standards) in 2010, have been reallocated to the Finance and Accounting O&M expenses for 2011 due to ongoing accounting requirements and the termination of the transition to IFRS at the end of 2010.

59.6 Given that the majority of FortisBC's capital work is near completion, would there be an expectation for less debt issuance in the test period and hence resulting in lower bank charges?

Response:

Bank charges included in O&M Expenses consist of the bank service fee expenses relating to bank transfers, wire payments, Internet banking services, lockbox payment services, remittance investigations and other daily banking services and are expected to increase by 2 percent during each of the years in the test period (2012 and 2013). The forecast of approximately $0.1 million per year is generally consistent with the 2011 bank charges.

Debt issuance expense is included in Cost of Debt (Tab, section 4.7 of the 2012-13 RRA).

While there may be less debt forecast to be issued during the test period (2012 and 2013) as compared to 2009 and 2010, there is still the BCUC approved capital structure requirement to finance 60 percent of the Company's rate base with debt. The bank charges included in the forecast 2012 and 2013 Finance and Accounting O&M expenses are not related to the costs associated with issuing debt during the test period and therefore are not expected to decrease.

While certain of FortisBC's capital work is currently nearing completion, capital expenditures of $105.86 million are forecast in 2012 and $129.08 million are forecast in 2013, as described in the 2012-2013 Capital Expenditure Plan (Tab 6 of the 2012-13 RRA). These capital expenditures are to be financed with a deemed capital structure of 60 percent debt and 40 percent equity as approved pursuant to Commission Order G-58-06. In addition, the Company has $15.0 million in Secured Debentures due for redemption on October 16, 2012. These investing requirements for the 2012 and 2013 capital expenditures and the 2012 debt maturity are expected to be financed with a combination of funds from operations, debt issuances by way of draws on the Company's $150 million operating credit facility and a forecast long-term debt issuance in the last half of 2013 in the amount of $120.0 million.

Debt drawn on the Company's $150 million operating credit facility incurs interest related to Bankers' Acceptances or Prime loans, as well as standby fees and banking agreement charges. These operating credit facility interest expenses are not included in the forecast 2012 and 2013 Finance and Accounting O&M expenses, rather they are included in short-term debt interest expense as part of Table 4.7.1-2 Weighted Average Cost of Debt (2012-2013) (Tab 4, page 120 of the 2012-13 RRA).

The proceeds on the forecast long-term debenture to be issued in the last half of 2013 will be used to repay the operating credit facilities as the draws approach approximately $100 million. The interest on the proposed long-term debenture issuance and the associated issuance costs are not included in the forecast 2012 and 2013 Finance and Accounting O&M expenses. The interest incurred on the debentures will be included as part of the long-term debt interest expense for Series 2013 as part of Table 4.7.1-2 Weighted Average Cost of Debt (2012-2013). The costs incurred to issue the debentures, as described in Table 5.4.5-7 Forecast Debt Issue Costs (Tab 5, page 37 of the 2012-13 RRA), are comprised primarily of dealers and professional fees and are included as deferred charges in rate base as described in subsection 5.4.5.xxi – Deferred Debt Issue Costs in Tab 5 of the 2012-13 RRA.

60.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.16, pp. 85-87

Transportation Services

60.1 Please provide a breakdown of the non-labour expenditures in Table 4.3.4.16 (lease, fuel, contract, other?) Provide detailed explanations for the 9% increase in 2011F.

Response:

Almost two-thirds of the projected variance in Non-Labour Expenses in 2011F is due to the increase in fuel costs of $0.173 million. The balance of the increase is due to an increase in forecast Maintenance costs of $0.055 million, additional Telecommunication costs of $0.064 million associated with Automated Vehicle Location (AVL) Technology and a rise in Office and Other Expenses of $0.027 million due to increases in Clothing, Small Tools and Freight costs. A detailed breakdown is provided in Table BCUC IR1 60.1 below.

Table BCUC IR1 60.1

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
	($000s)						
Fuel	1,029	1,185	853	887	1,060	1,176	1,194
Tires	151	121	125	157	103	99	99
Lease	1,047	972	801	804	795	858	858
Maintenance	958	972	891	850	905	866	881
Telecommunications	7	8	8	6	70	114	114
Insurance Expense	144	134	92	121	140	138	138
Staff Expenses	88	85	80	81	96	67	69
Training Expenses	7	7	13	26	11	12	12
Office and Other Expenses	60	63	54	62	89	78	88
Total Non-Labour Expenses	**3,491**	**3,547**	**2,917**	**2,994**	**3,269**	**3,408**	**3,453**

> "FortisBC outsources some of the routine and minor maintenance work on service trucks and automobiles as well as all body work and painting."

60.2 What is the ratio of total maintenance work that is outsourced versus done in-house? Please discuss the advantages and disadvantages of outsourcing all of the maintenance work.

Response:

An estimated 25 percent of maintenance work is outsourced versus 75 percent done in-house. The Company is of the opinion that outsourcing of the maintenance work is appropriate on the smaller non-specialized units where the work is routine or minor in nature, or when the facilities, tools and/or manpower is not readily available such as in body shop and painting repairs.

The Company is of the opinion that it is not appropriate to outsource maintenance work on large and/or specialized vehicles and equipment such as aerial devices or vehicles used in live-line work. Employee safety is crucial and the knowledge, training and fleet experience associated with specialized vehicles and equipment is best managed in-house.

60.3 The number of FTEs appear to be high given the size of FortisBC operations. Provide a comparison of fleet and FTEs in the transportation department for other utilities in BC.

Response:

The number of FTEs is a function of the amount of outsourcing done by each utility. Both FEI and Pacific Northern Gas Ltd. (PNG) outsource all service and maintenance. BC Hydro outsources approximately 70 percent. FortisBC currently outsources about 25 percent.

Table BCUC IR1 60.3

Utility	Fleet size	% Units Serviced In-House	FTEs	Number of vehicles serviced per FTE
FortisBC	350	75% (263)	14	18.8
BC Hydro	3080	30% (924)	95	9.7
FEI	840	0% (0)	3	n/a
PNG	181	0% (0)	1	n/a

"FortisBC continues to evaluate and monitor new green vehicle technologies. In concert with FEI, FortisBC is also currently investigating the economics of using natural gas powered vehicles."

60.4 Please discuss the investigative findings to date (in confidence if required) and describe any plans for the future regarding the use of NGVs.

Response:

FEI began to convert field and Manager Vehicles to run on both gasoline and natural gas about two years ago. The conversions concentrated on the Ford E-350 service van, Ford F-150, Chrysler Caravan and the Dodge Dakota product line. The converted vehicles currently in operation will run primarily on natural gas when available and switch to gasoline when the natural gas runs out. A quality, emissions and drivability evaluation was conducted prior to the conversions to ensure the highest level driveability and reliability and the lowest level of emissions. There is an ongoing monitoring of performance and non-traditional operational issues. To date there have been no significant issues logged. Some of the preliminary findings are as follows:

- Converted vehicles (NGVs) running on Natural Gas exhibit smoother idling characteristics and significantly lower idling emissions;
- NGVs have experienced minimal power-loss (not more than 7%);
- NGVs transition from NG to gasoline is automatic, smooth and “on the fly”;
- There have been no significant maintenance issues to date as a result of the conversion and the consumption of Natural Gas; and
- Economically Natural Gas is significantly less expensive than running the same vehicle on gasoline. For example: a F-150 running on Natural Gas (mixed city and highway kms) consumes an average of $0.105 per km, on Gasoline (same conditions) it consumes $0.153 per km.

As natural gas pumping infrastructure is put into place within the FortisBC service territory, FortisBC will also be able to leverage this resource to lessen the impact of conventionally powered vehicles on the environment.

60.5 Given that the majority of FortisBC’s capital work is near completion, should there be a lower charge out to capital in the test period (Recoveries)? Please discuss why or why not?

Response:

As presented in Table 4.4-3, Tab 4, Page 103 of the 2012-13 RRA, capital expenditures over the test period are expected to average approximately $117.8 million as compared to about $121.0 million over the last five years. The Company therefore expects the vehicle charges to capital to remain at current levels. In addition, fuel prices are expected to continue to put upward pressure on charge out rates.

60.6 On page 73 (in the IT section), FortisBC explains that there are "New technologies…Remote control and management tools…" in the IT department that have contributed to reducing travel time. As such, please quantify the fuel savings, employee hours, lower maintenance that would have resulted in this efficiency.

Response:

The travel time identified in this section is referring to personal vehicle use and Company vehicle use. The annual budget for personal vehicle use has been reduced from $24,000 in 2007 to $4,000 in 2012. The distance traveled in Company owned vehicles by the IT department has been reduced from 31,630 km in 2007 to 13,147 in 2010. The resulting savings for Company vehicles costs is approximately $3,600 annually compared to 2007.

Overtime costs alleviated through the described management tools are approximately $2,000 per year; however this does not include the productivity benefits due to less system downtime. With the new monitoring and management tools that have been implemented, and continue to be enhanced, system issues are recognized earlier and downtime is shortened or avoided altogether due to early warning systems.

61.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.17, pp. 87-90

Supply Chain Management

61.1 Provide a breakdown of the FTEs and associated costs in Table 4.3.4.17 into the two departments of Purchasing and Contracts and Material Services. Include a breakdown of the non-labour costs.

Response:

Please refer to the below table.

1 **Table BCUC IR1 61.1**

	Purchasing and Contracts	**2007A**	**2008A**	**2009A**	**2010A**	**2011F**	**2012F**	**2013F**
1.0	Full Time Equivalents	7	7	11	11	11	9	9
		($000s)						
2.0	Expenses							
2.1	Labour	509	636	293	465	492	463	471
	Staff Expenses	36	28	14	17	35	35	35
	Office Expenses	24	21	8	8	13	13	13
	Training Expenses	4	11	10	2	12	12	12
	Other	38	3	77	11	5	2	2
	Allocations to Other Dept	(31)	(35)	(19)	(25)	(30)	(26)	(27)
2.2	Non-Labour	71	28	91	13	34	35	35
	Subtotal O&M Expenditure	580	664	384	478	526	498	505
	Material Services	**2007A**	**2008A**	**2009A**	**2010A**	**2011F**	**2012F**	**2013F**
1.0	Full Time Equivalents	14	16	14.5	15	16	15	15
		($000s)						
2.0	Expenses							
2.1	Labour	1,251	1,358	1,316	1,385	1,491	1,544	1,534
	Materials & Material Recoveries	423	(227)	500	13	57	57	57
	Staff Expenses	24	23	16	22	23	23	21
	Office Expenses	35	40	40	35	38	35	35
	Freight and Other	405	215	128	164	169	169	169
	Allocations to Other Dept	(81)	100	(135)	(166)	-	-	-
2.2	Non-Labour	807	150	548	67	287	284	283
	Subtotal O&M Expenditure	2,058	1,508	1,865	1,452	1,777	1,828	1,817
TOTAL FULL TIME EQUIVALENTS		21	23	25.5	26	27	24	24
TOTAL LABOUR		1,761	1,993	1,609	1,850	1,983	2,008	2,005
TOTAL NON LABOUR		878	178	639	80	320	319	317
TOTAL O&M EXPENDITURE		2,638	2,172	2,249	1,930	2,303	2,327	2,322
RECOVERIES		(2,114)	(1,508)	(1,865)	(1,452)	(1,753)	(1,828)	(1,817)
NET O&M EXPENDITURE		524	664	384	478	550	498	505

> "Unlike the 2007 -2011 period, spending in 2012 and 2013 is expected to focus more on capital sustainment, with fewer large capital projects."

61.2 Why, then, are there more charge outs to capital projects (recoveries) in the test period than in the years 2008 – 2010?

Response:

Supply Chain Management includes two departments; (i) Purchasing & Contracts and (ii) Material Services. The Recoveries are a Materials Handling Charge that is applied to the cost of every item issued out of inventory in order to recover the cost of operating the Material Services department. When Material Services employees work on large capital projects, they charge their time directly to the actual project thereby reducing the cost to be recovered by the Material Handling Charge. The type of projects and the associated Material Services support varies from year to year. Fewer large capital projects will mean less direct charges to projects and higher recoveries through the Material Handling Charge.

61.3 As capital project work was winding down in 2011, why was there a need to add another FTE to this department?

Response:

As presented in Table 4.4-3, Tab 4, Page 103 of the 2012-13 RRA, capital expenditures in 2011 were lower than in the previous years, but over the test period are expected to average approximately $117.8 million as compared to about $121.0 million over the last five years.

The Company completed a project in 2010 to introduce Service Purchase Orders within the purchasing module of SAP in order to capture service work being contracted out. In order to manage the work load during the learning curve a temporary Buyer was hired for 2011. The Company does not expect to extend the term of that temporary position beyond 2011.

61.4 Shouldn't FTEs in this department for the test period be closer to the 2007 level?

Response:

The Company had been utilizing transportation companies to deliver materials to the District Stores. In late 2007 the Company determined that it would be more cost effective if Material Services were to provide the service since Material Services was visiting the Districts to pick up scrap and other equipment that had been removed from service. Two warehouse employees were added to the Material Services department and tasked with:

- Receiving District materials in SAP and stocking shelves;
- Delivering materials to the Districts (reducing the need for third party carriers);
- Changing stock numbers on shelves when material numbers change;
- Weekly cycle counts;
- Managing yards, including removal of PCB transformers;
- Pick up of leftover materials to be returned to main warehouses; and
- Managing consumable materials (nuts, bolts, etc).

The Company also hired an SAP Materials Management Business Analyst to provide support in the roll out of various Supply Chain Management initiatives. Adjusting for those three positions, the FTE count is equal to the 2007 level and lower than the FTE counts in each of the years 2009 through 2011.

On page 90, FortisBC states that the Company is utilizing consignment inventory where the vendor supplies “safety stock” transformers that are <u>inventoried at FortisBC sites</u>.

FortisBC then states that the “Company is also investigating the use of vendor managed inventory for some times of stock items in order to <u>reduce the Company’s warehousing requirements</u>.”

61.5 The two statements above appear to be providing a contradictory view of warehousing requirements and costs. Please discuss.

<u>Response:</u>

The two statements were made in reference to “Management of Cost and Efficiency” and are not in conflict.

In the first case, the Company has been able to reduce the cost of carrying safety stock by not having to pay for the transformer until it is actually used. By definition, safety stock is stock that is stored as close as necessary or practicable to where it may be required in the event of an emergency. So it is necessary to inventory that type of material and equipment throughout the service territory.

In the second case, the Company is attempting to reduce the amount of stock inventoried by the Company (outside of safety stock and other stock necessary for daily operations) by requesting vendors to hold inventory for the Company’s use.

Both initiatives will serve to reduce cost to the Company.

FortisBC states that there is an "application of bar coding technology in order to receive, manage and track inventory more efficiently and with minimal data entry."

61.6 Please explain what type of fixed assets tracking system was used prior to the bar coding. What staffing and cost savings are expected in the test period?

Response:

Bar coding technology is not being used by the Company today. At page 90 of Tab 4 of the 2012-13 RRA, the Company states that it is exploring bar coding technology.

Currently, the Company relies on manual data entry of material receipts and issues in the Materials Management module of SAP.

62.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.3.4.18, pp. 90-100

Corporate and Executive Management

"Currently, the cross charges to and from FEI include a fully loaded wage plus an overhead charge of 5.5 percent." (p. 91)

62.1 Please explain the overhead charge of 5.5% for cross charges to/from FEI. What is included in the overhead charge?

Response:

The 5.5 percent overhead charge is taken from the Company's approved Transfer Pricing Policy and is a recovery of General and Administrative costs incurred in the provision of the services to FEI.

The allocation for General and Administrative overhead includes but is not limited to the following incidental costs:

- Clerical support;
- Office supplies;
- Buildings and related building services;
- Phone equipment;
- Human resource support;
- Accounting and financial support;
- Legal support;
- Information systems;
- Office equipment;
- Small tools and equipment;
- Training;
- Work order system;
- Communications;

- Marketing services;
- Executive services including strategic and corporate planning; and
- Risk management and property and liability insurance.

62.2 Please confirm that FortisBC is proposing, in this Application, to eliminate the overhead charge?

Response:

Confirmed.

62.3 Please explain “fully loaded wage” and provide an example showing calculations.

Response:

Fully loaded wage is the employee’s base wage loaded for the cost of fringe benefits. Fringe benefits include the cost of items such as:

- Medical and Dental benefits;
- Pension and Post Retirement benefits;
- Vacation, Sick and Statutory Holidays; and
- CPP, EI and WCB premiums.

The Company applies the fringe benefit load to regular billable hours only. Excluding overtime hours increases the apparent fringe benefit load rate, but enables a more predictable cost recovery. The fully loaded wage is charged to O&M, Capital and Third Party work.

The fringe benefit load is forecast to average approximately 75 percent in 2012 and 2013. The calculation of a fully loaded wage would be the base salary (net of time away) times 1.75.

Example:

Base salary = $20 per hour (net of time away)

Fully loaded wage = $20 per hour times 1.75 = $35 per hour

> "FortisBC self-insures against the risk of damage to transmission and distribution poles, wires and related equipment… The coverage amounts and terms of the Corporation's insurance agreements are consistent with industry practices." (p. 92)

62.4 Please confirm whether FortisBC has obtained an auditors opinion on legitimacy and verification of the self-insurance terms and rates.

Response:

FortisBC's self-insurance expense does not include specific terms or rates similar to a regular insurance premium; therefore an auditor opinion has not been obtained. To clarify, the self insurance reserve balance of approximately $0.4 million that is being returned to customers as a reduction to 2012 operating expenses is representative of the accrual of the annual accounting book entries made to O&M Expense exceeding the actual costs incurred related to first and third party damages. The actual costs relating to the first and third party damages incurred tend to be more volatile and are primarily out of the Company's control and have drawn down the reserve. The annual accounting book entries that relate to the self insurance is recognized as an operating expense and is used to build up the self insurance reserve.

As part of the 2012-13 RRA, FortisBC has proposed to discontinue the use of a self insurance reserve, forecast the first and third party damages as part of the total 2012 and 2013 insurance expense and proposed a deferral account to capture the difference between actual and forecast insurance expense.

The insurance premiums, the self insurance operating expenses, the actual costs and any other related insurance transactions are all included in the pool of transactions that may be subject to scoping and potential testing by the external auditors as part of their annual audit procedures.

> "Insurance expense is expected to decrease from the 2007 level of $1.6 million to approximately $1.4 million in 2013." (p. 92)

62.5 Please explain the decrease in insurance expense when FortisBC has nearing the end of a period of capital infrastructure improvements? What other factors are contributing to the decrease?

Response:

The main factor that contributed to the decrease in insurance from 2007 through 2013 is (1) insurance market conditions; however (2) the change in forecasting for first and third party damages and (3) the participation in the Fortis group of companies insurance program also contributed to the decrease.

(1) Global events and insurance market conditions are beyond the Company's control and are the primary factors that have caused a decrease in insurance expense from 2007 to 2013 despite this being a period of capital infrastructure improvements. As stated on

page 92 of Tab 4 of the 2012-13 RRA, the decrease in insurance expense resulting from market conditions was further explained with the following statements:

"Favourable insurance market conditions in 2008 resulted in the stabilization or reduction of insurance premiums through to 2010."

"In 2008, the decline in global financial markets also decreased labour and primary construction material prices and as a result, FortisBC was subject to a decrease in replacement values and a corresponding reduction in property insurance."

(2) The removal of the self insurance expense and its replacement with a forecast of the first and third party liability insurance expenses has reduced the total insurance expense from 2007 to 2012 and 2013. Rather than accumulate the variance between forecast and actual insurance expense related to first and third party damages as a self insurance reserve account, the Company has forecast these expenses and proposed the accumulation of all variances between actual and forecast for all insurance expenses as a deferral account. This has permitted the refund of $0.4 million back to customers as a reduction to 2012 insurance expense and a forecast of first and third party damages for 2012 and 2013 which is less than the self insurance expense recognized from 2007 through 2011; and

(3) The decrease in insurance expense is also due in part to lower insurance premiums partially obtained through economies of scale with the consolidated Fortis group of companies insurance program. These savings are embedded in the historical and forecast insurance premium expense. The benefits of participation in the Fortis Group insurance program include pooling of a geographically spread risk, access to specialized markets, reduced broker fees, reduced administration and reduced insurance premiums.

"FortisBC has assumed a 5 percent increase in insurance premiums for each of 2012 and 2013." (p. 93)

62.6 Has the Company's risk profile changed during this period or is this increase mainly related to global events?

Response:

The Company's risk profile has not changed significantly during this period. The 5 percent increase in insurance premiums for each of 2012 and 2013 is mainly attributable to global and market events outside of the Company's control.

62.7 Provide supporting evidence for the 5% annual increase.

Response:

The 5 percent increase in insurance premiums for each of 2012 and 2013 was based primarily on qualitative factors. This would include the expectation that after several years of experiencing more favourable insurance market conditions, the market would eventually harden resulting in an increase in insurance premiums. It is very difficult to forecast insurance expense due to the influence of global events, hence the proposal for a deferral account to capture any variances between forecast and actual, as discussed in Tab 5 Rate Base, page 16, section 5.4.3.viii and Tab 4 Cost of Service, page 94, in the 2012-2013 RRA. The appropriateness of using a 5 percent forecast of insurance premiums for each of 2012 and 2013 has been further corroborated as a reasonable forecast due to the Company's payment of its July 2011 through to June 2012 insurance premiums at an increase of 7 percent over the July 2010 through June 2011 insurance premiums.

> "Every year, an evaluation of the Company's assets replacement value is required for determination of property insurance premiums… An update to the 2008 valuation of the Company's hydroelectric plants is forecast to occur in 2012 at an estimated cost of $60,000."

62.8 Please explain the 4 year lapse between the 2008 and 2012 valuation. Isn't the valuation process completed annually?

Response:

The valuation that occurs approximately every four years is one that is conducted by an external third party and is required by the insurers.

This external appraisal is to determine a replacement cost valuation and is used for the placement of the appropriate insurance coverage. The valuation consists of a review of the civil construction, generating assets and other specific equipment. The external consultant reviews the Company's documentation, completes site visits and conducts interviews with the Company's engineering staff. The results of the replacement cost valuation are then considered as part of the Company's annual insurance premium renewal process. For the years subsequent to the formal external valuation, an internal assessment is conducted to consider the annual changes to these assets while still considering the replacement cost valuation as a starting point. Every four years a new valuation process is conducted to ensure that the insurance coverage reflects the most current replacement costs.

> "Beginning in 2008, FortisBC Holdings, the parent company of FEI filled the role of providing certain specialized advisory services to FortisBC on more complicated insurance matters that FortisBC did not have available in house."

62.9 Provide examples of the types of "complicated insurance matters" that would require annual consulting services.

Response:

The more complicated insurance consulting services provided by the insurance specialists at FortisBC Holdings can include the following:

- Annual insurance renewal – review of the annual valuations and assistance in securing the underwriting information for submission to the external insurers;
- Contract review – review of contracts for insurance requirements in consultation with legal and/or procurement groups;
- Insurance inquiries – requests for certificates of insurance and coverage assessment;
- Loss control – coordination of loss control visits; and
- Claims assistance, capital project insurance and other insurance matters as required.

The nature of these matters requires a specific skill set and risk management insurance expertise, therefore the specialized insurance advisory services are procured from FortisBC Holdings on an ongoing basis.

> "FortisBC's insurance expense has also included an annual Self Insurance Reserve (SIR) expense to build up a provision. The SIR provision is then reduced by the actual costs incurred relating to smaller first and third party claims,…" (p. 94)

62.10 Please explain whether the SIR provision is interest bearing. Why or why not? Is it placed in a separate trust account in the Company's financial institution?

Response:

The self insurance reserve is not interest bearing and is not placed in a separate trust account in the Company's financial institution. It is not interest bearing as historically there has not been a significant balance outstanding in the SIR provision on which interest could be earned. It is only at the end of 2009 and throughout 2010 in which a balance began to accumulate, as a result of factors discussed further below.

The intent of a self insurance reserve is to ensure that there is sufficient expense in place to cover the less predictable and volatile first and third party damages. The expectation is that over a two year period, the self insurance expense will generally be the equivalent of the actual first and third party damages with no significant difference between the two and therefore no ability to earn interest. The self insurance expense is recognized on a straight-line monthly basis while the actual costs incurred are incident based. This means that there could be occasions during the year where the actual costs incurred exceed the expense resulting in a negative provision in which case interest could not be earned on the balance.

As a result of concerns around the frequency and amounts of various incidents, including the significant rise of copper theft in the industry, the Company recognized an increase to self insurance expense during both 2009 and 2010. Fortunately the actual costs did not materialize to the full extent and this resulted in an increase in the accumulated SIR provision during 2009 and 2010. The Company's management has recognized that a forecast accumulated balance of approximately $0.4 million in the SIR provision will exist at the end of 2011 and therefore has returned the amount to customers as a reduction to customer rates in 2012.

Table BCUC IR1 62.10 below provides a calculation of the foregone interest on the SIR provision since it was non-interest bearing from 2007 through to the end of 2011.

Table BCUC IR1 62.10

	2007A	2008A	2009A	2010A	2011F	Total
	($000s)					
Ending SIR provision balance	81	55	232	447	447	
Simple average of SIR provision balance for the year	81	68	144	340	447	
Average interest rate on high interest savings account	3.4%	2.1%	0.3%	0.7%	1.1%	
Forgone interest income	**3**	**1**	**0**	**2**	**5**	**12**

The calculation above assumes, for simplicity, that the first and third party damage costs were incurred on a predictable straight-line basis. The rates used to calculate the interest income are equivalent to the actual annual weighted average rate on the Company's high interest savings account from 2007 through to mid-2011 with a forecast in place for the balance of 2011. The cumulative interest to be earned on the SIR provision for 2007 through 2011 would not be significant (approximately $12,000). Investing the SIR provision amounts in a separate investment or trust account in the Company's financial institution would also require maintenance costs which would largely offset the $12,000 of interest earned. Such costs would include internal labour to monitor the account, as well as bank charges associated with transfers, wire payments and other daily banking services associated with maintaining a separate investment or trust account.

62.11 Please explain the decrease in the SIR account in 2011? What is reserve used to pay a claim? Provide details.

Response:

As shown in the reconciliation of the SIR account in the response to BCUC IR1 Q62.12 below, the ending balance of the SIR is expected to remain unchanged between 2010 and 2011. Rather it is the self insurance expense that has been forecast to decrease from $365,000 and $375,000 recognized in 2009 and 2010 respectively, to $175,000 in 2011. The Company increased the SIR expense in 2009 and 2010 as a result of concerns around the potential frequency and amounts of various incidents, including the significant rise of copper theft in the industry. Since the actual claims did not materialize to this extent in 2009 and 2010, the Company has forecast a 2011 SIR expense of $175,000 which is more consistent with the amount incurred prior to 2009.

The Self Insurance Reserve is used to cover off the smaller and more frequent claims associated with the following:

- First party damages – damages incurred to the Company's transmission and distribution assets, vehicle accidents and other incidents, including the thefts of tools and copper; and
- Third party damages – damages that the Company may cause to others, including smaller claims made by customers as a result of damaged property resulting from a failed neutral or a power surge.

"FortisBC is proposing to return the reserve balance of $0.4 million to customers in 2012." (p. 94)

62.12 Please provide the reconciliation of the 2 lines 4's in Table 4.3.4.18. Show the reconciliation to the $0.4million shown in the 2012 column. Include any accumulated interests in the reserve.

Response:

Table BCUC IR1 62.12

		2007A	2008A	2009A	2010A	2011F	2012F
		($000s)					
Opening SIR provision		82	81	55	232	447	447
Self Insurance Reserve expense	(A)	**175**	**175**	**365**	**375**	**175**	-
Actual claims		(176)	(201)	(188)	(160)	(175)	-
Refund of Self Insurance Reserve	(B)	-	-	-	-	-	(447)
Ending SIR provision		81	55	232	447	447	-

Line A above shows the amount of Self Insurance Reserve expense recognized in O&M expense for each of the years and ties to the first line 4 in Table 4.3.4.18-2.

Line B above shows the refund of $0.4 million in 2012 relating to the SIR provision at the end of 2011 and ties to the second line 4 in Table 4.3.4.18-2.

As stated in the response to BCUC IR1 Q62.10 above, there has been no interest accumulated on the reserve.

62.13 Please confirm that the return of the reserve balance of $0.4 million included accumulated interest to date.

Response:

As discussed in the response to BCUC IR1 Q62.10 the reserve balance of $0.4 million did not include accumulated interest to date.

> "In absence of a SIR provision available for 2012 and 2013, the Company has forecast the costs of first and third party claims based on an average of the historical actual amounts over the last several years." (p. 94)

62.14 Please explain whether this will be trued up for actual costs?

Response:

As part of forecasting the total 2012 and 2013 insurance expenses, the Company has provided a forecast of the costs for first and third party claims. The first and third party claims will be trued up for actual costs as part of the request for a deferral account to capture the variance between forecast and actual on all insurance expenses as referred to in Tab 5 Rate Base, section 5.4.3.viii and Tab 4 Cost of Service, page 94 of the 2012-13 RRA.

62.15 In regards to the Insurance Expense Deferral Account, please explain why this should be a rate-based deferral account.

Response:

Please see the response to BCUC IR1 Q98.1 below.

There is no impact on 2012 or 2013 rates (including from financing costs) related to this account because the forecast balance in each is zero.

> "Effective July 1, 2010 the Board of Directors is a joint Board that is shared with amongst FortisBC and the FEU…. based on a Massachusetts Formula…This allocation methodology has previously been approved by the BCUC for the FEU. Based on this methodology of allocating costs, FortisBC has forecast an allocation of 23.35 percent of the shared FortisBC Utilities Board and Committee compensation and expenses for 2012 and 2013." (p. 95)

62.16 Please provide references to BCUC Orders for the above approval.

Response:

The Massachusetts method has been submitted by FEI and reviewed and approved by the Commission in a number of regulatory proceedings. A Separation Study was filed by FEI in its 2003 Annual Review of 2004 Revenue Requirements and approved by Decision G-80-03. The separation study included utilization of the Massachusetts methodology. Directive No. 3 of that Order said that the Commission is satisfied with the cost allocation as contained in the Separation Study.

62.17 Please explain provide the allocations percentages for FEI for the same test period.

Response:

The remaining percentage, 76.65 percent, of the Board of Director costs are first allocated to Fortis Holdings Inc. and then allocated between all of the subsidiaries of Fortis Holdings Inc. The Board of Director costs are one of a number of types of costs that are pooled together and then allocated using the Massachusetts Formula. The allocation of costs using this allocation module results in approximately 83 percent of the pooled costs being allocated to FEI.

62.18 Has FortisBC obtained an audit opinion on the relevancy and appropriateness of the Massachusetts formula?

Response:

No, FortisBC Inc. has not obtained an audit opinion on the relevance and appropriateness of the Massachusetts formula; however in 2009 FortisBC Energy Inc. (formerly Terasen Gas Inc.) retained KPMG to perform an independent review of the corporate services allocation methodologies. In that report, KPMG states:

> *"The Massachusetts Formula is a widely used and accepted financial composite cost driver in the utility industry in North America as a method of allocating costs."*

"Beginning in 2008, Fortis Inc. began allocating its recoverable costs to FortisBC based on the relative assets by subsidiary as it is closely correlated to the net investment by Fortis Inc. in the respective subsidiaries." (p. 98)

62.19 Please explain how "net investments by the parent company" is considered to be an appropriate cost driver for corporate services? Was there any consideration to using other cost allocators such as the number of FTEs in each subsidiary or the number of corporate transactions?

Response:

The appropriateness of the cost driver was reviewed by KPMG in a 2009 independent review for FortisBC Energy Inc. (formerly Terasen Gas Inc.) of various corporate services allocation methodologies, including the Fortis Inc. (FI) allocation method. In that report, KPMG states:

> "*Although the use of total assets is not as commonly used as a financial composite, KPMG finds FI's use of total assets as a driver to be reasonable as it is representative of FI's primary function of raising capital in support of its subsidiaries."*

62.20 Which other subsidiary did most of these costs get transferred from?

Response:

Each of Fortis Inc.'s subsidiaries would have seen a change in allocation based on their respective asset base. In addition, the allocation to FortisBC was phased in over three years.

Please also refer to the response to BCUC IR1 Q62.22.

62.21 Was this change in corporate services allocation approved by the Commission? Provide references.

Response:

From 2007 to 2011 inclusive, FortisBC was regulated under a Performance Based Regulation model where the O&M Expense allowed in rates was determined by formula. O&M was a function of the Base O&M per Customer, the number of Customers, an inflation adjustment and a Productivity Improvement Factor. During that period, the Commission did not approve individual components of O&M expense but rather approved the factors that were used in the O&M formula.

62.22 There appears to be a 140% increase in Corporate Service Charges from 2001 to 2013F. Is this strictly related to the change in overhead allocation methodologies or can it be attributed to some other factor? Explain fully.

Response:

In addition to the increase in FortisBC's asset base, general inflation over the period and the loss of pole revenue, other factors impacting the increase from 2007A to 2013F included:

- 2007 – Recoverable costs were allocated under an old method of specific expenses and there was no allocation of Fortis Inc salaries and other overhead costs;
- 2008 – The allocation method changed to an asset base allocation method, however the costs were phased in at a rate of 75 percent;
- 2009 – The allocation method was the same as in 2008, except the phase in rate was 87.5 percent;
- 2010 – The allocation remained the same except there was no phase in rate (all allocations were at 100 percent); and
- 2011 onwards – The allocation remained the same except there was no longer any off-setting pole rental revenue. Please also refer to the response to BCMEU IR1 14.0.

62.22.1 How have the changes in corporate service allocations affected the costs at FEI? Provide the reference for FEI's approval to use this allocation methodology.

Response:

The change in the allocation methodology at Fortis Inc. had little or no impact on FEI. In 2008, the first full year that FHI and FEI were owned by Fortis Inc, FHI's allocation was based on Fortis Inc. net investment in FHI whereas the other Fortis Inc subsidiaries had this new allocation methodology phased in over a two year period starting in 2008. The allocation from FHI to FEI was fixed during 2008 and 2009 as FEI was under a PBR settlement during these years. In its 2010/2011 Revenue Requirements Application, FEI indirectly included the Fortis Inc. management fees based on the net assets by subsidiary. The fee from Fortis Inc. is indirect as it is allocated to FortisBC Holdings Inc first who then allocates costs to FEI, FEVI and FEW based on the Massachusetts Methodology. Additionally, FEI had KPMG perform a third party review of both the Fortis Inc management fee and allocation methodology and the cost allocation from FHI to FEI, FEVI and FEW. This review was filed with FEI's 2010/2011 Revenue Requirements Application. Through a Negotiated Settlement Agreement, the Commission approved the management fee and allocation methodology in Order G-141-09.

62.23 FortisBC presents Executive costs Table 4.3.4.17-7. Please explain the 9% increase in the "Operating Labour Costs for Officers Directly Paid by FortisBC" in 2009. Given that the total executive offices in the same period remained constant at 6, explain whether this increase relates to executive compensation, overtime or some other factor?

Response:

The increase in labour costs in 2009 over 2008 was primarily due to a combination of general salary increases for Executive and Administrative staff, increased benefit loadings due to salary increases, and a reduction in charges to capital.

CAPITALIZED OVERHEAD

63.0 Reference: Capitalized Overhead

Exhibit B-1, Tab 2, Section 2.2.1, pp. 9-10

"Any difference between this rate and a rate that is analyzed as meeting the criteria of directly attributable under IFRS would require recognition in a rate base deferral account for regulatory purposes rather than as part of property plant and equipment."

63.1 Please describe how the approach to the overhead study filed in Exhibit B-1, Tab 4, Section 4.4 differed from analyzing the "directly attributable" amounts as defined under IFRS.

Response:

While the concept of "directly attributable" is not clearly defined under IFRS, it has been generally interpreted as excluding administrative, corporate and general overhead costs. It should be noted that in practice, the concept of "directly attributable" has led to a differing of applications across countries and industries as to whether certain administrative costs are considered directly attributable to placing an asset into service.

The approach used in the overhead study included in the Company's 2012-13 RRA is not as restrictive as the directly attributable concept under IFRS. The approach considers that there are many departments in the Company that lend support, time and effort as part of the process to self construct plant and place an asset into service. The relative effort of these departments has been considered as part of the development of an appropriate overhead rate.

63.2 Please provide an analysis of the “directly attributable” amounts as defined under IFRS.

Response:

Since the Company prepared its 2012-13 RRA in compliance with US GAAP, a formal IFRS overhead study was not prepared and finalized. However, using the concept of “directly attributable” to develop an overhead rate that would comply with IFRS would result in a lower rate than the 20 percent of gross O&M expenses that was requested as part of the Company’s 2012-13 RRA.

There is not an abundance of explicit or detailed guidance around the concept of “directly attributable” under IFRS and it is therefore subject to different interpretation. Different industries and different countries may not have interpreted the concept of “directly attributable” in a consistent manner which is one of the challenges of implementing IFRS. There have been views taken that “directly attributable” suggests that no administrative or overhead type expenses should be capitalized. Other views suggest that incremental and support functions should be appropriately capitalized, particularly in an industry of self-construction. If the Company was required to report under IFRS, the Company would undertake a comprehensive analysis with the expectation of including those costs that lend support, time and effort to the process of self-constructing plant and placing an asset into service, as “directly attributable”.

Based on a high level preliminary analysis that was performed back in 2010 during the Company’s planned transition to IFRS, an appropriate IFRS overhead rate was expected to be in the range of approximately 6% to 12%. This range would have to be qualified in that a more thorough and detailed review would have to be undertaken prior to quantifying a supportable rate.

64.0 Reference: Capitalized Overhead

Exhibit B-1, Tab 4, Section 4.4, pp. 101-103

Overhead Distribution

> “Next, the departmental costs are allocated to the operating business units based on the corporate support allocations determined in step one. For example, Human Resource effort is generally proportionate to the number of employees in the departments it supports; based on the employee count in the operating business units, Human Resources costs of $1.638 million (shown in Table 4.4-2 following) are allocated 23.8 percent (95 of 400 employees) or $0.389 million to Generation, 59.0 percent or $0.966 million to Network Services and 17.3 percent or $0.283 million to Customer Service.”

64.1 Please explain why a portion of the departmental costs are not also assigned to an administrative operating function, which is presumably the difference between the 400 employees in the reference and the 2011 FTE count, thereby retaining a greater portion of these costs in the O&M budget instead of distributing them into capital expenditures.

Response:

Costs are not assigned to administrative departments for two reasons. First, the administrative departments are there to support the operating business units and in the absence of operations, there would be no administrative functions to assign costs to. Second, if costs were to be assigned administrative departments, those costs would in turn be allocated out to the operating business units. If for example, Human Resources were to allocate costs to the other administrative functions and those revised administrative costs were in turn allocated to the operating business units, the results would essentially be the same. The only difference would be the cost driver might be different, for example Employee count versus Total Expenditures.

65.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.6.2.3(b), pp. 110-111

Capitalized Overhead

FortisBC states “A portion (20%) of gross operating and maintenance expenses are deemed to be capitalized for accounting purposes. While these expenses are deemed necessary to put an item of property, plant and equipment in service for accounting purposes, these costs would normally not be capitalized for tax purposes, therefore these costs have been removed from UCC additions and have been deducted for determination of taxable income.”

65.1 Please provide an explanation as to why 20% of the gross O&M costs have been deemed to be capitalized to place equipment in-service when capitalized overhead is already included in the CPCN estimate or capital expenditure estimate.

Response:

Capitalized Overhead is a credit (reduction) to O&M Expense and (ultimately) a debit to Property, Plant and Equipment. Capitalized Overhead is charged from O&M Expense to the appropriate projects monthly while the project is in the work-in-progress phase, and then transferred to Property, Plant and Equipment when the asset is placed in-service. There is no duplication in the accounting for Capitalized Overhead.

65.2 What is the additional value provided by the 20% capitalized overhead?

Response:

Capitalized Overhead is a cost accounting allocation of indirect costs that were incurred in order to place a capital asset in service. Direct costs associated with capital work are charged directly to the project. A Capitalized Overhead allocation is used for administrative ease and recognizes that there are other indirect costs that are incurred that cannot be directly charged to a project. Capitalized Overhead includes the services provided by the departments included in Table 4.4-1 on page 102 of Tab 4 of the 2012-13 RRA.

66.0 Reference: Operation and Maintenance

Exhibit B-1, Tab 4, Section 4.4, pp. 100-103

Capitalized Overhead

66.1 Please explain what services are provided in the operating business unit: "Network Services."

Response:

Network Services includes Network Operations (daily operation and maintenance of the transmission and distribution system), Substation Maintenance, Engineering, System Control, and Lands and Right-of-Way Maintenance.

66.2 Please explain whether the corporate overhead loading calculation described in the Application was based on the same methodology used in the 2006 RRA?

Response:

Yes, the calculation was based on the same methodology used in the 2006 RRA.

66.3 How does FortisBC determine the capital intensities of the operating business units?

Response:

The Capital Intensity is the ratio of the actual 2010 labour charged to capital compared to the actual 2010 total labour for each respective operating business unit.

66.4 Please explain whether Table 4.4-3 “Gross Capital Expenditures” includes capitalized overheads?

Response:

Yes, Table 4.4-3 on page 103 of Tab 4 of the 2012-13 RRA includes Capitalized Overheads.

66.5 Please explain the reduction of the Gross Capital Expenditures in 2011F.

Response:

The reduction in 2011 gross capital expenditures is simply due to year over year differences in the timing of project expenditures.

Detailed gross capital expenditures for 2011 – 2012 are shown in Tab 7, pages 7-9, Table 1-A-1 of the 2012-13 RRA.

66.6 Why does FortisBC consider it appropriate to maintain the capitalized overhead rate at 20% over the test period?

Response:

As noted in Tab 4, Page 103 of the 2012-13 RRA, the Company is of the opinion that the level of capital expenditures over the test period are essentially at the same level as the average expenditures over the 2007 to 2011 period and therefore the 20 percent rate that was applied over the 2007 - 2011 period is still appropriate.

Further, keeping the rate at 20 percent will serve to mitigate Net O&M Expense variances and revenue requirement fluctuations.

OTHER INCOME

67.0 Reference: Other Income

Exhibit B-1, Tab 4.5, p. 104

67.1 Please update Table 4.5 to include actuals for 2008 and 2009 and revised 2011 for actuals through July 31, 2011.

Response:

Table BCUC IR1 Q67.1 below has been updated to include 2008 and 2009 actual values.

No change is forecast to Other Income in 2011.

Table BCUC IR1 Q67.1 – Other Income (2008-2013)

		Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
				($000s)			
1	Apparatus and Facilities Rental						
2	Electric Apparatus Rental	2,281	2,755	3,864	3,070	3,276	3,374
3	Rental of Facilities	-	-	-	-	-	-
4	Lease Revenue	169	169	141	138	108	104
5		2,450	2,924	4,005	3,208	3,384	3,478
6	Contract Revenue						
7	Waneta Management Fee	368	311	380	457	455	464
8	Waneta Management Fee Capital	170	2	8	91	77	-
9	Waneta Carrying Costs	94	94	94	94	94	94
10							
11	Brilliant Management Fee (including BTS)	139	174	208	320	305	273
12	Brilliant Management Fee Capital	314	289	280	221	295	205
13							
14	Fortis Pacific Holdings Inc.	516	530	592	625	488	279
15		1,601	1,400	1,562	1,808	1,714	1,315
16	Miscellaneous Revenue						
17	Connection Charges	469	482	489	1,038	1,079	1,122
18	NSF Cheque Charges	9	10	11	11	11	12
19	Sundry Revenue	175	183	162	66	67	69
20		652	675	662	1,115	1,157	1,203
21							
22	Transmission Access Revenue	-	-	-	1,109	1,098	1,071
23	Investment Income	332	188	224	162	128	98
24	**Total**	**5,035**	**5,187**	**6,453**	**7,402**	**7,481**	**7,165**

68.0 Reference: Other Income

Exhibit B-1, Tab 4.5, p. 105

Apparatus and Facilities rental

68.1 Please provide further explanation to the resolution of the Shaw dispute and how it affects revenues in the test period.

<u>Response:</u>

An agreement between Shaw and FortisBC provides, among other things, for a long-term lease of FortisBC-owned fibre optic cable. This agreement confers significant positive benefit to FortisBC customers both in the test period and well into the future. The settlement assures long term telecommunications access necessary for the efficient operation of the electrical system. The impact of this settlement on revenues for test period and for the long term is an increase of $0.4 to $0.5 million annually. The settlement also facilitates additional revenue opportunities for fibre leasing to other third parties to the benefit of customers. Please refer to Tab 4, section 4.5.1, and Table 4.8.1 of the 2012-13 RRA and the response to BCUC IR1 Q105.1.

69.0 Reference: Other Income

Exhibit B-1, Tab 4.5, p. 105

City of Kelowna Contract

69.1 Please provide details on the City of Kelowna contract revenues and why FortisBC is not confident that it will be renewed in October 2012. Will the Company experience equal savings in the Utility if the contract is not renewed?

<u>Response:</u>

It is the Company's intention to pursue discussions regarding renewal of the contract. However, the renewal of any contract will be determined through the appropriate negotiation process. At this time it is uncertain as to whether a renewal that addresses both parties' interests would be achievable. Should the contract not be renewed the Company would not likely experience savings equal to the loss of the contract revenue.

70.0 Reference: Other Income

Exhibit B-1, Tab 4.5, p. 106

Sundry Revenue

70.1 Please explain the sundry revenue decline in 2011?

Response:

Approximately $49,000 of the 2010 actual Sundry Revenue was reclassified to Transmission Access Revenue in 2011 shown on line 18, Table 4.5, Tab 4, Page 104 of the 2012-13 RRA. The balance of the difference between 2010 and 2011 of $47,000 is primarily due to higher than anticipated administrative cost recoveries on third party billings for damage to Company property as a result of motor vehicle accidents in 2010.

TAXES

71.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.1, pp. 106-108

Property Tax-Calculation

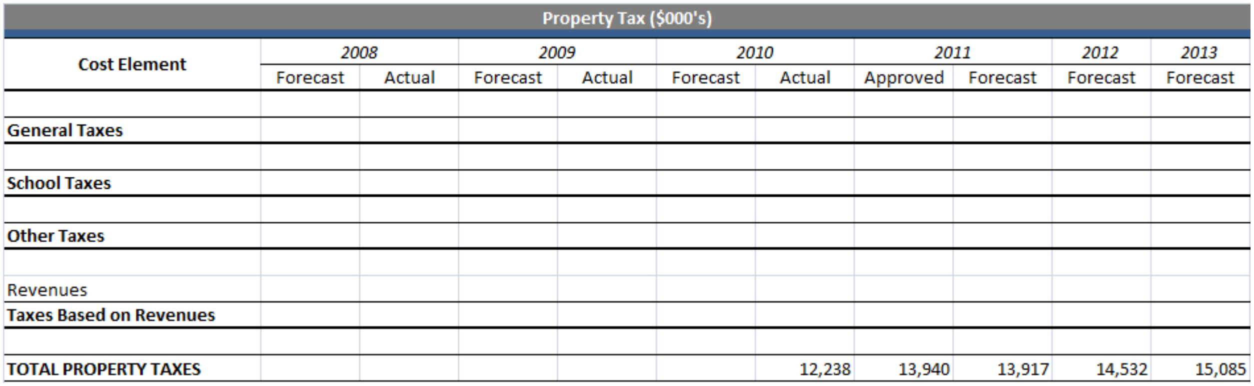
> “Tax policy is applied by various taxing authorities under their legislated authority and determines how their budget will be distributed to the various classes of properties through the property tax. Property Taxes payable by FortisBC is categorized into four general categories of taxes as follows: General Taxes, School Taxes, Other Taxes, Taxes based on Revenues.” (Tab 4, p. 107)

71.1 Please confirm, or explain otherwise, that the revenue values used to calculate the “taxes based on revenue” component of total property tax is based on corporate revenues from two years prior.

Response:

Confirmed.

71.2 Please provide a breakdown for property tax in the following format:



Property Tax ($000's)

Cost Element	2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Approved	Forecast	Forecast	Forecast
General Taxes										
School Taxes										
Other Taxes										
Revenues										
Taxes Based on Revenues										
TOTAL PROPERTY TAXES						12,238	13,940	13,917	14,532	15,085

Response:

Please refer to the below table.

Table BCUC IR1 71.2

Property Tax ($000s)

Cost Element	2008		2009		2010		2011		2012	2013
	Forecast*	Actual	Forecast	Actual	Forecast	Actual	Approved	Forecast	Forecast	Forecast
General Taxes	2,223	2,195	2,358	2,323	2,636	2,496	2,967	2,931	3,114	3,218
School Taxes	5,183	5,118	5,288	5,393	5,837	5,633	6,389	6,349	6,554	6,728
Other Taxes	2,743	2,708	2,868	2,832	3,031	3,084	3,477	3,397	3,517	3,629
Revenues	102,720	101,418	104,663	101,292	104,331	102,414	110,716	123,909	134,689	150,986
Taxes Based on Revenues	1,027	1,015	1,047	1,025	1,044	1,025	1,107	1,240	1,347	1,510
TOTAL PROPERTY TAXES	11,176	11,036	11,561	11,573	12,548	12,238	13,940	13,917	14,532	15,085

**2008 Forecast allocated using 2008 Actuals*

72.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.1, p. 108

Property Tax-Asset Variance Deferral Account

"The BC Assessment Authority is undertaking a review of the valuation of certain electrical system rates for property tax purposes. This review could potentially impact FortisBC and result in a variance from the property tax amounts forecast in 2012 and 2013 in Table 4.6.1.3 above. The Company is seeking a property tax variance deferral account related to the BC Assessment Authority's review of asset valuation, in the event that a review is conducted, as it is largely out of the Company's control and any impact cannot be reasonably forecast at this time." (Tab 4, p. 108)

72.1 Is FortisBC requesting that accumulated variances between forecast and actual 2012 and 2013 Total Property Taxes be captured in the Property Tax Variance Deferral Account? If not, please answer the following:

Response:

FortisBC is not requesting that all variances between forecast and actual 2012 and 2013 property taxes be captured in the Property Tax Variance Deferral Account, only those variances that specifically result from the potential BC Assessment Authority review of the valuation of certain electrical system assets and rates.

72.1.1 Given that all components of property taxes are largely out of the Company's control why would it be appropriate to capture some of the variances in a deferral account while others would at the ratepayer's risk?

Response:

Depending on the results of a BC Assessment Authority review, the proposes deferral account could result in a positive or negative variance that would either be refunded to or recovered from customers, therefore a variance is not automatically a ratepayer risk. There are clearly various components of property taxes that are out of the Company's control, each subject to varying degrees of uncertainty and the Company proposes that the item that is the least predictable, the results of the BC Assessment Authority electrical system review, to be captured in a deferral account. The Company cannot confirm the timing of the BC Assessment Authority review or whether it will have a significant impact on either of the 2012 and 2013 property taxes for FortisBC. As described in Section 5.4.3 of Tab 5 Rate Base of the 2012-13 RRA, the Company has taken the position that variances between forecast and actual resulting from government or legislative changes, including the BC Assessment Authority property tax asset valuation, would be considered out of the Company's control and therefore should be recovered by the customer in future rates. While the Company has requested to capture only this one component of potential property taxes variance, there are other components in the determination of property taxes that may be subject to change and not entirely within the Company's control. As such, the Company would not be opposed to the establishment of a property taxes deferral account with a broader scope of the other components.

> "For purposes of the 2012 and 2013 revenue requirement, any additions to this rate base deferral account would be included in deferred charges and an amortization term of any accumulate variances will be proposed as part of the 2014 Revenue Requirements Application." (Tab 4, p. 108)

> 72.2 Please explain why the Company considers it appropriate to classify the proposed deferral account as a rate base account as opposed to an interest bearing deferral account.

Response:

Please see the response to BCUC IR1 Q98.1 below.

There is no impact on 2012 or 2013 rates (including from financing costs) related to this account because the forecast balance in each is zero.

> 72.3 Would it be reasonable to assume that the accumulated variances in this type of deferral account would likely be recovered over a one year period? If not, please discuss.

Response:

Since the outcome of the BC Assessment Authority review on 2012 and 2013 property taxes cannot be reasonably forecast, a recovery period will be suggested as part of the 2014 Revenue Requirements Application. Depending on the value of the accumulated variance, the Company may suggest a recovery period that balances out the objective of mitigating customer rate increases while still ensuring that current customers pay for the current cost of service. If the value of the accumulated variances is not too significant, then a shorter recovery period, such as a one-year period, would likely be recommended.

73.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.2, pp. 109-115

Income Taxes-Financing Fees

> "Financing fees are those costs incurred to issue long-term debt and for tax purposes are permitted to be deducted over a five year period under the Income Tax Act ("ITA"). The deduction of financing fees for tax purposes is representative of the annual tax amortization of the cumulative debt issue cost balance in a given year." (Tab 4, p. 111)

73.1 Are there any financing fees (transaction costs, debt issuance costs) forecast to occur in 2012 or 2013?

Response:

Yes, the Company has forecast debt issuance fees of $1.6 million to be incurred in 2013 as described in Section 5.4.5.xxi of Tab 5 Rate Base of the 2012-13 RRA.

73.2 If yes, were the full amounts deducted in determining Utility Net Income Before Tax?

Response:

The debt issue costs do not affect Net Income Before Tax in 2012 or 2013. Debt issuance costs are deducted for Utility Net Income Before Tax by way of amortization expense. In this case, the $1.6 million of 2013 debt issuance fees was forecast using a term of 30 years. Under pre-changeover CGAAP, IFRS and US GAAP, these costs are amortized over the term of the related debt. Since the debt issuance is expected to occur in the last half of 2013, amortization of debt issue costs in the amount of approximately $50,000 would be deducted in determination of 2014 Utility Net Income Before Tax.

73.2.1 If yes, please show where they have subsequently been added back?

Response:

As described in the response to BCUC IR1 Q73.2, the Company expects approximately $50,000 of the total $1.6 million in 2013 debt issuance costs to be added back in the determination of 2014 taxable income by way of annual amortization of deferred charges. Included in Table 4.6.2 Income Tax, on page 109 of Tab 4 Cost of Service of the 2012-13 RRA, the amortization of deferred charges (indicated as reference "f") of $4.468 million and $4.358 million, for 2012 and 2013 respectively, include the annual amortization of the initial debt issue costs from 2004, 2005, 2007, 2009 and 2010. The annual amortization of the 2013 debt issuance costs over the forecast 30 year term will be added back in the same manner beginning in 2014.

> "The deferred charge tax effects shown in the above schedule relate specifically to debt issue costs, as the tax effects must be recognized over a five year period, similar to the deduction for the debt issue costs themselves pursuant to the federal and Provincial Income Tax Acts." (p. 113)

73.3 For each year 2011-2013 please provide the detailed calculations for line 24 (Deferred Charges Tax Effect) from Table 4.6.2 on page 109.

Response:

The detailed calculation is provided in the table below.

Table BCUC IR1 73.3

Determination of annual tax effect related to each debt issuance	Calculation	2011F	2012F	2013F
		($000s)		
Series 2007-1				
Debt issue costs incurred	1,246			
2007 statutory tax rate	34.12%			
Tax effect (debt issue cost multiplied by statutory tax rate)	425			
Tax effect divided by 5 years purusuant to Income Tax Act 20(1)(e)	85			
Adjustment to annual tax effect for costs incurred in 2007 vs. 2008	3			
Annual tax effect related to this debt issuance for 2011	**88**	88		
Medium Term Note Series 1 - 2009				
Debt issue costs incurred	991			
2009 statutory tax rate	30.00%			
Tax effect (debt issue cost multiplied by statutory tax rate)	297			
Tax effect divided by 5 years purusuant to Income Tax Act 20(1)(e)	59			
Annual tax effect related to this debt issuance for 2011 to 2013	**59**	59	59	59
Medium Term Note Series 2 - 2010				
Debt issue costs incurred	941			
less non deductible debt discount pursuant to Income Tax Act 20(1)(f)	(172)			
Reversal of accrued costs in 2011	(38)			
Subtotal of 2010 debt issue costs subject to tax effect	731			
2010 statutory tax rate	28.50%			
Tax effect (debt issue cost multiplied by statutory tax rate)	208			
Tax effect divided by 5 years purusuant to Income Tax Act 20(1)(e)	42			
Adjustment to annual tax effect for costs incurred in 2010 vs. 2011	(3)			
Annual tax effect related to this debt issuance for 2011 to 2013	**39**	39	39	39
2013 Debt Issuance				
Debt issue costs incurred	1,587			
2009 statutory tax rate	25.00%			
Tax effect (debt issue cost multiplied by statutory tax rate)	397			
Tax effect divided by 5 years purusuant to Income Tax Act 20(1)(e)	79			
Annual tax effect related to this debt issuance for 2013	**79**			79
Total Deferred Charge Tax Effects (line 24) on Table 4.6.2 Income Tax on page 109 of Tab 4 Cost of Service of the 2012-2013 RRA		186	98	177

Table BCUC IR1 73.3 above contains references to:

- Income Tax Act (ITA) 20(1)(e) –Expenses regarding financing; and
- ITA 20(1)(f) – Discount on certain obligations.

Each is discussed below.

Income Tax Act (ITA) 20(1)(e) – Expenses regarding financing

This section refers to the deduction of debt issue costs over a specified 5 year (20 percent per year) period as follows:

> *(e) Expenses re financing*
>
> *such part of an amount (other than an excluded amount) that is not otherwise deductible in computing the income of the taxpayer and that is an expense incurred in the year or a preceding taxation year…*
>
> *…(ii) in the course of a borrowing of money used by the taxpayer for the purpose of earning income from a business or property (other than money used by the taxpayer for the purpose of acquiring property the income from which would be exempt),…*
>
> *…(iii) that proportion of 20% of the expense that the number of days in the year is of 365 and*
>
> *(iv) the amount, if any, by which the expense exceeds the total of all amounts deductible by the taxpayer in respect of the expense in computing the taxpayer's income for a preceding taxation year,…*

Therefore the Company has deducted the actual debt issue costs incurred over a five year period (on line 9 of Table 4.6.2 Income Tax and described on page 111 of Tab 4) and the related tax effect over a five year period (on line 24 of Table 4.6.2 Income Tax and described on page 113 of Tab 4). This treatment is specific only to debt issue costs and the related tax effects due to the restrictions in place under Income Tax Act (ITA) 20(1)(e). All other deferred charge costs, excluding preliminary and investigate spending which do not recognize a tax effect until included in capital, are deducted or added back in the year incurred, therefore the related tax effect is recognized at 100% in the year that the costs are incurred. The tax effect treatment for both debt issue costs and all other deferred charges ensures the proper matching of costs and benefits and is consistent with Commission Order G-52-05 and approved revenue requirements applications from 2006 onwards.

ITA 20(1)(f) – Discount on certain obligations

In 2010, the deferred charge account for debt issue costs included the debt discount of approximately $172,000 on the 2010 debt issuance. The debt discount cannot be deducted until which time the debt instrument is repaid. Therefore this amount has been added back for tax purposes, as it is not deductible until paid per 20(1)(f), which states:

- *An amount paid in the year in satisfaction of the principal amount of any bond, debenture, bill, note, mortgage, hypothecary claim or similar obligation issued by the taxpayer after June 18, 1971 on which interest was stipulated to be payable, to the extent that the amount so paid does not exceed,*

  i. in any case where the obligation was issued for an amount not less than 97% of its principal amount, and the yield from the obligation, expressed in terms of an annual *rate on the amount for which the obligation was issued (which annual rate shall, if the terms of the obligation or any agreement relating thereto conferred on its holder a right to demand payment of the principal amount of the obligation or the amount outstanding as or on account of its principal amount, as the case may be, before the maturity of the obligation, be calculated on the basis of the yield that produces the highest annual rate obtainable either on the maturity of the obligation or conditional on the exercise of any such right) does not exceed 4/3 of the interest stipulated to be payable on the obligation, expressed in terms of an annual rate on*

A. the principal amount of the obligation, if no amount is payable on account of the principal amount before the maturity of the obligation, or
B. the amount outstanding from time to time as or on account of the principal amount of the obligation, in any other case,

- *the amount by which the lesser of the principal amount of the obligation and all amounts paid in the year or in any preceding year in satisfaction of its principal amount exceeds the amount for which the obligation was issued, and*

ii. in any other case, 1/2 of the lesser of the amount so paid and the amount by which the lesser of the principal amount of the obligation and all amounts paid in the year or in any preceding taxation year in satisfaction of its principal amount exceeds the amount for which the obligation was issued;

73.4 Please explain the relationship between Financing Fees discussed on page 111 and Debt Issuance Costs discussed on page 113.

Response:

Financing fees on page 111, Tab 4 of the 2012-13 RRA are those amounts deducted in the determination of taxable income. The Financing Fees are the same as the Debt Issuance Costs referred to in the discussion on tax effects discussed on page 113.

74.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.2, pp. 112-113

Income Taxes-Deferred Charges

"Certain costs are deferred for accounting purposes, however are deducted or added back as a period expense for tax purposes in the year incurred." (p. 112)

74.1 Please show where on Table 4.6.2 (page 109) the deferred charges additions are added back or deducted as a period expense for tax purposes.

Response:

On Table 4.6.2 (page 109, Tab 4, 2012-13 RRA) it is not clearly evident that the deferred charge additions are added back or deducted for tax purposes, therefore to explain the treatment of deferred charge additions for tax purposes and the related tax effects, it is necessary to re-create the table to provide a comparison of two presentation options (Gross Presentation (Option 1) and "Netted Out" Presentation (Option 2)) as follows:

Table BCUC IR1 74.1a (Actual 2010, Approved 2011 and Forecast 2011)

	Actual 2010			Approved 2011			Forecast 2011		
	Gross Presentation (Option 1)	"Netted Out" Presentation (Option 2)	Variance in Presentation	Gross Presentation (Option 1)	"Netted Out" Presentation (Option 2)	Variance in Presentation	Gross Presentation (Option 1)	"Netted Out" Presentation (Option 2)	Variance in Presentation
		($000s)			($000s)			($000s)	
UTILITY INCOME BEFORE TAX	77,975	77,975	-	90,531	90,531	-	94,726	94,726	-
Deduct:									
Interest Expense	35,138	35,138	-	40,505	40,505	-	39,364	39,364	-
ACCOUNTING INCOME	42,837	42,837	-	50,026	50,026	-	55,362	55,362	-
Deductions:									
Capital Cost Allowance	52,849	52,849	-	56,903	56,903	-	56,954	56,954	-
Capitalized Overhead	9,529	9,529	-	10,777	10,777	-	10,777	10,777	-
Incentives	629	629	-	2,770	2,770	-	(2,266)	(2,266)	-
Financing Fees	597	597	-	619	619	-	594	594	-
Deferred Charges accounting additions	**3,135**	**-**	**(3,135)**	**7,909**	**-**	**(7,909)**	**9,677**	**-**	**(9,677)**
All Other (net effect)	3,020	3,020	-	(217)	(217)	-	(36)	(36)	-
	69,759	66,624	(3,135)	78,761	70,852	(7,909)	75,700	66,023	(9,677)
Additions:									
Amortization of Deferred Charges	3,695	3,695	-	3,297	3,297	-	3,233	3,233	-
Depreciation	38,075	38,075	-	42,201	42,201	-	42,118	42,118	-
	41,770	41,770	-	45,498	45,498	-	45,351	45,351	-
TAXABLE INCOME	14,848	17,983	3,135	16,763	24,672	7,909	25,013	34,690	9,677
Federal Corporate Tax Rate	18.00%	18.00%	-	16.50%	16.50%	-	16.50%	16.50%	-
Provincial Corporate Tax Rate	10.50%	10.50%	-	10.00%	10.00%	-	10.00%	10.00%	-
Combined Corporate Tax Rate	28.50%	28.50%	-	26.50%	26.50%	-	26.50%	26.50%	-
Income Taxes Payable	4,232	5,125	893	4,442	6,538	2,096	6,628	9,193	2,565
Investment Tax Credit	(27)	(27)	-	-	-	-	-	-	-
Taxes Payable	4,205	5,098	893	4,442	6,538	2,096	6,628	9,193	2,565
Prior Years' (Overprovisions)/Underprovisions	(738)	(738)	-	-	-	-	61	61	-
Deferred Charges Tax Effect - Debt Issue Costs	184	184	-	195	195	-	186	186	-
Deferred Charges Tax Effect	**893**	**-**	**(893)**	**2,096**	**-**	**(2,096)**	**2,565**	**-**	**(2,565)**
REGULATORY TAX PROVISION	4,544	4,544	-	6,733	6,733	-	9,440	9,440	-
Effective Tax Rate	10.6%	10.6%	-	13.5%	13.5%	-	17.1%	17.1%	-

Total Additions per Deferred Charges (Table 1-B)	3,976 (a)	8,383 (b)	4,572 (c)
Add:			
Income tax impacts - DSM	1,059	2,078	1,945
Income tax impacts - all others	18	213	806
Incentive	2,061	-	5,035
	3,138	2,291	7,786
Less:			
Debt issue costs	917	-	(38)
Preliminary and investigative	2,142	2,059	1,838
Automated Meter Reading Feasibility Study costs	455	706	881
Reversal of cumulative tax effects on AMI	465	-	-
	3,979	2,765	2,681
Deferred Charges accounting additions (per above) deducted	**3,135**	**7,909**	**9,677**
Combined Corporate Tax Rate	28.5%	26.5%	26.5%
Deferred Charges tax effect	**893**	**2,096**	**2,565**

(a) - Additions per Deferred Charges schedule on page 12 of 2010 Annual Report to the BCUC April 29, 2011.

(b) - Additions per Table 1-B Deferred Charges and Credits (2011) schedule of approved 2011 Revenue Requirements Application pursuant to BCUC Order G-184-10 and G-195-10.

(c) - Additions per line item 101 on Table 1-B Deferred Charges and Credit (2011) schedule on page 11 of Tab 7 Financial Schedules of 2012-2013 RRA.

Minor differences due to rounding.

Table BCUC IR1 74.1b (Forecast 2012 and 2013)

	Forecast 2012			Forecast 2013		
	Gross Presentation (Option 1)	"Netted Out" Presentation (Option 2)	Variance in Presentation	Gross Presentation (Option 1)	"Netted Out" Presentation (Option 2)	Variance in Presentation
	($000s)			($000s)		
UTILITY INCOME BEFORE TAX	92,723	92,723	-	99,418	99,418	-
Deduct:						
Interest Expense	41,319	41,319	-	43,553	43,553	-
ACCOUNTING INCOME	51,404	51,404	-	55,865	55,865	-
Deductions:						
Capital Cost Allowance	61,305	61,305	-	65,958	65,958	-
Capitalized Overhead	10,834	10,834	-	11,159	11,159	-
Incentives	5,416	5,416	-	-	-	-
Financing Fees	345	345	-	662	662	-
Deferred Charges accounting additions	**9,257**	**-**	**(9,257)**	**9,898**	**-**	**(9,898)**
All Other (net effect)	1,088	1,088	-	574	574	-
	88,245	78,988	(9,257)	88,251	78,353	(9,898)
Additions:						
Amortization of Deferred Charges	4,468	4,468	-	4,358	4,358	-
Depreciation	46,931	46,931	-	48,870	48,870	-
	51,399	51,399	-	53,228	53,228	-
TAXABLE INCOME	14,558	23,815	9,257	20,842	30,740	9,898
Federal Corporate Tax Rate	15.00%	15.00%	-	15.00%	15.00%	-
Provincial Corporate Tax Rate	10.00%	10.00%	-	10.00%	10.00%	-
Combined Corporate Tax Rate	25.00%	25.00%	-	25.00%	25.00%	-
Income Taxes Payable	3,640	5,954	2,314	5,211	7,685	2,474
Investment Tax Credit			-			-
Taxes Payable	3,640	5,954	2,314	5,211	7,685	2,474
Prior Years' (Overprovisions)/Underprovisions	-	-	-	-	-	-
Deferred Charges Tax Effect - Debt Issue Costs	98	98	-	177	177	-
Deferred Charges Tax Effect	**2,314**		**(2,314)**	**2,474**		**(2,474)**
REGULATORY TAX PROVISION	6,052	6,052	-	7,862	7,862	-
Effective Tax Rate	11.8%	11.8%	-	14.1%	14.1%	-

Total Additions per Deferred Charges (Table 1-B)	8,793	(d)	9,608	(e)
Add:				
Income tax impacts - DSM	1,933		1,970	
Income tax impacts - all others	480		682	
Incentive	-		-	
	2,413		2,652	
Less:				
Debt issue costs	-		1,587	
Preliminary and investigative	1,938		775	
Automated Meter Reading Feasibility Study costs	11		-	
Automated Meter Reading Feasibility Study costs	-		-	
	1,949		2,362	
Deferred Charges accounting additions (per above) deducted	**9,257**		**9,898**	
Combined Corporate Tax Rate	25.0%		25.0%	
Deferred Charges tax effect	**2,314**		**2,475**	

(d) - Additions per line item 108 on Table 1-B Deferred Charges and Credit (2012) schedule on page 13 of Tab 7 Financial Schedules of 2012-2013 RRA.

(e) - Additions per line item 98 on Table 1-B Deferred Charges and Credit (2013) schedule on page 15 of Tab 7 Financial Schedules of 2012-2013 RRA.

Minor differences due to rounding.

Gross Presentation (Option 1)

The first option would be to present the tax impact of deferred charge accounting additions during the year by showing a separate line item in deductions as “Deferred Charges accounting additions” to arrive at taxable income and then recognize a related additional tax effect (also shown as a separate line item “Deferred Charges Tax Effect” in the table above) other than the tax effect that relates to debt issue costs. This is the presentation format that FortisBC had included in its 2006 Revenue Requirements Application.

“Netted Out” Presentation (Option 2)

This second presentation option is what was used to prepare Table 4.6.2 included in the 2012-13 RRA. In this format, the amount of deferred charges accounting additions is zeroed out on the deductions line (highlighted in the above tables), as is the removal of the related tax effects from the Deferred Charges Tax effect so that only the tax effects pertaining to the debt issuance costs remains as discussed in greater detail in the response to BCUC IR1 Q73.3. This “Netted Out” Presentation (Option 2) format of “netting out” the deferred charges tax impacts is one that FortisBC first adopted as part of its 2007 Revenue Requirements Application as requested by Commission staff so that FortisBC had consistent presentation of the tax impacts of its deferred charges with other rate regulated entities in BC.

The important point to note is that as shown in the above comparative tables, the total dollar amounts of the regulatory tax provisions are the same under both presentation formats because the substance of the calculations is the same under each method.

> “The deferred charges additions are essentially offset by the tax effects in a given year and therefore are “netted out” on the above tax schedule.” (p. 113)

74.2 Please provide further detail and explanation of what this statement indicates and show where the amounts are “netted out.”

<u>Response:</u>

Please see the response to BCUC IR1 Q74.1 which provides detail and explanation regarding the deferred charges “netted out” presentation option.

75.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.2, pp. 113-114

Income Taxes-Prior Years Over/Under provisions

"The Prior Years' (over)/under provisions represents the difference between the estimated income tax owing at the end of the year and the actual filed income taxes owing on the tax return." (p. 113)

75.1 Has the overprovision on Table 4.6.2 (page 109), line 23 of $738,000 been refunded, or will be refunded, to rate payers? Please explain.

Response:

Yes, the overprovision has been refunded to customers. The Company had filed its 2009 Corporate Tax Return in June 2010 taking the position that certain costs of removal qualified as a 100 percent deduction in the year incurred, rather than deducting the annual composite 8 percent CCA as per prior years. This change in tax treatment resulted in a tax savings of approximately $0.7 million which the Company flowed 100 percent of these savings through to customers as a reduction to 2011 rates.

75.2 What will happen to any (over)/under provisions that results from the estimates made in calculating the Regulatory Tax Provision in 2012 and 2013? Is it the Company's intention to capture these variances in the requested Income Tax Variance Deferral account?

Response:

It is not the Company's intention to capture the over/under provisions in the requested Income Tax Variance Deferral account, rather it is to be used to capture uncontrollable variances resulting from changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial or any other level of jurisdiction. The proposed Income Tax Variance deferral account would also accumulate any required compliance costs, including changes to information systems.

Any uncontrollable legislative and governmental changes that would impact income tax expense would most likely be known at the time of booking the year-end income tax provision and therefore are not expected to be the main drivers in a resulting over/under provision. The over/under provisions are not permanent variances, rather they are timing differences in which the income tax variance is trued-up the following year. In other words, the income tax variance over/under provision differs from a permanent variance that may result from legislative or governmental changes beyond the Company's control. For example, a change to a capital cost allowance rate would be included in the Income Tax Variance Deferral account because the variance would be permanent. Such a change could not be trued up from year to year in a manner similar to the over/under tax provision.

76.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.2, p. 114

Income Taxes- Income Tax Variance Deferral

"For purposes of the 2012 and 2013 revenue requirement, any additions to this rate base deferral account would be included in the deferred charges schedule and an amortization term of any accumulated variances will be proposed as part of the 2014 RRA." (p. 114)

76.1 Please explain why the Company considers it appropriate to classify the proposed deferral account as a rate base account as opposed to an interest bearing deferral account.

Response:

Please see the response to BCUC IR1 Q98.1 below.

There is no impact on 2012 or 2013 rates (including from financing costs) related to this account because the forecast balance in each is zero.

76.2 Would it be reasonable to assume that the accumulated variances in this type of deferral account would likely be recovered over a one year period? If not, please discuss.

Response:

Since the outcome of any tax legislative changes cannot be reasonably forecast at this time, a recovery period will be suggested as part of the 2014 Revenue Requirements Application. Depending on the value of the accumulated variance, the Company may suggest a recovery period that balances out the objective of mitigating customer rate increases while still ensuring that current customers pay for the current cost of service. If the value of the accumulated variance is not too significant, then a shorter recovery period, such as a one-year period, would likely be recommended.

77.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.2, pp. 109-115

Income Taxes - General

77.1 Has FortisBC taken any tax deductions in the past which it opted not to pass along to ratepayers at that time because the Company considered them to be aggressive or uncertain tax positions? Please explain.

Response:

The Company forecasts and files its tax positions, in what it believes to be, compliance with the Income Tax Act, tax law and rulings so that its corporate tax returns can be supported when under review by an external third party, such as the Canada Revenue Agency (CRA). Management is not aware of taking tax deductions in the past and opting not to pass them along to ratepayers because the Company considered them to be aggressive or uncertain tax positions.

78.0 Reference: Taxes

Exhibit B-1, Tab 4, Section 4.6.3, pp. 115-117

Harmonized Sales Tax-HST Reform Deferral Account

> "The HST referendum outcome and resulting decisions are out of the Company's control and we are not able to reasonably forecast the potential resulting effect, if any. Once reasonably determinable or estimable, the Company will bring forth the implications based on the outcome of the HST referendum. If the implications are not known prior to approval of final 2012 and 2013 rates, the Company is requesting approval to capture the related costs in a rate base deferral account for proposed disposition as part of the 2014 RRA." (Tab 4, p. 115)

78.1 Please explain why the Company considers it appropriate to classify the proposed deferral account as a rate base account as opposed to an interest bearing deferral account.

Response:

Please see the response to BCUC IR1 Q98.1 below.

There is no impact on 2012 or 2013 rates (including from financing costs) related to this account because the forecast balance in each is zero.

78.2 Would it be reasonable to assume that the accumulated variances in this type of deferral account would likely be recovered over a one year period? If not, please discuss.

Response:

On Friday, August 26, 2011, as a result of a public referendum the BC government announced that it will extinguish the federally administered HST system and reinstate PST with a current target date set for April 2013. Due to the complexities and current uncertainties around the unwinding of HST and reinstatement of the PST, the Company is not able to forecast the dollar amounts that could potentially be captured in the HST Removal or Reform Deferral Account at this time.

As a result, a recovery period will be suggested as part of the 2014 Revenue Requirements Application which will depend on the value of the accumulated variance. Depending on the amount accumulated in the variance deferral, the Company may suggest a recovery period that balances out the objective of mitigating customer rate increases while still ensuring that current customers pay for the current cost of service. If the value of the accumulated variances is not too significant, then a shorter recovery period, such as a one-year period, would likely be recommended.

FINANCING COSTS

79.0 Reference: Financing Costs

Exhibit B-1, Tab 4, Section 4.7, p. 117

Long-Term and Short-Term Debt

FortisBC states that “the allocation between long-term and short-term debt is managed by the Company”.

79.1 Please provide in tabular form FortisBC’s actual or forecast long-term debt, short-term debt and total debt (both in dollar amount and percentage) for the period 2009 to 2013.

Response:

The following tables show the Company’s actual or forecast long-term debt, short-term debt and total debt, both in dollar amounts and percentage, from 2009 through to 2013. Note that these tables are identical as to what was provided in Table 4.7.1-1 Weighted Average Cost of Debt (2010-2011) and Table 4.7.1-2 Weighted Average Cost of Debt (2012-2013) in the 2012-13 RRA, with the only difference being the addition of 2009 actual debt dollars and percentages.

Table BCUC IR1 79.1a

			2009 Actual		2010 Actual		2011 Approved	
Description of Debt	Maturity Dates	Rates	Weighted Average Balance	Interest Expense	Weighted Average Balance	Interest Expense	Weighted Average Balance	Interest Expense
			($000s)		($000s)		($000s)	
Long-Term Debt								
Series E	01-Dec-09	11.00%	3,591	378	-	-	-	-
Series F	16-Oct-12	9.65%	15,000	1,448	15,000	1,448	15,000	1,448
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953	25,000	1,953
Series J	31-Jul-09	6.75%	31,164	1,970	-	-	-	-
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,602	100,000	5,601
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	57,247	3,755	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	-	-	12,603	507	110,000	5,609
Series 2013	30 year est.	5.90%	-	-	-	-	-	-
Total Long-Term Debt			**527,002**	**33,363**	**552,603**	**34,174**	**650,000**	**39,275**
Weighted average rate on Long-Term Debt				**6.33%**		**6.18%**		**6.04%**
Short-Term Debt								
Draws on facility/deemed adjustment			(24,722)	(1,222)	(3,686)	(184)	5,945	220
Financing Fees								
Total Standby Fees				647		560		511
Total Banking Agreement Charges				485		410		260
Other financing fees				109		143		170
Demand Line interest				29		35		70
Total Financing Fees				1,270		1,148		1,011
Total Short-Term Debt			**(24,722)**	**48**	**(3,686)**	**964**	**5,945**	**1,231**
Weighted average rate on Short-Term Debt				**(0.19%)**		**(26.15%)**		**20.71%**
Total Long-Term and Short-Term Debt			**502,280**	**33,411**	**548,917**	**35,138**	**655,945**	**40,506**
Weighted average rate on Total Debt				**6.65%**		**6.40%**		**6.18%**

Table BCUC IR1 79.1b

			2011 Forecast ($000s)		2012 Forecast ($000s)		2013 Forecast ($000s)	
Description of Debt	Maturity Dates	Rates	Weighted Average Balance	Interest Expense	Weighted Average Balance	Interest Expense	Weighted Average Balance	Interest Expense
Long-Term Debt								
Series E	01-Dec-09	11.00%	-	-	-	-	-	-
Series F	16-Oct-12	9.65%	15,000	1,448	12,483	1,205	-	-
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953	25,000	1,953
Series J	31-Jul-09	6.75%	-	-	-	-	-	-
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,601	100,000	5,600	100,000	5,600
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000	100,000	5,000
Series 2013	30 year est.	5.90%	-	-	-	-	25,151	1,484
Total Long-Term Debt			**640,000**	**38,666**	**637,483**	**38,422**	**650,151**	**38,701**
Weighted average rate on Long-Term Debt				**6.04%**		**6.03%**		**5.95%**
Short-Term Debt								
Draws on facility/deemed adjustment			2,718	(110)	49,669	2,002	77,158	4,004
Financing Fees								
Total Standby Fees				458		367		301
Total Banking Agreement Charges				150		275		280
Other financing fees				165		180		190
Demand Line interest				36		74		77
Total Financing Fees				809		896		848
Total Short-Term Debt			**2,718**	**699**	**49,669**	**2,898**	**77,158**	**4,852**
Weighted average rate on Short-Term Debt				**25.72%**		**5.83%**		**6.29%**
Total Long-Term and Short-Term Debt			**642,718**	**39,365**	**687,152**	**41,320**	**727,309**	**43,553**
Weighted average rate on Total Debt				**6.12%**		**6.01%**		**5.99%**

80.0 Reference: Financing Costs

Exhibit B-1, Tab 4, Section 4.7, p. 118

Table 4.7 Financing Costs

80.1 Please include a new column in Table 4.7 with the Approved 2011 data.

Response:

Table 4.7 on page 118, Tab 4 of the 2012-13 RRA incorrectly labeled the column related to "Approved 2011" data as "Approved 2010". The revised table with the updated title is shown below. Please also refer to Errata 2.

Table BCUC IR1 80.1

	Actual 2010	**Approved 2011**	Forecast 2011	Forecast 2012	Forecast 2013
			($000s)		
CAPITALIZATION					
Debt	548,917	655,945	642,718	687,152	727,309
Common Equity	396,927	437,296	428,479	458,101	484,872
	945,844	1,093,241	1,071,197	1,145,253	1,212,181
Equity as % of Total	42%	40%	40%	40%	40%
EARNED RETURN					
Interest Expense	35,138	40,506	39,364	41,320	43,553
Net Earnings	38,293	43,292	45,922	45,352	48,002
	73,431	83,798	85,286	86,672	91,555
RETURN ON CAPITAL					
Weighted Average Cost of Debt	6.40%	6.18%	6.12%	6.01%	5.99%
Return on Equity	9.65%	9.90%	10.72%	9.90%	9.90%
Weighted Average Cost of Capital	7.76%	7.67%	7.96%	7.57%	7.55%

81.0 Reference: Cost of Debt

Exhibit B-1, Tab 4, Section 4.7.1, p. 119

Table 4.7.1-1 Weighted Average Cost of Debt (2010-2011)

81.1 In Table 4.7.1-1, please provide the information on the issuance date for each of the Long-Term Debt Series.

Response:

Table 5.4.5-8 in Tab 5 of the 2012-13 RRA contained the issuance date information from 2005 onwards; however the table included in the response to BCUC IR1 Q81.3 shows the issuance dates for all long-term debt.

81.2 In Table 4.7.1-1, please indicate whether the rates for the Long-Term Debt Series correspond to the coupon rates or the all-in rates that include the issuance costs.

Response:

The rates for the Long-Term Debt Series in Table 4.7.1-1 in Tab 4 of the 2012-13 RRA are the coupon rates only and do not include debt issuance costs. The Company recovers the coupon interest rate on its long term debt instruments through Cost of Debt and the debt issuance costs through amortization of Deferred Charges. This treatment is consistent with previous revenue requirement applications and is in compliance with US GAAP.

81.3 Please provide the issuance costs (in dollar amount and percentage of the debt debentures) and amortization schedule for each of the Long-Term Debt Series in Table 4.7.1-1.

Response:

Please refer to the below table.

Table BCUC IR1 81.3 Long-Term Debt and Amortization of Debt Issuance Costs Schedule

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast
Series	**Series F**	**Series G**	**Series H**	**Series I**	**Series 1 - 04**	**Series 1 - 05**	**Series 1 - 07**	**MTN Series 1 - 2009**	**MTN Series 2 - 2010**	**Series 2013**
	($000s)									
Principal	$ 15,000	$ 25,000	$ 25,000	$ 25,000	$ 140,000	$ 100,000	$ 105,000	$ 105,000	$ 100,000	$ 120,000
Coupon rate	9.65%	8.80%	8.77%	7.81%	5.48%	5.60%	5.90%	6.10%	5.00%	5.90%
Issuance Date	16-Oct-92	27-Aug-93	01-Feb-96	15-Apr-97	30-Nov-04	10-Nov-05	04-Jul-07	02-Jun-09	24-Nov-10	2013
Maturity Date	16-Oct-12	28-Aug-23	01-Feb-16	01-Dec-21	28-Nov-14	09-Nov-35	04-Jul-47	02-Jun-39	24-Nov-50	2043
Term (years)	20	30	20	25	10	30	40	30	40	30
Issuance Costs ($)	$ 322	$ 244	$ 272	$ 331	$ 2,124	$ 1,241	$ 1,246	$ 991	$ 903	$ 1,587
Issuance Costs (% of debt)	2.1%	1.0%	1.1%	1.3%	1.5%	1.2%	1.2%	0.9%	0.9%	1.3%

									(A)	
Debt Issuance Costs subject to amortization	$ 322	$ 244	$ 272	$ 331	$ 2,124	$ 1,241	$ 1,246	$ 991	$ 903	$ 1,587
1992	(2)									
1993	(13)	(3)								
1994	(13)	(9)								
1995	(13)	(9)								
1996	(13)	(9)	(14)							
1997	(13)	(9)	(14)	-						
1998	(13)	(9)	(14)	(13)						
1999	(13)	(9)	(14)	(13)						
2000	(13)	(9)	(14)	(13)						
2001	(13)	(9)	(14)	(13)						
2002	(13)	(9)	(14)	(13)						
2003	(13)	(9)	(14)	(13)						
2004	(13)	(9)	(14)	(13)						
2005	(13)	(9)	(14)	(13)	(193)					
2006	(13)	(9)	(14)	(13)	(215)	(42)				
2007	(13)	(9)	(14)	(14)	(215)	(42)	-			
2008	(13)	(9)	(14)	(14)	(215)	(42)	(31)			
2009	(11)	(9)	(13)	(15)	(214)	(41)	(32)			
2010	(35)	(7)	(11)	(14)	(214)	(41)	(31)	(34)	-	
2011	(39)	(7)	(13)	(14)	(219)	(42)	(32)	(34)	(23)	
2012	(29)	(7)	(13)	(14)	(219)	(42)	(32)	(34)	(23)	
2013		(7)	(13)	(14)	(219)	(42)	(32)	(34)	(23)	
2014		(7)	(13)	(14)	(200)	(42)	(32)	(34)	(23)	(53)
2015		(7)	(13)	(14)		(42)	(32)	(34)	(23)	(53)
2016		(7)	-	(14)		(42)	(32)	(34)	(23)	(53)
2017		(7)		(14)		(42)	(32)	(34)	(23)	(53)
2018		(7)		(14)		(42)	(32)	(34)	(23)	(53)
2019		(7)		(14)		(42)	(32)	(34)	(23)	(53)
2020		(7)		(14)		(42)	(32)	(34)	(23)	(53)
2021		(7)		(13)		(42)	(32)	(34)	(23)	(53)
2022		(7)				(42)	(32)	(34)	(23)	(53)
2023		(4)				(42)	(32)	(34)	(23)	(53)
2024						(42)	(32)	(34)	(23)	(53)
2025						(42)	(32)	(34)	(23)	(53)
2026						(42)	(32)	(34)	(23)	(53)
2027						(42)	(32)	(34)	(23)	(53)
2028						(42)	(32)	(34)	(23)	(53)
2029						(42)	(32)	(34)	(23)	(53)
2030						(42)	(32)	(34)	(23)	(53)
2031						(42)	(32)	(34)	(23)	(53)
2032						(42)	(32)	(34)	(23)	(53)
2033						(42)	(32)	(34)	(23)	(53)
2034						(42)	(32)	(34)	(23)	(53)
2035						(36)	(32)	(34)	(23)	(53)
2036							(32)	(34)	(23)	(53)
2037							(32)	(34)	(23)	(53)
2038							(32)	(34)	(23)	(53)
2039							(32)	(14)	(23)	(53)
2040							(32)		(23)	(53)
2041							(32)		(23)	(53)
2042							(32)		(23)	(53)
2043							(32)		(23)	(53)
2044							(32)		(23)	
2045							(32)		(23)	
2046							(32)		(23)	
2047							(16)		(23)	
2048									(23)	
2049									(23)	
2050									(20)	
Remaining amortization	-	-	-	-	-	-	-	-	-	-

'(A) – The original estimate of the MTN Series 2 - 2010 debt issuance cost of $941,000 was reduced by $38,000 to $903,000 in 2011 as a result of actual costs being less than the accrual. This balance agrees to Table 1-B Deferred Charges and Credits (2011) included in Tab 7 of the 2012-13 RRA.

Note that minor adjustments to the amortization of debt issuance costs are occasionally required as a result of rounding.

81.4 For the Short-Term Debt, please explain the variance between the ‘2011 Approved’ and ‘2011 Forecast’ figure for each of the: 1) weighted average balance; 2) interest expense; and 3) financing fees (i.e., standby fees, banking agreement charges, other financing fees and demand line interest).

Response:

Please refer to Table BCUC IR1 81.4.

Table BCUC IR1 81.4 2011 Weighted Average Cost of Short-Term Debt - Approved Compared to Forecast

Description of Debt	Maturity Dates	Rates	2011 Approved Weighted Average Balance ($000s)	2011 Approved Interest Expense	2011 Forecast Weighted Average Balance ($000s)	2011 Forecast Interest Expense	Variance Weighted Average Balance ($000s)	Variance Interest Expense and Rates
Short-Term Debt								
Draws on facility/deemed adjustment			5,945	220	2,718	(110)	(3,227)	(330)
Financing Fees								
Total Standby Fees				511		458		(53)
Total Banking Agreement Charges				260		150		(110)
Other financing fees				170		165		(5)
Demand Line interest				70		36		(34)
Total Financing Fees				1,011		809		(202)
								-
Total Short-Term Debt			**5,945**	**1,231**	**2,718**	**699**	**(3,227)**	**(532)**
								-
Weighted average rate on Short-Term Debt				**20.71%**		**25.72%**		**5.01%**

Short-Term Debt – (1) Weighted average balance, (2) interest expense and (3) financing fees

The Company’s Short-Term Debt consists of the weighted average balance of the operating credit facilities draws, or the deemed debt adjustment, and the relatively fixed financing fees.

Draws on Facility/Deemed adjustment and interest expense

Under short-term debt, the line item “Draws on Facility/Deemed adjustment” consists of a weighted average balance and an interest expense amount.

The short-term debt weighted average balance is representative of the approximate amount of draws on the Company’s operating credit facility which are used to make up the shortfall or overage between the issued long-term debt and the 60 percent component of deemed debt used to finance rate base as required under the Company’s approved capital structure pursuant to Commission Order G-58-06. In other words, this short-term debt weighted average balance is not based on a forecast of monthly debt draws, rather it is the deemed amount to ensure that total regulated debt equals the 60 percent debt structure.

The interest expense portion of this short-term debt balance is generally based on an interest rate equivalent to a mix of Bankers’ Acceptances and prime rate loans. An exception to this rate would be instances where the weighted average balance/deemed adjustment line is a negative, which suggests that, along with the interest expense on the operating credit facility, a portion of the long-term debt interest expense may be deemed out of regulated operations.

For 2011 Forecast Short-Term Debt, there is a short-term debt weighted average balance of $2.718 million and an interest expense recovery of $0.110 million. Based on the methodology previously described, the short-term debt weighted average balance is necessary to achieve the 60 percent debt structure and the related interest expense should be a positive amount based on a rate that uses a mix of Bankers' Acceptances and prime rate loans.

In this circumstance, the forecast 2011 interest expense on the weighted average balance of short-term debt (draws on facility/deemed adjustment) should have been a positive balance of approximately (3% x $2.718 million) $0.082 million instead of a recovery of $0.110 million. This difference of approximately $0.2 million results in the understatement of regulated short-term interest included in the 2012-13 RRA. FortisBC will incorporate this adjustment to interest expense in its final calculation of rates.

Financing Fees

The majority of the $0.2 million decreased variance between approved and forecast 2011 Financing Fees relates to the standby fees and banking agreement charges. The standby fees and banking agreement charges used to determine the 2011 Approved cost of debt were based on the terms and rates from the Company's most recent renegotiated operating credit facility agreement dated April 30, 2010 which was approved pursuant to Commission order G-74-10. The standby fees and banking agreement charges used to determine the 2011 Forecast cost of debt are based on the terms and rates from the Company's most recent renegotiated operating credit facility agreement dated April 28, 2011 which was approved pursuant to Commission Order G-59-11.

In addition to the savings obtained through the latest operating credit facility agreement, the Company has revised its forecast of the demand line (overdraft facility) interest expense downwards, based on less volume of draws resulting from an increase in cash flows from operations caused partially by a decrease in power purchase costs.

The result of the renegotiated terms and favourable pricing of the April 28, 2011 operating credit facility has resulted in a $0.2 million decrease in financing fees which has been flowed back 100 percent to customers as a reduction in 2012 revenue requirements.

81.4.1 Please also explain why, for the 2011 Forecast data, the Short-Term Debt Balance is positive while the interest expense is negative.

Response:

Please see the response to BCUC IR1 Q81.4.

82.0 Reference: Long-Term Debt Financing

Exhibit B-1, Tab 4, Section 4.7.1.1, p. 121

2012 Debt Maturity

FortisBC states that "FortisBC has $15.0 million in Secured Debentures due for redemption on October 16, 2012."

82.1 Please explain whether FortisBC plans to issue more secured debt in the future. If not, please explain why not.

Response:

For the period of 2012 to 2013, the Company currently does not plan to issue any additional secured debt. The Company's debt covenants restrict the amount of secured debt the Company may issue. The forecast 2013 debt issuance is expected to be unsecured debt.

83.0 Reference: Forecast of Long-Term Interest Rates for 2013 Debt Debenture

Exhibit B-1, Tab 4, Section 4.7.1.1, p. 122

Table 4.7.1.1 Long-Term Interest Rate Forecast

83.1 For the 30-year Government of Canada Bond average forecast rate of 4.45%, on which date were each of the forecasts made by the four Canadian chartered banks realized. Please provide the supporting documentation.

Response:

Please refer to the below table.

Table BCUC IR1 83.1

Canadian Chartered Bank	Publication Date	Q4-2012	2013
Toronto Dominion Quarterly Economic Forecast	March 16, 2011	4.40%	N/A
Scotia Economics Global Forecast	May 3, 2011	4.50%	N/A
CIBC World Markets Economic Insights	April 29, 2011	4.25%	N/A
RBC Capital Market Forecasts	May 3, 2011	4.55%	N/A
Average of Q4-2012 GofC 30 year rates (no 2013 forecasts published) used since issuance expected in late 2013		4.43%	N/A
Rounded up to nearest 0.05%		0.02%	
30 year Government of Canada Bond used in Table 4.7.1.1		4.45%	

The Company used the most recent publications available at the time of forecasting for the 2012-13 RRA during late May 2011. FortisBC expects to issue its next long-term debenture in the second half of 2013, however the forecast publications from the Canadian Chartered Banks only provide forecasts until the end of 2012. Therefore the Company has used an average of the 30 year Government of Canada Bond rates forecast for the fourth quarter of 2012 as the closest approximation.

The Canadian Chartered bank publications themselves are attached as Appendix BCUC IR1 83.1.

83.2 Please indicate whether the "all-in 30-year borrowing rate" is the coupon rate or the rate that includes the issuance costs.

Response:

The all-in 30 year borrowing rate in Tab 4, Table 4.7.1.1 of the 2012-13 RRA is the coupon rate which has been used as a component in the determination of the costs of debt. The issuance costs described and quantified in Tab 5, Table 5.4.5-7 Forecast Debt Issue Costs, will be recovered in cost of service by way of amortization of deferred charges.

83.3 Please provide similar data as in Table 4.7.1.1 for the 2009 and 2010 debt issuance (actual data as opposed to forecast).

Response:

Please refer to Table BCUC IR1 83.3 below.

Table BCUC IR1 83.3

	2009A	2010A	2013F
Series	MTN Series 1	MTN Series 1	2013 Issuance
Date of Issuance	2-Jun-09	24-Nov-10	2013
Term (Years)	30	40	30
30-year Government of Canada Bond	4.15%	3.66%	4.45%
Long-term Debt Rate Spread	1.95%	1.35%	1.45%
All-in Borrowing Rate	**6.10%**	***5.01%**	**5.90%**

*As per the November 19, 2010 Pricing Supplement No. 2 to a Short Form Base Shelf Prospectus dated May 22, 2009, the debt was issued at a yield of 5.01% compared to a coupon of 5.00% with the difference creating a debt discount of $0.172 million, which was included in the debt issuance costs included in the deferred charge schedule.

83.4 Please provide the 10-year Government of Canada Bond rate at the issuance date of the 2010 debt and the indicative credit spread for the 10-year term.

Response:

It is not possible to provide the exact 10-year indicative spreads on the pricing date of issuance as the Company was contemplating between a 30 and 40 year term due to the attractive all-in long-term rates, therefore the 10 year term pricing information was generally not considered on the day of issuance. When an issuer goes to market with a public debt offering, a single debt instrument, with a defined term, is presented to potential investors for pricing. Once the market has received the offering, the issuer is committed to execute on those terms and to change the process could result in increased costs and decreased investor confidence. Therefore comparing costs for 10 year and 30 year terms cannot reasonably be done for a Company's specific debt issue at the time of the offering, nor is it recommended.

To provide a general sense of comparison, three days subsequent to the pricing of the 2010 MTN debt issuance, the 10 year Government of Canada Bond rate was 3.171 percent, however it is important to note that this rate would have differed from the actual rate on the date of pricing.

In addition, on December 8, 2010, the Company did file in confidence a range of 10 year Government of Canada Bond rates and 10 year indicative spreads provided by the various banks as part of the Medium Term Note Debentures 2010 post-issuance analysis filed with the BCUC pursuant to Commission Order G-51-09. In the weeks leading up to the actual pricing and issuance of the 2010 MTN debentures, the all-in 10 year rate (10 year Government of Canada Bond rate plus 10-year indicative spreads) ranged from 3.90% to 4.20% for FortisBC.

It should be noted that since this range of all-in rates for a 10 year term include indicative spreads, that these rates were still estimates and may not have been entirely reflective of the actual market pricing.

83.5 Please provide similar data as in Table 4.7.1.1 for the proposed 2013 debt issuance using a 10-year term for the Government of Canada Bond instead of a 30-year term.

Response:

The 2013 debt issuance interest rate forecast for the 10-year Government of Canada Bond is based on the average of projections by four Canadian Chartered banks. Credit spreads on new 10-year debt using a term of 10 years, approximate current indicative rates specific to FortisBC.

Table BCUC IR1 83.5 10-Year Debt Interest Rate Forecast

10 year-term Interest Rate Forecast	
10-year Government of Canada Bond	4.15%
Long-term Debt Rate Spread	1.14%
All-in 10-year Borrowing Rate	5.29%

83.6 Please elaborate on possible reasons including market conditions on why the utility may issue 40-year, 30-year, or 10-year debt.

Response:

When choosing the anticipated issue term of 40-year, 30-year or 10-year, FortisBC considers (1) the expected useful life of its assets, (2) the frequency of exposure to market conditions, (3) the estimated coupon rate at time of issuance compared to historical rates, and (4) the frequency of incurring issue costs when choosing the anticipated issue term of 30 years or more. These factors are discussed in more detail below.

(1) FortisBC's rationale for choosing longer-term debt (30 or 40 years) is typically to attempt to match the term of debt instruments to the life of the underlying assets being financed.

(2) Issuing debt at a term of less than 30 years exposes the Company to the risk of the markets on a more frequent basis. For example, issuing debt each time with a term of 10 years would expose the Company to potential market volatility on three different occasions. A single issuance with a term of 30 years would expose the Company to market volatility only once during the comparable time and embed that fixed interest expense in the Company's cost of service over the long-term. Exposure to market rates over a long-term period can result in significant volatility.

(3) The Company considers the estimated coupon rate at the time of issuance compared to the historical rates based on its embedded long-term debt. In the case of the 2010 MTN debenture issuance, the difference in the interest rate for a 30 year as compared to a 40 year term was minimal therefore the Company took advantage of the 40 year opportunity. The 40 year debt at 5.0% represents the lowest coupon of all the Company's embedded long-term debt and those savings have been embedded for the benefit of customers over the next 40 years.

(4) Issuing longer term debt to finance long lived assets allows the Company to avoid incurring new debt issue costs multiple times over the life of the underlying assets.

Based on these factors, the Company prefers to issue debt with a term of 30 or 40 years; however the final decision regarding the term would be made based on market factors closer to the time of actual issuance.

84.0 Reference: Short-Term Debt Financing

Exhibit B-1, Tab 4, Section 4.7.1.1, p. 121; Section 4.7.1.2, p. 123

Operating Credit Facilities

FortisBC states "Generally, when the Company's $150 million operating credit facilities and upcoming debt maturities reach approximately $100 million, the Company prepares to issue longer term public debt. Proceeds are then used to repay the credit facilities, provide for upcoming cash outflows and refinance maturing debt."

FortisBC also states "The amended operating credit facility is comprised of a $100.0 million, three year revolving facility maturing on May 7, 2014 and a $50.0 million, 364-day revolving facility maturing on May 3, 2012."

84.1 Please provide the monthly balances, actual or forecast, for each of the two operating credit facilities for 2010, 2011, 2012 and 2013.

Response:

In determining the annual 2010 actual and 2011 – 2013 forecast operating credit facility balances, the Company does not estimate draws on its operating credit facility on a monthly basis. The forecast operating credit facility balances are represented in the Short-Term Debt balance line item "Draws on facility/deemed adjustment" in Table 4.7.1-1 Weighted Average Cost of Debt (2010-2011) and Table 4.7.1-2 Weighted Average Cost of Debt (2012-2013) in Tab 4 of the 2012-13 RRA. Rather than calculate on a monthly basis, the weighted average balances for the operating credit facilities are deemed adjustments to make up the variance between the Company's actual and forecast long-term debt balances and the 60 percent component of deemed debt used to finance rate base as required under the Company's approved capital structure pursuant to Commission Order G-58-06.

84.2 Please explain what FortisBC plans to do to replace the $50.0 million operating credit facility maturing next year.

Response:

Each year both Facility A ($100.0 million) and B ($50.0 million) are rolled over for another year.

85.0 Reference: Forecast of Short-Term Interest Rates for 2012-2013

Exhibit B-1, Tab 4, Section 4.7.1.2, p. 123

Table 4.7.1.2-1 Short-Term Interest Rate Forecast

Table 4.7.1.2-2 Short-Term Interest Expense Forecast

85.1 Please also provide the data in Table 4.7.1.2-1 for the years 2009 (actual), 2010 (actual) and 2011 (forecast).

Response:

Below is the data for the years 2009 (actual), 2010 (actual) and 2011 (forecast, which includes several months of actual), in a format similar to Table 4.7.1.2-1 of the 2012-13 RRA.

Table BCUC IR1 85.1

Bankers' Acceptances	**2009A**	**2010A**	**2011F**
Bankers' Acceptance Rates (3 month T-bill)	0.78%	0.80%	1.50%
Acceptance Fee Rate	1.48%	2.25%	1.41%
Bankers' Acceptance Rate	2.26%	3.05%	2.92%
Prime Rate Loan	**2009A**	**2010A**	**2011F**
Prime Rate (Overnight Bank Rate plus 200bp)	2.25%	2.50%	3.38%
Prime Rate Margin	1.50%	1.13%	0.37%
Prime Interest Rate	3.75%	3.63%	3.75%
Weighted Average Short-Term Debt Rate	2.30%	3.07%	3.00%

85.2 Please provide the supporting documentation with respect to the four Canadian chartered banks' forecasts of the Bankers' Acceptance Rates and Prime Interest rate.

Response:

Please refer to the below tables.

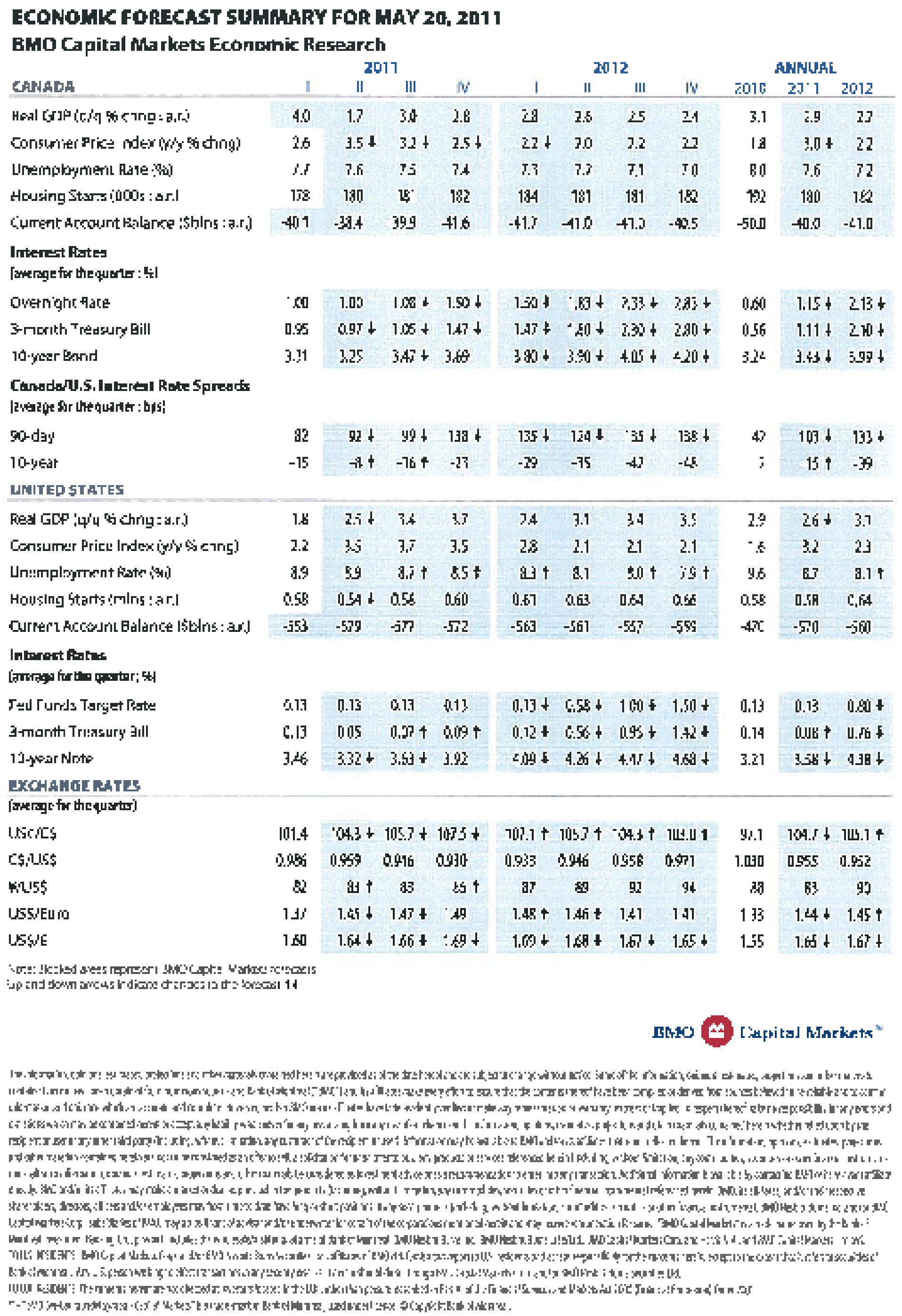
Table BCUC IR1 85.2a Bankers' Acceptance Rates on Term Bank Debt (3 month T-bill)

		2012					2013
Canadian Chartered Bank	Publication Date	Q1	Q2	Q3	Q4	Average	Annual
BMO Capital Markets Research	May 20, 2011	1.47%	1.80%	2.30%	2.80%	2.09%	N/A
Toronto Dominion Quarterly Economic Forecast	March 16, 2011	2.25%	2.50%	2.80%	3.05%	2.65%	3.80%
Scotia Economics Global Forecast	May 3, 2011	2.20%	2.30%	2.30%	2.30%	2.28%	N/A
CIBC World Markets Economic Insights	April 29, 2011	1.85%	1.85%	1.85%	1.90%	1.86%	N/A
RBC Captial Market Forecasts	May 3, 2011	2.40%	2.65%	2.90%	3.15%	2.78%	N/A
Average rate		***2.03%***	***2.22%***	***2.43%***	***2.64%***	***2.33%***	*3.80%*
Spread		0.30%	0.30%	0.30%	0.30%	0.30%	0.10%
Sub total before Stamping Fee		2.33%	2.52%	2.73%	2.94%	2.63%	3.90%
Rounded up to nearest 0.10%		**2.40%**	**2.60%**	**2.80%**	**3.00%**	**2.70%**	**3.90%**

Table BCUC IR1 85.2a Prime Rate (Overnight Bank Rate plus 200 basis points)

		2012					2013
Canadian Chartered Bank	Publication Date	Q1	Q2	Q3	Q4	Average	Annual
BMO Capital Markets Research	May 20, 2011	1.50%	1.83%	2.33%	2.83%	2.12%	N/A
Toronto Dominion Quarterly Economic Forecast	March 16, 2011	2.25%	2.50%	2.75%	3.00%	2.63%	3.75%
Scotia Economics Global Forecast	May 3, 2011	2.00%	2.25%	2.25%	2.25%	2.19%	2.75%
CIBC World Markets Economic Insights	April 29, 2011	2.00%	2.00%	2.00%	2.25%	2.06%	N/A
RBC Captial Market Forecasts	May 3, 2011	2.25%	2.50%	2.75%	3.00%	2.63%	N/A
Average rate		**2.00%**	**2.22%**	**2.42%**	**2.67%**	**2.32%**	**3.25%**
Add 200 basis points		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Sub total before prime rate margin fee		4.00%	4.22%	4.42%	4.67%	4.32%	5.25%
Rounded up to nearest 0.25%		**4.00%**	**4.25%**	**4.50%**	**4.75%**	**4.50%**	**5.25%**

The above tables make reference to Canadian Chartered Bank publications which are included in the response to BCUC IR1 Q83.1 with one exception. BMO Capital Markets did not provide an estimate for 30 year debt and therefore was not included in the response to BCUC IR1 Q83.1. BMO Capital Markets do however provide forecast rates for Bankers' Acceptances and Prime Rate which have been used to forecast the above rates, therefore the publication is included as follows.



ECONOMIC FORECAST SUMMARY FOR MAY 20, 2011

BMO Capital Markets Economic Research

	2011				2012				ANNUAL		
CANADA	I	II	III	IV	I	II	III	IV	2010	2011	2012
Real GDP (q/q % chng : a.r.)	4.0	1.7	3.0	2.8	2.8	2.6	2.5	2.4	3.1	2.9	2.7
Consumer Price Index (y/y % chng)	2.6	3.5 ↓	3.2 ↓	2.5 ↓	2.2 ↓	2.0	2.2	2.2	1.8	3.0 ↓	2.2
Unemployment Rate (%)	7.7	7.6	7.5	7.4	7.3	7.2	7.1	7.0	8.0	7.6	7.2
Housing Starts (000s : a.r.)	178	180	181	182	184	181	181	182	192	180	182
Current Account Balance ($blns : a.r.)	-40.1	-38.4	39.9	-41.6	-41.7	-41.0	-41.0	-40.5	-50.0	-40.0	-41.0
Interest Rates (average for the quarter : %)											
Overnight Rate	1.00	1.00	1.08 ↓	1.50 ↓	1.50 ↓	1.83 ↓	2.33 ↓	2.83 ↓	0.60	1.15 ↓	2.13 ↓
3-month Treasury Bill	0.95	0.97 ↓	1.05 ↓	1.47 ↓	1.47 ↓	1.80 ↓	2.30 ↓	2.80 ↓	0.56	1.11 ↓	2.10 ↓
10-year Bond	3.31	3.25	3.47 ↓	3.69	3.80 ↓	3.90 ↓	4.05 ↓	4.20 ↓	3.24	3.44 ↓	3.99 ↓
Canada/U.S. Interest Rate Spreads (average for the quarter : bps)											
90-day	82	92 ↓	99 ↓	138 ↓	135 ↓	124 ↓	135 ↓	138 ↓	47	103 ↓	133 ↓
10-year	-15	-8 ↑	-16 ↑	-23	-29	-35	-42	-45	7	15 ↑	-39
UNITED STATES											
Real GDP (q/q % chng : a.r.)	1.8	2.5 ↓	3.4	3.7	2.4	3.1	3.4	3.5	2.9	2.6 ↓	3.1
Consumer Price Index (y/y % chng)	2.2	3.5	3.7	3.5	2.8	2.1	2.1	2.1	1.6	3.2	2.3
Unemployment Rate (%)	8.9	8.9	8.7 ↑	8.5 ↑	8.3 ↑	8.1	8.0 ↑	7.9 ↑	9.6	8.7	8.1 ↑
Housing Starts (mlns : a.r.)	0.58	0.54 ↓	0.56	0.60	0.61	0.63	0.64	0.66	0.58	0.58	0.64
Current Account Balance ($blns : a.r.)	-553	-579	-577	-572	-563	-561	-557	-555	-470	-570	-560
Interest Rates (average for the quarter : %)											
Fed Funds Target Rate	0.13	0.13	0.13	0.13	0.13 ↓	0.58 ↓	1.00 ↓	1.50 ↓	0.13	0.13	0.80 ↓
3-month Treasury Bill	0.13	0.05	0.07 ↑	0.09 ↑	0.12 ↓	0.56 ↓	0.95 ↓	1.42 ↓	0.14	0.08 ↑	0.76 ↓
10-year Note	3.46	3.32 ↓	3.63 ↓	3.92	4.09 ↓	4.26 ↓	4.47 ↓	4.68 ↓	3.21	3.58 ↓	4.38 ↓
EXCHANGE RATES (average for the quarter)											
USc/C$	101.4	104.3 ↓	105.7 ↓	107.5 ↓	107.1 ↑	105.7 ↑	104.3 ↑	103.0 ↑	97.1	104.7 ↓	105.1 ↑
C$/US$	0.986	0.959	0.946	0.930	0.933	0.946	0.958	0.971	1.030	0.955	0.952
¥/US$	82	83 ↑	83	85 ↑	87	89	92	94	88	83	90
US$/Euro	1.37	1.45 ↓	1.47 ↓	1.49	1.48 ↑	1.46 ↑	1.41	1.41	1.33	1.44 ↓	1.45 ↑
US$/£	1.60	1.64 ↓	1.66 ↓	1.69 ↓	1.69 ↓	1.68 ↓	1.67 ↓	1.65 ↓	1.55	1.65 ↓	1.67 ↓

Note: Blocked areas represent BMO Capital Markets forecasts
Up and down arrows indicate changes to the forecast ↑↓

BMO Capital Markets

85.3 Please also provide the data in Table 4.7.1.2-2 for the years 2009 (approved and actual), 2010 (approved and actual) and 2011 (approved and forecast).

Response:

Table BCUC IR1 85.3 provides a high level comparison of the totals for 2009 (approved and actual), 2010 (approved and actual) and 2011 (approved and forecast) short-term interest in a format similar to Table 4.7.1.2-2.

Table BCUC IR1 85.3

Column	(A)	(B)	(C)	(D)
Description	**Actual Bankers' Acceptance Rate & Prime Interest Rate (from BCUC IR 85.1)**	**All-In Interest Rate (including deemed adjustment)**	**Draws on Facility/Deemed Adjustment ($000s)**	**Short Term Interest Expense ($000s)**
Approved 2009	n/a	5.00%	4,812	241
Actual 2009	2.30%	4.94%	(24,722)	(1,222)
Approved 2010	n/a	4.50%	24,110	1,085
Actual 2010	3.07%	5.00%	(3,686)	(184)
Approved 2011	n/a	3.70%	5,945	220
Forecast 2011	3.00%	3.00%	2,718	*82

**The Forecast 2011 Short-Term Interest Expense rate included in the above table as compared to the negative $0.110 million of interest included in the 2012-13 RRA is discussed further in the response to BCUC IR 81.4.*

(A) Actual Bankers' Acceptance Rate & Prime Interest Rate (from BCUC IR1 Q85.1)

The rates in this column are consistent with those provided in the response to BCUC IR1 Q85.1. These rates are based on the actual monthly balances and rates drawn on the operating credit facilities.

(B) All-Interest Rate (including deemed adjustment)

The rates in this column are those used to calculate the short-term interest expense for actual, approved and forecast purposes for 2009 through to 2011. These rates are based on a mix of monthly interest associated with Bankers' Acceptance Rates, Acceptance Fee Rates, Prime Rates and Prime Rate Margins as described in column (A). Adjustments are required to the operating credit facility rates in instances where the weighted average balance/deemed debt adjustment line is negative, which suggests that, along with the interest expense on the operating credit facility, a portion of the long-term debt interest expense may be deemed out of regulated operations.

(C) Draws on Facility/Deemed Debt Adjustment

The short term debt weighted average balance is representative of the deemed amount of draws on the Company's operating credit facility which are used to make up the shortfall or overage between the issued long-term debt and the 60 percent component of deemed debt used to finance rate base as required under the Company's approved capital structure pursuant to Commission Order G-58-06. In other words, this short term debt weighted average balance is not based on a forecast of monthly debt draws, rather it is the deemed amount to ensure that total regulated debt equals the 60 percent debt structure.

(D) Short Term Interest Expense

This column represents the multiplication of the All-Interest Rate (including deemed adjustment) (Column B) with Draws on Facility/Deemed Debt Adjustment (Column C) to arrive at short-term interest expense for regulatory purposes.

86.0 Reference: Forecast of Financing Fees for 2012-2013

Exhibit B-1, Tab 4, Section 4.7.1.2, p. 125

Standby fees

FortisBC states "The forecast standby fee rate for 2012 and 2013 is 0.30 percent. This fee compensates the bank syndicate for providing continued access to the operating credit facility on short notice."

86.1 Please provide the standby fee rate for 2009, 2010 and 2011.

Response:

Table BCUC IR1 86.1 Standby Fee Rate for FortisBC's Operating Credit Facilities

Year (Actual)	Effective Date	Facility A	Facility B
2009	January 2009 to May 2009	0.100	0.100
	May 2009 to December 2009	0.750	0.625
2010	January 2010 to May 2010	0.750	0.625
	May 2010 to October 2010	0.500	0.438
	October 2010 to December 2010	0.438	0.375
2011	January 2011 to May 2011	0.438	0.375
	May 2011 to December 2011	0.300	0.300

87.0 Reference: Allowed Return of Equity

Exhibit B-1, Tab 4, Section 4.7.2, p. 127

2012 and 2013 Revenue Requirements ROE

FortisBC states "FortisBC's ROE remained at 9.90 percent for the 2011 RRA pursuant to Commission Order G-162-09. For purposes of the 2012-13 RRA, FortisBC has continued to use an ROE of 9.90 percent, calculated as FEI's approved 9.50 percent ROE pursuant to the FortisBC Energy Utilities ROE Decision and layering on FortisBC's 40 basis points risk premium pursuant to Commission Order G-58-06."

87.1 Please clarify which ROE would FortisBC be seeking approval for if FEI's approved ROE were to change. Would FortisBC be seeking approval for the same calculation method, i.e., benchmark ROE plus 40 basis points risk premium or for an ROE of 9.90%?

Response:

Assuming FEI's approved ROE remains the benchmark ROE, if it were to change, FortisBC's revised ROE would equal the new FEI approved ROE, plus the 40 basis points risk premium which was approved pursuant to Commission Order G-58-06.

87.2 Please provide a detailed explanation for the variance between the 2011 forecast ROE of 10.72% and the 2011 approved ROE of 9.90%. In addition to explaining the percentage variance, please also explain the difference in the dollar amounts and the source of additional return.

Response:

Please refer to the response to BCUC IR1 Q94.1 and BCMEU IR1 Q6.

DEPRECIATION

88.0 Reference: Depreciation and Amortization

Exhibit B-1, Tab 4, Section 4.7.3.6,Table 4.7.3.6, p. 134; Section 4.7.3.4, p. 131; Appendix J, Section III-4, p.44; Order G-58-06

Depreciation Rates for Transmission – Station Equipment (Accounts 353) and Structures – Masonry (Account 390.1)

FortisBC states that "Pursuant to Order G-58-06,…the proposed depreciation rates for six asset classes…were adjusted downwards to 3.0 percent in order to reflect longer average service lives for those assets… The parties did not agree that the findings of the Depreciation Study were otherwise appropriate and no precedent value was attached to the Depreciation Study" (Tab 4, p. 131). A summary of those six asset classes with their recommended depreciation rates for 2012-2013 follows:

Account	Description	2006 Depreciation Study	Negotiated Current Rate	Recommended Depreciation Rate
353	Transmission - Station Equipment	3.26%	3%	3.40%
355	Transmission - Poles Towers & Fixtures	3.73%	3%	2.60%
356	Transmission - Conductors and Devices	3.52%	3%	2.10%
364	Distribution - Poles Towers & Fixtures	4.05%	3%	2.10%
365	Distribution - Conductors and Devices	3.42%	3%	2.60%
390.1	Structures - Masonry	5.92%	3%	6.10%

From the above table, large swings are observed in the depreciation rates from the 2006 Depreciation Study compared to the recommended depreciation rates from the 2011 Depreciation Study. Most of the depreciation rates for these asset classes have been reduced which is consistent with the longer asset life discussed in Order G-58-06. However, Transmission – Station Equipment (account 353) and Structures – Masonry (account 390.1) have higher proposed depreciation rate contributing to an increase in depreciation for 2012 by $1 million and $0.8 million (Tab 4, p. 134), respectively.

88.1 For Transmission – Station Equipment (account 353), please provide an explanation of the key factors considered in justifying a depreciation rate change from 3% to 3.4% including what has changed significantly from the last negotiated rate. In your explanation, please comment on how the depreciation rate for Transmission – Station Equipment compares to the recommended depreciation rate of 2.2% for Distribution – Station Equipment (account 362).

Response:

According to Gannett Fleming, the recommended depreciation rate for Account 353 – Transmission-Station Equipment of 3.4% is based on the recommended 50-S4 Iowa curve. The use of a 50 year average service life estimate is consistent with the 50 year recommendation in the 2004 depreciation study. However, the 2004 depreciation study recommended a depreciation rate of 3.26%, which was ultimately negotiated to an implemented rate of 3.0%. The use of the lower than required 3.0% depreciation rate since 2006 has caused this account to be significantly under depreciated as at December 31, 2009. As indicated at page VI-10 of the Gannett Fleming depreciation study, the difference between the Calculated Accrued (column 3) and the Allocated Book Reserve (column 4) for Account 353 is in excess of $37 million.

In summary, the underlying depreciation parameters have not significantly changed, however the continued use of the lower than required depreciation rate since 2006 has been the most significant factor in the depreciation rate increase in this study.

When comparing the recommended depreciation for the station equipment account for Transmission Assets (Account 353) to the station equipment account for Distribution Assets (Account 362), the comparison should focus on the depreciation parameters that underpin the depreciation rates. Firstly, the average service life estimate for Account 362 is 55 years compared to the average service life estimate of 50 years for account 353. Transmission Stations and Distribution Stations are composed of different assets with different remaining lives, and should be analyzed independently which has resulted in a longer average service life estimate for Account 362. Secondly, at the time of the 2004 depreciation study, a depreciation rate of 3.0% was recommended for Account 362 and was accepted as filed. Therefore, Account 362 was not adjusted downwards in the same manner as Account 353, and is not under-depreciated in the same manner as Account 353.

88.2 Similarly, please provide the key reasons to justify why the depreciation rate for Structures – Masonry should be increased from 3% to 6.1% including what has changed significantly from the last negotiated rate.

Response:

The 2011 Depreciation Study prepared by Gannett Fleming, recommends a depreciation rate for Account 390.1 – Structures-Masonry of 6.1% is based on the recommended 35-R3 Iowa curve. The use of a 35 year average service life estimate is slightly longer than the recommendation of 30 years in the 2004 depreciation study. However, the 2004 depreciation study recommended a depreciation rate of 5.92%, which was ultimately negotiated to an implemented rate of 3.0%. The use of the lower than required 3.0% depreciation rate since 2006 has caused this account to be significantly under depreciated as at December 31, 2009. As indicated at page VI-25 of the Gannett Fleming depreciation study, in Account 390.1 the difference between the Calculated Accrued (column 3) and the Allocated Book Reserve (column 4) is in excess of $3.5 million. In addition to this account being depreciated with a rate below the recommended rate, this account has witnessed a significant amount of retirement activity which has further contributed to the under-depreciated position.

88.3 How do the recommended depreciation rates for the six asset classes in the table above compare to similar rates used by other electric distribution companies? Please include benchmarks from ATCO Electric, BC Hydro and other relevant electric distribution companies.

Response:

The following rates have been obtained from relevant utilities with transmission and distribution services. FortisBC was not able to obtain information from ATCO Electric.

Table BCUC IR1 88.3

	Newfoundland Power	BC Hydro	SaskPower	Hydro Quebec	FortisBC Recommended Rate
Transmission - Station Equipment	2.6%	3.3%	2.5%	2.5%	3.4%
Transmission - Poles Towers & Fixtures	3.8%	1.9%	2.1%	2.0%	2.6%
Transmission - Conductors & Devices	2.6%	1.9%	2.2%	2.0%	2.1%
Distribution - Poles Towers & Fixtures	2.8%	2.4%	2.9%	2.5%	2.1%
Distribution - Conductors & Devices	3.1%	2.4%	2.9%	3.3%	2.6%
Structures - Masonry	2.3%	3.5%	2.3%	2.0%	6.1%

89.0 Reference: Depreciation and Amortization

Exhibit B-1, Tab 4, Section 4.7.3.6,Table 4.7.3.6, p. 134; Section 4.7.3.4, p. 131; Appendix J, Section III-4, p.44;

Depreciation Rates – Accounts 373 and 392

A comparison of the recommended depreciation rates to the current rates in Table 4.7.3.6 revealed these three other accounts with significant rate changes:

Account	Description	Current Rate	Recommended Depreciation Rate
373	Street Lighting and Signal Systems	2.4%	23.0%
392	Transportation equipment	0.4%	10.7%
391.1	Computer equipment	10.6%	7.6%

Table 4.7.3.6 shows that the proposed increase in the depreciation rate for Street Lighting and Signal Systems (account 373) and Transportation equipment (account 392) would increase depreciation for 2012 by $2.4 million and $2.1 million, respectively. The reduction in Computer Equipment (account 391.1) would reduce depreciation for 2012 by $2.1 million.

89.1 Please provide detailed explanations on why the current rate for Street Lighting and Signal Systems is increasing ten-folds to 23% and what key factors were considered in justifying this rate increase. Please include in your explanation significant developments since the last depreciation study that is contributing to this increase.

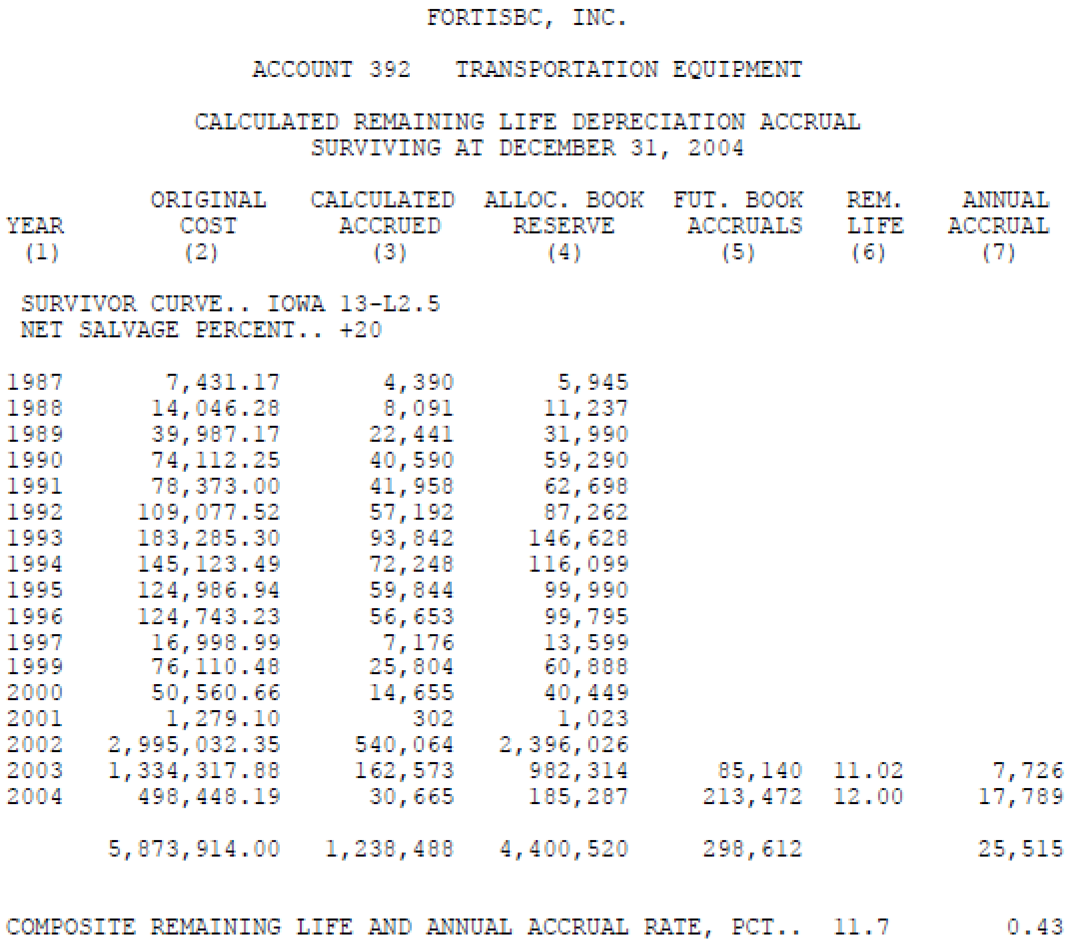
Response:

Account 373 – Street Lighting and Signal Systems is significantly under-depreciated as at December 31, 2009 as determined in the 2011 Depreciation Study prepared by Gannett Fleming. Over 70% of the investment in this account is in excess of 45 years of age with the depreciated value of the account currently less than 15% of its total balance. As such, a large amount of true-up through depreciation expense is required in order to provide for the recovery of the investment within the period prior to the anticipated retirement of the plant.

89.2 FortisBC states that "based on data analyzed from 2005 to 2009, proceeds from disposal of vehicles were less than expected and… certain transportation equipment… have little to no end of life value" (Tab 4, p. 133). Please explain what factors are contributing to the company's lower recoveries from transportation equipment retirements where historically it has been able to recoup cost to keep its depreciation rate at 0.4%.

Response:

Proceeds from disposal of vehicles depend on which vehicles are sold each year, and based on further investigation proceeds (relative to original cost of equipment sold) from 2005 to 2009 are not materially different from relative proceeds prior to 2004. According to the 2011 Depreciation Study prepared by Gannett Fleming, the increase in depreciation rate from the 2004 depreciation study, which produced an abnormally low rate of 0.43%, resulted from an extreme over depreciated position as at December 31, 2004. As indicated in the excerpt below from the 2004 depreciation study, the difference between the Allocated Book Reserve (column 4) and the Calculated Accrued (column 3) is in excess of $3 million, representing an extreme over depreciated position. The 2004 data indicated a lot of fully depreciated plant dating back as far as 1987. Generally, the 10.7% depreciation rates recommended in the current 2011 Depreciation Study, while much higher than the 0.43% rates from the 2004 depreciation study, are more consistent with the life estimates for vehicles.



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                          FORTISBC, INC.

                 ACCOUNT 392   TRANSPORTATION EQUIPMENT

             CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
                    SURVIVING AT DECEMBER 31, 2004

          ORIGINAL   CALCULATED  ALLOC. BOOK  FUT. BOOK   REM.    ANNUAL
YEAR        COST       ACCRUED     RESERVE     ACCRUALS   LIFE   ACCRUAL
 (1)        (2)          (3)         (4)          (5)      (6)      (7)

 SURVIVOR CURVE.. IOWA 13-L2.5
 NET SALVAGE PERCENT.. +20

1987       7,431.17      4,390       5,945
1988      14,046.28      8,091      11,237
1989      39,987.17     22,441      31,990
1990      74,112.25     40,590      59,290
1991      78,373.00     41,958      62,698
1992     109,077.52     57,192      87,262
1993     183,285.30     93,842     146,628
1994     145,123.49     72,248     116,099
1995     124,986.94     59,844      99,990
1996     124,743.23     56,653      99,795
1997      16,998.99      7,176      13,599
1999      76,110.48     25,804      60,888
2000      50,560.66     14,655      40,449
2001       1,279.10        302       1,023
2002   2,995,032.35    540,064   2,396,026
2003   1,334,317.88    162,573     982,314      85,140   11.02      7,726
2004     498,448.19     30,665     185,287     213,472   12.00     17,789

       5,873,914.00  1,238,488   4,400,520     298,612             25,515


COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PCT..  11.7        0.43
```

89.3 How do the proposed rates for Transportation Equipment, Street Lighting and Signal Systems and Computer Equipment compare to the rates used by other electric distribution companies? Please include benchmarks from ATCO Electric, BC Hydro and other electric distribution companies.

Response:

The following rates have been obtained from relevant utilities with transmission and distribution services. FortisBC was not able to obtain information from ATCO Electric.

Table BCUC IR1 89.3

	Newfoundland Power	BC Hydro	SaskPower	Hydro Quebec	FortisBC Recommended Rate
Street Lighting and Signal Systems	5.9%	2.4%	2.9%	2.9%	23.0%
Transportation Equipment	10.3%	7.8%	9.6%	8.7%	10.7%
Computer Equipment	11.5%	17.6%	21.2%	15.4%	7.6%

90.0 Reference: Depreciation and Amortization

Exhibit B-1, Tab 4, Section 4.7.3.6, p. 137;

2011 Depreciation Study

FortisBC states “the study… has been prepared based on plant in service as of December 31, 2009. Fortis BC considers that the study results continue to be applicable for the 2012 and 2013 forecast period as Gannett Fleming estimates that rates calculated in the depreciation study are reasonable for a period of three to five years” (Tab 4, p. 131).

In Appendix J, the 2011 Depreciation Study states “The survivor curves estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined through conversations conducted as part of this study with operations and management personnel; incorporating the knowledge that Gannett Fleming has gained through the completion of a number of Fortis assignments over a number of years; and survivor curve estimates from previous studies of this Company and other electric distribution companies.” (Appendix J, Section II-23, p. 31)

90.1 Please confirm that there has been no significant change in the current or future composition of the assets balances, new technology investments or significant events and/or developments since December 2009 that would change the proposed depreciation rates.

Response:

There are no significant changes in the current composition of asset balances from those studied as part of plant in service at December 2009 that would change proposed depreciation rates.

The only change in technological investment relates to the implementation of the Advanced Metering Infrastructure (AMI), which has been forecast as a phased deployment beginning in 2013. The depreciation rates for the new meters, which have not yet been placed into service, and the disposition of the old standard meters have not been addressed in the 2012-13 RRA since they would impact depreciation expense beginning in 2014. The depreciation rates and expense related to the AMI project is being considered as part of the AMI CPCN to be filed in 2011 and would be included in the Company’s 2014 RRA.

90.2 In assessing the amount of subjective judgment involved in determining the depreciation rates, please provide an estimate of the weighting (in percentages) of the following factors used in determining the survivor curves for the asset balances:

- actual statistical data analysis
- interviews with operations and management personnel
- knowledge and experience from Gannett Fleming
- survivor curves from previous studies of the Company and other electric distribution companies

*Note that the total of the percentages should add to 100%.

Response:

According to Gannett Fleming, for most accounts the firm prepares a full mortality study (retirement rate analysis, as described at pages II-10 through II-23 of the Gannett Fleming depreciation study), which forms the initial step in the determination of the average service life recommendations. Once the retirement rate analysis is completed, Gannett Fleming then considers other factors such as the information determined in operational interviews, the approved depreciation parameters from the peer group of companies, and the more general industry experience of Gannett Fleming.

Gannett Fleming applies professional judgment on an account by account basis. The use of professional judgment is not predicated on any sort of predetermined criteria; it must be applied based on the specific circumstances of each account. However, in order to be responsive to this request, Gannett Fleming has prepared Attachment 1 – 90.2 being a chart indicating an estimated weighting of the various factors in the determination of the average service life recommendations. Gannett Fleming does not intend for the attached chart to be construed as the precise or empirical weighting that was applied at the time the average service life recommendations were developed. Rather the attached chart is an after the fact indication of the factors considered, and the extent to which the factors may have been considered.

Attachment 1 - 90.2

FORTISBC INC.

ESTIMATION OF APPROXIMATE WEIGHTING APPLIED TO EACH FACTOR IN THE DETERMINATION OF EACH AVERAGE SERVICE LIFE ESTIMATE

Factors considered :	Actual Data Anaysis of Retirement History	Peer Industry experience	Gannett Fleming Professional Judgement	Expected innovations in technology	Discussions with FortisBC Staff	Total
Account:						
330.1 - Generation - Land Rights	10	10	80			100
331.0 - Generation - Structures and improvements	75	10			15	100
332.0 - Generation - Reserviours, Dams and Waterways	75	15			10	100
333.0 - Generation -Water Wheels, Turbines and Generators	40	40	10		10	100
334.0 - Generation - Accessory Electrical Equipment	30	40	20		10	100
335.0 - Generation - Other Plant Equipmnet	30	40	20		10	100
336.0 - Generation - Roads, Railways and Bridges	30	40	20		10	100
350.1 - Transmission - Land Rights	10	10	80			100
353.0 - Transmission - Substation Equipment	30	40	20		10	100
355.0 - Transmission - Poles, Towers and Fixtures	50	30			20	100
356.0 - Transmission - Conductors and Devices	50	30			20	100
359.0 - Transmission - Roads and Trails	10	10	80			100
360.1 - Distribution - Land Rights	10	10	80			100
362.0 - Distribution - Substation Equipment	75	15			10	100
364.0 - Distribution - Poles, Towers and Fixtures	75	15			10	100
365.0 - Distribution - Conducotrs and Devices	75	15			10	100
368.0 - Distirbution - Line Transformers	65	15			20	100
369.0 - Distribution - Services	65	15			20	100
370.0 - Distribution - Meters	10	25	25	25	15	100
371.0 - Distribution - Installations on Customers Premises			100			100
373.0 - Distribution - Street Lightning and Signal Systems	30	40	20		10	100
390.0 - General Plant - Structures - Frame and iron	30	40	20		10	100
390.1 - General Plant - Structures - Masonry	30	40	20		10	100
390.2 - Gneeral Plant - Operations Buildings	30	40	20		10	100
391.0 - General Plant - Office Furniture and Equipment		40	20		40	100
391.1 - General Plant - Computer Equipment and Software		40	20		40	100
391.2 - General Plant - PC Computer Equipment and Software		40	20		40	100
392.1 - General Plant - Light Duty Vehicles	65	15			20	100
392.2 - General Plant - Heavy Duty Vehicles	65	15			20	100
394.0 - General Plant - Tools and Work Equipment		40	20		40	100
397.0 - General Plant - Communications Structures and Equipment		40	20		40	100

90.3 Has the 2011 Depreciation Study been reviewed by another independent party or accepted by the Company's auditors?

Response:

The 2011 Depreciation Study has not been reviewed by another independent party or accepted by the Company's auditors. Gannett Fleming is an independent professional services firm whose Valuation and Rate Division has extensive experience in conducting depreciation studies for use in public pricing policy. The statistical methods employed in the Depreciation Study are widely recognized in the utility industry for representing an appropriate estimation of service life, adequacy of book reserves, and depreciation accrual rate. The Company's auditors review depreciation in the context of their annual assessment of accounting estimates, and would look to the independent Depreciation Study as support for any new estimates proposed.

90.4 The 2011 Depreciation Study uses data for retirements, additions and other plant transactions for the period from 1960 to 2009, please explain how the addition of five years of data would cause such a large swings in depreciation rates with some depreciations rates dropping by almost 50% (eg. Distribution Poles Towers & Fixtures) and others increasing ten-folds (eg. Street Lighting and Signal Systems) when compared to the 2006 Depreciation Study.

Response:

The larger than normally anticipated swings in depreciation rates are caused by three primary factors.

Firstly, as recommended at page I-4 of the Gannett Fleming depreciation study, "Continued surveillance and periodic revisions are normally required to maintain use of appropriate depreciation rate". The depreciation study completed in 2004 provided recommendations for a number of accounts that were negotiated downwards to an implemented rate of 3.0%. As such, the investment in plant has not had an appropriate opportunity to adjust for any amounts of accumulated depreciation surpluses or deficiencies that existed as at 2004. Therefore, the depreciation rates as recommended in the current study are providing for the complete true up of accumulated depreciation variances that have not been appropriately dealt with.

Secondly, a number of the accounts have witnessed a significant amount of plant additions over the 2005 through 2009 period. These large capital expenditure programs have been depreciating at a rate that does not recognize the average service life characteristics due to the adjustments made to the 2004 recommended Gannett Fleming depreciation rates in 2006.

Lastly, over the past five years, actual amounts of net salvage expenditures have been charged to the accumulated depreciation account as well as losses on retirement. These cost of removal expenditures, which were not provided for in the previous depreciation rates, are now causing an amount of accumulated depreciation deficiency which requires true up over the composite remaining life of the account.

91.0 Reference: Depreciation and Amortization

Exhibit B-1, Appendix E, Tab 4, Section 4.7.3.8, p. 137-138, Section 4.7.3.9, p. 138

US GAAP accounting for depreciable assets

FortisBC is adopting US GAAP and has provided a summary of its approach in Appendix E.

91.1 For the following depreciation related topics not included in Appendix E, please explain how these items are treated under US GAAP and quantify change from CGAAP if significant:

- Start of depreciation on a new capital project when available for use
- Cost of removal
- Gain and losses on retirement
- Any changes to opening asset balances on changeover to US GAAP

Response:

The guidance for these depreciation related topics is generally consistent between US GAAP and CGAAP. Since both sets of accounting guidance permit the accounting for the effects of rate-regulation, if the regulator approves a certain treatment of these depreciation related topics for setting rates, then by default it is permitted under both US GAAP and CGAAP. Non-regulated entities may account for these topics differently.

a. FortisBC begins depreciating assets at the beginning of the year subsequent to initial capitalization. If the BCUC approves keeping the depreciation methodology unchanged from FortisBC's prior year revenue requirement applications, this policy will be permitted under US GAAP;

b. Costs of removal, net of salvage proceeds, are charged to accumulated depreciation when incurred. Subsequent depreciation studies adjust future depreciation rates in the amount of the deferred costs of removal so that any costs of removal that are charged to accumulated depreciation will be reflected in future depreciation expense. If the BCUC approves keeping the costs of removal methodology unchanged from FortisBC's prior year revenue requirements applications, this policy will be permitted under US GAAP;

c. Gains and losses on the retirement of assets are charged to accumulated depreciation unless they are outside the normal course of business. Subsequent depreciation studies adjust future depreciation rates in the amount of the deferred gains or losses so that any gain or loss which is charged to accumulated depreciation will be reflected in future depreciation expense. If the BCUC approves keeping the gains and losses on retirement methodology unchanged from FortisBC's prior year revenue requirements applications, this policy will be permitted under US GAAP; and

d. As a result of no difference between CGAAP and US GAAP in the application of capital asset accounting for entities subject to rate-regulation, there are no changes to opening asset balances on changeover to US GAAP.

91.2 Please provide a comparison of the accounting treatment for depreciable assets between FortisBC and FortisBC Energy Utilities, including its treatment on the items covered in IR 4.1. Please explain the rationale for any differences.

Response:

Item	FortisBC Treatment	FortisBC Energy Utilities Treatment
1. Net Negative Salvage Value (removal cost less proceeds)	No provision for estimated net negative salvage value is included in depreciation rates. The recovery of actual costs of removal incurred is included in depreciation rates each time a depreciation study is updated.	A provision for estimated net negative salvage value is included in depreciation rates.
<u>Rationale for Difference</u>: Implementing a provision for negative salvage would result in a significant increase to the electricity rates of FortisBC customers. In light of adverse customer rate impacts, FortisBC has proposed to maintain its current method of accounting for and collecting future costs of removal, as explained in Section 4.7.3.8 of Tab 4 of the 2012-2013 Revenue Requirements Application. FortisBC supports the principle of collecting net negative salvage in depreciation rates and will propose consistent accounting treatment at a time when there is less pressure on customer rates.		
2. Commencement of Depreciation	Assets begin depreciating at the beginning of the year subsequent to initial capitalization.	Assets begin depreciating when placed into service.
<u>Rationale for Difference</u>: Adjusting the timing of depreciation would result in an increase to the electricity rates of FortisBC customers. In addition, due to the relative value of FortisBC's current capital expenditure programs, changing the methodology would expose the customer to depreciation expense variances based on the timing of when certain capital expenditures are placed into service. Lastly, there would be system development costs related to making the appropriate changes to SAP. In light of adverse customer rate impacts, FortisBC has proposed to maintain its current method of accounting for		

depreciation expense. In their most recent RRAs, the FEU changed their depreciation commencement policy from commencing depreciation in the year subsequent to an asset being put into service to being depreciated when placed into service. This change in policy was adopted to accommodate the adoption of IFRS. Given that FEU are now adopting US GAAP, this specific policy is not a requirement of US GAAP.		
3. Gains and Losses on Disposal	Charged to accumulated depreciation when incurred. Subsequent depreciation studies adjust future depreciation rates in the amount of the deferred gains or losses so that any gain or loss which is charged to accumulated depreciation will be reflected in future depreciation expense.	Recorded in a deferral account. Amortization period of 20 years proposed to align with the average service life of the asset categories that are contributing to the net losses.
Rationale for Difference: From a customer rate perspective, there is not a significant difference between charging gains and losses to accumulated depreciation and deferring them in a separate account since they would both form part of Rate Base and unwind over time. In order to keep capital accounting methodology comparable to previous rate filings, FortisBC has proposed to maintain its current method of accounting for gains and losses on disposal. In their most recent RRAs, the FEU changed how they treat gains and losses on disposal of an asset. Prior to 2010, the FEU had a policy similar to FBC but changed the policy and segregated gains and losses into a deferral account in order accommodate the anticipated adoption of IFRS. Given that FEU are now adopting US GAAP, either policy would be allowed under US GAAP.		
4. Investigative Spending	Deferred while determining a proper scope, timing and type of capital project to initiate. Costs are transferred to capital once the project is identified and approved.	Beginning in 2010, these costs are expensed.
Rationale for Difference: Adjusting the treatment of investigative spending would result in an increase to the electricity rates of FortisBC customers. In light of adverse customer rate impacts, FortisBC has proposed to maintain its current method of accounting for investigative spending, but depending on the nature of future costs, is considering consistent treatment at a future date. The difference in the treatment of investigative spending costs is expected to be minimized on a prospective basis as such costs are expected to decrease in the next few years.		
5. Capitalized Overhead	Recorded at 20% of Gross O&M. This rate has been previously approved as part of the 2006 NSA. Management reassessed	Recorded at 14% of Gross O&M. This rate has been previously approved as part of FEI's 2010-2011 NSA. Due to no material change in utility operations since that time, FortisBC Energy has

<table>
<tr><td></td><td>the rate as part of the 2012-2013 RRA and considers it reasonable.</td><td>proposed that the rate remain at 14% of Gross O&M for 2012 and 2013.</td></tr>
<tr><td colspan="3">Rationale for Difference: FortisBC and the FEU are different in terms of size and in terms of commodity being delivered, which affects the nature and type of assets constructed. These factors would create an expectation that a different capitalized overhead rate would exist between the two utilities.</td></tr>
</table>

92.0 Reference: Depreciation and Amortization

Exhibit B-1, Tab 4, Section 4.7.3.10, p. 139; Tab 7, Table 1-A, pp. 4-6, Table 1-C, pp. 17-18

Charges Less Recoveries

FortisBC states "charges less recoveries…are representative of the effects on accumulated depreciation from items retired from Property, Plant and Equipment. When an item is retired from service, its gross cost is removed from plant in service… The related accumulated depreciation, less costs of removal and any gain or loss on retirement, are recorded against accumulated depreciation and included… as charges less recoveries" (Tab 4, p. 139)

The following table compares the amount of Retirements cost deducted from the Plant in Service and the amount of Charges less Recoveries deducted from Accumulated Depreciation:

(000's)	2012	2013	
Utilities Plant in Service - Retirements	(12,256)	(12,256)	Table 1-A
Accumulated Depreciation - Charges less Recoveries	(17,628)	(16,271)	Table 1-C
Difference	5,372	4,015	

92.1 The Retirements cost deducted against the Utilities Plant in Service balance is exactly the same for 2012 and 2013. Please provide an explanation on how these are derived for 2012 and 2013 and why.

Response:

Please refer to the response to BCUC IR1 Q97.2.

92.2 For the Charges less Recoveries that are reducing the accumulated depreciation, please provide an explanation on how these are derived for 2012 and 2013 showing amounts related to cost of removals, gross gains on retirement and gross losses on retirement included therein.

Response:

When an item Of Property, Plant and Equipment is retired, its cost and accumulated depreciation is removed and the difference, which is a gain or loss, is charged to Accumulated Depreciation. Therefore, the total retired cost recorded against Utility Plant in Service in Table 1-A will be equivalent to the retired accumulated depreciation and resulting gain or loss recorded as Charges less Recoveries in Table 1-C. In addition, any costs of removing the item of Property, Plant and Equipment are charged to Accumulated Depreciation.

As noted in BCUC IR1 Q92.1, FortisBC does not forecast cost, Accumulated Depreciation, or the resulting gains or losses on Property, Plant and Equipment disposed. Therefore, the amount of Charges less Recoveries related to Accumulated Depreciation and the amount related to gains or losses is not separable, however in total will equal the amount of retired cost. The amount related to cost of removal has been forecast and included in Appendix 7B of Tab 7 of the 2012-13 RRA.

92.3 Please confirm that the difference between the Retirements and Charges less Recoveries relates to cost of removals or net gains and losses on retirement. If there are other components, please provide brief description.

Response:

Any difference between the total retired cost recorded against Utility Plant in Service in Table 1-A and the Charges less Recoveries in Table 1-C is related to the cost of removal.

92.4 By reducing the Accumulated Depreciation by a higher amount than the Utilities Plant in Service for retirements, this essentially increases the Utility Rate Base by $5,372,000 for 2012 and $9,387,000 for 2013 cumulatively and thereby increases the Company's return on equity. Please confirm if this is correct.

Response:

Utility Rate Base is increased by the reduction of accumulated depreciation by a higher amount than the Utilities Plant in Service for retirements. While the concept of increasing rate base is correct, the actual calculation of the Company's return on equity is based on Mid-Year Utility Rate Base.

92.5 Please confirm that the Charges less Recoveries include net negative salvage cost.

Response:

Net negative salvage cost normally refers to the accrual recorded in depreciation rates to collect for future removal costs. The 2012-13 RRA does not include any accruals in depreciation expense for the collection of future net negative salvage cost.

However, the Charges less Recoveries for 2012 and 2013 do include the forecast costs of removal as outlined in Appendix 7B of Tab 7 of the 2012-13 RRA.

INCENTIVES

93.0 Reference: Incentives

Exhibit B-1, Tab 4.8, p. 140

2010 True up

93.1 What were the primary changes in late 2010 that led to the $0.38 million true up?

Response:

The primary changes that led to the $0.38 million true up between the forecast incentive for 2011 Revenue Requirements and the 2010 actuals were interest expense and Net Income.

The calculation of the true-up is shown in Table BCUC IR1 93.1 below.

Table BCUC IR1 93.1

2010 Incentives	**2011 Revenue Requirements & NSA**					**2010 Year End Actual Data**				**2010 YE Variance**
	($000s)					($000s)				($000s)
1 **2010 Flow Through Adjustments**										
2 Interest Expense					**(918)**				**(1,174)**	(256)
3 **2010 ROE Incentive Adjustments**	**Approved**	**Forecast**	**Variance**	**Customer Share**		**Actual YE**	**Actual YE Variance**	**Customer Share**		
4 Net Income for ROE Incentive	38,614	37,718	896	50%	**448**	37,965	649	50%	**325**	(124)
5 **Total Year End Variance:**										**(380)**

94.0 Reference: Incentives

Exhibit B-1, Tab 4.8, p. 142

2011 ROE sharing

94.1 What were the primary drivers that lead to an expected ROE sharing from 2011? Please include the dollar value of these drivers and explain the variance from forecast occurred.

Response:

The primary drivers that lead to a forecast ROE sharing of $2.63 million are explained in Table BCUC IR1 94.1 below.

Table BCUC IR1 94.1

	ROE Parameters	**ROE Variance**		**Primary Reasons for Variance**
1	Higher Revenue	848		Higher GWh Sales
2	Lower Power Purchase Cost	5,256		Market opportunities
3	Higher Other Income	838		Higher Contract Revenue and Connection Charges
		6,943		
4	**Less:**			
6	Higher Income Tax Expense	1,840		Higher income before tax
7	Other Off-setting Items	(159)		Miscellaneous
		1,681		
8	**Total Variance:**	**5,261**		
9	Customer Share: 50%	50%	**2,630**	
10	**ROE Incentive Adjustment:**		**2,630**	

94.2 What is the most current estimate of net income for 2011?

Response:

The most current estimate of net income presently remains unchanged at $45.9 million. This can be seen by subtracting the ROE incentive adjustment from the Net Income for ROE Sharing as shown in the table below. The Net Income of $45.9 million is also seen in Schedule 5 – Return on Capital, line 18 at Tab 7, page 36 of the 2012-13 RRA.

Table BCUC IR1 94.2 ROE Sharing Adjustments

		($000s)
1	Forecast Net Income for ROE sharing:	48,553
2	Approved Net Income:	43,292
3	Variance :	**5,261**
4	Customer Share 50%	(2,630)
5	Net Income after ROE sharing:	**45,922**

RATE BASE

95.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.2.2, p. 5

AFUDC

FortisBC says: “the Company applies AFUDC to projects that are greater than $0.1 million and more than three months in duration.”

95.1 Please explain whether projects must meet both criteria before AFUDC is applied. What kind of carrying costs are applied to projects that are under $0.1M but longer than 3 months duration? For projects that are greater than $0.1M but shorter than 3 months durations?

Response:

The Company applies AFUDC to projects that are greater than $0.1 million and more than three months in duration. Hence for the application of AFUDC, projects must meet both of the criteria:

1. Project expenditure greater than $0.1 million, and
2. Project duration more than three months.

No AFUDC (carrying cost) is applied to projects that are:

1. Under $0.1 million but longer than 3 months duration, or
2. Greater than $0.1 million but shorter than 3 months duration.

96.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.2.4, p. 6

CIAC

96.1 There appears to be a 49% increase in additions to CIAC in 2012F while the increase in the forecast number of customer additions is 2,128 or 1.9%. Please explain the relationship between customer additions and forecast CIAC.

Response:

The increase in additions to CIAC in 2012F is a result of the changes to Schedule 74 as part of the 2009 Cost of Service and Rate Design Application and the new Company contribution level for customers. There is no correlation to customer growth.

97.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.3.1.1, p. 9

Retirement of Assets

97.1 Please provide the actual asset retirement figures for 2007 – 2010.

Response:

The asset retirement figures for years 2007 – 2010 are provided in Table BCUC IR1 97.1 below:

Table BCUC IR1 97.1

	Asset Retirements	**2007**	**2008**	**2009**	**2010**
		($000s)			
1	Hydraulic Production Plant	617	358	618	659
2	Transmission Plant	78	15	47	7,434
3	Distribution Plant	2,281	2,821	5,334	3,255
4	General Plant	1,098	1,675	1,755	908
5	**Total Retirements**	**4,074**	**4,869**	**7,754**	**12,256**

97.2 Given FortisBC's statement that the "Retirements of assets may occur from causes no reasonable assumed to have been anticipated or contemplated..." (p. 9), please explain why the retirement of assets for the test period is based solely on 2010 levels and not on an historical average?

<u>Response:</u>

FortisBC analyzed 3 methods for forecasting retirement of assets for the purpose of 2012 and 2013 rate setting as follows:

1. Previous Year Method: Uses the last actual year of asset retirement data.
2. 3-Year Rolling Average Method: Uses the rolling average of last 3 years of actual asset retirement data.
3. 5-Year Rolling Average Method: Uses the rolling average of last 5 years of actual asset retirement data.

It was observed that the Previous Year Method resulted in a better estimate of 2010 asset retirements than the 3 or 5 Year Rolling average Methods The Company chose the Previous Year Method not only because it yielded a better forecast in 2010, but also since this was the simplest approach.

It is however recognized that in any given year any one of the above methods may result in a better asset retirement forecast. This is because actual retirement of assets do not have a definite trend (please refer to Table BCUC IR1 97.2 below and also the response to BCUC IR1 Q97.1), as retirement not only occurs when plant reaches end of its service life, but also from causes that may include unusual casualties, such as fire, storm, flood, etc or even obsolescence.

A comparison of the three methods is provided in the following table.

Table BCUC IR1 97.2

Asset Retirement Forecasting Procedure		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
		($000s)									
1	Actual Asset Retirement Data (Year 2009 modified)	2,283	3,222	4,281	4,074	4,869	3,356	12,256			
2	Previous Year Method of Forecasting for the purpose of Rate Setting							4,869	3,356	12,256	12,256
3	3 Year Rolling Average Method of Forecasting (comparative only)							4,408	4,100	6,827	6,827
4	5 Year Rolling Average Method of Forecasting (comparative only)							3,746	3,960	5,767	5,767

Note: 2009 actual expenditures of $7.754 million were adjusted to eliminate a non recurring asset retirements for Installation on Customer's Premises, of $4.398 million, resulting in a revised 2009 amount of $3.356 million.

97.3 Please discuss whether using a 3 or 5 year historical average to forecast retirements in the test period is or is not suitable.

Response:

Please refer to the response to BCUC IR1 Q97.2.

98.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4, p. 11

Deferred Charges and Credits

98.1 Please explain how FortisBC determine whether a deferral account should be rate based or not.

Response:

FortisBC holds deferred amounts outside of rate base which are primarily notional (non-cash) assets or liabilities (see Schedule 1A Non-Rate Base Assets at page 3 of Tab 7, 2012-13 RRA). The Company does not earn a return on these assets.

The Utilities Commission Act provides that prudently incurred costs, which include financing costs, are recoverable by the utility. FortisBC believes that all deferred expenditures or credits (with the exception of those identified in Schedule 1A) should be included in Rate Base, which is financed at the Weighted Average Cost of Capital (WACC). WACC reflects the costs to the Company of financing its regulated activities at the proportions of debt and equity and rates of return approved by the Commission.

If a deferred expenditure is to be held outside of rate base, then AFUDC should be applicable. The AFUDC rate is the return on rate base, adjusted to the after-tax cost of debt, and is the earned return that compensates the utility’s investors, both debt and equity. Where AFUDC is applicable, the deferral account is not included in Rate Base.

98.2 Please provide brief explanations for why the 5 Rate Based deferral accounts shown in Table 5.4-1 should be rate based deferral accounts as opposed to interest bearing deferral accounts.

Response:

The deferral accounts referenced are:

1. Demand Side Management;
2. Preliminary and Investigative Charges;
3. Non-Controllable Items Variances;
4. Deferred Regulatory Expense;
5. Other Deferred Charges and Credits; and
6. Deferred Debt Issue Costs

Demand Side Management costs are specifically included in Rate Base pursuant to the Commission's DSM Accounting Policy approved by Order G-55-95.

In regard to the remainder of the accounts, as stated in the response to BCUC IR No. 1 Q98.1 above, FortisBC believes that all deferred expenditures or credits (with the exception of the non-cash items identified in Schedule 1A) should be included in Rate Base and financed at the Weighted Average Cost of Capital (WACC). WACC reflects the costs to the Company of financing its regulated activities at the proportions of debt and equity and rates of return approved by the Commission.

If a deferred expenditure is to be held outside of rate base, then AFUDC should be applicable.

99.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.2, p. 12-14

Preliminary Investigative Charges

99.1 Please describe the difference between "preliminary" and "investigative" charges.

<u>Response:</u>

There is no difference between "preliminary" and "investigative" charges. This cost category is meant to capture very preliminary costs of potential projects where the economics of the project options have yet to be discovered such as in the choice between a new substation or a transmission line in order to meet load, or where more investigation has to be undertaken in order to determine if a project is viable from an engineering perspective.

99.2 In a table format, please show a calculation and reconciliation of all the projects which make up line 2 of Tables 5.4-1, 5.4-2, and 5.4-3. Show the additions to the deferral account and transfers out to capital. What is the vintage of all the projects that have been charged to this deferral account?

Response:

The tables below show the breakdown of the Preliminary and Investigative Charges by project for years 2011-2013 along with the year the project was initiated. This information was provided in Tab 7 pages 10 -15, Tables 1 - B – for 2011, 2012 & 2013 (except for the year the project was initiated).

Table BCUC IR1 Q99.2(a) – Preliminary and Investigative Charges (2011)

	Balance at Dec. 31, 2010	Additions and Transfers	Amortized / Transferred to Other Accounts	Balance at Dec. 31, 2011	Year Project Initiated
			($000s)		
Preliminary and Investigative Charges					
Long Term Facilties Strategy 2008	142	-	(142)	-	2008
Pumped Storage Hydro	227	-	-	227	2008
PCB Environmental Compliance	136	-	(136)	-	2010
2012 Integrated System Plan	1,748	1,638	-	3,386	2010
2011 Capital Expenditure Plan	182	-	(182)	-	2009
P1-P4 Sustainment Capital	-	25	-	25	2011
Kelowna Bulk Transformer Capacity Addition	-	173	-	173	2011
	2,435	**1,836**	**(460)**	**3,811**	

Table BCUC IR1 Q99.2(b) – Preliminary and Investigative Charges (2012)

	Balance at Dec. 31, 2011	Additions and Transfers	Amortized / Transferred to Other Accounts	Balance at Dec. 31, 2012	Year Project Initiated
			($000s)		
Preliminary and Investigative Charges					
Pumped Storage Hydro	227	-	-	227	2008
2012 Integrated System Plan	3,386	-	(677)	2,709	2010
P1-P4 Sustainment Capital	25	25	(25)	25	2011
Kelowna Bulk Transformer Capacity Addition	173	100	-	273	2011
Advanced Metering Infrastructure Project	-	1,812	(1,812)	-	2007
	3,811	**1,937**	**(2,514)**	**3,234**	

Table BCUC IR1 Q99.2(c) – Preliminary and Investigative Charges (2013)

	Balance at Dec. 31, 2012	Additions and Transfers	Amortized / Transferred to Other Accounts	Balance at Dec. 31, 2013	Year Project Initiated
			($000s)		
Preliminary and Investigative Charges					
Pumped Storage Hydro	227	-	-	227	2008
2012 Integrated System Plan	2,709	-	(677)	2,032	2010
P1-P4 Sustaining Capital	25	25	(25)	25	2011
Kelowna Bulk Transformer Capacity Addition	273	-	(273)	-	2011
2014 - 2015 Capital Expenditure Plan	-	750	-	750	2013
	3,234	**775**	**(975)**	**3,034**	

99.3 What is the rate impact for a $1M charge to this deferral account?

Response:

There is no perceptible variance to rate impacts for an additional $1 million charge in year 2012 to the Preliminary Investigative deferral account as indicated in the Table below:

Table BCUC IR1 99.3

		2012	**2013**
1	Base Case Preliminary Investigative Charges ($000s) (2012-13 RRA as filed on June 30, 2011)	1,937	775
2	Base Case Rate Impacts (2012-13 RRA as filed on June 30, 2011)	4.0%	6.9%
3	Revised Preliminary Investigative Charges ($000s) (Year 2012 increased by $1 million)	2,937	775
4	Revised Rate Impacts	4.0%	6.9%
5	Variance: Preliminary Investigative Charges ($000s)	1,000	-
6	Variance: Rate Impacts	0.0%	0.0%

99.4 Please explain why this deferral account should be a rate base deferral account? Are there any other carrying costs that are accrued to this deferral account?

Response:

Please see the response to BCUC IR1 Q98.2 above.

Only the financing costs on rate base are applicable to this account. AFUDC is not applied to these amounts until the projects are approved and placed into Construction Work in Progress. If the projects do not proceed to the capital construction stage, the balances in the deferred account are expensed. However should the projects proceed, treating these costs as rate base ensures cost recovery of the carrying costs for properly incurred preliminary investigation charges.

99.5 What are the decision criteria or guidelines that FortisBC uses to determine whether a project costs get expensed or carried forward to another year?

Response:

If a project is still viable or the need still exists, but requires further definition, it will be carried forward; otherwise the project costs will be expensed.

100.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.2, p. 12-14

Preliminary Investigative Charges

FortisBC states that development costs incurred to prepare for the 2012 Integrated System Plan are forecast to be $3.4M and that these “costs will be transferred to the approved capital projects over the five year period 2012 to 2016.”

FortisBC also states that preliminary investigation and engineering costs expected for the 2014-2015 Capital Expenditure Plan is forecast at $0.8M which will be absorbed into the those capital projects.

100.1 Please describe how FortisBC plans to determine which approved capital projects these costs will be allocated to?

Response:

The Company plans to allocate the 2012 Integrated System Plan and the 2014-2015 Capital Expenditure Plan expenditures over all approved capital projects proportionately based on actual expenditures.

FortisBC states that $1.8 million of investigative funds related to the AMI project will be moved to a Rate Base deferral account in 2012.

100.2 Please provide a breakdown of the year and costs which make up the $1.8M.

Response:

Table BCUC IR1 100.2a below breaks the costs down into the applicable year. Table BCUC IR1 100.2b provides the budget categories.

Table BCUC IR1 100.2a

Years	Costs
2007(A)	68
2008(A)	174
2009(A)	222
2010(A)	455
2011 (F)	881
2012 (F)	11
	1,812

Table BCUC IR1 100.2b Breakdown of Budget by Expenditure Category ($000s)

Third Party Studies	128
Consulting	230
Procurement	1,068
CPCN Application Preparation	265
AFUDC	121
Total	1,812

101.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.2, pp. 12-13

Preliminary and Investigative Charges - Pumped Storage Hydro and 2012 Integrated System Plan

> “Development costs, primarily for preliminary planning and engineering, are forecast to be $3.4 million. These costs will be transferred to the approved capital projects over the five year period 2012 to 2016. The Company expects to file its next long term capital expenditure plan for the period beginning in 2017.”

101.1 Please explain why the pumped storage hydro investigative account is not part of the overall 2012 ISP costs, since neither has yet received Commission approval. Why could the pumped storage hydro investigate costs not be transferred to the ultimate project as with the remainder of the 2012 ISP costs?

Response:

The pumped storage hydro investigative account costs are not part of the overall 2012 ISP costs because the costs were to a single, specific future capital project. The overall ISP costs were not separately tracked and relate to the preliminary planning and engineering of a large number of future capital projects. The overall 2012 ISP costs were tracked and recorded as a group for administrative ease. The intent is to transfer the pumped storage hydro costs to the eventual pumped storage hydro project when the project is initiated. In the event that the Company decides to not move forward with the pumped storage hydro project, the Company will seek disposition of the investigative costs in a future application to the Commission. The 2012 ISP costs are intended to be allocated to all capital projects over the period 2012 through 2016.

101.2 Please provide a line item reconciliation of the projects to which the 2012 ISP costs will be distributed.

Response:

The ISP costs will be allocated to capital projects as follows:

Table BCUC IR1 101.2

	2012	2013	2014	2015	2016	Total
Allocation ($000s)	677	677	677	677	677	3,386

The capital projects to which these costs will be proportionately allocated are those identified in 2012 through 2016 in Appendix J of the 2012 Long Term Capital Plan (ISP, Volume 2).

102.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.3, p. 14

Non-Controllable Item Deferral Account

On pages 14-16 in Tab 5, FortisBC proposes 9 different deferral accounts which are deemed to be non-controllable items:

i. Power Purchase Expense Variance Deferral Account
ii. Revenue Variance Deferral Account
iii. Income Tax Variance Deferral Account
iv. HST Removal or Reform Variance Deferral Account
v. Property Tax Asset Variance Deferral Account
vi. Interest Expense Variance Deferral Account
vii. Pension and Other Post-Employment Benefits Expense Variance

viii. Insurance Expense Variance Deferral Account

ix. Extraordinary Costs (Z Factor) variance Deferral Account

102.1 Please explain why each of the above proposed deferral accounts should be a rate-based deferral account?

Response:

Please see the response to Q98.1 above.

There is no impact on 2012 or 2013 rates (including from financing costs) related to these accounts because the forecast balance in each is zero.

102.2 Is it FortisBC's intention that all related variances will accrue to these deferral accounts during the test period without further Commission approval for the values going into the accounts?

Response:

Yes. Approval of the deferral accounts establishes the circumstances under which amounts would be deferred. The balances in the accounts will be subject to examination and approval as part of the next Revenue Requirements application, prior to recovery or refund through rates.

102.3 Please discuss how FortisBC intends on maintaining the transparency for all expenses captured in these deferral accounts.

Response:

All of the variances to be captured in these deferral accounts have been proposed for recovery in rates beginning in 2014. Therefore it is expected that a review of the nature of the costs will be undertaken as part of setting 2014 rates in a manner and process that is similar to what is currently undertaken for the Company's deferral accounts. As part of the existing revenue requirements application process, the Company justifies that its variances accumulated in deferral accounts relating to legislative tax changes, interest expense, pension and other post-employment benefits and extraordinary items relate to costs that are reasonable and prudent. This transparency that is currently achieved, and is proposed to continue, for reviewing deferral accounts is achieved through the preparation of the revenue requirements applications, the information request process and workshop presentations.

102.4 Please explain why the Extraordinary Costs (Z Factor) Variance Deferral Account is necessary and prudent, particularly when all the other accounts are related to specific circumstances.

Response:

The Extraordinary Costs (Z Factor) Variance Deferral Account is simply a mechanism to recover prudently incurred costs, which were unforeseen at the time of forecasting and may result from factors beyond the Company's control. This variance deferral account has been proposed to capture the impacts on rates as a result of directives and decisions made by the Commission or other competent regulatory agencies, including acts of legislation or regulation of government, changes due to GAAP, Force Majeure events or other extraordinary events. All of these potential factors have a common theme in that the Z-factors require the Company to implement changes that differ from forecast and the drivers are out of the Company's control for forecast purposes. Costs to be recovered or refunded as a result of government or regulatory decisions would undergo the same level of scrutiny for reasonableness and prudency as other rate base accounts.

The other deferral accounts may refer to specific line items in the cost of service by name, such as interest expense, power purchase expense and pension expense, however they all contain factors that are out of the Company's control, no different than Z-factors.

102.4.1 Please explain why FortisBC would not consider applying for a specific deferral account when and if the situation arose that requires a specific "extraordinary" cost.

Response:

FortisBC requires regulatory approval to record the costs in a deferral account for US GAAP purposes. In addition, FortisBC believes that it is efficient and reasonable to gain approval for the deferral account in this application, rather than submitting a new application if and when needed. As the forecast balance in the account is zero, there is no impact on rates (including from financing costs) in 2012 or 2013. Any balance in the account would be subject to examination and approval in the next Revenue Requirements application before being recovered or refunded through rates.

102.5 Please confirm that FortisBC intends to carry forward the ending balance in each account from 2012 to 2013 as opposed to recalculating the rate impact to 2013 based on year-end balances.

Response:

Confirmed. Once rates are determined at the conclusion of this process, the Company does not propose any further adjustment to 2013 rates. The Company's recommendations regarding disposition of any balances in these deferral accounts will be included in its 2014 Revenue Requirements application.

103.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.3, p. 14; FortisBC Residential Inclining Block (RIB) Rate Application, Exhibit B-5, BCUC IR 5.2

RIB Rate Revenue Adjustments

The following information requests and response was obtained from FortisBC's RIB Rate Application Proceeding:

"Q5.2: Please comment if the above RIB rate design has considered the impact on other rate classes, e.g., whether the other rate classes will be held harmless in the event of lower consumption in the residential class.

A5.2 The RIB rate design has not incorporated any elasticity impacts in the 2011 proposed RIB rate. This is placing additional risk on all FortisBC customers since any revenue shortfall resulting from the RIB rate will be recovered from all customers in the following year…. the Company anticipates <u>proposing (in its upcoming Revenue Requirements Application) a deferral and flow-through mechanism for revenue variances to eliminate the effect of any such over- or under-collection.</u>" [emphasis added]

103.1 It does not appear that the proposed Revenue Variance Deferral Account is intended to include revenue variances resulting from the RIB application, please explain where FortisBC has made such proposal in the Application.

Response:

In describing the proposed Revenue Variance Deferral Account, the Application states on page 25 of Tab 4 that:

> " …as the Company implements conservation rates, … the proposed deferral mechanism will help to ensure that the extent to which conservation occurs, will not cause the Company to over or under recover its revenue requirement".

Revenue variances resulting from the implementation of RIB rates as well as all other revenue variances would be captured in the proposed deferral account.

103.2 If FortisBC has not made such a proposal, pleased explain how it intends to capture the potential revenue variances resulting from the RIB Application.

Response:

Please see the response to BCUC IR1 Q103.1 above.

104.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.4, pp. 17-22

Deferred Regulatory Expense

104.1 Please provide in a table view, a list of all the deferred regulatory items listed on pages 17-22, along with their balances, references to Orders, their dates / proposed dates of amortization, and the amortization amounts in 2012F and 2013F.

Response:

Table BCUC IR1 104.1 below lists the deferred regulatory items which includes the December 31, 2011 forecast balance, approving Orders, proposed amortization dates and forecast 2012 and 2013 amortization amounts.

Please also refer to Table 1 – B Deferred Charges and Credits for 2011, 2012 and 2013 pages 10, 12 and 14 of Tab 7 of the 2012-13 RRA where schedules of the balances and amortization are provided.

Table BCUC IR1 104.1

	Approval to Defer	Approval to Amortize	Amortization Period	Balance	Amortized/Transferred	
				Dec. 31, 2011	2012	2013
Project				**($000s)**		
2009 Flow-through and ROE Sharing Mechanism Adjustments	G-184-10	G-184-10	2011	-	-	-
2010 Flow-through and ROE Sharing Mechanism Adjustments	G-184-10	G-184-10	2011	-	-	-
2010 Flow-through and ROE Sharing True-up	Requested	Requested	2012	(380)	380	-
2011 Flow-through and ROE Sharing Mechanism Adjustments	Requested	Requested	2012	(5,036)	5,036	-
Implementation of New Rate Structures	G-24-11	Requested	2012	18	(18)	-
Shaw Application for Transmission Facility Access	G-184-10	Requested	2012	233	(233)	-
Tariff Amendment - Adaptive Street Lighting			Note 1	-	-	-
Residential Inclining Block (RIB) and Industrial Stepped Rate Applications	G-24-11	Requested	2012	73	(73)	-
Irrigation Rate Payer Group Consultation and Load Research	G-24-11	Requested	2013	73	-	(73)
2010 Revenue Requirements	G-193-08	G-184-10	2011	-	-	-
2011 Revenue Requirements	G-162-09	Requested	2012	54	(54)	-
2014 Revenue Requirements	Requested			-	-	-
2014-15 Capital Expenditure Plan	Requested			-	-	-
Section 71 Filing (Waneta Expansion Power Purchase Agreement)	G-184-10	G-184-10	2011-2013	172	(86)	(86)
Cost of Service and Rate Design Application	G-147-07	G-184-10	2011-2014	1,122	(374)	(374)
BC Hydro Amendment to 3808 Power Purchase Agreement (PPA) Proceedings	G-162-09	G-162-09	2010-2012	26	(26)	-
Section 5 Provincial Transmission Inquiry	G-162-09	G-184-10	2011	-	-	-
Renewal of BC Hydro PPA	G-193-08	Requested	2012-2016	223	(45)	(45)
2012 Integrated System Plan and 2012-2013 Revenue Requirements	G-184-10	Requested	2012-2016	2,381	(476)	(476)
BC Hydro Waneta Transaction Application	G-162-09	G-184-10	2011-2013	132	(67)	(67)
FortisBC Utilities (formerly Terasen Utilities) Return on Equity (ROE) and Capital Structure Application	G-162-09	G-184-10	2011	-	-	-
Total				**(906)**	**3,964**	**(1,121)**

Note 1: FortisBC anticipated applying to the Commission in 2011 to amend Rate Schedule 50 - Lighting to charge customers whose street lighting fixtures are equipped with automated dimming controls (ADC) a reduced amount for the period during which the lights are dimmed. Since then, the principle vendor for the ADC system has entered into bankruptcy proceedings. FortisBC incurred development costs of approximately $0.002 million ($0.003 million before tax) for the proposed tariff amendment, which was expensed in 2011 once it was determined that the proposed tariff amendment would not be submitted to the Commission in 2011.

105.0 Reference: Deferred Regulatory Expenses

Exhibit B-1, Tab 5, Section 5.4.4, pp. 17-22

Shaw Application for Transmission Facility Access

"The Company has incurred costs related to Shaw's application to the Commission process of $0.2 million ($0.3 million before tax) which it proposes to amortize in 2012."

105.1 Please explain the intended benefits that would have accrued to the ratepayers at the outset of the Shaw dispute? Have any of these benefits been realized with the agreement reached between FortisBC and Shaw in April 2011?

Response:

FortisBC intended that the resolution of the dispute would increase the Company's revenue from telecommunications contacts on its transmission lines. As stated in the response to BCUC IR1 Q68.1 above, the impact of the settlement on revenues is an increase of $0.4 to $0.5 million annually.

106.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.4, p. 20

Deferred Regulatory Expenses - Section 71 Filing (Waneta Expansion Power Purchase Agreement)

106.1 What amounts are being amortized in 2011, 2012 and 2013 with respect to the Section 71 Filing associated with Waneta Expansion Power Purchase Agreement?

Response:

With respect to the Section 71 Filing associated with the Waneta Expansion Power Purchase Agreement, costs of $0.086 million ($0.12 million before tax) are being amortized in 2011, 2012, and 2013.

Amortization of this account can be seen in Tab 7 at:

Page 10 - Table 1-B Deferred Charges and Credits (2011) - Rows 32 and 33

Page 12 - Table 1-B Deferred Charges and Credits (2012) - Rows 45 and 46

Page 14 - Table 1-B Deferred Charges and Credits (2013) - Rows 39 and 40

107.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.5, p. 33

Other Deferred Charges and Credits – Revenue Protection

107.1 FortisBC says "Beginning in 2012, the costs of the Revenue Protection activities are included in Operating and Maintenance Expenses in the Customer Services department."

107.2 Please confirm that these costs and savings were previously captured in the Revenue Protection deferral account.

Response:

Confirmed. The Revenue Protection costs and savings were previously captured in the Revenue Protection deferral account.

107.3 Why is the Revenue Protection deferral account still required if the costs are now recorded in O&M? Please explain the rationale for the change.

Response:

The deferred account for Revenue Protection activity in section 5.4.5 reflects the amortization in 2012 of the forecast 2011 expenditures approved by Order G-184-10. As shown at Line 69 of Table 1-B Deferred Charges and Credits (2012) at page 13 of Tab 7, there are no charges to the Revenue Protection deferred account in 2012. The costs of Revenue Protection activities were not included in the calculation of Base O&M Expense under the PBR Plan, and deferral treatment was necessary because approval to recover the costs in rates was required in the following years' Revenue Requirements. Beginning in 2012, these ongoing costs will be recorded as current year O&M Expense.

107.4 Please provide a summary table of the annual costs and realized benefits associated with the power diversion inspections since 2007.

Response:

Please refer to the below table.

Table BCUC IR1 107.4

Year	Annual Costs	Annual Benefit	NPV Benefit*
2007	$125,000	$75,000	$300,000
2008	$195,000	$132,000	$527,000
2009	$190,000	$82,000	$327,000
2010	$200,000	$67,716	$270,370
2011F	$204,000	$95,865	$382,761

**Discounted savings at 8% over five years*

108.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.5, p. 34; Exhibit B-1-1 Long-Term Capital Plan, pp. 1-3

Other Deferred Charges and Credits – Asset Management

FortisBC is proposing that the costs for the initial development stage of an asset management approach be captured in a deferral account. “Expenditures of $785,000 in 2012 and 2013 are proposed to accommodate the development of a project team comprising internal and external resources.” (Exhibit B-1-1, Long Term Capital Plan, p. 5)

108.1 Please explain why Asset Management activities should not be captured as a function of the Generation O&M and / or Utility Operations O&M or some other O&M department.

Response:

The cost to develop an asset management strategy will be captured in a deferred account. The work for this development is incremental to FortisBC’s existing workload. At the conclusion of the development stage, FortisBC will identify the implementation strategy and costs associated with it. Treatment of the costs in the deferred account as well as the identified implementation costs will be submitted for approval in a future application.

108.2 Is it FortisBC's intention that only the development costs would be captured in the deferral account in the test years whereas future annual operation and management costs would be captured in an O&M department?

Response:

Yes, the intention is to capture development costs in the deferral account. Future costs to maintain the program would be included in O&M Expense. Any related capital costs will be submitted for approval in a future Capital Expenditure Plan.

108.3 Please provide further breakdown of the projected $785,000 in 2012 and 2013. What activities do these relate to and what is the number of FTEs working on this project.

Response:

The current scope of the project has been developed at a high level. The functional tasks to complete and estimated timelines are as follows:

Task	Timeline
Develop Functional requirements for external support	1 month
Request for Proposal development and external support selection	3 months
Development of detailed requirements	3 months
Gap Analysis	3 months
Investigation of solutions and options (costs, resources, maintainability)	6 months
Conclusion/Recommendation	3 months

The costs per year are currently identified as follows. The majority of the costs are required to support the engagement of external consultants and contractors. No task-based cost breakdown is available at this time.

2012 - $500,000

2013 - $285,000

The quantity of internal FTEs will vary throughout the project. FortisBC estimates an average of 2 to 4 internal FTEs will be providing input and support to the project.

109.0 Reference: Rate Base

Exhibit B-1, Tab 5, Section 5.4.5, p. 35

Other Deferred Charges and Credits – Joint Pole Use Audit 2013

109.1 Please explain why the audit costs in 2013 will be doubled from the last audit in 2008. Is it related to the number of poles in the system or an increase in labour costs?

Response:

The FortisBC portion of audit costs in 2013 are forecast at $0.250 million (pre-tax) as compared to $0.156 million in 2008 (Tab 7 Table 1-B, p. 15 of the 2012-13 RRA). This increase is attributed to the increase in inventory identified in the 2008 audit, the normal annual inventory increases anticipated for the 2008-2013 period and a forecast inflationary impact on labor and other audit expenses.

2012-2013 CAPITAL EXPENDITURE PLAN

110.0 Reference: 2012-2013 Capital Expenditure Plan

Exhibit B-1, Tab 6, Section 1.1, p. 2

Table 1.1 - 2012-13 Capital Expenditure Plan

110.1 Provide a table in a similar format to Table 1.1 showing the previous five years of data for the same line items.

Response:

The table below provides five years of data for the Capital Expenditure Plan.

Table BCUC IR1 110.1

	2007		2008		2009		2010		2011		2012	2013	2012	2013	2012	2013	2012	2013
Capital Expenditure Plan	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Forecast**	**Current Estimate**	**Requested**		**Previously Approved**		**CPCN Application**		**Total**	
									($000s)									
Generation	21,659	21,604	19,079	17,357	21,535	20,622	20,068	19,510	19,755	20,780	4,495	2,947	5,636	-	-	-	10,131	2,947
Transmission and Stations	64,405	70,435	66,392	49,001	59,996	51,209	101,801	84,462	28,728	32,962	33,035	29,134	2,219	-	-	3,720	35,254	32,855
Distribution	19,761	25,821	20,245	26,904	24,046	26,266	24,763	26,651	20,968	20,329	29,249	25,889	-	-	-	-	29,249	25,889
Telecom SCADA Protection & Control	4,940	1,192	2,544	2,918	2,085	2,569	2,057	2,195	3,265	4,365	2,329	3,682	-	-	-	-	2,329	3,682
General Plant	15,650	14,719	8,697	8,616	10,022	9,027	9,193	9,303	12,990	14,115	12,503	19,317	69	75	10,521	38,408	23,093	57,800
Subtotal Plant and Equipment	**126,415**	**133,771**	**116,957**	**104,796**	**117,684**	**109,693**	**157,882**	**142,121**	**85,706**	**92,551**	**81,612**	**80,969**	**7,924**	**75**	**10,521**	**42,128**	**100,057**	**123,173**
Demand Side Management	1,657	1,623	1,613	1,858	2,568	2,396	2,826	2,656	5,764	5,396	5,798	5,909	-	-	-	-	5,798	5,909
Total	**128,072**	**135,394**	**118,570**	**106,654**	**120,252**	**112,089**	**160,708**	**144,777**	**91,470**	**97,947**	**87,410**	**86,878**	**7,924**	**75**	**10,521**	**42,128**	**105,855**	**129,082**

111.0 Reference: Certificates of Public Convenience and Necessity (CPCN)

Exhibit B-1, Tab 6, Section 1.3, pp. 5-6

CPCN Applications

111.1 Please provide an estimated additional rate impact for each of the following projects:

- Kelowna Bulk Transformer Capacity Addition project, described in section 3.1.4, estimated at $25.6 million (exceeds the cost threshold);
- Advanced Metering Infrastructure (AMI) project, described in section 6.2, estimated at $38.5 million (exceeds the cost threshold); and
- Kootenay Long Term Facilities Strategy, described in section 6.1, estimated at $16.5 million (project planning falls between capital expenditure plan applications). (See Tab 6, p. 6)

Response:

The estimated additional cumulative rate impact for each of the above projects during the Test Period (2012-13) will be as follows:

1. Kelowna Bulk Transformer Capacity Addition project:	nil
2. Advanced Metering Infrastructure (AMI) project:	nil
3. Kootenay Long Term Facilities Strategy project:	0.3%

The Company will file detailed CPCN applications for these projects.

112.0 Reference: Expenditures by Plant Category

Exhibit B-1, Tab 6, Section 1.4, p. 7

Table 1.4 - Expenditures by Plant Category

112.1 Provide a table in a similar format to Table 1.4 showing the previous five years of data, both forecast and actual, for the same line items.

Response:

The Table below provides the forecast and actual expenditures by Plant Category.

Table BCUC IR1 112.1

Expenditures by Plant Category	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
Generation	($000's)											
Growth	-	-	-	-	-	-	-	-		-	-	-
Sustainment	21,659	21,604	19,079	17,357	21,535	20,622	20,068	19,510	19,755	20,780	10,131	2,947
Subtotal	**21,659**	**21,604**	**19,079**	**17,357**	**21,535**	**20,622**	**20,068**	**19,510**	**19,755**	**20,780**	**10,131**	**2,947**
Transmission and Stations												
Growth	56,926	62,763	60,136	40,499	50,924	44,187	92,010	77,065	23,509	24,561	11,832	8,847
Sustainment	7,479	7,672	6,256	8,502	9,072	7,022	9,791	7,397	5,219	8,401	23,423	24,007
Subtotal	**64,405**	**70,435**	**66,392**	**49,001**	**59,996**	**51,209**	**101,801**	**84,462**	**28,728**	**32,962**	**35,254**	**32,855**
Distribution												
Growth	11,745	14,850	11,224	16,770	13,544	11,995	13,809	11,520	11,990	9,744	13,646	13,759
Sustainment	8,016	10,971	9,021	10,134	10,502	14,271	10,954	15,131	8,978	10,585	15,603	12,129
Subtotal	**19,761**	**25,821**	**20,245**	**26,904**	**24,046**	**26,266**	**24,763**	**26,651**	**20,968**	**20,329**	**29,249**	**25,888**
Telecom, SCADA, Protection & Control												
Growth	3,458	162	1,456	1,111	1,338	1,801	1,438	1,512	1,652	2,172	1,212	2,549
Sustainment	1,482	1,030	1,088	1,807	747	768	619	684	1,613	2,193	1,117	1,133
Subtotal	**4,940**	**1,192**	**2,544**	**2,918**	**2,085**	**2,569**	**2,057**	**2,195**	**3,265**	**4,365**	**2,329**	**3,682**
General Plant												
Kootenay Long Term Facilities Strategy	-	-	-	-	-	-	-	-	503	503	6,020	10,477
Trail Office Lease Purchase	-	-	-	-	-	-	-	-	-	-	-	10,000
Okanagan Long Term Solution	-	-	-	-	-	-	-	-	507	507	69	75
Central Warehousing	-	-	-	-	-	-	-	-	-	-	1,755	-
Advanced Metering Infrastructure	-	-	-	-	-	-	-	-	-	-	4,501	27,931
Environmental Compliance (PCB Mitigation)	-	-	-	-	-	-	-	-	1,926	2,126	-	-
Mandatory Reliability Standars Compliance	-	-	-	-	-	-	-	1,811	615	600	-	-
Information Systems	5,640	6,655	3,776	4,543	5,167	4,768	4,499	4,309	4,682	4,682	5,672	4,692
Vehicles	3,400	4,388	2,461	1,277	2,000	1,947	2,000	1,225	2,072	2,738	2,541	2,574
Metering Changes	64	481	136	115	526	136	559	181	221	472	403	406
Telecommunications	175	221	175	258	105	86	106	54	371	394	121	183
Buildings	5,410	1,790	1,312	1,599	1,305	1,271	1,062	948	1,288	1,288	1,362	883
Furniture and Fixtures	212	248	187	237	347	294	393	268	182	182	121	122
Tools and Equipment	749	936	650	587	572	525	574	507	623	622	528	457
Subtotal	**15,650**	**14,719**	**8,697**	**8,616**	**10,022**	**9,027**	**9,193**	**9,303**	**12,990**	**14,115**	**23,094**	**57,799**
Total Plant and Equipment	126,415	133,771	116,957	104,796	117,684	109,693	157,882	142,121	85,706	92,551	100,057	123,171
Demand Side Management	1,657	1,623	1,613	1,858	2,568	2,396	2,826	2,656	5,764	5,396	5,798	5,909
Total	**128,072**	**135,394**	**118,570**	**106,654**	**120,252**	**112,089**	**160,708**	**144,777**	**91,470**	**97,947**	**105,855**	**129,080**

112.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

The class and accuracy of the Generation projects can be found below in response to BCUC IR1 Q113.1. The class and accuracy of the Transmission and Stations projects can be found below in response to BCUC IR1 Q125.2. The class and accuracy of the Distribution projects can be found below in response to BCUC IR1 Q145.2. The class and accuracy of the Telecommunications, SCADA and Protection and Control projects can be found below in response to BCUC IR1 Q155.2. The class and accuracy of the General Plant projects can be found in the Table BCUC IR1 112.2 below.

Table BCUC IR1 112.2

17	**General Plant**	AACE Class	Accuracy
18	Kootenay Long Term Facilities Strategy	-	-
19	Trail Office Lease Purchase	Class 2	-10 % / +10%
20	Okanagan Long Term Solution	Class 4	-15 % / +20%
21	Central Warehousing	Class 3	-15 % / +20%
22	Advanced Metering Infrastructure	-	-
23	Information Systems	Class 3	-15 % / +20%
24	Vehicles	Class 3	-15 % / +20%
25	Metering Changes	Class 3	-15 % / +20%
26	Telecommunications	Class 3	-15 % / +20%
27	Buildings	Class 3	-15 % / +20%
28	Furniture and Fixtures	Class 3	-15 % / +20%
29	Tools and Equipment: Transmission-Distribution-Generation	Class 3	-15 % / +20%
32	Demand Side Management (Net of Tax)		

113.0 Reference: Generation

Exhibit B-1, Tab 6, Section 2, p. 10

Table 2.0 – Generation Projects

113.1 Provide a table in a similar format to Table 2.0 showing the previous five years of data, both forecast and actual, for the same line items.

Response:

Please refer to Table BCUC IR1 113.1 below.

Table BCUC IR1 113.1

		AACE Estimate Class	AACE Estimate Accuracy Range	2007		2008		2009		2010		2011		2012	2013	2014	2015	2016	2017	2018
1		Financial		Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Forecast	Requested		Proposed Costs				
2	**Physical Infrastructure Projects**											($000s)								
3	All Plants Concrete and Structural Rehabilitation																			
4	Plant Additions			-	-	-	-	-	-	-	-	-	-	495	543	566	583	602	581	581
5	Cost of Removal			-	-	-	-	-	-	-	-	-	-	75	74	81	83	84	86	88
6	**Total All Plants Concrete & Structural Rehabilitation**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**570**	**617**	**647**	**666**	**686**	**667**	**669**
7	Upper Bonnington Spill Gate Rebuild (G-195-10)																			
8	Plant Additions			-	-	-	-	-	-	-	-	630	621	1,061	-	-	-	-	-	-
9	Cost of Removal			-	-	-	-	-	-	-	-	-	-	24	-	-	-	-	-	-
10	**Total Upper Bonnington Spill Gate Rebuild (G195-10)**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**630**	**621**	**1,085**	**-**	**-**	**-**	**-**	**-**	**-**
11	Lower Bonnington Powerhouse Windows (G-195-10)																			
12	Plant Additions			-	-	-	-	-	-	-	-	362	354	366	8	-	-	-	-	-
13	Cost of Removal			-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-	-
14	**Total Lower Bonnington Powerhouse Windows (G-195-10)**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**362**	**401**	**366**	**8**	**-**	**-**	**-**	**-**	**-**
15	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows																			
16	Plant Additions			-	-	-	-	-	-	-	-	-	-	-	430	-	-	-	-	-
17	Cost of Removal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Total Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**		**-**	**-**	**430**	**-**	**-**	**-**	**-**	**-**
19	**Physical Infrastructure Projects Total**			**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**992**	**1,022**	**2,021**	**1,055**	**647**	**666**	**686**	**667**	**669**
20																				
21	**Mechanical and Electrical Equipment Projects**																			
22	Corra Linn Unit 2 Life Extension (C-5-09)																			
23	Plant Additions			-	-	-	-	-	33	2,987	3,505	12,781	12,748	3,423	-	-	-	-	-	-
24	Cost of Removal			-	-	-	-	-	-	-	8	825	844	-	-	-	-	-	-	-
25	**Total Corra Linn Unit 2 Life Extension (C-5-09)**	**See Note 1**		**-**	**-**	**-**	**-**	**-**	**33**	**2,987**	**3,513**	**13,606**	**13,592**	**3,423**	**-**	**-**	**-**	**-**	**-**	**-**
26	All Plants Station Service (G-147-06)																			
27	Plant Additions			255	672	473	498	484	646	1,191	1,228	1,352	1,352	672	-	-	-	-	-	-
28	Cost of Removal			-	0	-	0	-	6	-	1	6	40	-	-	-	-	-	-	-
29	**Total All Plants Station Service (G-147-06)**	**See Note 1**		**255**	**672**	**473**	**498**	**484**	**652**	**1,191**	**1,229**	**1,358**	**1,392**	**672**	**-**	**-**	**-**	**-**	**-**	**-**
30	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade (Revenue Meter Replacement) (G-195-10)																			
31	Plant Additions			-	-	-	-	-	-	-	-	89	89	90	-	-	-	-	-	-
32	Cost of Removal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**Total Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade (Revenue Meter Replacement) (G-195-10)**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**89**	**89**	**90**	**-**	**-**	**-**	**-**	**-**	**-**
34	Corra Linn Unit 3 Completion																			
35	Plant Additions			-	-	-	-	-	-	-	-	-	-	675	-	-	-	-	-	-
36	Cost of Removal			-	-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-
37	**Total Corra Linn Unit 3 Completion**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**722**	**-**	**-**	**-**	**-**	**-**	**-**
38	Upper Bonnington Old Plant Various Unit Upgrades																			
39	Plant Additions			-	-	-	-	-	-	-	-	-	-	1,277	-	-	-	-	-	-
40	Cost of Removal			-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-
41	**Total Upper Bonnington Old Plant Various Unit Upgrades**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,311**	**-**	**-**	**-**	**-**	**-**	**-**
42	**Mechanical and Electrical Equipment Projects Total**			**255**	**672**	**473**	**498**	**484**	**685**	**4,178**	**4,742**	**15,053**	**15,073**	**6,218**	**-**	**-**	**-**	**-**	**-**	**-**
43																				
44	**Dam, Public and Worker Safety Projects**																			
45	Lower Bonnington, Upper Bonnington and Corra Linn Fire Panels																			
46	Plant Additions			-	-	-	-	-	-	-	-	-	-	250	259	264	-	-	-	-
47	Cost of Removal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	**Total Lower Bonnington, Upper Bonnington and Corra Line Fire Panels**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**250**	**259**	**264**	**-**	**-**	**-**	**-**
49																				
50	All Plants Safety & Security																			
51	Plant Additions			-	-	-	-	-	-	-	-	-	-	471	475	424	437	-	-	-
52	Cost of Removal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	**Total All Plants Safety & Security**	**Class 3**	**-15% to +20%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**471**	**475**	**424**	**437**	**-**	**-**	**-**
54	**Dam, Public and Worker Safety Projects Total**			**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**721**	**734**	**688**	**437**	**-**	**-**	**-**
55																				
56	**All Plants Minor Sustainment Projects**																			
57	All Plants Minor Sustainment Capital																			
58	Plant Additions			-	-	-	-	-	-	-	-	634	634	1,061	1,051	1,095	1,127	1,165	1,124	1,124
59	Cost of Removal			-	-	-	-	-	-	-	-	-	75	110	107	108	17	17	17	18
60	**Total All Plants Minor Sustainment Capital**	**See Note 1**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**634**	**709**	**1,171**	**1,158**	**1,203**	**1,144**	**1,182**	**1,141**	**1,142**
61	**All Plants Minor Sustainment Projects Total**			**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**634**	**709**	**1,171**	**1,158**	**1,203**	**1,144**	**1,182**	**1,141**	**1,142**
62																				
63	**Total Generation Projects**			**255**	**672**	**473**	**498**	**484**	**685**	**4,178**	**4,742**	**16,679**	**16,804**	**10,131**	**2,947**	**2,538**	**2,247**	**1,868**	**1,808**	**1,811**

Note 1: AACE estimating methodology was not in use at the time this project was estimated. However an estimate was completed and this project can be considered to be estimated as a Class 3 by AACE standards.

Note 2: Cost of removal was not forecast prior to 2011.

113.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

Please refer to the response to BCUC IR1 Q113.1.

113.3 Also in the referenced table, separately show previously approved expenditures from those for which approval is being sought. Provide total forecast and approved costs for previously approved expenditures.

Response:

The projects which have been previously approved are identified in the response to BCUC IR No. 1 Q113.1.

113.4 For those projects which impact longer term projects, such as the All Plants Concrete and Structural Rehabilitation project and All Plants and Security Project, please include the annual and total proposed costs of those projects for the years 2014 to 2018.

Response:

Please refer to the response to BCUC IR1 Q113.1.

114.0 Reference: All Plants Concrete and Structural Rehabilitation

Exhibit B-1, Tab 6, Section 2.1.1, pp. 10-11

Remaining Life of Concrete Structures

114.1 As the generating facilities range from 70 to 100 years old and the “All Plants Concrete and Structural Rehabilitation” projects spans the next 18 years but does not include major rehabilitation projects required over the next 20 years, please explain why the major rehabilitation projects are not included at this time considering the age of the infrastructure and the money already invested in the ULE program.

Response:

The All Plants Concrete and Structural Rehabilitation project is an ongoing program to address smaller deficiencies and provide a sustaining level of investment to ensure the deterioration does not progress to the point where major refurbishment is necessary.

Major rehabilitation projects have been identified within the 20 year planning horizon and are included as separate projects in the Integrated System Plan. The timing of these major projects will be dependent upon condition and will be the subject of future regulatory filings.

114.2 Provide a risk assessment table for the do-nothing option versus the minor rehabilitation projects option for worker and public safety.

Response:

A number of projects involving the mitigation of potential risk to public and worker safety have been included in the “All Plants Concrete and Structural Rehabilitation” category. A risk assessment for the do-nothing option was not completed as these projects were included within the program based on engineering judgment and the potential to create hazards for employees or the public at FortisBC facilities.

Of the 22 total projects put forward between 2012 and 2013, 18 of them involve some degree of risk to public or worker safety. These projects represent a cost of $0.671 million out of the $1.2 million proposed in these years. By contrast, projects involving some degree of risk to public or worker safety account for only an estimated $0.225 million out of $2.0 million proposed between 2014 and 2016. This allocation of work demonstrates the priority FortisBC is placing on this type of work within the All Plants Concrete and Structural Rehabilitation Program.

114.3 Considering the generating facilities range from 70 to 100 years old and the statement that major rehabilitation projects will be required over the next 20 years, what would the cost difference be to transition from the minor rehabilitation projects to the major rehabilitation projects at this time?

Response:

FortisBC does not understand the question as posed.

The All Plants Structural Rehabilitation program consists of a distinct scope of projects intended to address numerous deterioration issues at the facilities. The scope of work for this program is distinct from that of the Major Rehabilitation projects noted in Table 2.5(a), page 43 in the 2012 Long Term Capital Plan. The timing of the Major Rehabilitation projects is the Company’s best estimate of when the work will be required. Similarly, the timing of the work proposed in the All

Plants Structural Rehabilitation program is required in the timeframe proposed in the Application.

114.4 Please provide a magnitude estimate of the total cost of these major rehabilitation projects which will be required over the next 20 years and the forecasted rate impact.

Response:

Table BCUC IR1 114.4

Major Rehabilitation Project Names		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Cumulative
1	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	7,874	865	1,786	1,728	1,728	1,828	1,840	2,055	1,046	-	-	-	-	1,724	1,783	1,806	1,787	**27,851**
2	Upper Bonnington Overflow Spillway Concrete Resurface	-	-	-	-	-	-	-	-	-	-	-	-	5,833	6,006	6,190	6,282	6,266	**30,576**
3	South Slocan Spillway Concrete Repair	-	-	-	-	-	-	-	-	-	10,519	10,278	10,463	11,110	-	-	-	-	**42,370**
4	All Plants Superstructure Upgrade	-	-	-	-	-	-	-	-	536	529	513	520	553	572	593	603	600	**5,020**
5	**Total Major Rehabilitation Projects:**	**7,874**	**865**	**1,786**	**1,728**	**1,728**	**1,828**	**1,840**	**2,055**	**1,581**	**11,048**	**10,791**	**10,983**	**17,495**	**8,302**	**8,567**	**8,691**	**8,654**	**105,817**
6	**Expected (approximate) Rate Impact:**	**0.04%**	**0.12%**	**0.02%**	**0.04%**	**0.03%**	**0.03%**	**0.03%**	**0.03%**	**0.02%**	**0.07%**	**0.14%**	**0.14%**	**0.15%**	**0.15%**	**0.09%**	**0.09%**	**0.10%**	**1.28%**

114.5 Considering the costs of rehabilitation of the generating facilities that range from 70 to 100 years old, please explain what other alternatives have been considered.

Response:

FortisBC has focused its efforts on providing the most economical method of rehabilitating the generating facilities to ensure their long term low cost viability. A do nothing and resulting plant shutdown/decommissioning alternative was discarded early in the analysis given the value of the energy generated to FortisBC customers and the high cost to replace this energy and capacity through long term contracts or new generation resources. A deferral was also considered, but eliminated due to the increased public and employee safety risks. As well, future rehabilitation costs will be higher with the accelerated deterioration if left in its current state.

114.6 Please provide the specific activities in the "All Plants Concrete and Structural Rehabilitation" for which approval is being sought in this application.

Response:

This project includes a variety of small projects, some examples are:

- Regrout Head Gate Support Base Plates at Corra Linn;
- Upgrade hoist frame to tower connections at Upper Bonnington;
- Refurbish power house crane rail lower sills at Lower Bonnington;
- Refurbish rock trap cleanout pipe at Lower Bonnington;
- Replace bent bracing on head gate towers at Upper Bonnington;
- Resurface Stair Nosings at South Slocan Forebay Access Stairs;
- Install kick plate on walkway at Corra Linn stop log access gates;
- Refurbish corroded stairs in switch yard at Corra Linn;
- Replace bent bracing on head gate towers at Corra Linn; and
- Refurbish crack in power house wall at Upper Bonnington.

114.7 Please provide the total costs of the eighteen year program, with a comprehensive description of the scope and need for each element.

Response:

Please refer to the below table for an estimate of the eighteen year program costs.

Table BCUC IR 1 114.7

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
1		Requested		Proposed																
2		($000s)																		
3	All Plants Concrete and Structural Rehabilitation																			
4	Plant Additions	495	543	566	583	602	710	710	744	748	823	835	2,627	808	822	869	895	922	932	15,236
5	Cost of Removal	75	74	81	83	84	103	105	107	108	110	112	631	116	118	120	122	124	126	2,403
6	Total All Plants Concrete and Structural Rehabilitation	570	617	647	665	686	813	815	851	856	933	947	3,258	924	940	989	1,017	1,046	1,058	17,638

The scope of work for the projects included in this program varies depending on the type of work. They can be divided into the following two categories:

1. Concrete Restoration - Concrete restoration typically includes the removal of deteriorated concrete by mechanical means, repairs to the reinforcing steel and replacement of the new concrete;
2. Steel Refurbishment - Steel refurbishment typically includes the removal of damaged, corroded or undersized members followed by the replacement with new steel. Recoating is typically required.

The need for each project listed is based on a variety of factors ranging from immediate risk to personal safety, upgrades required for seismic hazards, replacement of failed (or failing) components and upgrades required for legislative compliance.

Projects within the two year time frame have been selected as those immediately required and are to proceed as outlined below. However, projects selected in future years will be reviewed and selected based on needs and may include projects which are currently unforeseen.

The following projects are currently included within the Concrete and Structural Rehabilitation Program in the next two years:

2012 to 2013 Current Projects

- P1 - LBO - Rock Trap Cleanout Refurbish Leaking Pipe

  The rock trap cleanout pipe at Lower Bonnington is leaking through the dam alongside the pipe; the rehabilitation involves underwater concreting followed by pressure grouting to reestablish the integrity through the dam.
- P2 - UBO - Replace Damaged Bracing On Head Gate Towers

  A number of steel braces on the truss tower structures have been damaged over the years; the project involves removing and replacing the damaged braces.
- P3 - SLC - Resurface Stair Nosings

  The stairs accessing the switch yard area at South Slocan have deteriorated and currently require rehabilitation to reduce the risk of tripping and fall hazards in a high voltage area.
- P4 - COR - Install Kick Plate On Walkway

  Sections of the existing handrail at Corra Linn do not meet the WorkSafe BC requirements for handrail; these sections require the installation of kick plate to reduce the risk of falling objects.
- P4 - COR - Refurbish Damaged Stairs

  The stairs accessing the Forebay area at Corra Linn have deteriorated and currently require rehabilitation to reduce the risk of tripping and fall hazards.
- P4 - COR - Replace Damaged Bracing On Head Gate Towers

  A number of steel braces on the truss tower structures have been damaged over the years; the project involves removing and replacing the damaged braces.

- P1 - LBO - Service Tunnel Crack - Monitor At This Time

  A crack is visible in the service tunnel at Lower Bonnington which could indicate foundation issues; the project involves installing a crack gauge for future monitoring.

- P1 - LBO - Upgrade Hoist Frame To Tower Connections

  An engineering analysis of the head gate superstructure has noted that the connections between to hoist frames and the steel towers at Lower Bonnington are undersized and in some locations show signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.

- P3 - SLC - Stairway To Head Gates - Replace Rotten Roof

  The roof above the stairs leading to the head gates at South Slocan is wood construction exposed to the elements. Over time the supports and joists in the roof have deteriorated and could fail under heavy snow loads. The project involves replacing rotten beams and reinforcing the roof structure.

- P4 - COR - Resurface Tailrace Wall

  The tailrace wall at Corra Linn has significant deterioration at the water level. There are a number of spalled areas and in some places reinforcing steel is visible. This project involves resurfacing the deteriorated areas to ensure long term stability of the tail race wall.

- P4 - COR - Regrout Head Gate Superstructure Base Plates

  A number of grout pads beneath the steel tower bases which support the superstructure for both the spillway gates and the head gates have deteriorated over the years. These grout pads are a direct path for the load transfer between steel and concrete. The project involves refurbishing the deteriorated grout pads.

- P2 - UBO - Upgrade Hoist Frame To Tower Connections

  An engineering analysis of the head gate superstructure has noted that the connections between to hoist frames and the steel towers at Upper Bonnington are undersized and in some locations show signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.

- P1 - LBO - Refurbish Tailrace Gantry Lower Sills

  The tail race gantry crane at Lower Bonnington is supported by a crane rail partially embedded in a concrete beam. These concrete beams supporting the crane have significant deterioration which impacts the safety and rating of the crane. The project involves removing deteriorated concrete and restoring the support beams to original design standards.

- P4 - COR - Upgrade Spillway Gantry Lifelines To Current Standards

  The lifelines on the spillway gate gantry crane do not meet current WorkSafe BC standards and require upgrades to ensure worker safety during maintenance activities.

- P2 - UBO - Refurbish Crack In Power House Wall

  A large crack is present in the power house wall at Upper Bonnington located directly above the glass windows. There is concern that the failing concrete is transferring load through the window structure and could present a hazard during window operation. This project involves reinforcing the concrete and refinishing the crack area.

- P4 - COR - Upgrade Hoist Frame To Tower Connections

An engineering analysis of the head gate superstructure has noted that the connections between to hoist frames and the steel towers at Corra Linn are undersized and in some locations show signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.

- P3 - SLC - Upgrade Hoist Frame To Tower Connections

  An engineering analysis of the head gate superstructure has noted that the connections between to hoist frames and the steel towers at South Slocan are undersized and in some locations show signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.

- P4 - COR - Work Platforms On Crane Bridge

  The gantry crane for lifting spillway gates at Corra Linn has a number of grating panels that are currently lifting due to deteriorated and missing fasteners. This project involves refastening of grating panels to ensure worker safety.

- P4 - COR - Upgrade Gate Access Lifelines To Current Standards

  The existing spillway gate lifelines do not meet the current WorkSafe BC standards and require replacement. The current practice involves the use of temporary lifelines each time a spillway gate requires operation. This project will replace the existing lifelines and remove the requirement to install and remove the temporary system each time a gate is operated.

- P1 - LBO - Refurbish Core Holes In Forebay Walkway

  There are a number of cored holes along the dam crest area at Lower Bonnington. These holes were presumably cored in the past to investigate concrete quality but are no longer required. The existence of these holes poses a tripping hazard to workers and allows for the water to collect - accelerating freeze thaw deterioration in the winter months.

- P1 - LBO - Resurface Forebay Wall and Intake Piers

  The north forebay wall and intake piers at Lower Bonnington have significant spalling and deterioration at the waterline. The surface concrete in this area appears to be highly susceptible to freeze thaw action and reinforcing is visible in many locations. The project involves the removal and replacement of deteriorated concrete and reinforcing steel to restore the areas to original condition.

- P1 - LBO - Resurface Forebay Deck Area

  The forebay deck area at Lower Bonnington is deteriorating and has resulted in the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.

The following projects are currently proposed for future years within the Concrete and Structural Rehabilitation Program:

2014 to 2030 Proposed Projects

- P4 - COR - Refurbish Corroded Transformer Area Stairs And Retaining Wall

  The stairs accessing the switch yard area at Corra Linn have deteriorated and currently require rehabilitation to reduce the risk of tripping and fall hazards in a high voltage area. There is also a retaining wall in the vicinity of the stairs that requires repair. In order to realize some economies this project includes refurbishment of the concrete stairs and adjacent retaining wall.

- P2 - UBO - Minor Refurbish Of Spillway Area

  The UBO overflow spillway refurbishment project is currently not scheduled until 2026. This project involves a minor refurbishment to allow for continued operation of the overflow spillway for the period between 2014 and 2026.

- P4 - COR - Refurbish Spillway Splash Wall

  The spillway splash wall adjacent the first spillway gate at Corra Linn is beginning to show signs of deterioration and will require refurbishment for continued operation. This project is currently proposed under the Concrete and Structural Rehabilitation but the timing will be evaluated based on future deterioration.

- P4 - COR - Replace Tail Race Grating

  The tail race grating currently on the tailrace deck at Corra Linn was not designed for today’s vehicle weights. As such, the grating requires upgrading to allow for crane and vehicle access to the riverside of the powerhouse.

- P4 - COR - Resurface Spillway Piers

  The spillway pier caps at Corra Linn are showing signs of deterioration. This project is proposed to resurface those pier caps affected to ensure continued structural integrity for towers above into the future.

- P2 - UBO - Upgrade Existing Handrail

  An engineering inspection of the head gate superstructure at Upper Bonnington has noted that the current handrails do not meet the WorkSafe BC requirements for load resistance. This project addresses those areas which are out of compliance.

- P4 - COR - Upgrade Handrail Connections

  An engineering inspection of the head gate superstructure at Corra Linn has noted that the current handrails do not meet the WorkSafe BC requirements for load resistance. This project addresses those areas which are out of compliance.

- P4 - COR - Refurbish Tower To Bridge Connections

  Some of the towers to bridge connections have been reported to be structurally deficient under current earthquake loading criteria. This project is included to further investigate and upgrade these connections as necessary.

- P1 - LBO - Resurface Forebay Walls South Of Piers

  The south forebay wall at Lower Bonnington is showing signs of deterioration at the waterline. The surface concrete in this area is exposed to repeated freeze thaw cycles and known to deteriorate faster than other concrete at FortisBC facilities. This portion of the wall has been separated from the project “P1 - LBO - Resurface Forebay Wall and Intake Piers” in order to level the program spending. The project involves the removal and replacement of deteriorated concrete and reinforcing steel to restore the areas to original condition.

- P3 - SLC - Refurbish Switch Yard Wall

  This is a small project and involves the repair to various switch yard retaining walls at South Slocan. The project involves the removal and replacement of deteriorated concrete and reinforcing.

- P2 - UBO - Replace Chain Gates With Swing Gates

  Recent updates to the WorkSafe BC regulations now require engineering certification of chain gates used within a handrail system. Based on a cost analysis and a recent engineering report that suggested the replacement of these gates with self closing swing gates it was determined that the installation of swing gates was most cost effective.

- P3 - SLC - Refurbish Overflow Spillway Wall

  The forebay wall adjacent to overflow spillway at South Slocan is showing signs of deterioration at the waterline. The area exposed to continuous wetting and drying is particularly susceptible to freeze thaw deterioration and will likely require restoration in the near future. The project involves the removal and replacement of deteriorated concrete and reinforcing steel to restore the areas to original condition.

- P1 - LBO - Resurface Tailrace Deck Area

  The surface of the tailrace deck area at Lower Bonnington has deteriorated quite badly and is now a tripping hazard to workers. This particular item has been raised at FortisBC safety meetings. This project will resurface those deteriorated areas where ponding occurs to reduce future deterioration and slipping hazards for workers in the winter months.

- P1 - LBO - Resurface Transformer Deck

  The transformer slabs at Lower Bonnington are deteriorating and will lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.

- P1 - LBO - Resurface Power House Wall At Entrance Way

  At the entrance to the Lower Bonnington power house there is a wall that extends into the abutment. Over time the surface of this wall has eroded due to water runoff from the rocks above. This project includes the removal and restoration of deteriorated concrete and reinforcing to restore the wall to original condition.

- P3 - SLC - Patch Hole In Power House Wall At Base

  This is a small project that includes patching a hole in the power house wall. This project will be scheduled to coincide with other concrete work in the vicinity.

- P1 - LBO - Refurbish Various Control Joints

  Over time the caulking in expansion joints in the power house, dam and concrete structures have lost their integrity or in some cases are no longer present. This project involves the installation of backer rod and caulking to seal various expansion joints and prevent the ingress of water.

- P1 - LBO - Resurface Forebay Access Cover Edges

  The hatch covers in the forebay area bear on embedded angles to transfer the load from the cover into the concrete. This project involves replacing the embedded angles which have deteriorated and in some cases are no longer present to restore the original capacity of the hatch covers.

- P1 - LBO - Resurface Forebay Trash Rack Wall Edges

The trash rack walls at Lower Bonnington are subject to freeze thaw action and abrasion from trash removal and flowing debris laden water. These walls are beginning to show signs of deterioration and will be in need of restoration in the near future.

- P2 - UBO - Resurface Corroded Forebay Deck Area

  The forebay deck area at Upper Bonnington is deteriorating and has lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.

- P3 - SLC - Resurface Concrete Deck Area Base Of Stairs

  The concrete deck area at the base of forebay access stairs at South Slocan is deteriorating and has lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.

- P2 - UBO - Refurbish Forebay Air Chamber Ceiling

  The concrete beams which support the elevated slab above the air chamber at Upper Bonnington are showing signs of deterioration with evidence of rust and minor spalling concrete visible. This project proposes the removal and restoration of deteriorated concrete and reinforcing to restore the support beams to their original condition.

- P3 - SLC - Resurface Forebay Piers

  The forebay intake piers at South Slocan are beginning to show deterioration at the water line. This area is particularly susceptible to freeze thaw deterioration and will likely require restoration in the near future. This project involves the removal and restoration of deteriorated concrete and reinforcing to restore the affected areas to their original condition.

- P4 - COR - Resurface Run Of River Spillway Walkway Areas

  The concrete deck area at the spillway walkway area at Corra Linn is deteriorating and has resulted in the development of high and low areas which allow for water to pond. In addition there are a number of cored holes along this section of the dam. These areas allow for the water to collect - accelerating freeze thaw deterioration in the winter months and presenting a slipping hazard to workers in the winter months. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.

- P3 - SLC - Resurface Concrete Walkway Area

  This is a small project that involves the patching of a few small depressions and tripping hazards along the walkway leading through the switchyard at South Slocan.

- P1 - LBO - Resurface Top Spillway Piers

  The spillway pier caps at Lower Bonnington are deteriorated. This project is proposed to resurface those pier caps affected to ensure continued structural integrity for towers and bridges above into the future.

- P1 - LBO - Resurface Tailrace Piers & Walls

  The tailrace piers at Lower Bonnington currently show deterioration at the water line. This area is particularly susceptible to freeze thaw deterioration and will likely require restoration in the near future. This project involves the removal and restoration of deteriorated concrete and reinforcing to restore the affected areas to their original condition.

- P3 - SLC - Refurbish Forebay Trash Rack Wall

  The trash rack walls at South Slocan are subject to freeze thaw action and abrasion from trash removal and flowing debris in the water. These walls are beginning to show signs of deterioration and will be in need of restoration in the near future.

- P2 - UBO - Repaint Handrail

  The handrail on the existing superstructure at Upper Bonnington is in need of recoating due to coating failure. This project will follow directly behind “P2 - UBO - Upgrade Existing Handrail” and capture the areas that do not require upgrades along with the new handrails.

- P2 - UBO - Resurface Forebay Pier Caps

  The spillway pier caps at Upper Bonnington are showing signs of deterioration. This project is proposed to resurface those pier caps affected to ensure continued structural integrity for towers and bridges above into the future.

- P4 - COR - Resurface Air Chamber Ceiling Areas

  The concrete beams which support the elevated slab above the air chamber at Corra Linn are badly deteriorated with evidence of rust and spalled concrete visible. This project proposes the removal and restoration of deteriorated concrete and reinforcing to restore the support beams to their original condition.

- P3 - SLC - Refurbish Cracks In Spillway

  The South Slocan Overflow Spillway project is not scheduled until 2023. This project involves the removal of vegetation and recaulking of joints in the overflow section of the spillway to reduce additional deterioration and ensure the continued operation of the overflow spillway until 2023.

- P4 - COR - Refurbish Air Wash Wall

  The air wash system at Corra Linn relies on a large concrete duct to move the air from the air wash chamber into the power house structure. This concrete duct bears on a narrow section of concrete wall and is currently pulling away from the power house. This project involves reinforcing the connection between the powerhouse and concrete duct along with addressing the narrow support wall.

- P4 - COR - Refurbish Power House Walls

  This project addresses a number of vertical cracks located between every other column bay line in the power house at Corra Linn. Although these cracks appear to be dormant, this project allows for the installation of crack gauges and patching of cracks in future years.

- P4 - COR - Resurface Forebay Piers

  The forebay intake piers at Corra Linn are beginning to show signs of deterioration at the waterline. The surface concrete in these areas exposed too many freeze thaw cycles increasing the rate of deterioration relative to other areas. The timing of the project will be based on rate of deterioration. The scope of the project involves the removal and replacement of deteriorated concrete and reinforcing steel to restore the areas to original condition.

- P3 - SLC - Resurface Air Chamber Ceiling Areas

  The concrete beams which support the elevated slab above the air chamber at South Slocan are somewhat deteriorated with evidence of rust and some spalled concrete visible. This project proposes the removal and restoration of deteriorated concrete and reinforcing to restore the support beams to their original condition.
- P2 - UBO - Resurface Tailrace Pier Bottoms At Waterline

  The tailrace piers at Upper Bonnington are beginning to show deterioration at the water line. This area is particularly susceptible to freeze thaw deterioration and restoration will likely be required toward the end of 18 year period.
- P3 - SLC - Resurface Tailrace Track Edge

  The existing concrete surround the embedded rails (tracks) have deteriorated edges and pose a tripping hazard to workers. This particular item has been raised by workers as an area of concern during safety meetings.
- P3 - SLC - Resurface Power House Courtyard Slab Area

  The power house court yard slabs at South Slocan are deteriorating and have lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.
- P4 - COR - Upgrade Trolley Crane Handrails & Ladders

  An engineering inspection of the spill gate superstructure at Corra Linn has noted that the current handrails do not meet the WorkSafe BC requirements for load resistance and ladders do not meet design standards for cages. This project addresses those areas which are out of compliance.
- P4 - COR - Refurbish Forebay Slab Areas

  The Forebay area slab at Corra Linn is deteriorating and has lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.
- P3 - SLC - Resurface Power House Exterior Columns

  The power house columns as South Slocan are beginning to show signs of deterioration. This project is proposed to refurbish the exterior of columns but the timing will be based on future deterioration and need.
- P4 - COR - Refurbish Top Of Spray Wall Between Sluice Ways

  The spillway splash wall at Corra Linn has extensive deterioration and requires refurbishment for continued operation. This project is currently proposed under the Concrete and Structural Rehabilitation but may be moved into the Corra Linn Spillway Gate project to gain some economies.
- P3 - SLC - Resurface Switch Yard Slab Areas

  The switch yard slabs at South Slocan are deteriorating and have lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.

- P3 - SLC - Superstructure Repainting

  The superstructure at South Slocan is currently is relatively good structural condition. However, the coating of the structural steel is failing and requires recoating to maintain the condition of the steel work.

- P4 - COR - Install Swing Gates At Trolley Crane Platforms

  Recent updates to the WorkSafe BC regulations require engineering certification of chain gates used within a handrail system. Based on a cost analysis and a recent engineering report that suggested the replacement of these gates with self closing swing gates it was determined that the installation of swing gates was most cost effective.

114.8 Please provide the current list of jobs and details of the priority ratings system.

Response:

Please refer to BCUC IR1 Appendix 114.8 for a current list of projects proposed in 2012 and 2013.

The priority rating system ranks projects by weighing serviceability (ie. potential of failure) and any potential impact on public and workers (ie. injury priority). Priority of injury is provided a higher weighting than serviceability, and the Company utilizes engineering judgment to assign the rankings to each category.

115.0 Reference: Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows

Exhibit B-1, Tab 6, Section 2.1.4, pp. 12-13

Remaining Life of Windows

FortisBC states that “A proposed capital project in 2013 will address the worst locations in these powerhouses, but given the age of the remaining windows it is expected that the balance of the windows will require replacement within the next 30 years.” (Exhibit B-1-1, Tab2, p. 33)

115.1 Given the age of the facilities, would postponement of the window replacement significantly increase the risk to the safety of plant personnel?

Response:

Given the age and condition of the existing windows, FortisBC does not feel that postponing the replacement of these components is acceptable. The risk to the safety of plant personnel will increase each year the windows are not replaced.

As noted in the application, the project is intended to only address the windows in the worst condition and which present the greatest safety risk. The balance of the windows in these facilities will be addressed in future regulatory applications.

115.2 Please provide a risk assessment table to demonstrate the risk to the safety of plant personnel.

Response:

A risk assessment table was not completed for this project.

The windows expected to be replaced as part of this project are the ones which are opened by an employee standing directly below the window using a chain to pull the window open. Due to the age of the windows, some of the windows have broken free from their hinges and pose a direct risk to the worker opening them.

Due to the frequency of window operation (plant cooling in the spring and fall) and the height of the windows there is a high risk of major injury should this project not proceed.

115.3 Please provide the analysis of replacement options and describe whether the use of non-transparent solid panels has been considered in order to reduce costs. If not, why not?

Response:

A solid panel was considered and rejected because these windows are part of the ventilation system and operation is required for cooling during the summer months. In addition the windows provide light to the powerhouses and could lead to a lighting upgrade requirement should the amount of incoming light be reduced.

Non-transparent solid panels may be considered for replacement of some of the window openings in future years provided they are cost effective and do not have a detrimental effect on plant cooling or lighting levels.

116.0 Reference: Corra Linn Unit 3 Completion

Exhibit B-1, Tab 6, Section 2.2.4, pp. 13-14

Transformer Oil Containment

116.1 Please describe the proposed method of transformer **oil containment.**

Response:

The proposed oil containment around the unit transformer will consist of a concrete pit with adequate volume for transformer oil containment and include a sloped concrete floor. This pit will be lined with an epoxy liner to inhibit oil leakage. The containment will be filled with fire quenching rock and drain into the oil water separator.

116.2 Please provide a risk assessment table to demonstrate a transformer failure and the risk of oil entering the river.

Response:

FortisBC bases its decisions on transformer oil containment on best practices as outlined by the Centre for Energy Advancement through Technological Innovation (CEATI). CEATI is an interest group that allows utility industry professionals to collaborate on projects, share knowledge and address technical issues. The decision includes a number of considerations, including proximity to water courses and permeability of the surrounding soil as well as the total volume of contained oil.

FortisBC considers the risk of a transformer failure as low given its current maintenance practices and the condition of this equipment. However, the consequence of any event is considered very high. The potential for harm combined with the potential that a failure event could occur (even at a lower probability) drives the basis for the decision to provide containment at this location.

The transformer at Corra Linn is located within very close proximity to the Kootenay River and presents a high risk of impact to the environment in the event of any type of transformer failure which results in the release of oil. The Kootenay River joins the Columbia River and enters the United States approximately 70 km downstream of Corra Linn. Furthermore, the “endangered” White Sturgeon is known to inhabit the waters downstream of the FortisBC Generating Facilities.

116.3 As the existing containment is known to leak, has FortisBC investigated plugging the leak or installing a liner? Please explain.

Response:

The total volume of containment available in the existing Unit No. 3 pit (including allowances for crushed stone) is approximately 11,000 liters which matches the volume of oil contained in the transformer. FortisBC cannot determine to what standard the existing containment was constructed, however the current design criteria for oil containment on all other ULE projects has been to provide a minimum containment volume of 110% of the total oil contained in the transformer. Since the existing volume does not meet this requirement, and the installation of a liner would further reduce the available containment, these options were discarded.

117.0 Reference: Corra Linn Unit 3 Completion

Exhibit B-1, Tab 6, Section 2.2.4, pp. 13-14

Spare Generator Coils

FortisBC states that "Several coils installed during the ULE did not pass quality control standards but remained in the unit due to the high cost to repair. Although testing of coils indicates they are not at risk of immediate failure,…" (Exhibit B-1, Tab 6, p. 14)

117.1 Please provide an explanation as to why these coils did not pass the quality control standards.

Response:

Problems with coils during installation were that the coils did not pass the hi-pot test procedure (also known as a Dielectric Withstand Test). A hi-pot test involves applying high voltage to the coil to confirm the coil insulation integrity, verifying that the insulation of a product or component is sufficient to protect the operator from electrical shock. The coils that failed testing were replaced by the contractor.

See Errata 2 for section 2.2.4 Corra Linn Unit 3 Completion.

117.2 Please provide an estimate of the cost of repair.

Response:

With spare coils on hand, the class five estimated direct cost of the repair is $0.3 million which does not include outage costs or coil supply costs.

117.3 Please explain why the cost of repair is a capital expenditure and not a warranty issue.

Response:

To clarify the statement (Exhibit B-1, Tab 6, p. 14 of the 2012-13 RRA), the coils that did not pass the quality control standards were removed and the contractor replaced these coils. This is not a warranty issue because the contractor by replacing the coils fulfilled its quality control obligations and the unit was put in service. The supply of spare coils was not part of original contractor obligations.

117.4 Please provide a risk assessment table for failure of these coils since they are not at risk of immediate failure.

Response:

A risk assessment table was not completed for this item. However, there is minimal risk of coil failure but should a coil fail the length of forced outage time will be greatly extended while extra coils are procured.

117.5 Please identify if there are any spare coils for the Corra Linn Unit 3 Generator. In the event of individual coil failure, is it possible to “cut-out” failed coils and run the generator at reduced capacity?

Response:

There are no spare coils available for this unit. With regard to a possible “cut-out”, an outside engineering consultant has confirmed this option is available.

The terminology “cut-out” literally means to bypass the failed coil by reconnecting the stator winding circuit in such a fashion that the coil is no longer used. Depending on how many coils are cut out, the machine can be returned to service quickly at partial or sometimes full load. However, cutting out a coil may give rise to negative sequence currents or other circulating currents, resulting in hot spots in specific areas of the stator, and noticeable increase in noise or vibration, particularly at higher loads. In summary, cutting- out failed coils is an option, however the preferred option is to have spare coils available.

117.6 Please provide a line item cost breakout for the Corra Line Unit 3 Completion Project.

Response:

The cost components are estimated as follows:

Table BCUC IR1 117.6

	($000s)
Trash Rack Overhaul	169
Transformer Bay Work	216
Procure Spare Coils	244
Mechanical Switches and Valves	46
Cost of Removal	47
Total	722

118.0 Reference: Upper Bonnington Old Plant Various Unit Upgrades

Exhibit B-1, Tab 6, Section 2.2.5, pp. 14-15

Scope

FortisBC states that “The scope of work includes sustainment capital work on headgate seals, generators, turbines, governors and unit transformers. For example, the headgate seals require new sealing timbers. The generator, turbine and governor require replacement and rehabilitation of some mechanical components such as links, pins, bushings and brake system refurbishment. The unit transformers require development of a connection point for a mobile substation to minimize outage times in the event of a transformer failure. ” (Exhibit B-1, Tab 6, p. 15)

118.1 Please provide a risk assessment table for failure of a unit transformer.

Response:

FortisBC has not prepared a risk assessment table for the failure of a unit transformer. FortisBC has assessed the risk of failure for these units based on the following:

Over the past five years, FortisBC has experienced two failures of unit transformers resulting in a total of 26 days of forced outage for these units. Two of the four existing transformers were installed between 1907 and 1916 making them more than 95 years old; they also contain internal cooling coils with water which have failed in the past resulting in water in the transformer oil.

The mean life of a transformer is considered to be 50 years with a deviation of 20 years; therefore these transformers are well beyond their anticipated life span and are at high risk of failure. In addition, the existing paper insulation is likely brittle and susceptible to failure. Ageing of the paper insulation in the windings is irreversible and considered one of the life limiting processes of a transformer. As paper ages its mechanical properties are reduced.

118.2 Please provide the installed costs for the addition of a connection point for a mobile substation including access roads, etc.

Response:

The cost of establishing a mobile connection point is estimated at $0.239 million for all four units.

118.3 Please provide the installed costs for the new sealing timbers.

Response:

The estimated installed cost for the new sealing timber is $0.233 million.

118.4 Please explain why the new sealing timbers are considered sustainment capital and not O&M costs.

Response:

The Upper Bonnington Old Plant Various Unit Upgrades project is a capital project as it is a significant expenditure for major repairs that extend the useful life of assets and is not recurring in nature. The assets capitalized will provide benefits for more than one year. The head gate timber replacement is a component of this project, this component is not recurring in nature, the timbers are over 50 years old. Replacing the timbers extends the useful life of the asset, and this asset is used to generate income.

118.5 Please provide the installed costs for the generator mechanical components.

Response:

The installed costs for the generator mechanical components are estimated at $0.772 million.

118.6 Please explain why the generator mechanical components are considered sustainment capital and not O&M costs.

Response:

The Upper Bonnington Old Plant Various Unit Upgrades project is a capital project as it is a significant expenditure for major repairs that extend the useful life of assets and is not recurring in nature. The assets capitalized will provide benefits for more than one year. The generator mechanical parts replacement is a component of this project, this component is not recurring in nature, and the mechanical parts are over 50 years old. Replacing the parts extends the useful life of the asset, and this asset is used to generate income.

118.7 Please provide a table showing the actual annual generation of Upper Bonnington Units 1 to 4 since 2007.

Response:

Please refer to the below table.

Table BCUC IR1 118.7

Unit Generation (MWh)	2006	2007	2008	2009	2010
Unit 1	9,662	9,913	8,144	7,082	5,132
Unit 2	5,172	10,621	6,591	6,035	4,064
Unit 3	7,522	10,642	6,498	3,967	3,957
Unit 4	8,535	8,939	7,609	4,802	4,741
UBO "Old Plant" Total Generation (MWh)	30,891	40,115	28,842	21,886	17,894

119.0 Reference: Upper Bonnington Old Plant Various Unit Upgrades

Exhibit B-1, Tab 6, Section 2.3.1, pp. 16-17

Personnel Egress

FortisBC states that "The proposed fire alarm panels will be multi zone and will include fire pull stations, audible and visual alarms, and fire and smoke detectors. These alarm panels are for employee safety only. These panels will not include controls nor will it be linked to a suppression system. The fire panel will annunciate to a central monitoring location." (Exhibit B-1, Tab 6, p. 16)

119.1 Please explain why personnel egress was rejected but may be a concern in the All Plants Fire Safety project.

Response:

In order to mitigate rate impacts and levelize spending for fire safety in the plants, it was decided to install the fire panels first and proceed with improvements to egress in a separate project. The Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels project will provide audible alarms in the event of a fire and ensure that employees have a minimum level of protection in the case of a fire. FortisBC has identified the All Plants Fire Safety project to address personnel egress on page 66 of the 2012 Integrated System Plan (excerpt below).

2.5.3.3 All Plants Fire Safety

This project involves upgrading the fire egress from the power houses at all four river plants. The upgrades will include new exits from the river side of the turbine floor to the outside via the operating floor, enclosing stairways with fire rated walls, upgrading wooden doors with metal fire doors, adding crash bars to the doors, installing fire stop to all openings between rooms and floors and upgrading the generator fire deluge system.

120.0 Reference: Generation Capital Expenditures

Exhibit B-1, Tab 6, Section 2.3.1, pp. 16-17

Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels

120.1 As these plants have operated for 70 to 100 years without centralized panels, please provide additional justification for the proposed project.

Response:

FortisBC has an obligation to ensure that its workers are provided with a safe work environment. Even though fire detection systems were not required by code at the time the plants were constructed, it is common practice now to include these systems in newer facilities. The installation of these fire panels will ensure that employees working in the plants will receive an audible alarm to alert them of danger in the facility. This installation is viewed as a minimum requirement, and provides the foundation to continue to ensure the Company meets its corporate responsibilities to its employees.

121.0 Reference: All Plants Minor Sustainment Projects

Exhibit B-1, Tab 6, Section 2.4, pp. 18-21

Historical Data & Table 2.4.1

121.1 Provide a table showing the previous five years of data (total only), both forecast and actual.

Response:

Please refer to Table BCUC IR1 121.1 which shows the previous five years of forecast and actual data for the All Plants Minor Sustainment Capital Projects.

Table BCUC IR1 121.1

		2007		2008		2009		2010		2011		2012	2013
1		Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
2		($000s)											
3	All Plant Minor Sustaining Capital												
4	Plant Additions	828	(416)	1,368	1,170	1,778	1,056	1,287	1,024	634	634	1,061	1,051
5	Cost of Removal	-	157	-	61	-	37	-	39	75	75	110	107
6	Total All Plants Minor Sustaining Capital	828	(259)	1,368	1,231	1,778	1,093	1,287	1,063	709	709	1,171	1,158

Note 1: Cost of removal not forecast prior to 2011.

Note 2: 2007 All Plants Minor Sustainment Project credit of $416,000 due to Provincial Sales Tax audit recovery payment

121.2 Please provide the estimate class and accuracy of the estimated costs in the Table 2.4.1.

Response:

The estimate developed for the minor sustainment projects is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

122.0 Reference: All Plants Telephone Communications (2012 and 2013)

Exhibit B-1, Tab 6, Section 2.4.1.4, p. 19

Phones

122.1 Please provide an explanation as to why cell phones or satellite phones are not discussed.

Response:

The magnetic fields and bulk reinforced concrete surrounding hydro-electric facilities often disrupt cellular phone communication and therefore an additional method of communication is required.

123.0 Reference: Lower Bonnington and Upper Bonnington Upgrade 4 Spillway Gate Control Phase 2 (2012 and 2013)

Exhibit B-1, Tab 6, Section 2.4.1.8, p. 20

Code Issues

123.1 Please provide the number of times the existing control system has failed to operate in the last 5 years.

Response:

FortisBC has no record of a control system failure in the past five years.

The spill gates at both Upper Bonnington and Lower Bonnington are secondary spill systems as both facilities have overflow weirs which manage the majority of the spill requirements in a typical freshet. The use of the spill gates at each of these facilities would be required at a time when water levels have reached flood levels and the proper operation of these gates would be critical.

The completion of this project would ensure that the investment in restoration of the gates at Upper Bonnington and future rehabilitation of the Lower Bonnington spill gates (as outlined in the 2012 Long Term Capital Plan Table 2.5(a) page 43) are supported by reliable operations at a time when they are most critically required.

123.2 Please explain why asbestos affects the reliability of the system.

Response:

Asbestos does not affect the reliability of the system. The system reliability is affected by the age of the controls which are over 50 years old. The asbestos inhibits the ability to work on the control system.

123.3 Please explain what electrical code applies to FortisBC in this instance.

Response:

The design and installation of electrical systems to support utility infrastructure is specifically exempt from the scope of the Canadian Electrical Code, however FortisBC considers it prudent utility practice to ensure that the design and installation of such systems meet the intent of this code.

123.4 Please identify when these gates were last operated to pass spill.

Response:

Lower Bonnington was operated this year during spring runoff while Upper Bonnington spillway gate has not been operated since the mid 1980's.

123.5 Please explain why the spillway gates are necessary in the presence of the overflow weirs.

Response:

The Probable Maximum Flood for both Facilities is 275,000 cubic feet per second (cfs). The overflow spillway at Lower Bonnington can only pass 137,000cfs while Upper Bonnington overflow spillway can only pass 200,000cfs. Thus the spillway gates are necessary to pass the Probable Maximum Flood under severe flood conditions.

123.6 Please identify all the unapproved sustaining projects (and the annual costs) associated with the Lower Bonnington and Upper Bonnington spillway gates for the years 2011 to 2018.

Response:

The following projects are proposed but currently unapproved;

Table BCUC IR1 123.6

Project	2012	2013	2014	Total
Lower Bonnington and Upper Bonnington Upgrade Spillway Gate Control Phase 2	$ 75,000	$ 168,000		**$ 243,000**
Upper Bonnington Spillway Gate Hoist Upgrade		$ 105,000		**$ 105,000**
Lower Bonnington Spillway Gate Hoist Upgrade			$ 107,000	**$ 107,000**

124.0 Reference: Lower Bonnington, Upper Bonnington, Corra Linn Old Wiring Removal (2012 and 2013)

Exhibit B-1, Tab 6, Section 2.4.1.11, p. 20

Health and Safety Concerns

124.1 Please explain the health and safety concerns with the asbestos wiring and lead sheath cables if the wiring and cables remain undisturbed.

Response:

There are minimal health and safety concerns if the wiring remains undisturbed. However, it is impractical to leave the wiring and cables undisturbed indefinitely because they often occupy the same conduit or cable tray as the “in service” cables.

124.2 Please explain the health and safety concerns if the removal of the asbestos wiring and lead sheath cables commences.

Response:

Asbestos is known for causing respiratory ailments while lead interferes with a variety of body processes and is toxic to many organs. Both of these are considered work place hazardous materials under WorkSafe BC regulations.

Although FortisBC has procedures for handling both lead and asbestos to minimize the health and safety concerns, an active program to identify and remove these hazards is preferred to dealing with them on a random basis when plant maintenance issues force work in the areas where these hazards are present.

125.0 Reference: Transmission and Stations Projects

Exhibit B-1, Tab 6, Section 3, p. 23

Table 3.0 – Transmission and Stations Projects

125.1 Provide a table showing the previous five years of data (total only) for both forecasted and actual costs?

Response:

Table BCUC IR1 125.1 below provides forecast and actual expenditures.

Table BCUC IR1 125.1 Transmission and Stations

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Transmission Growth	56,926	62,763	60,136	40,499	50,924	44,187	92,010	77,065	23,509	24,561	11,832	8,847
Transmission Sustaining	3,671	3,307	3,738	3,251	4,401	3,513	4,871	3,913	2,455	2,970	9,453	9,581
Station Sustaining	3,808	4,365	2,518	5,251	4,671	3,509	4,920	3,484	2,764	5,431	13,969	14,427
Transmission and Stations Sustaining	7,479	7,672	6,256	8,502	9,072	7,022	9,791	7,397	5,219	8,401	23,423	24,007

125.2 Please provide the estimate class and accuracy of the estimated costs in the table.

Response:

Please refer to the below table.

Table BCUC IR1 125.2

1		2012	2013	Total	AACE Class	Accuracy
2	**Transmission Growth** (approving Orders)	($000s)				
3	Okanagan Transmission Reinforcement (C-5-08)	2,219	-	2,219	Class 2	-10% / +10%
4	Ellison to Sexsmith Transmission Tie	7,122	413	7,535	Class 4	-15% / +20%
5	Grand Forks Transformer Addition /High Capacity Communications	2,491	4,714	7,205	Class 4	-15% / +20%
6	Kelowna Bulk Transformer Capacity Addition	-	3,720	3,720	Class 5	-50% / 100%
7	**Total Transmission Growth**	**11,832**	**8,847**	**20,679**		
8						
9	**Transmission and Station Sustainment Projects**					
10	**Transmission Sustainment**					
11	Transmission Line Condition Assessment	522	485	1,007	Class 4	-15% / +20%
12	Transmission Line Rehabilitation	3,372	2,621	5,993	Class 4	-15% / +20%
13	Transmission Line Urgent Repairs	594	620	1,214	N/A	N/A
14	Transmission Line Right-of-Way Easements	400	400	800	N/A	N/A
15	6 Line /26 Line River Crossing Reconfiguration	1,185	-	1,185	Class 3	-15% / +20%
16	27 Line Rebuild (Corra Linn-Salmo)	1,161	-	1,161	Class 3	-15% / +20%
17	21-24 Lines Rebuild (Generation Plants)	2,219	-	2,219	Class 3	-15% / +20%
18	19 Line/29 Line Reconfiguration	-	791	791	Class 3	-15% / +20%
19	20 Line Rebuild (Warfield Terminal-Salmo)	-	4,664	4,664	Class 3	-15% / +20%
20	**Total Transmission Sustainment**	**9,453**	**9,581**	**19,034**		
21						
22	**Station Sustainment**					
23	Environmental Compliance (PCB Mitigation)	11,269	11,553	22,822	Class 4	2012: -15% / +20% 2013: -20% / +30%
24	Station Urgent Repairs	818	907	1,725	N/A	N/A
25	Station Assessment/Minor Planned Projects	1,343	1,354	2,697	Class 3	-15% / +20%
26	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	1,083	Class 4	-15% / +20%
27	Huth Low Voltage Breaker Replacement	-	69	69	Class 4	-15% / +20%
28	**Total Station Sustainment**	**13,969**	**14,427**	**28,396**		
29	**Total Transmission and Stations Sustainment**	**23,423**	**24,007**	**47,430**		

Note that FortisBC uses the AACE estimate class and the AACE estimate accuracy range to describe two related, but also somewhat independent, aspects of a project estimate:

AACE Estimate Class

FortisBC considers the AACE estimate class number to be representative of the level of project definition at the time the estimate was developed for inclusion in the Capital Plan. The highest level of definition (pre-approval) is a Class 3 estimate and the lowest level of definition is Class 5 estimate. FortisBC has produced summary checklists to assist in evaluating project estimates in order to assign an estimate class. For example, a Class 3 estimate would typically involve the production of certain required drawings (single-line and logic diagrams and site general arrangements) as well require the consideration of site-specific issues such as permitting, geotechnical studies or site selection. Class 4 estimates are typically applicable to program work such as the Distribution Rehabilitation or Station Condition Assessments programs. In these instances, the level of scope definition may not be as detailed as a Class 3 estimates, but the key scope elements and potential risk factors related to project execution are still considered. Class 5 estimates are appropriate for work which has been scoped to a conceptual level only; this level of definition is typical for projects beyond the five year planning horizon.

AACE Estimate Accuracy Range

FortisBC considers the accuracy range of cost estimates to be generally independent from associated AACE Estimate Class. The accuracy represents the level of cost certainty or the potential for scope control as opposed the level of project definition. Projects presented for approval in the 2012/13 Capital Plan are generally classified as +20 / -15% accuracy. This range indicates that FortisBC has considered the relevant cost factors that may affect the ability to successfully execute the required work for the forecast amount. These projects have also been reviewed by other departments such as Operations and/or Project Management as necessary. In some cases where insufficient information was available at the time of development of the Application, a wider accuracy range has been assigned.

FortisBC notes however, that the accuracy range and cost estimate for any given project is still an estimate based on professional judgment and the information available to the Company at the time. FortisBC believes that all prudently incurred costs associated with safely and reliably completing necessary capital work is legitimately included in rate base.

126.0 Reference: Ellison to Sexsmith Transmission Tie

Exhibit B-1, Tab 6, Section 3.1.2, p. 25

Overbuild of 13kV Distribution Line

126.1 Please explain how the 13kV distribution line underbuild will be protected from extreme temporary overvoltages that can occur when the 138kV transmission line comes into contact with the distribution line.

<u>Response:</u>

The majority of the 138 kV transmission system in the Kelowna area currently has 13 kV distribution underbuild. Due to the 138 kV transmission voltage, the spacing between transmission and distribution circuits is much larger compared to a 63 kV transmission circuit with distribution underbuild. This larger spacing decreases the likelihood of undesired contact between the transmission and distribution conductors. As well, there are few trees adjacent to the 138 kV transmission lines in the Kelowna area and thus the potential for a tree falling into the line and causing a short-circuit between the transmission and distribution conductors is extremely low. Finally, due to the type of relaying used on the 138 kV transmission lines, the clearing time following a transmission fault is generally much faster compared to 63 kV transmission line protection, thus limiting the duration of any potential overvoltage event.

The combination of large conductor spacing, few adjacent trees and high-speed fault clearing effectively mitigates the concerns for extreme temporary overvoltage events on these lines. It should be noted that the Company is not aware of any claims resulting from this issue in the Kelowna area.

FortisBC is currently targeting deployments of station-class arrestors on some distribution circuits underbuilt on 63 kV transmission lines. These devices are expected to reduce the damage to customer equipment that occurs following a transmission to distribution circuit contact. If these devices are proven to be effective they could potentially be deployed on 138 kV transmission circuits. However, given the very low probability of an extreme temporary overvoltage event occurring on the Ellison to Sexsmith transmission circuit, it is not expected that the potential benefits would outweigh the installation and equipment costs.

126.2 Please provide the class and accuracy of the estimated cost of $8.2 million. What is not included in the estimate and the assumptions made?

Response:

The estimate for the 2012-2013 expenditures for the Ellison to Sexsmith Transmission Tie project are considered equivalent to an “AACE Class 4” level and the accuracy is considered consistent with what is specified in the AACE estimating guidelines.

The estimate includes everything foreseeable to the project at the time. A line route has been chosen to proceed along Highway 97 and the total project estimate includes the costs to construct the necessary station, transmission, and telecommunication/protection works. Some risks have been identified but not specifically quantified in the estimate. These issues are expected to be minor and will be absorbed within the project contingency.

127.0 Reference: Grand Forks Terminal Transformer Addition and High Capacity Communications Project

Exhibit B-1, Tab 6, Section 3.1.3, pp. 29-38

Transformer Addition and Leased Dark Fibre

127.1 Please provide the capital expenditures and the NPV for Options 1, 2, and 3.

Response:

The following table includes the capital costs and the NPV of the revenue requirements for options 1-3 for the Grand Forks Transformer Addition and High Capacity Communications project.

Table BCUC IR1 127.1

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**NPV 2012-2038**	**Rate Impact**
	($000s)							
Option 1	2,491	4,714	1,274	7,548	-	-	9,586	0.19%
Option 2	207	207	9,628	2,009	-	-	9,051	0.18%
Option 3	207	207	3,600	3,600	3,600	3,600	9,382	0.18%

Option 1: Construct fibre 2012/13 - Add GFT T2 2014/15 - Salvage 9L/10L in 2015
Option 2: Add GFT T2 and full ring-bus in 2014/15 - Salvage 9L/10L in 2015
Option 3: Rebuild 9L/10L in 2014-17

127.2 For the recommended option 1, please separate the cost into the components identified in the table below:

	Work Plan Option 1	Capital Expenditures				
Year		2012	2013	2014	2015	Total
2012	Transport and store ex-Oliver T1 transformer at Grand Forks Terminal.					
2014	Complete engineering design for Grand Forks T2 installation.					
2015	Install Grand Forks T2 transformer.					
	Sub-total T2 Transformer					
2012	Complete engineering design for Grand Forks/Warfield fibre installation.					
2012	Procure fibre-optic cable.					
2015	Install fibre optic cable between Grand Forks and Warfield.					
	Sub-total fibre-optic install					
2012	Condition assessment of 9L/10L.					
2013	Condition assessment of 9L/10 (if unable to complete previous year).					
2015	Salvage 9L/10L between Rossland and Christina Lake.					
	Sub-total Salvage 9L/10L					
	Total					

<u>Response:</u>

Please refer to Table BCUC IR1 127.2 below.

Table BCUC IR1 127.1

Work Plan Option 1	Capital Expenditures				
	2012	2013	2014	2015	**Total**
	($000s)				
Transport and store ex-Oliver T1 transformer at Grand Forks Terminal.	470	-	-	-	**470**
Complete engineering design for Grand Forks T2 installation.	-	-	1,076	-	**1,076**
Install Grand Forks T2 transformer.	-	-	-	5,539	**5,539**
Sub-total T2 Transformer	470	-	1,076	5,539	**7,085**
Complete engineering design for Grand Forks/Warfield fibre installation.	534	-	-	-	**534**
Procure fibre-optic cable.	952	-	-	-	**952**
Install fibre optic cable between Grand Forks and Warfield.	-	4,714	-	-	**4,714**
Sub-total fibre-optic install	1,486	4,714	-	-	**6,199**
Condition assessment of 9L/10L.	536	-	-	-	**536**
Condition assessment of 9L/10 (if unable to complete previous year).	-	-	-	-	**-**
Salvage 9L/10L between Rossland and Christina Lake.	-	-	198	2,009	**2,208**
Sub-total Salvage 9L/10L	536	-	198	2,009	**2,743**
Total	**2,491**	**4,714**	**1,274**	**7,549**	**16,027**

Note: The totals include capital costs only and do not capture the benefit of avoided O&M costs or ongoing revenue attributable to this option.

Minor differences due to rounding.

127.3 Please provide in a similar format to the table for Option 1, the capital expenditures for Options 2 and 3.

Response:

Tables BCUC IR1 127.3a and 127.3b provided below detail the capitals expenditures for Options 2 and 3.

Table BCUC IR1 127.3a Option 2

Work Plan Option 2	Capital Expenditures				
	2012	2013	2014	2015	Total
	($000s)				
Install Grand Forks T2 transformer. (includes Engineering and Transport)	-	-	9,431	-	9,431
Condition assessment of 9L/10L	207	207	-	-	414
Salvage 9L/10L between Rossland and Christina Lake	-	-	198	2,009	2,207
Sub-total Salvage 9L/10L	207	207	198	2,009	2,621
Total	207	207	9,629	2,009	12,052

Table BCUC IR1 127.3b Option 3

Work Plan Option 3	Capital Expenditures						
	2012	2013	2014	2015	2016	2017	Total
	($000s)						
Rebuild 9/10L	207	207	3,600	3,600	3,600	3,600	14,815

127.4 If the GFT T1 transformer experiences a forced outage, how long does it take to manually reconfigure the backup supply from Trail?

Response:

The customer outage duration would depend on the operating configuration of the 63 kV system and on the switching requirements necessary to isolate the transformer and establish a connection via the two 63 kV lines back to Trail. If all of the necessary switching could be completed by SCADA remote control, then the outage duration would typically be about 30 minutes. If personnel callouts were required to complete the switching, then the outage duration could last up to approximately one to two hours.

127.5 If Oliver T1 was to be placed in storage at GFT, please describe how long it would take to remove GFT T1 and replace with Oliver T1 (in the event of a GFT T1 failure).

Response:

Based on experience from the failure of the Summerland T2 transformer in December 2008, it is expected that approximately three to four weeks would be necessary to:

1. Develop a work plan for the transformer removal and replacement;
2. Gather the required employees, contractors and tools/equipment;
3. Remove the failed transformer (dry weight of approximately 68 t and contains 45,000L of oil); and
4. Install and commission the replacement transformer.

This time estimate assumes that no major environmental mitigation or repairs to other station equipment resulting from the transformer failure would be required.

127.6 Please provide FortisBC's level of confidence in the statement "that approximately 40% of the total line length requires rebuilding." (Tab 6, lines 21-22, p. 37)

Response:

This estimate has generally been developed using knowledge such as:

- Information from operations crews and engineers with intimate experience with the lines;
- The vintage of the line construction;
- The recent repair history;
- Recent forced outage and scheduled maintenance information; and
- Assessment experience from other similar transmission circuits such as 20 and 27 Lines.

It is difficult to assign a precise range of uncertainty; however, as stated on Tab 6, line 6, p. 32 of the 2012-13 RRA, FortisBC expects that 30 to 50 percent of the lines will require rebuilding in the near future.

127.7 Please provide the estimated cost for rebuilding 40% of the total line length.

Response:

Given the condition of the lines and limited construction access due to terrain and elevation, FortisBC estimates the cost to rebuild 40% (approximately 30 km) over the period of 2014 to 2017 at $14.4 million (+ 50/-30% accuracy).

127.8 Please provide the anticipated date that the high capacity fibre-optic link between the Okanagan and Kootenay will be required due to the MRS requirements or the Smart Grid projects.

Response:

The North American Electric Reliability Corporation (NERC) Mandatory Reliability Standards (MRS) which form the basis for the BC MRS continue to develop and include new requirements. FortisBC is unable to predict exactly when MRS requirements will drive the need for a communications link between the Okanagan and Kootenays. However, the initial Smart Grid project that would leverage off and benefit from a link between the Okanagan and Kootenays fibre infrastructure is the Advanced Metering Infrastructure. If approved, this project is tentatively scheduled for deployment in 2013 and 2014.

Please refer also to the response to BCMEU IR1 Q20 for a further discussion of the future requirements.

127.9 Please provide the estimated cost to provide the high capacity fibre-optic link between the Okanagan and Kootenay in 5 years time.

Response:

FortisBC anticipates the costs for installation of this fibre link will effectively remain constant over the next five years, with the exception of inflation. On the other hand, the benefit of an ongoing revenue stream from the lease of excess fibre strands will be lost if the build is deferred by 5 years. The NPV of this benefit is approximately $ 2.5 million.

127.10 Please provide the cost of the lease, the term of the fibre lease agreement and whether or not this lease amount has been included in the capital cost.

Response:

Due to the sensitive commercial information with respect to the third-party communications provider, FortisBC is unable to provide details of the term or rates of the lease agreement. Notwithstanding this, the expected annual income resulting from the agreement is approximately $0.230 million. As well, FortisBC calculates the NPV over the term of the lease to be approximately $2.5 million. Please refer to the response to BCMEU IR1 Q18 for a redacted copy of the agreement.

This NPV of the lease revenue has been applied as a reduction to the total project NPV when comparing between project options.

127.11 When calculating the NPV of $2.5 million for leased fibre, did FortisBC factor in the cost of the future high capacity fibre-optic link between the Okanagan and Kootenay? Why or why not?

Response:

The $2.5 million figure is the net present value of a written commitment to lease capacity on the fibre optic link only. This figure does not include the cost to build the link. FortisBC did not include this cost in the referenced NPV figure because the capital expenditures were already included in the revenue requirements calculations for the entire project.

The $2.5 million figure was included to highlight the scale of the commitment compared to the total project cost and to provide further justification for the timing.

127.12 Please provide the class and accuracy of the estimated cost of $7.2 million (total of 2012 and 2013 costs). What is not included in the estimate and the assumptions made?

Response:

The $7.2 million figure for this project is considered an AACE Class 4 estimate (-15% to +20% accuracy range).

Not Included:

- HST; and
- If required, any outage costs on 11L have not been estimated.

Assumptions:

- Construction work completed in snow free conditions;
- No replacement of transmission structures needed, but some additional poles needed for long spans and dead ends;
- Fibre to be primarily under built on the existing 11L transmission line; and
- Line access upgrade costs have been estimated from previous line construction projects.

127.13 Please explain whether FortisBC investigated the option of having a third party pay for the fibre on FortisBC infrastructure and lease back dark fibre to FortisBC, and if not, why not? Please provide a cost comparison of the “build and lease to others” approach versus the “have others build and lease back” approach.

Response:

FortisBC considered whether to own or lease fibre for this project but no third party had indicated any desire to locate its own fibre on FortisBC infrastructure in this area as it is not a high traffic corridor. However, FortisBC has entered into a binding agreement with a third party communications provider who is willing to commit to a firm, long-term lease of excess fibre capacity. This revenue stream will contribute a NPV benefit of $2.5 million to the cost of the project.

127.14 Please provide the class and accuracy of the estimated cost of $8.82 million. What is not included in the estimate and the assumptions made?

Response:

The estimate for the 2014-2015 expenditures of $8.82 million for the Grand Forks Terminal Transformer Addition and High Capacity Communications project are considered equivalent to an “AACE Class 4” level and the accuracy is within a -20 to +30 percent window, consistent with what is specified in the AACE estimating guideline.

The estimate includes all costs to design and install the ex Oliver T1 transformer in the Grand Forks Terminal. The estimate assumes a reasonable amount of rehabilitation will be required for the transformer but that it will otherwise be serviceable.

127.15 As the total cost is approximately $16 million depending on the accuracy of the estimated costs, please explain why this option is not being submitted as a CPCN similar to Kootenay Long Term Facilities Strategy proposed CPCN.

Response:

The Commission has previously accepted the following criteria to determine whether a CPCN will be required for a specific project:

1. The total project cost is $20 million or greater; or
2. The project is likely to generate significant public concerns; or
3. FortisBC believes for any reason that a CPCN application should proceed; or
4. After presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application; or
5. The Commission directs FortisBC to file a CPCN application.

In the case of the Kootenay Long Term Facilities Strategy, the information available at the time of filing the 2012-13 Capital Plan (including project cost estimates and options analysis) was insufficient for the project to be submitted for approval. On this basis, the Company has chosen to file a CPCN application for that project.

In the case of the Grand Forks Terminal Transformer Addition and High-Capacity Communications Project, the project cost is not expected to exceed $20 million nor is the project expected to generate any public concerns since all of the work will be confined within existing FortisBC property or rights-of-way.

FortisBC feels that the information already provided in the project description (including the cost estimates and options analysis), combined with the clarification gained through the regulatory process will be sufficient to allow the Commission to make a determination.

127.16 Provide a magnitude estimate of the cost for mitigation of 9/10 lines (Option 3) and associated potential rate impact referred to below:

Response:

As discussed in the response to BCUC IR1 Q127.7, the estimated cost to rebuild 9 and 10 Lines (Option 3) is approximately $12 million. This represents approximately a 0.23 percent one-time equivalent rate impact.

Fortis BC states "As discussed previously, given the age, condition and historical reliability of 9 and 10 Lines, the Company expects that large portions of these lines will require rehabilitation/rebuilding in the near to medium-term. If the required expenditures are deferred, then the ongoing risks associated with transmission line failures such as long duration customer outages, potential public and environmental safety risks and potential customer over-voltages due to transmission to distribution contacts will be incurred for longer than necessary. As a result, a significant amount of capital expenditures are inevitable in order to mitigate these risks." (Tab 6, lines 10-15, lines1-2, pp. 37-38)

127.17 Please discuss abandoning either 9 line or 10 line and rehabilitating the remaining line, including a cost summary. Please provide a comparison of the structure types and specific reliability associated with each line since 2007, and provide the amount of planned and emergency maintenance expenditures annually on each line since 2007.

Response:

a) Single 63 kV Transmission Line Option Discussion

FortisBC did consider the option of retiring one of the two 63 kV lines between Christina Lake and Rossland. The expected cost for rehabilitating portions of the remaining 63 kV line to provide an adequate level of reliability and salvaging the other line is approximately $8 million (+50%, -30%).

However, as discussed on page 31 of Section 3.1.3, the transmission line right-of-way traverses high elevations, is exposed to severe environmental conditions (snow, wind and lighting) year round and has poor access for maintenance. None of these issues can be resolved simply by rebuilding the line infrastructure. Even if entirely rebuilt, there would still remain several hundred pole structures between Christina Lake and Rossland which would require ongoing outage response, patrols, condition assessment, maintenance and upgrades.

As well, there are customers along the length of the right of way who continue to need service. Currently, these customers are supplied via a distribution underbuild circuit. If this under-built circuit remains to serve these customers, then this distribution circuit will continue to be exposed to potential temporary extreme overvoltage events when trees from outside of the right-of-way fall into the line and cause a short-circuit between the transmission and distribution conductors. Removing the 63 kV transmission circuit from this corridor and leaving only a distribution circuit to supply the customers in the area would remove this risk.

For the reasons cited above, and considering that the capital cost of this alternative is comparable to the cost of installing the spare transformer at Grand Forks, FortisBC did not consider the single 63 kV line rebuild a cost-effective solution. The installation of the second transformer at Grand Forks will address the customer reliability issues, reduce the exposure to temporary extreme overvoltage events and reduce ongoing transmission line-related operating costs. Thus FortisBC believes that proceeding with the transformer installation option is in the best interests of the customer.

b) Existing Line Construction and Reliability

Most of the structures on these lines are single-pole tangent construction (one wood pole with a wood cross-arm) with H-frame structures (two wood poles with a wood cross-arm) in some areas. Since both lines were constructed at the same time (originally in the 1910's), and have received roughly equal rehabilitation over the years, the overall condition of each line is similar.

Following is a table of the number of outages experienced by each line for the requested period:

Table BCUC IR1 127.17a

	Year				
Element	**2007**	**2008**	**2009**	**2010**	**Avg./Year**
9 LINE	6	6	7	6	6
10 LINE	3	14	5	8	8

c) Planned and emergency maintenance expenditures

Following is a table of planned and emergency maintenance expenditures recorded for these two lines over the requested period:

Table BCUC IR1 127.17b

Year	9 Line O&M and Capital	10 Line O&M and Capital	Combined Costs (i.e. 9/10L engineering)	Total
2007	$53,507	$42,167	$16,938	$112,612
2008	$139,238	$86,154	$211,128	$436,520
2009	$55,278	$19,597	$3,200	$78,075
2010	$12,100	$70,343	$0	$82,443
Total	**$260,123**	**$218,261**	**$231,266**	**$709,650**

128.0 Reference: Kelowna Bulk Transformer Capacity Addition

Exhibit B-1, Tab 6, Section 3.1.4, pp. 38-42

CPCN

128.1 Please provide the estimate class and accuracy of the estimated cost of the $3.72 million.

Response:

As the Kelowna Bulk Transformer Capacity Addition project will be submitted for approval in a separate CPCN application, for the purposes of the 2012-13 CEP the estimate was completed at a Class 5 level. In this specific instance the project alternatives have currently only received a preliminary review. The accuracy of the information is consistent with an order of magnitude estimate +100/-50%.

128.2 To avoid delay, please provide the proposed regulatory timetable required to meet the in-service of the winter 2015/2016.

Response:

FortisBC expects to file a CPCN application for the Kelowna Bulk Transformer Capacity Addition in approximately April 2012 and is anticipating that the regulatory process will be completed by mid February 2013. Following is an approximate regulatory timeline:

Table BCUC IR1 128.2

Task Name	Duration	Start	Finish
CPCN filing	0 days	Monday April 9, 2012	Monday April 9, 2012
Regulatory Timetable	224 days	Tuesday April 10, 2012	Friday February 15, 2013
IR Round One	40 days	Tuesday April 10, 2012	Monday June 4, 2012
Responses Round One	25 days	Tuesday June 5, 2012	Monday July 9, 2012
IR Round Two	30 days	Tuesday July 10, 2012	Monday August 20, 2012
Responses Round Two	25 days	Tuesday August 21, 2012	Monday September 24, 2012
Oral Hearing (if required)	60 days	Tuesday November 6, 2012	Monday January 28, 2013
BCUC Decision	0 days	Friday February 15, 2013	Friday February 15, 2013

Although FortisBC does not believe that an oral public hearing will be required to review the application, the schedule above would accommodate an oral hearing.

128.3 Please explain whether a connection to the BC Hydro system at Westbank would help mitigate risk to both the FortisBC and BC Hydro systems in the event of a failure in either system. Has such a solution been investigated, and if not, why not?

Response:

Yes, preliminary studies have been previously conducted by both FortisBC and BC Hydro to investigate the option of interconnecting the FortisBC and BC Hydro transmission systems on either side of Okanagan Lake. Any proposed solution would require some amount of overhead transmission line construction on both sides the lake as well as high-voltage cable to cross Okanagan Lake itself. Some studies were conducted from the perspective of FortisBC providing a backup supply for load in the Westbank area, and some studies examined using a supply from Westbank to support the FortisBC transmission system.

With respect to the Kelowna Bulk Transformer Capacity Addition project, a transmission tie with sufficient capacity to eliminate the project was forecast to cost in excess of $100 million.

129.0 Reference: Transmission Sustainment Programs and Projects

Exhibit B-1, Tab 6, Section 3.2, p. 42

Table 3.2 - Transmission Sustainment

129.1 Provide a table in a similar format to Table 3.2 showing the previous five years of data, both forecast and actual, for similar line items?

Response:

The Table below has been provided for Transmission Sustainment Projects.

Table BCUC IR 129.1 Transmission Sustainment Projects

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	Requested
	($000s)											
Transmission Line Condition Assessment	616	152	647	639	427	413	496	343	461	469	522	485
Transmission Line Rehabilitation	1,763	1,051	1,884	1,344	1,639	1,441	1,888	1,912	1,228	1,604	3,372	2,621
Transmission Line Urgent Repairs	257	514	308	362	338	526	343	487	414	491	594	620
Transmission Line Right-of-Way Easements	334	332	350	333	311	395	345	267	352	358	400	400
Transmission Line Right-of-Way Reclamation	339	1,051	359	162	468	421	496	440	-	-	-	-
Switch Additions	362	207	190	411	-	98	-	-	-	-	-	-
Transmission Line Pine Beetle Hazard Allocation	-	-	-	-	1,218	218	821	379	-	-	-	-
6 Line/26 Line River Crossing Reconfiguration	-	-	-	-	-	-	-	-	-	-	1,185	-
27 Line Rebuild	-	-	-	-	-	-	-	-	-	-	1,161	-
21-24 Lines Rebuild	-	-	-	-	-	-	-	-	-	-	2,219	-
19 Line/29 Line Reconfiguration	-	-	-	-	-	-	-	-	-	-	-	791
20 Line Rebuild	-	-	-	-	-	-	-	-	-	-	-	4,664
Castlegar Sub Switch CAS-6/CAS-26 Upgrade	-	-	-	-	-	-	132	84	-	48	-	-
30 Line Crossing	-	-	-	-	-	-	350	-	-	-	-	-
Total Transmission Sustainment	3,671	3,307	3,738	3,251	4,401	3,512	4,871	3,912	2,455	2,970	9,453	9,581

129.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

Please see below for the AACE estimate class and accuracy of the Transmission Sustainment projects and programs.

Table BCUC IR1 129.2 Transmission Sustainment

	AACE Estimating Class	AACE Estimating Accuracy
Transmission Line Condition Assessment	Class 3	-15% to +20%
Transmission Line Rehabilitation	Class 4	-15% to +20%
Transmission Line Urgent Repairs	n/a (see note below)	n/a
Transmission Line Right of Way Easements	n/a (see note below)	n/a
6 Line /26 Line River Crossing Reconfiguration	Class 3	-15% to +20%
27 Line Rebuild (Corra Linn-Salmo)	Class 3	-15% to +20%
21-24 Lines Rebuild (Generation Plants)	Class 3	-15% to +20%
19 Line/29 Line Reconfiguration	Class 3	-15% to +20%
20 Line Rebuild (Warfield Terminal-Salmo)	Class 3	-15% to +20%

The costs associated with Transmission Line Urgent Repairs and Right of Way Easements program are not suitably addressed through the AACE Cost Estimate Classification System. These programs address unforeseen work and the forecast costs are generally based on historical rolling averages and hence do not have a specific level of project definition or expected accuracy range of expenditures.

130.0 Reference: Transmission Line Condition Assessment

Exhibit B-1, Tab 6, Section 3.2.1, pp. 42-43

Assessment Report

130.1 Please provide an electronic copy of the latest transmission line condition assessment report?

Response:

Please refer to BCUC IR1 Appendix Q130.1. These attachments are the Transmission Line Condition Assessment reports from 2010 including 30 Line, 42 Line, 45 Line, 45A Line, and 47 Line. All of the deficiencies identified in these reports are intended to be corrected as part of the 2011 Transmission Line Rehabilitation project.

130.2 Please provide the forecasted and actual total amounts for the years 2007 to 2010.

Response:

The table below provides the forecast and actual expenditures.

Please refer also to the 2012 Long Term Capital Plan page 129 Table 2.9.1.

Table BCUC IR1 130.2 Transmission Line Condition Assessment

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Transmission Line Condition Assessment	616	152	647	639	427	413	496	343	461	469	522	485

130.3 Please provide the class and accuracy of the estimate for 2012 and 2013.

Response:

The estimate developed for the Transmission Line Condition Assessment program is considered equivalent to an AACE Class 4 level, with an expected accuracy range of -15% to +20%.

131.0 Reference: Transmission Line Rehabilitation

Exhibit B-1, Tab 6, Section 3.2.2, pp. 43-45

Table 3.2.2 (b) - Transmission Line Rehabilitation Expenditures

131.1 Please provide the forecasted amounts for the years 2007 to 2010.

Response:

The Table below provides for forecast amounts for Transmission Line Rehabilitation.

Table BCUC IR1 131.1 - Transmission Line Rehabilitation Forecast Expenditures 2007 - 2010

	2007	2008	2009	2010
	Forecast	Forecast	Forecast	Forecast
	($000s)			
Transmission Line Rehabilitation	1,763	1,884	1,639	1,888

131.2 Please provide a table in a similar format to Table 3.2.2 (b) adding the expenditure per total installed km, the number of poles that underwent rehabilitation, and the cost per installed poles as additional rows?

Response:

Please refer to the below table.

Table BCUC IR1 131.2

	2007	2008	2009	2010	2011	2012	2013
	Actual				Forecast	Requested	
Budgeted ($000s)	1,051	1,329	1,441	1,905	1,604	3,372	2,621
Expenditure/km ($000s)	14.7	10.7	12.0	26.5	11.3	22.9	17.0
# of Poles Rehabbed	976	1,084	1,089	1,215	1,417	2,191	1,687
Cost/Installed Pole ($)	1,076	1,226	1,323	1,567	1,131	1,539	1,553

131.3 In the Application, please confirm that FortisBC is planning to rehabilitate 2191 poles in 2012 and 1565 poles in 2013 which represents approximately 25% of the total number of transmission line poles.

Response:

FortisBC plans on rehabilitating 2,191 poles in 2012 and 1,687 poles in 2013. The 2012 work is detailed in Table 3.2.2 (a) at page 44 of Tab 6, 2012-13 CEP. The 2013 work is based on the 2012 Transmission Line Condition Assessment Projects detailed in Table 3.2.1 (a) at page 43 of Tab 6, 2012-13 CEP. This does represent about 25 percent of the total number of transmission poles.

132.0 Reference: Transmission Line Urgent Repairs

Exhibit B-1, Tab 6, Section 3.2.3, p. 46

Table 3.2.3 - Transmission Line Urgent Repairs Expenditures

132.1 Please provide the forecast and actual amounts for the years 2007 to 2010.

Response:

The Table below provides the forecast and actual expenditures for Transmission Line Urgent Repairs.

Table BCUC IR1 132.1 Transmission Line Urgent Repairs

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Transmission Line Urgent Repairs	257	514	308	362	338	526	343	487	414	491	594	620

132.2 For the years 2007 to 2010, please provide the total number of deficiencies involving failed equipment or equipment showing imminent signs of failure and requires more than $1,000 in value to repair.

Response:

FortisBC is unable to provide a total number of deficiencies for all Transmission Urgent Repairs as that information is not tracked.

The Transmission Urgent Repair budget is used to track repairs exceeding $1000 (consistent with FortisBC's Capitalization Policy) and is set up with an order number per transmission line. Therefore, the Company is able to report on the amount of money spent per transmission line each year but unable to report on the number of deficiencies experienced on each line. While this information would have some value it would be complex and cost-prohibitive to manage each individual urgent repair under a separate order in order to be able to report on it.

The costs for individual repair events below $1000 are covered under O&M budgets and are also not tracked separately.

132.3 For the years 2007 to 2011, please provide the total actual expenditures assigned to the Routine Maintenance Budget (Operating).

Response:

Actual expenditures for the years 2007 to 2011 for Routine Maintenance Budget (Operating) are show in Table BCUC IR1 132.3.

Table BCUC IR1 132.3

2007	2008	2009	2010	2011 YTD(1)
($000s)				
171	296	127	179	80

(1) To July 31, 2011

132.4 Please explain why FortisBC forecasts urgent repairs in 2012 and 2103 to be at least 20 percent more than the average of the previous 5 years, even after adjusting for inflation.

Response:

The 3 year rolling average calculation takes an average of the last 3 years unloaded budget expenditures. This value is then loaded and adjusted for inflation for each given year. For example, to determine the Transmission Urgent Repair Budget the unloaded cost for each year has to first be determined as outlined in the following table.

Table BCUC IR1 132.4

	2008 (Actual)	**2009 (Actual)**	**2010 (Forecast)**[1]
Total Loaded Project Costs ($000s)	362	526	494
Loadings (%)	15%	19%	21%
Total Unloaded Project Costs Project Costs ($000s)	315	442	408

[1] Forecast used for 2010 as actual expenditures unavailable at the time of budget preparation.

To determine the 3 year rolling average value for 2012 of $0.594 million, the unloaded data from 2008 – 2010 (as 2011 information isn't currently finalized) is used as follows:

(315+442+408)/3 = $0.388 million unloaded

This number is the adjusted for loadings and Consumer Price Index (CPI) increases:

$0.388 * 1 + CPI (2%) ^ 2 * 2012 loadings (27%) =$0.513 million

Cost of Removal (COR) is assumed 20% of unloaded capital costs = $388 * 0.2 = $78K. COR costs are also inflated with the appropriate CPI.

$0.077 million * 1 + CPI (2%) ^ 2 = $0.081 million

Thus, total Project Costs = $0.513 million + 0.081 million = $0.594 million.

The same method is used for 2013 except the years used to average are 2009 – 2011, with 2011 based on a three year average of the unloaded project costs for the period 2007 – 2009.

133.0 Reference: Right of Way Easements

Exhibit B-1, Tab 6, Section 3.2.4, pp. 46-47

Table 3.2.4 - Transmission Right-of-Way Easements Expenditures

133.1 Please provide the forecasted and actual amounts for the years 2007 to 2010 in Table 3.2.4.

Response:

Table BCUC IR1 133.1 below provides the forecast and actual expenditures for Right-of-Way Easements (Transmission and Distribution).

Table BCUC IR1 133.1 Transmission and Distribution Right-of-Way Easements

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Transmission and Distribution Right-of-Way Easements	334	332	350	333	311	395	345	267	352	358	400	400

133.2 Please add the number of right of way easements secured from 2007 to 2010.

Response:

FortisBC does not track this specific element. Individual Right of Way easements vary so greatly in complexity, scope and cost, that volume is not considered a relative comparison. Extrapolated from residential extension and operations information, FortisBC estimates that it acquired the following total number of Right of Way Easements, from all customer and capital driven programs for the years shown:

Table BCUC IR1 133.2

	Estimated Total Number of RoW Easements
2007	456
2008	528
2009	406
2010	318

If a three year rolling window approach to expenditures is used to forecast future expenditures:

133.3 When will all the outstanding rights-of-way be obtained?

Response:

FortisBC has not done a detailed gap analysis to identify outstanding land rights issues and therefore does not have the ability to predict when all of the outstanding Rights of Way will be obtained. Rights of Way issues are identified through various sources such as referrals, third party notifications, new connects or capital projects and are resolved as they become known. Right of Way easements that are not specifically attributable to a current project are executed under Right of Way Easement Expenditures.

133.4 If a three year rolling average is used to forecast the expenditures in 2012 and 2013, then please explain why the expenditures are $0.4M for each year?

Response:

Table 3.2.4 -Transmission Right of Way Easement Expenditures (Exhibit B-1) showed actual expenditures for only transmission facilities for the period 2007-2010, but forecast the requested expenditures for both transmission and Distribution facilities for the period 2012 – 2013.

Using the same methodology detailed in the response to BCUC IR1 Q132.4 above, the following calculation is provided.

Table BCUC IR1 133.4 - Right of Way Easement Expenditures (Transmission and Distribution)

	2008 (Actual)	2009 (Actual)	2010 (Forecast)[1]
Total Loaded Project Costs ($000s)	333	395	348
Loadings (%)	15%	19%	21%
Total Unloaded Project Costs Project Costs ($000s)	290	332	288

[1] Forecast used for 2010 as actual expenditures unavailable at the time of budget preparation.

To determine the 3 year rolling average value for 2012 of $0.4 million, the unloaded data from 2008 – 2010 (as 2011 information isn't currently finalized) is used as follows:

(290+332+288)/3 = $0.303 million (unloaded)

This number is the adjusted for loadings and Consumer Price Index (CPI) increases:

$0.388 * 1 + CPI (2%) ^ 2 * 2012 loadings (27%) = $0.4 million

The same method is used for 2013 except the years used to average are 2009 – 2011, with 2011 based on a three year average of the unloaded project costs for the period 2007 – 2009.

134.0 Reference: 6 Line/26 Line River Crossing Reconfiguration

Exhibit B-1, Tab 6, Section 3.2.5, pp. 47-49

Costs and Cost Savings

134.1 Provide the costs of the various options explored to determine how to best rehabilitate the crossings. Explain how the proposed alternative is selected.

Response:

The following analysis outlines the options investigated with high level costs of each (where available) followed with the reason for the selection of the recommended option.

Option 1: Leave 6L and 26L as is and continue to condition assess and rehabilitate the river crossings and lines like-for-like in future years.

Pros:

- Lowest Capital Investment.

Cons:

- Condition assessments showed that many of the poles on the river crossing and back to Brilliant Switching Station are in poor condition.
- Need to rehabilitate and maintain these sections of line which will be a large capital expenditure.
- Still exposed to potential failure risk by having the four river crossings.
- One structure is very complicated and has a large number of guy lines. Operationally it is difficult to access and maintain.

Cost: The cost required to implement this option is derived as follows;

- Condition Assessment of 8 km (~60 structures) of transmission line per 8 year cycle = $18,000
- Replace and rehabilitate the river crossing structure deficiencies already identified through an external engineering consultant = $400,000
- Rehabilitate the remaining 8km of 63kV transmission line every 8 year cycle = $350,000 the first cycle and approximately $91,000 every 8 years thereafter.
- Urgent Repairs for the 8km of line per 8 year cycle = $50,000 (assuming 2 structure failure per cycle in poor access area)
- O&M costs to maintain the redundant set of transmission lines over an 8 year cycle = $20,000

Total cost: $0.912 million (Including NPV of O&M costs)

Option 2: Create a new tap off point on the south side of the river and salvage the eastern river crossings and sections of lines up to the existing tap off point near Brilliant Switching Station. Rehabilitate the remaining two river crossings.

Pros:

- This will eliminate unnecessary transmission plant and avoid the large capital costs for the required ongoing rehabilitation.
- Reduces the operating costs for that portion of line going forward.
- Reduces the risk of river crossing failures

Cons:

- Highest capital investment

Total Costs: $1.19 million

Option 3: Replace the southwest transmission structure and relocate the distribution underbuild onto its own new set of structures (as option 2). Once new condition assessment data is available the costs can be reviewed to determine which option is more cost effective, the like-for-like replacement of the lines in Option 1, or the reconfiguration that is Option 2.

Pros:

- Mitigates some immediate concerns with structure condition.
- Detailed estimates can be calculated and not based upon historical costs per structure.

Cons:

- Still exposed to the risk of having the four river crossings for an extended period.

Total Costs: Depends on Condition Assessment Data.

In consultation with an external consultant, FortisBC conducted an engineering assessment on all of the 6/26 Line river crossing structures. All structures showed various signs of deterioration requiring rehabilitation or replacement. Four structures were recommended to be replaced in a non urgent manner in the next capital expenditure plan, one structure was considered to be marginal and could possibly last for another eight year cycle and two structures do not have a sufficient pole diameter for current standards.

It was determined that it would be more efficient from an operational and environmental perspective to salvage the upstream transmission river crossings and to create a new tap point between the loops of 6 Line and 26 Line than to rehabilitate all four river crossings like for like. The reconfiguration will reduce the ongoing capital rehabilitation expenditures required to maintain the lines through the condition assessment program. It will also reduce public safety and environmental risk exposure from river crossing failures by eliminating two long redundant spans of conductor across the Kootenay River which is heavily populated with a wide variety of fish including Sturgeon. Thus, given the potential risk of a conductor or structure failure and potential reliability/environmental issues, it was determined that Option 2 was in the customers' best interest.

134.2 As FortisBC determined that it would be more efficient from an operational and environmental perspective to salvage the upstream transmission river crossings and to create a new tap point between the loops of 6 Line and 26 Line, as shown in the Figure 3.2.5 (b) after reconfiguration, than to rehabilitate all four river crossings like for like and that the reconfiguration will reduce the ongoing capital rehabilitation expenditures required to maintain the lines through the condition assessment program, please provide the amount of reduction of on-going capital expenditures.

Response:

The following breakdown outlines the approximate incremental costs that the Company will no longer incur once the 6 Line/26 Line River Crossing Project is completed.

1. Condition Assessment costs for 4 km (30 structures) of transmission line every 8 year cycle using 2012-13 costs = $9,000;
2. Rehabilitation of 4 km of 63kV transmission line every 8 year cycle using 2012-13 costs = $47,000 (This is potentially low as it is based on costs required to rehabilitate an entire line, not a specific section); and
3. Urgent Repairs for the 4 km of line per 8 year cycle = $25,000 (assuming 1 structure fail per cycle in poor access area).

Thus, the total approximate capital savings per 8 year cycle is $81,000. As well, there is an approximate $10,000 reduction in operating costs over the same period due to reduced line patrol requirements.

134.3 Please provide the class and accuracy of the cost estimate.

Response:

The estimate developed for the 6 Line/26 Line Reconfiguration project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

135.0 Reference: 27 Line Rebuild (63 kV Circuit)

Exhibit B-1, Tab 6, Section 3.2.6, pp. 49-50

Costs and Safety Concerns

135.1 Please identify the customers' safety concerns in Nelson, Whitewater, Ymir and Salmo areas.

Response:

As outlined in Exhibit B-1, Tab 6, Section 3.2.6, pp. 49-50, an external engineering consultant performed an assessment of 27 Line and concluded that, in general, the circuit is in poor condition with numerous steel stubbed structures requiring replacement, some areas have insufficient anchoring that needs to be upgraded and there is inadequate circuit spacing which should be addressed.

The first two concerns deal with the structural integrity of the poles/structures. A stubbed pole needs to be replaced when the wood has essentially rotted away and the only reason the structure remains erect is due to the stub itself and the tension from the conductors. Anchoring is used to counteract the forces the conductors exert on the line from their weight or from when the line has to be dead-ended or routed around an obstacle. If not addressed, structural integrity issues can lead to a structure collapse resulting in energized conductors contacting the ground or otherwise violating acceptable limits of approach.

The circuit-to-circuit spacing issue pertains to insufficient clearance between the transmission and distribution circuits on the same pole structure. Conductor 'sag' fluctuates with changing weather conditions and load levels. If the circuit-to-circuit clearance is insufficient, the conductors on the top circuit may sag into the bottom circuit (for example due to heavy snow loading) and cause a transmission to distribution contact. Trees falling into the line from outside of the right-of-way may result in a similar fault. This type of a contact can create a temporary extreme overvoltage event that may result in potential customer hazards. FortisBC has piloted the installation of station-class arrestors to mitigate potential overvoltage events in the interim, but a more comprehensive solution is to reframe the structures to increase the circuit-to-circuit clearance.

135.2 As 27 Line has a variety of configurations consisting primarily of three-phase and 12 kV single-phase distribution underbuild, please explain how FortisBC proposes to protect their customers from extreme temporary overvoltages when the transmission line comes into contact with the distribution line.

Response:

FortisBC has recently installed station-class surge arrestors in some locations along the transmission line to help protect customers from extreme temporary overvoltage events.

Furthermore, the proposed 27 Line Rebuild project is planned to upgrade the areas with significant clearance issues and deficient structures to further protect against this problem. Please also refer to the response to BCUC IR1 Q135.1.

135.3 Please provide the class and accuracy of the cost estimate.

Response:

The estimate developed for the 27 Line Rebuild project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

135.4 Please provide an electronic copy of the 2010 engineering assessment report.

Response:

An electronic copy of the report is provided as BCUC IR1 Appendix 135.4.

135.5 Has FortisBC encountered any grounding issues with 27 Line that need to be addressed?

Response:

Some grounding issues have been identified. Please refer also to BCUC IR1 Appendix 135.4. Following is an excerpt from the 27 Line Engineering Assessment report:

> "The ground wire and bonding is absent on most older/original structures with the majority of the newly installed structures having only bonding wire installed on the transmission hardware. This lack of grounding and bonding provides an increased risk and liability for pole fires and thus possible forest fires in the surrounding areas, as both 20L and 27L are located primarily in heavily treed regions. The grounding and bonding issue will only become more and more severe as facilities continue to age."

135.6 Although the line may have been originally constructed in 1930, please reconcile the condition-related concerns with the data shown at Exhibit B-1-1, Appendix F, page 20 of 42, which shows that the vast majority of poles are less than 30 years old.

Response:

Note that in the description of the project there are 14 structures that require replacement. Of these 14 structures, 12 of them are older than 40 years. Therefore only two structures on the line are being replaced that are newer than 30 years.

Also, the project notes that there are 84 structure repairs that are required. These 84 structure repairs make up the majority of the project and include, but are not limited to, replacement of double cross arms, repair of wood pecker holes, cross arm reframing to eliminate clearance issues, structure tagging, improved anchoring/guy poles, etc. Although many of the structures these repairs will take place on are newer than 30 years of age, they are still required because at the time when the structures were replaced they were replaced like-for-like and not necessarily upgraded to current standards.

136.0 Reference: 21 - 24 Line Rebuild

Exhibit B-1, Tab 6, Section 3.2.7, pp. 50-51

Replacement vs. Repair

136.1 Please provide an electronic copy of the 2008 engineering assessment and the recent update.

Response:

Electronic copies of the 2008 engineering assessment report and the 2011 updated assessment report are attached as BCUC IR1 Appendix 136.1.

136.2 Please provide the magnitude amount of the financial implications if the outages result in a generator forced outage by line.

Response:

The tables below show the replacement cost of power resulting from losing the complete Lower Bonnington Facility as a result of an outage to 21 Line. Costs are based on an estimate of the forward market price. Loss of 22, 23 or 24 lines will not result in material generation losses unless more than a single line is lost.

Table BCUC IR1 136.2a Lower Bonnington Entitlement Loss

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Capacity (MW)	47.8	48.0	48.0	47.7	45.0	42.2	44.8	47.4	47.9	48.0	48.0	48.0	
Energy (GWh)	33.447	30.443	30.389	32.183	31.524	28.584	31.364	33.204	31.969	31.269	30.194	32.383	376.953

Table BCUC IR1 136.2b Total Cost per Month

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	$1,120,759	$ 980,620	$ 904,405	$ 878,064	$741,370	$603,681	$ 978,490	$1,153,317	$1,101,140	$1,105,338	$1,103,602	$1,261,021	$11,931,807
2013	$1,312,750	$1,157,459	$1,150,974	$1,008,037	$853,065	$713,139	$1,122,193	$1,342,394	$1,281,795	$1,347,480	$1,336,091	$1,485,069	$14,110,446

136.3 Please provide a breakdown of the costs for:

- Line 21 requires 10 structure replacements and the risk assessment of failure over the next 5 years without the rebuild.
- Line 22 requires 23 structure replacements and the risk assessment of failure over the next 5 years without the rebuild.
- Line 23 requires 29 structure replacements and the risk assessment of failure over the next 5 years without the rebuild.

Response:

Line 21 requires 10 structure replacements and 4 structure repairs. The total estimated cost is $0.233 million. The risk of failure over the next five years of this line is high. Five of the ten structures requiring replacement are in poor condition and should be replaced as soon as possible. The remaining five structures are considered slightly less urgent and should be replaced before the next condition assessment cycle.

Line 22 requires 23 structure replacements and 9 structure repairs. The total estimated cost is $0.518 million. The risk of failure over the next five years of this line is high. Four of the 23 structures requiring replacement are in poor condition and should be replaced as soon as possible. The remaining 19 structures are considered slightly less urgent and should be replaced before the next condition assessment cycle.

Line 23 requires 29 structure replacements and 10 structure repairs. The total estimated cost is $0.652 million. The risk of failure over the next five years of this line is moderate to high. Two of the 29 structures requiring replacement are in poor condition and should be replaced as soon as possible. The remaining 27 structures are considered slightly less urgent and should be replaced before the next condition assessment cycle.

136.4 As Line 24 requires 37 structure replacements, please provide a risk assessment of failures over the next 5 years without the rebuild?

Response:

Line 24 requires 37 structure replacements and 11 structure repairs. The total estimated cost is $0.818 million. The risk of failure over the next five years of this line is moderate to high. Three of the 37 structures requiring replacement are in poor condition and should be replaced as soon as possible. The remaining 34 structures are considered slightly less urgent and should be replaced before the next condition assessment cycle.

136.5 Please provide the class and accuracy of the cost estimates.

Response:

The estimate developed for the 21-24 Line Rebuild project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

136.6 Has FortisBC encountered any grounding issues with 21 -24 Lines that need to be addressed?

Response:

FortisBC is not aware of any grounding issues with 21-24 Lines nor has the Engineering Assessment report provided for 21-24 Lines identified any problems associated with grounding.

136.7 Please explain whether sufficient redundancy exists among the lines to allow any line to be taken out of service for urgent repairs without impacting the generation at the generating facilities. Where sufficient redundancy exists and the impacts are acceptable, please explain why the “urgent repair upon failure” approach is not the most cost-effective approach.

Response:

Sufficient redundancy does exist amongst 21-24 Lines that, in the event of any single-contingency forced transmission outage, there would be no resultant loss in generation. Double-contingency events will likely result in significant generation loss. However, FortisBC does not consider the potential loss of generation to be the prime driver for this project.

Significant safety and environmental issues have been identified with the lines. If not remedied, these issues could result in forest fires or hazards to public and employee safety. Of the 99 structures recommended for replacement, only one is newer then 50 years old. As the lines continue to deteriorate, structure failures are expected to become increasingly frequent. Given that these transmission lines are in the same right-of-way, if a structure failure were to occur it is possible that it could result in an outage to one or more parallel lines and thus result in a significant generation loss. FortisBC has assessed these lines consistent with the criteria used to assess other transmission rebuild and rehabilitation projects. Rather than waiting for potentially serious failures to occur and then having to repair them as a Transmission Line Urgent Repairs item, the Company considers it prudent to proactively repair the previously identified deficiencies.

136.8 Please provide the amount spent on urgent repairs for Lines 21 through 24 on an annual basis since 2007.

Response:

Table BCUC IR1 136.8 below provides the amount spent on urgent repairs for 21 – 24 Lines since 2007.

Table BCUC IR1 136.8

	2007	2008	2009	2010
	($)			
21 Line	-	1,514	-	3,970
22 Line	-	1,514	-	3,971
23 Line	-	1,514	-	3,968
24 Line	-	1,347	-	3,968
Total	-	5,889	-	15,878

137.0 Reference: 19 Line /29 Line Reconfiguration

Exhibit B-1, Tab 6, Section 3.2.8, pp. 51-52

Reliability

137.1 Please provide the class and accuracy of the cost estimate.

Response:

The estimate developed for the 19/29 Line Reconfiguration project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

137.2 As 19 Line is 12.5 km between South Slocan Switching station and the Passmore station, why should it not be left in service and maintained as a backup to 29 Line?

Response:

This option was considered and dismissed for a number of reasons:

1. If 19 Line was left in service as a backup to 29 Line, it would need to remain normally energized to ensure that it was available when required and not otherwise faulted by a fallen tree or other cause. Even with no connected load, if the line were to trip for any reason, crews would still need to be dispatched to determine the cause and carry out any necessary repairs. Accessing this section of line can be difficult and time-consuming thus resulting in unnecessary costs;
2. All FortisBC transmission lines are assessed and rehabbed on an 8 year cycle and also brushed at least once in this 8 year period. Removing unnecessary transmission line infrastructure eliminates the associated ongoing operational and maintenance and
3. FortisBC outage records show that 29 Line has only experienced four outages in the past 10 years. Of these outages, two were planned/scheduled outages, one was caused by human interference and the last was a legitimate fault. Given that 29 Line is built to 138 kV standards and energized at 63 kV, and that it is situated in the middle of the right of way the reliability of the line in this area is good. In contrast, the parallel section of 19 Line has more exposure to outages, and is difficult to access for maintenance or repairs. Thus, the removal of this parallel line is not expected to have any quantifiable impact on customer reliability.

137.3 Please provide the cost of maintaining 19 Line as is for the next 5 years.

Response:

The approximate costs to maintain 19 Line for the next 5 years can be broken down as follows;

Condition Assessment and Rehabilitation

12.5 km of line approximately = 100 structures. Using 2012 costs/structure for condition assessment and rehabilitation = 100*(234+1,203) = $143,700

Vegetation Control

$3,000/km * 12.5km = $37,500

Annual Line Patrol

$1,500/year * 5 years = $7,500

Urgent Repairs

3 callouts/year * 5 years * $500/callout = $7,500

1 structure replacement/year * 5 years * $12,000/structure = $60,000

Thus, the total costs (capital and operating) to leave 19 Line in service for the next 5 years are approximately **$256,200.**

137.4 Is the cost of the 19/29 Line interconnecting switch at the South Slocan Switching Station included in the scope of the estimate?

Response:

Yes, this work has been included in the estimate.

137.5 Using reliability terms, does this project reduce or improve reliability of the system when removal of an alternate feed, 19 Line, is removed? Please explain.

Response:

Please refer to the response to BCUC IR1 Q137.2 (specifically item 3).

137.6 Please explain why a 19 Line breaker position is being retained at South Slocan Station as part of the proposed project.

Response:

Both 19 Line and 29 Line breaker bays in the South Slocan station will remain in service for reliability and maintenance purposes. Having two breakers to supply the transmission line has two benefits:

1. It will allow all of the load to be picked up from the 19 Line breaker should the 29 Line breaker fail at South Slocan and vice versa. If the 19 Line breaker was removed from South Slocan and the 29 Line breaker failed, all customers served from Passmore and Valhalla sub stations would experience a lengthy outage; and
2. It will allow for maintenance to be carried out on each 19 Line and 29 Line breaker. If only one breaker was available to serve this line it could not be removed from

service for maintenance without resulting in a complete outage to all customers served from the Passmore and Valhalla sub stations.

137.7 Please describe when and why 29 Line recently underwent extensive rehabilitation, at what cost and how this was justified since it was redundant to the existing 19 Line. Please describe why 29 Line was extensively rehabilitated instead of 19 Line.

Response:

29 Line was rehabilitated in 2010 at a total cost of approximately $250,000. This work was consistent with its assessment schedule within the 8 year condition assessment and rehabilitation cycle. FortisBC had previously planned to remove 19 Line from service prior to its next assessment and rehabilitation cycle and to transfer the Passmore and Valhalla stations load to 29 Line. 19 Line is now due for assessment so this project has been proposed to salvage the line instead.

There are a number of reasons why 29 Line was, and still remains, the better of the two lines to keep in service:

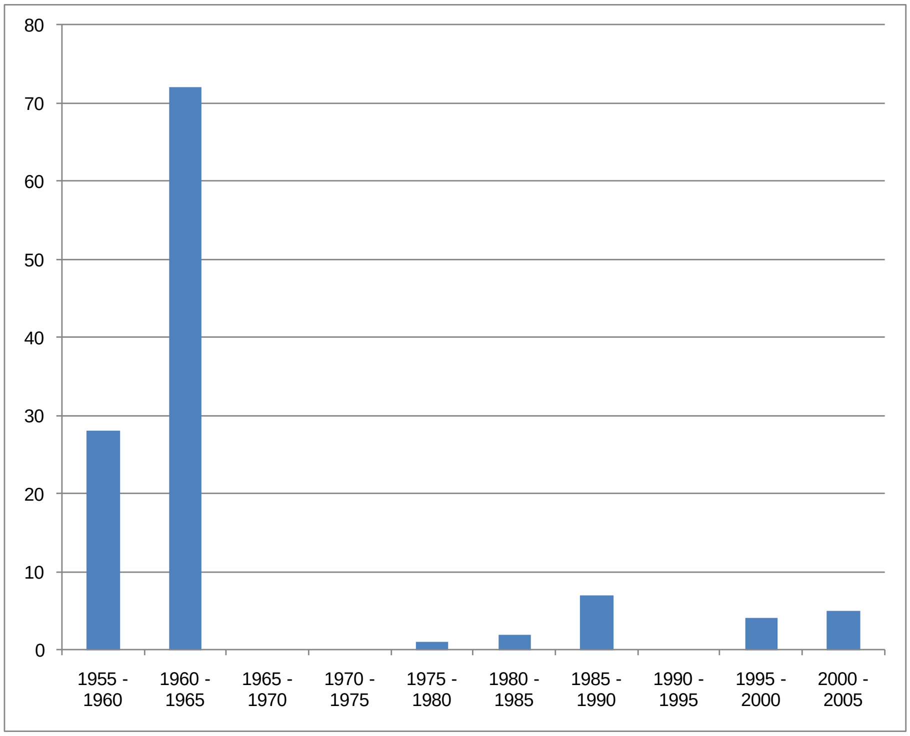
1. 19 Line is built to 63 kV standards and consists primarily of single pole structures and 63kV insulation. 29L is built to 138 kV standards and consists primarily of larger 2 and 3 pole structures with 138kV insulation;
    a. The 2 and 3 pole structures are much stronger than single pole structures and a single-pole failure is unlikely to result in a structure collapse; and
    b. Insulation flashover events are greatly reduced due to the higher rated insulators. Consequently, pole fires and outages due to insulator flashover are essentially eliminated.
2. 19 line is located near the edge of the right of way and very close to vegetation. As a result, the line has suffered multiple outages due to vegetation contacts. Due to the 138 kV construction, 29 Line is physically much higher than typical 63kV construction. This greater height, combined with the location of 29 Line in the middle of the right-of-way corridor greatly reduces the potential for vegetation-related outages on 29 Line; and
3. Even prior to 29 Line having been rehabilitated, it was in better condition compared to 19 Line and thus required less rehabilitation work.

137.8 Please provide the vintage of poles graph for 19 Line between South Slocan Station and Passmore.

Response:

The following graph outlines the 19 Line pole vintage in 5 year increments for the area proposed to be salvaged.

Figure BCUC IR1 137.8 19L Pole Vintage



138.0 Reference: 20 Line Rebuild (63 Kv)

Exhibit B-1, Tab 6, Section 3.2.9, p. 53

Cost

138.1 Please provide the class and accuracy of the cost estimate.

Response:

The estimate developed for the 20 Line Rebuild project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

138.2 Please identify the customers' safety concerns in Trail, Waneta, Montrose, Fruitvale and Salmo areas.

Response:

As outlined in Exhibit B-1, Tab 6, Section 3.2.9, page 53 of the 2012-13 RRA, an external engineering consultant performed an assessment of 27 Line and concluded that, in general, the circuit is in poor condition with numerous steel stubbed structures requiring replacement, some areas have insufficient anchoring that requires upgrading and there is inadequate circuit spacing which should be addressed.

The first two concerns deal with the structural integrity of the poles/structures. A stubbed pole needs to be replaced when the wood has essentially rotted away and the only reason the structure remains erect is due to the stub itself and the tension from the conductors. Anchoring is used to counteract the forces the conductors exert on the line from their weight or from when the line has to be dead-ended or routed around an obstacle. If not addressed, structural integrity issues can lead to a structure collapse resulting in energized conductors contacting the ground or otherwise violating acceptable limits of approach.

The circuit-to-circuit spacing issue pertains to insufficient clearance between the transmission and distribution circuits on the same pole structure. Conductor 'sag' fluctuates with changing weather conditions and load levels. If the circuit-to-circuit clearance is insufficient, the conductors on the top circuit may sag into the bottom circuit (for example due to heavy snow loading) and cause a transmission to distribution contact. Trees falling into the line from outside of the right-of-way may result in a similar fault. This type of a contact can create a temporary extreme overvoltage event that may result in potential customer hazards. FortisBC has piloted the installation of station-class arrestors on 27 Line in the Salmo area to mitigate potential overvoltage events. Depending on the performance of these devices they may be deployed in other areas such as 20 Line. Regardless, FortisBC believes that a more comprehensive solution is to reframe the structures to increase the circuit-to-circuit clearance.

138.3 As 20 Line has distribution underbuild, please explain how FortisBC proposes to protect their customers from extreme temporary overvoltages when the transmission line comes into contact with the distribution line.

Response:

FortisBC has recently installed station-class surge arrestors in some locations along 27 Line in the Salmo area to help protect customers from extreme temporary overvoltage events. Depending on the performance of these devices, they may be more widely deployed in the FortisBC service area.

The proposed 20 Line Rebuild project is planned to upgrade areas with significant inter-circuit clearance issues and deficient structures to further protect against this problem. Please also refer to the response to BCUC IR1 Q138.2.

138.4 Please provide an electronic copy of the update 2010 engineering assessment report.

Response:

Please refer to BCUC IR1 Appendix 135.4.

138.5 Please explain any investigation FortisBC has performed to assess the true vintage of poles for which there is no data (as shown at Exhibit B-1-1, Appendix F, page 17 of 42).

Response:

If the age of the pole could not be determined from the pole stamp, the assessors would either:

a) Enter the date from adjacent poles if the pole in question appeared similar to other poles in immediate area; or

b) Enter no age for the pole.

Since no other source of pole age information is available, no further investigation was conducted to determine the pole vintage.

139.0 Reference: Station Sustainment Programs and Projects

Exhibit B-1, Tab 6, Section 3.3, p. 54

Table 3.3 - Station Sustainment Programs and Projects

139.1 Provide a table showing the previous five years of data (total only) for both forecasted and actual costs?

Response:

The table below provides the forecast and actual expenditures for Station Sustainment Programs and Projects.

Table BCUC IR1 139.1 Station Sustainment Programs and Projects

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Station Sustainment Programs and Projects	3,808	4,365	2,518	5,251	4,671	3,509	4,920	3,484	2,764	5,431	13,969	14,427

139.2 Please provide the estimate class and accuracy of the estimated costs in the table.

Response:

Please refer to the below table.

Table BCUC IR1 139.2

		2012	2013	AACE Estimate Class	AACE Expected Accuracy Range (Typical variation in low and high ranges)
	Station Sustainment	($000s)			
1	Environmental Compliance (PCB Mitigation)	11,269	11,553	Class 4	2012: -15% to +20% 2013: -20% to +30%
2	Station Urgent Repairs	818	907	N/A (see answer to BCUC IR1 Q141.4)	
3	Station Assessment/Minor Planned Projects	1,343	1,354	Class 3	-15% to +20%
4	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	Class 4	-15% to +20%
5	Huth Low Voltage Breaker Replacement (2 Units)	-	69	Class 4	-15% to +20%

Please refer to BCUC IR1 Q125.2 for a discussion regarding AACE Estimate Classes and AACE Expected Accuracy Range.

140.0 Reference: Environmental Compliance (PCB Mitigation)

Exhibit B-1, Tab 6, Section 3.3.1, pp. 54-59

Table 3.3.1 (b) - PCB Environmental Compliance Forecast Expenditures

2012 Integrated System Plan

Exhibit B-1-1, Section 4, pp. 21-22

140.1 Please provide the estimate class and accuracy of the estimated costs in the table.

Response:

The estimate is based on the AACE International Recommended Practice No. 18R-97 for cost estimating and budgeting. For the PCB Mitigation project the estimate is considered equivalent to an “AACE Class 4” level. The accuracy would be consistent with the AACE guideline which is typically -30% to +50% for this level of estimate.

At the time this estimate was generated the comprehensive list of affected equipment had not been finalized. Much of the equipment that is likely to contain high levels of PCB was determined to be a sealed unit or equipment that could not be tested with a safe and practical method.

Survey information obtained from the Canadian Electrical Association provided some data on PCB levels typically found in substation equipment. Attempts have been made to obtain information from the original manufacturer of the equipment to determine PCB levels. This information is currently being combined with the available test results to produce a project plan that will provide a Class 2 estimate with an expected accuracy that is typically -15% to +20% for the 2012 work and a Class 3 estimate (-20% to +30%) for the 2013 work scope. This work is expected to be completed by November 2011.

140.2 As the combined amounts exceed $22 million, why has FortisBC not proceeded with a CPCN?

Response:

The Company believes that a CPCN application is not required for a number of reasons. First, the work is driven by Federal environmental legislation and is thus non-discretionary. All work will be confined within existing substation fence-line boundaries and is not expected to generate any public concerns due to the construction itself. It should be noted that some customer outages will be required for FortisBC crews to safely complete the work. While these outages may have public impacts, they are necessary to ensure that the work is completed safely and efficiently.

FortisBC believes that the information already provided in the project description, combined with the clarification gained through the regulatory process, will be sufficient to allow the Commission to determine that the expenditures are in the public interest.

140.3 Would FortisBC be willing to provide quarterly progress reports for the program?

Response:

FortisBC would be willing to submit PCB Mitigation progress reports every six months. The company currently submits reports containing the PCB mitigation data on an annual basis to the Federal and provincial governments. A six month reporting regime would help to keep reporting consistent and minimize duplication costs.

> "FortisBC established a Polychlorinated Biphenyls (PCB) testing and monitoring program in response to Environment Canada's review of PCB regulations. FortisBC initiated additional effort to deal with PCB health and environmental concerns and the release of draft PCB regulation in 2002. The draft regulation suggested that depending on level of concentration some items would be required to be removed from service. To ensure worker health and safety and compliance with the pending regulation, FortisBC submitted the PCB test program to the BCUC as part of its 2005 Revenue Requirements Capital and details on the Company's proposed seven year PCB oil sampling program." (Exhibit B-1, Tab 4, Section 4.3.4.13, pp. 75, 76)

140.4 Please provide a summary of the results of the seven year PCB oil sampling program.

Response:

Please refer to the response to BCUC IR1 Q140.5.

140.5 Please provide a list of all known equipment with PCB levels above 500 PPM and between 50 PPM and 500 PPM.

Response:

Please refer to the attached spreadsheet Appendix BCUC IR1 Electronic Attachment 140.5 which contains the PCB test result list compiled to date. 588 pieces of equipment on this list have not been tested for several reasons:

- The equipment is sealed and cannot be sampled;
- Attempts to sample the equipment failed because it could not be obtained without risk of damage to the equipment;
- Attempts to sample the equipment were not practical due to safety concerns;
- Attempts to sample the equipment were not successful and time constraints required the equipment to be returned to service; or
- Access to the equipment would require significant outages.

Environment Canada requires all equipment listed on the extension with unknown PCB quantities to be considered over 500ppm for calculation of kilograms of PCB. On this basis, equipment with an unknown quantity of PCB is listed as over 500ppm. Also included is an additional list of equipment that contains large volumes of oil contaminated with detectable PCB levels below 50ppm.

140.6 Please describe the costs and activities of any PCB mitigation programs undertaken since 1995, and describe how these programs addressed the applicable legislation at the time.

Response:

PCBs were first identified as toxic under the Environmental Contaminants Act (ECA) of 1976 and were listed in the Schedule of that Act. The classification and listing of PCB as toxic has been maintained in Schedule 1 of Canadian Environmental Protection Act (CEPA). In 1997, Environment Canada concluded that PCBs meet the criteria for Track 1 substances— i.e. they are toxic substances that result predominantly from human activity, are persistent and bio-accumulative in the environment. Virtual elimination from the environment of Track 1 substances is the main objective as required under the 1995 Government of Canada Toxic Substances Management Policy.

The sale of PCBs was made illegal in Canada in 1977 and release to the environment of PCBs was made illegal in 1985. Previous Canadian legislation has allowed owners of PCB equipment to use PCB equipment until the end of its service life in small equipment. The storage of PCBs has been regulated since 1988. Handling, transport and destruction of PCBs are also regulated, under provincial regulations.

FortisBC undertook work to remove contaminated oil from large oil containing equipment in the early 1980s in order to meet the legislated requirements. As well, the Company conducted PCB contamination removal as part of the equipment servicing and asset management strategy. PCB mitigation programs were integrated into operations procedures after the large equipment program of the early 1980s and did not separate operational PCB changes until the pending legislation changes of 2004.

A PCB program was initiated in 2004 to address the changing legislation.

Costs and activities:

2004 - $0.039 million: Planning and design for PCB program based on PCB draft regulation

2005 - $0.653 million: Planning and execution of PCB inspection, testing, and reporting program

2006 - $1.560 million: Planning and execution of PCB inspection, testing, and reporting program

2007 - $0.962 million: Planning and execution of PCB inspection, testing, and reporting program based on proposed PCB Regulations released in Gazette I Nov 2006.

2008 - $0.917 million: Planning and execution of PCB inspection, testing, and reporting program. PCB Regulations released in Gazette II September 2008.

2009 - $ 0.152 million: Planning and execution of PCB inspection, testing, reporting and removal program for compliance with Dec 31, 2009 500 ppm deadlines under PCB Regulation section

16. The proposed Regulations Amending the PCB Regulations were published in the Canada Gazette, Part I on September 26, 2009 to clarify the 2008 release of PCB Regulations.

2010 - - $0.0 million - Planning for Substation PCB contaminated equipment removal under PCB Regulation section 17 extension to 2014. PCB Regulations Amendments released in Gazette II March 2010

2011 – to date $1.135 million: Planning and execution of Substation PCB contaminated equipment removal under PCB Regulation section 17 extension to 2014.

FortisBC has been granted an extension to 2014 to remove substation equipment and oil containing PCB concentrations greater than 500 mg/kg.

140.7 Is FortisBC on track to complete this removal?

Response:

Yes. Based on current information, and assuming receipt of a Commission Decision and Order to proceed in early 2012, FortisBC expects to complete the equipment removal by December 31, 2014.

141.0 Reference: Station Urgent Repairs

Exhibit B-1, Tab 6, Section 3.3.2, pp. 59-60

Table 3.3.2 - Station Urgent Repairs Expenditures

141.1 Please provide the 2012/2013 expenditures using a 5 year rolling window.

Response:

Please see Table BCUC 141.1 below.

Table BCUC IR1 141.1 Station Urgent Repairs – 5 Year Average

2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Actual					**Forecast**	**Requested**	
($000s)							
562	418	599	782	639	674	750	755

141.2 Please provide a forecast for the year 2014/2015 based on the assumption that the 2012/2013 expenditures are approved using the 3 year rolling window approach.

Response:

Please see Table BCUC IR1 141.2 below for requested 2014/15 expenditures based on 2012/13 expenditures. Please also refer to Errata 2 for the revised 2012 and 2013 requested expenditures.

Table BCUC IR1 141.2

2010	2011	2012	2013	2014	2015
Actual	**Forecast**	**Requested**			
($000s)					
639	674	811	808	794	843

141.3 Please provide the forecasted and actual total amounts for the years 2007 to 2010.

Response:

The table below provides the forecast and actual expenditures for Station Urgent Repairs.

Table BCUC IR1 141.3 Station Urgent Repairs

	2007		2008		2009		2010	
	Forecast	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**
	($000s)							
Station Urgent Repairs	353	418	400	599	473	782	448	639

141.4 Please provide the class and accuracy of the estimated costs in the table.

Response:

The costs associated with the Station Urgent Repairs program are not suitably addressed through the cost estimate classification system, as the work is unforeseen and thus the budget is based on historical rolling averages and not level of project definition or expected accuracy range of expenditures as stated in the AACE Cost Estimate Classification system.

142.0 Reference: Station Assessments and Minor Planned Projects

Exhibit B-1, Tab 6, Section 3.3.3, p. 60

Table 3.3.3 - Station Assessments and Minor Planned Projects Expenditures

142.1 Please provide the forecasted amounts for the years 2007 to 2010, including a breakdown for each program.

Response:

The table below provides the forecast and actual expenditures for Station Assessments and Minor Planned projects.

Table BCUC IR1 142.1 Station Assessments and Minor Planned Projects

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Station Assessments and Minor Planned Projects	1,145	2,148	1,186	1,509	236	286	350	286	623	708	1,343	1,354

142.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

The estimate developed for the Station Assessments and Minor Planned Projects is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

142.3 The failure of the gap-type arrestor in Coffee Creek in 2008 is described as causing $8,000 in damage. What amount has since be spent in replacing arrestors?

Response:

The Gap Type Surge Arrester program expenditures were $94,000 in 2010 for material purchases for 11 substations, and installation costs of $86,000 as of August 16, 2011 to install surge arresters at four substations.

143.0 Reference: Add Arc Flash Detection To Legacy Metal-Clad Switchgear

Exhibit B-1, Tab 6, Section 3.3.4, pp. 62-64

Table 3.3.4 (b) - Add Arc Flash Detection Legacy Metal-Clad Switchgear Expenditures

143.1 Please provide the class and accuracy of the estimated costs in the table that total $4.26 million.

Response:

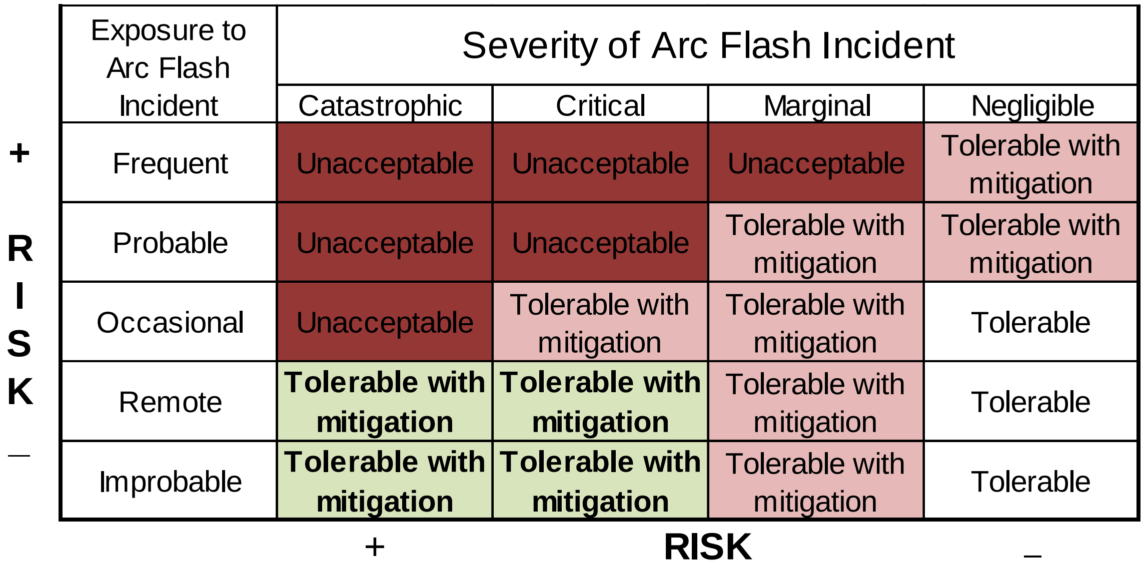
The estimate for the Add Arc Flash Detection Legacy Metal-Clad Switchgear projects for which FortisBC is seeking approval in 2012-13 is considered equivalent to an AACE Class 4 level, with an expected accuracy range of -15% to +20%. For the projects in 2014 and beyond, the estimate is considered equivalent to an AACE Class 4 level, with an expected accuracy range of -30% to +50%.

143.2 Provide a risk assessment of an arc flash event occurring while staff is working in the room, with the equipment energized and not wearing protective suits.

Response:

The chart below outlines the risk associated with an arc flash incident occurring while staff are working in close proximity to metal-clad switchgear without protective suits. In the first column, the exposure to an arc flash incident is listed, ranging from frequent exposure to the actual arc flash to very unlikely exposure to arc flash (improbable). The perceived probability of this occurring is between remote and improbable. The rest of the chart depicts the consequences of an arc flash incident occurring with staff in close proximity to the arc flash incident and without protective suits. The catastrophic and critical consequence columns apply to arc flash incidents with unprotected staff in close proximity to the arc flash, as the energy released would likely cause severe harm. The exposure to the incident and the resulting consequences combine to produce the risk to unprotected staff. On the chart, the intersection that describes the exposure to and the consequences of an arc flash incident are highlighted in green. These risks are more tolerable as long as barriers are in place to reduce the risk to staff. Barriers in this circumstance include Arc Flash Detection Relays. Currently, without Arc Flash Detection Relays, employees have the same amount of exposure, but without the barrier provided by the Arc Flash Detection Relays, the risk to the employee is higher.

Figure BCUC IR1 143.2



Exposure to Arc Flash Incident	Severity of Arc Flash Incident			
	Catastrophic	Critical	Marginal	Negligible
Frequent	Unacceptable	Unacceptable	Unacceptable	Tolerable with mitigation
Probable	Unacceptable	Unacceptable	Tolerable with mitigation	Tolerable with mitigation
Occasional	Unacceptable	Tolerable with mitigation	Tolerable with mitigation	Tolerable
Remote	**Tolerable with mitigation**	**Tolerable with mitigation**	Tolerable with mitigation	Tolerable
Improbable	**Tolerable with mitigation**	**Tolerable with mitigation**	Tolerable with mitigation	Tolerable

143.3 Is the arc flash retrofit considered a requirement or an enhancement within the utility industry?

Response:

Modern arc flash detection relays are relatively new within the utility industry, having only been deployed within the last decade in North America. As such, not all utilities have recognized the benefits of this equipment and adopted the technology. As such, the arc flash retrofit is considered an enhancement which helps provide a safe working environment. Some utilities forgo the installation of arc flash relays, opting instead to upgrade the switchgear along with the metal clad enclosures to modern standards when retrofitting or replacing. Generally this is more expensive than retrofitting just the arc flash relays. Other utilities install arc flash detection relays with new installations only.

144.0 Reference: Huth Low Voltage Breaker Replacement (2 Units)

Exhibit B-1, Tab 6, Section 3.3.5, p. 64

Costs

144.1 Please provide the estimate class and accuracy of the estimated costs in the table that total $0.62 million.

Response:

The estimate developed for the Huth Low Voltage Breaker Replacement Project is considered equivalent to an AACE Class 4 level, with an expected accuracy range of -15% to +20%.

144.2 Please provide an explanation as to why it will cost $.62 million to replace 2-8 kV OCB's.

Response:

The Huth Low Voltage Breaker replacement project will replace two 15kV class bulk oil circuit breakers that are operated at 8kV. The scope of the replacement project includes physical and civil work, removal and disposal of existing circuit breakers, instrument transformers and a small metal clad building housing the Feeder 2 breaker, and the installation of new circuit breakers and instrument transformers and the associated wiring. Re-alignment of buswork to accommodate the new circuit breakers, and modification to the ground grid to meet current FortisBC standards will also be completed.

144.3 Please provide a scope of supply for the OCB replacement and the FortisBC-standard 13 kV equipment.

Response:

Detailed engineering is scheduled to be completed in 2013, with construction to start and finish in 2014. The project will include physical and civil work to provide foundations for the new circuit breakers, removal and disposal of existing circuit breakers, instrument transformers and a small metal clad building housing the Feeder 2 breaker, and the installation of new FortisBC-standard circuit breakers and instrument transformers and the associated wiring. Re-alignment of buswork to accommodate the new circuit breakers, and modification to the ground grid to meet current FortisBC standards will also be completed.

145.0 Reference: Distribution

Exhibit B-1, Tab 6, Section 4.0, p. 65

Table 4.0 - Distribution Projects

145.1 Provide a table showing the previous five years of data (totals only) for the forecasted and actual costs.

Response:

The table below provides the forecast and actual expenditures for Distribution.

Table BCUC IR1 145.1 Distribution Projects

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Distribution Growth	11,745	14,850	11,224	16,770	13,544	11,995	13,809	11,520	11,990	9,744	13,646	13,759
Distribution Sustaining	8,016	10,971	9,021	10,134	10,502	14,271	10,954	15,131	8,978	10,585	15,603	12,129
Total Distribution	19,761	25,821	20,245	26,904	24,046	26,266	24,763	26,651	20,968	20,329	29,249	25,889

145.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

Please see below for the AACE estimate class of the Distribution Growth and Sustainment projects and programs. The accuracies for the projects are considered to be consistent with the specifications in the AACE document.

Table BCUC IR1 145.2a Distribution Growth

	AACE Estimating Class	AACE Accuracy Range
Distribution Growth		
New Connects System Wide	N/A	N/A
Small Growth Projects	Class 3	-15% to +20%
Distribution Unplanned Growth	N/A	N/A
Glenmerry Feeder 2 - Glenmerry Feeder 3 Tie Line	Class 4	-15% to +20%
Ellison Feeder 2 to Sexsmith Feeder 1 Tie	Class 3	-15% to +20%

Table BCUC IR1 145.2b Distribution Sustainment

	AACE Estimating Class	AACE Accuracy Range
Distribution Sustainment		
41 Line Salvage and Distribution Underbuild Rehabilitation	Class 4	-15% to +20%
Distribution Line Condition Assessment	Class 3	-15% to +20%
Distribution Line Rehabilitation	Class 4	-15% to +20%
Distribution Line Rebuilds	Class 3	-15% to +20%
Distribution Urgent Repairs	No AACE Estimate Class	N/A
Forced Upgrades and Lines Moves	No AACE Estimate Class	N/A
Distribution Line Small Planned Capital	Class 3	-15% to +20%

The costs associated with New Connects System Wide, Distribution Line Urgent Repairs, and Forced Upgrades and Line Moves are not suitably addressed through the AACE Cost Estimate Classification System as the programs are driven by unforeseen requirements. Thus these costs are based on historical rolling averages and not a level of project definition.

146.0 Reference: Distribution Line New Connects System Wide

Exhibit B-1, Tab 6, Section 4.1.1, pp. 66-67

Table 4.1.1 - Distribution Line New 1 Connects System Wide Expenditures

FortisBC states “The expenditures shown in Table 4.1.1 are derived based on a three-year rolling average adjusted for anomalous years (2008), projected customer growth, inflation and changes to overhead loading. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years’ budgets is the most logical approach from FortisBC’s perspective.” (Tab 6, p. 65)

146.1 Provide the values used for projected customer growth, inflation and changes to overhead loading.

Response:

Projected Customer Growth:

- The projected customer growth for both 2012 and 2013 is 1.9 percent. Please also refer to Table 3C on page 14 of Tab 3 of the 2012-13 RRA.

<u>Inflation Rate:</u>

- 2 percent

<u>Overhead Loading Rates:</u>

- 2012: 27.0 percent
- 2013: 25.6 percent

146.2 Provide a table showing the previous five years of data (totals only) for the forecasted and actual costs.

<u>Response:</u>

The table below provides the forecast and actual expenditures for Distribution Line New Connects System Wide.

Table BCUC IR1 146.2 Distribution Line New Connects System Wide

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Distribution Line New Connects System Wide	7,245	8,861	7,977	12,845	11,782	8,782	9,535	8,660	11,003	8,758	11,057	10,780

146.3 Please provide the class and accuracy of the estimated costs in the table.

<u>Response:</u>

The costs associated with New Connects System Wide are not suitably addressed through the AACE Cost Estimate Classification System, as the basis for these costs are historical rolling averages and not level of project definition or expected accuracy range of expenditures.

As FortisBC has an obligation to serve, this program is dependent on the number of new customer connection requests in a given year. Therefore, there is no way of applying a meaningful AACE Cost estimate class.

146.4 Please identify the reason for the anomalous expenditures in 2008, and explain the reason for the large increase in expenditures in 2012 and 2013 which is above the average for the period 2009 through 2011.

Response:

It is suspected that the anomalous expenditure in 2008 was attributed to the last year of the "construction boom" prior to the economic downturn in late 2008. It was reduced slightly (when determining the average) to account for the fact that FortisBC does not expect to have that level of New Connect expenditures in the near future and bring the "anomalous year" down to something more consistent with the other recent years.

The historic values shown in Table 4.1.1 on page 67 of the 2012-13 CEP are net of Contributions In Aid of Construction (CIAC). CIAC include those from New Connections, Forced Upgrades and any other CIAC received. The three year rolling average calculation is based on the actual historic New Connect expenditures including New Connect CIAC only. The Company did not forecast CIAC from Forced Upgrades and other sources in 2012 and 2013.

147.0 Reference: DG Bell Feeder 1 and Feeder 2 Upgrades (2012)

Exhibit B-1, Tab 6, Section 4.1.2.1, p. 67

Concerns

147.1 Please explain the statement "… created concerns in contingency situations."

Response:

FortisBC's Distribution Planning Criteria requires that "In the event of a single distribution contingency, a percentage of the peak load must be able to be supplied from the remaining distribution feeders in the study area. The percentage of peak load to be supplied is determined from the load duration curve if available or 80% of peak load." D.G. Bell Feeder 2 has experienced significant load growth recently and is forecast to violate normal feeder loading criteria within the next five years. The feeder also currently violates contingency planning criteria. With the addition of the Benvoulin station in 2010, FortisBC was able to transfer some load from the D.G. Bell substation to the new Benvoulin substation thus freeing-up capacity at D.G. Bell. The D.G. Bell Feeder 1 and Feeder 2 upgrade project will take advantage of this additional capacity by reconfiguring the two feeders in order to balance loads. This will prevent future feeder overloads and provide both feeders the ability to back up the other in a contingency.

147.2 Please explain why this project, resulting from the construction of the Benvoulin substation in 2010, was not included as part of that project's budget. Was the need for the feeder reconfiguration known at the time of the substation project, and if not, why not?

Response:

The scope of the Benvoulin project was to offload overloaded feeders and substations within economic reach of the new station location. The contingency operations issue this project is solving did not result from the construction of the Benvoulin substation in 2010, but rather is an opportunity presented by its construction. By taking advantage of feeder and substation capacity that has been freed-up by the transfer of load onto the Benvoulin substation, FortisBC is now able to resolve contingency violations at the D.G. Bell substation.

148.0 Reference: Hollywood Feeder 2 and Feeder 3 Offload (2012)

Exhibit B-1, Tab 6, Section 4.1.2.2, pp. 67-68

Deferment

148.1 Please explain the statement "…to defer the need for more costly capacity upgrades." If so, how much is being deferred and for how long?

Response:

The scope of this project is to upgrade feeder egress cables to a larger ampacity rating and to upgrade some existing single-pole switches to gang-operated air break switches. This will allow the transfer of some Hollywood Feeder 1 and 2 load onto the Hollywood Feeder 7. This solution is more cost-effective than any alternative which would involve the construction of a new underground feeder tie. The cost of the new feeder tie was not estimated in detail; however, it was expected to be over $0.5 million. This project is expected to defer the need for a new feeder tie outside of the five year window (beyond 2016).

149.0 Reference: Distribution Line Unplanned Growth

Exhibit B-1, Tab 6, Section 4.1.3, pp. 69-70

Table 4.1.3 - Distribution Line Unplanned Growth Expenditures

149.1 Please provide the forecasted and actual amounts (totals only) for the years 2007 to 2010.

Response:

The table below provides the forecast and actual expenditures.

Table BCUC IR1 149.1 Distribution Line Unplanned Growth

	2007		2008		2009		2010	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
	($000s)							
Distribution Line Unplanned Growth	685	1,065	713	834	974	604	994	750

149.2 Please provide the estimate class and accuracy of the estimated costs in the table.

Response:

The costs associated with New Connects System Wide are not suitably addressed through the AACE Cost Estimate Classification System, as the basis for these costs are historical rolling averages and not level of project definition or expected accuracy range of expenditures.

As FortisBC has an obligation to serve, this program is dependent on the number of new customer connection requests in a given year. Therefore, there is no way of applying a meaningful AACE Cost estimate class.

150.0 Reference: Distribution Growth Project

Exhibit B-1, Tab 6, Section 4.1.4, p. 70

Glenmerry Feeder 2 to Glenmerry Feeder 1 Tie Line

150.1 Please explain the nature of the increase in connected customer load on Beaver Park Feeder 2. Was this an increase in existing loads or a new load, and if new, what new load was connected relative to the existing feeder loads?

Response:

Beaver Park Feeder 2 has experienced significant growth over the past few years. In addition to normal residential growth there has been new commercial/industrial load connected to the feeder with three of the customers having new loads of 300 kVA, 1.0 MVA and 1.5MVA. As well, one of the existing industrial customers increased its contract demand from 700kVA to 1200kVA.

150.2 What is FortisBC's extension policy for new large customers that cause the need for substation upgrades or other infrastructure?

Response:

FortisBC's distribution planning process studies the distribution system over the succeeding five years to ensure it meets the needs of the customers from a capacity and voltage perspective. If there are any major deficiencies observed in the study, solutions are identified so that they can be corrected before they become an issue. The feeder loading for these studies are based on actual peak loading and forecast load growth.

If a new large customer applies for service and its individual load requirements result in issues with either capacity or voltage on the distribution feeder, that customer is responsible for all feeder upgrades to ensure that other customers' standard of service is not impacted. If a new large customer requires substation upgrades due to a lack of capacity, the process may involve advancing or changing station upgrade plans, and would include any detail on applicable Contributions in Aid of Construction for which the prospective customer would be responsible. Alternatively, large customers may avail themselves of transmission-level service to avoid incurring costs associated with upgrades to FortisBC substation infrastructure which would otherwise be required to support their load addition.

151.0 Reference: Ellison Feeder 2 to Sexsmith Feeder 1 Tie

Exhibit B-1, Tab 6, Section 4.1.5, p. 72

Sexsmith T1 Transformer

151.1 Please provide the class and accuracy of the estimated costs.

Response:

The estimate developed for the Ellison Feeder 2 to Sexsmith Feeder 1 Tie project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

151.2 Please provide the nameplate data for the Sexsmith T1 transformer and provide an explanation of summer rated capacity.

Response:

Following is the nameplate data for the Sexsmith T1 transformer:

Manufacturer: Ferranti Packard
Year of manufacture: 1989
Capacity rating: 24/32MVA ONAN/ONAF, 55/65 deg Celsius, 3phase
Voltage rating: 132,000/66,000-13,000Y/7200 volts with on-load tap-changer

The Sexsmith T1 transformer has an operational load limit of 32 MVA in the summer with all fans in operation.

151.3 Please provide the percentage of time Sexsmith T1 transformer exceeds its summer rating and the expected life reduction due to operating at the higher temperatures.

Response:

With the addition of the Ellison substation in 2009 and the consequent offloading of the Sexsmith substation, the Sexsmith T1 transformer currently does not exceed its summer rating during summer peak loads.

The expected life reduction of a transformer due to operation at temperatures higher than rated is a function of how high the over temperature is and how long the over temperature is sustained. FortisBC does not overload substation transformers under normal operating conditions.

151.4 Can fan cooling be added to the transformer to increase the summer rating?

Response:

It is unknown at this time whether fans could be added to the transformer to increase the summer rating. FortisBC would need to engage a transformer engineering consultant to conduct a design study for the transformer in order to determine this.

152.0 Reference: Distribution Line Condition Assessment

Exhibit B-1, Tab 6, Section 4.2, p. 73

Table 4.2 - Distribution Sustainment Programs and Projects

152.1 Provide a table showing the previous five years of data (totals only) for both forecasted and actual costs and provide the number of poles by year on a separate line in the table.

Response:

The Table below provides the forecast and actual expenditures for Distribution Line Condition Assessment.

Table BCUC IR1 152.1 Distribution Line Condition Assessment

	2007		2008		2009		2010		2011	2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Requested	
Distribution Line Condition Assessment	**($000s)**										
Plant Additions	637	928	678	692	599	659	667	605	992	1,410	1,398
Cost of Removal	-	10	-	-	-	-	-	-	-	-	-
Total	**637**	**938**	**678**	**692**	**599**	**659**	**667**	**605**	**992**	**1,410**	**1,398**
Number of Poles	**13,724**		**14,011**		**8,568**		**8,968**		**15,720**	**12,317**	**12,117**

Note: Cost of removal not forecasted prior to 2011.

FortisBC does not have actual pole counts readily available for the years requested. FortisBC tracks completed work as actual costs in asset classes. Individual pole tracking information, while potentially interesting, is not currently recorded. Further, this information cannot be extracted from the FortisBC Geographic Information System since that system is unable to replicate the configuration of the power system at any arbitrary historical time. Consequently, it is not possible to derive completed pole counts for historical work from that system.

152.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

The estimate developed for the Distribution Line Condition Assessment program is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

153.0 Reference: Distribution Line Rehabilitation

Exhibit B-1, Tab 6, Section 4.2.3, pp. 76-78

Table 4.2.3 (b) - Distribution Line Rehabilitation Expenditures

153.1 Provide a table showing the previous five years of data (totals only) for both forecasted and actual costs and provide the number of poles by year on a separate line in the table.

Response:

The Table below provides the forecast and actual expenditures and number of poles for Distribution Line Rehabilitation.

Table BCUC IR1 153.1 Distribution Line Rehabilition

	2007		**2008**		**2009**		**2010**		**2011**	**2012**	**2013**
	Forecast	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Requested**	
Distribution Line Rehabilitation	**($000s)**										
Plant Additions	1,606	1,232	1,645	3,001	2,848	2,634	3,209	2,779	1,937	4,646	3,142
Cost of Removal	-	143	-	726	-	660	-	307	366	652	375
Total	**1,606**	**1,375**	**1,645**	**3,727**	**2,848**	**3,294**	**3,209**	**3,086**	**2,303**	**5,298**	**3,517**

Number of Poles	**10,835**		**13,724**		**14,011**		**8,568**		**8,968**	**15,720**	**12,317**

Note: Cost of removal not forecasted prior to 2011.

FortisBC does not have actual pole counts readily available for the requested years. FortisBC tracks completed work as actual costs in asset classes. Individual pole tracking information, while potentially interesting, is not currently recorded. Further, this information cannot be extracted from the FortisBC Geographic Information System since that system is unable to replicate the configuration of the power system at any arbitrary historical time. Consequently, it is not possible to derive completed pole counts for historical work from that system.

153.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

The estimate developed for the Distribution Line Rehabilitation program is considered equivalent to an AACE Class 4 level, with an expected accuracy range of -15% to +20%.

154.0 Reference: Distribution Line Rebuilds

Exhibit B-1, Tab 6, Section 4.2.4, pp. 76-78

Estimates

154.1 Provide a table showing the previous five years of data (totals only) for both forecasted and actual costs and provide the number of poles by year on a separate line in the table.

Response:

The Table below provides the forecast and actual expenditures for Distribution Line Rebuilds.

Table BCUC IR1 154.1 Distribution Line Rebuilds

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Distribution Line Rebuilds	1,576	1,470	1,945	1,284	1,178	1,056	1,167	1,031	1,854	1,886	1,372	1,328
Cost of Removal	-	175	-	26	-	315	-	209	-	185	307	332
Total	1,576	1,645	1,945	1,310	1,178	1,371	1,167	1,240	1,854	2,071	1,679	1,660

Number of Poles		111		26		165		88				

Note: Cost of Removal not forecast prior to 2011.

FortisBC does not track a historical pole count for the Distribution Rebuild program nor is a forecast pole count (such as that developed for the Condition Assessment and Rehabilitation programs) produced for this program. Individual distribution rebuild scopes vary significantly from year-to-year and also include work such as reconductoring due to condition related issues, cable replacements in underground systems, and line relocations due to deteriorated plant that would be better relocated to a new right-of-way. Thus, due to the widely varying scopes included in this program FortisBC does not have the requested information available.

154.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

The estimate developed for the Distribution Line Rebuild projects is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

155.0 Reference: Telecommunications, Scada Protection And Control

Exhibit B-1, Tab 6, Section 5.0, p. 81

Table 5.0 - Telecommunications, SCADA, Protection and Control Projects

155.1 Provide a table showing the previous five years of data (totals only) for both forecasted and actual costs.

Response:

The table below provides the forecast and actual expenditures for Telecommunications, SCADA, Protection and Control projects.

Table BCUC IR1 155.1 Telecommunications, SCADA, Protection and Control Projects

	2007		2008		2009		2010		2011		2012	2013
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Current Estimate	Requested	
	($000s)											
Growth												
Plant Additions	3,458	162	1,456	1,108	1,338	1,784	1,438	1,488	1,602	2,127	1,212	2,549
Cost of Removal	-	-	-	3	-	17	-	24	50	45	-	-
Total Growth	3,458	162	1,456	1,111	1,338	1,801	1,438	1,512	1,652	2,172	1,212	2,549
Sustaining												
Plant Additions	1,482	1,022	1,088	1,764	747	765	619	680	1,613	2,138	1,117	1,133
Cost of Removal	-	8	-	43	-	3	-	4	-	55	-	-
Total Sustaining	1,482	1,030	1,088	1,807	747	768	619	684	1,613	2,193	1,117	1,133
Telecom SCADA Protection and Control	4,940	1,192	2,544	2,919	2,085	2,569	2,057	2,195	3,265	4,365	2,329	3,682

Note: Cost of Removal not forecast prior to 2011.

155.2 Please provide the class and accuracy of the estimated costs in the table.

Response:

The AACE estimate classes and associated accuracies for the expenditures for Telecommunications, SCADA, Protection and Control projects appear in the following table.

Table BCUC IR1 155.2

Project	Estimate Class	Accuracy
Kelowna 138 kV Loop Fibre Installation	Class 4	-15% to +20%
Communication Upgrades	Class 4	-15% to +20%
SCADA Systems Sustainment	Class 3	-15% to +20%

156.0 Reference: Kelowna 138 kV Loop Fibre Installation

Exhibit B-1, Tab 6, Section 5.1.1, pp. 81-95

Options E and F and Table 5.1.1

156.1 As the only difference between options E and F is the fully redundant capability for a cost of $546,000, what is the cost impact for selecting Option E?

Response:

FortisBC presumes the question is referring to the cost impact to the customer based on the figure that was provided for societal costs resulting from failure of the communications systems.

This particular figure was derived assuming a communications failure was likely to interfere with attempts to remotely reconfigure the power system, as is the case with the current radio system. As discussed on page 85 of Tab 6 of the 2012-13 RRA, both options E or F would be considered nearly fully available, and therefore there would likely be no customer cost impact due to failures of the communications system with either option. Power system outages would still occur, but failures of the communications system would not be expected to increase the duration of these outages.

156.2 What is the difference in reliability between Option E and Option F considering impact on the customers and loss of revenue?

Response:

From a reliability standpoint, option E specifies redundant equipment installed in a ring configuration without path redundancy. This means that for option E, both communications paths follow the same physical fibre route and are interrupted when a physical failure of the cable occurs. The impact on reliability and on customers is due to an increased probability of outage resulting from this failure of the fibre optic cable when compared to option F.

Failure rates due to defects or installation of fibre optic cables after deployment are infrequent enough that they can be assumed to be zero. The plausible external events that can therefore cause a failure of the fibre path are:

- Splicing work inadvertently interrupting or damaging fibre path;
- Other line work interfering and severing the cable;
- Vehicular accident severing the cable;
- Vandalism causing cable damage and severing the cable;
- Rodents chewing through and severing the cable.

These events are random and rely on too many variables to be able to accurately predict their occurrence. However, FortisBC has experienced several fibre cable failures in the past due to these events.

For the Kelowna 138 kV Loop, FortisBC anticipates a higher probability of failure due to two reasons:

- Increased risk of vandalism due to fibre installation in highly populated areas;
- Increased exposure to potential motor vehicle accidents due to a portion of the deployment being on distribution (as opposed to transmission) structures, which are generally closer to the road and not as well protected.

Though not quantified for the reasons outlined above, FortisBC considers a fibre break in the Kelowna area to be likely at some point in the future. Since FortisBC plans to fully mesh the protection systems in the Kelowna area to increase reliability, a break in the fibre would compel FortisBC to fallback to operating the system in a less reliable radial mode for the duration of the communications outage. Fibre restorations typically take several hours or days but can sometimes be longer. Alternatively for option F, a physical break in the fibre cable does not have any reliability implications as communications are re-routed and are not interrupted.

FortisBC does not assess loss of revenue due to system failures as it is not considered to fully consider outage costs to the customer.

156.3 Please provide the class and accuracy of the estimated costs for the options in the table.

Response:

FortisBC provides the following class and accuracy of estimates costs for both options E and F.

Table BCUC IR1 156.3

	AACE Estimate Class	AACE Estimate Accuracy
Option E	Class 4	-15% to +20%
Option F	Class 4	-15% to +20%

156.4 Please explain the timing and the amounts of future capital expenditures that will be required if Option D, the least cost option, is selected.

Response:

Option D would require additional capital expenditures estimated at $0.280 million (adjusted for inflation) approximately every 10 to 15 years. This expenditure is based on the replacement of telecommunications modems required for the third party services provided.

156.5 For the section of proposed new fibre in Option F, please explain whether FortisBC investigated the option of having a third party pay for the fibre on FortisBC infrastructure and lease back dark fibre to FortisBC, and if not, why not? Please provide a cost summary of the "have others build and lease back" approach, and evidence that FortisBC has investigated this option.

Response:

FortisBC did have informal discussions with a third party communications provider from whom FortisBC is already leasing dark fibre in the Kelowna area. The third party provider did have some facilities in the general area, but not near the substations that require fibre connections. Since the third party already had sufficient facilities in the area for their purposes they expressed no interest in constructing additional fibre solely for FortisBC use. It is on that basis that FortisBC is proposing to construct new fibre infrastructure which will augment existing leased fibre in the Kelowna area and complete the necessary communications path.

As noted, the discussions were informal and did not appear to present a workable solution. As a result no cost analysis was done and there is no formal documentation available for submission.

156.6 Please provide the detailed cost estimates for Options A, D, E and F including an equipment-specific breakdown at each location.

Response:

Please refer to document attached as BCUC IR1 Appendix 156.6. Note that the detailed cost estimates do not include corporate loadings, but these loadings have been included in the summary table.

157.0 Reference: Communication Upgrades

Exhibit B-1, Tab 6, Section 5.2.1, pp. 95-96

Cost Separation

157.1 Please provide the estimate class and accuracy of the costs shown.

Response:

Please refer to the response to BCUC IR1 Q157.2 for estimate class and accuracy for these projects.

157.2 Please provide separate costing for the Jungle MUX Laser upgrade and the upgrade of the backhaul to North Warfield Station.

Response:

Please refer to the below table.

Table BCUC IR1 157.2

	Estimated Cost ($000s)	Estimate Class	Accuracy
JungleMUX Laser Upgrade	144	Class 4	-20% to +30%
Nkwala backhaul upgrade	155	Class 4	-20% to +30%

Note that in the 2012 – 13 Capital Plan, the Nkwala (NKW) site reference was inadvertently transcribed as North Warfield (NWD). The correct reference is shown in the table above. Please also refer to Errata 2.

The purpose of the Communications Upgrades program is to provide ongoing funding for specific one-time upgrades, periodic upgrades and unforeseen telecom upgrade expenditures. This funding may be required for the following reasons:

- Third party providers of telecom services discontinue services without sufficient warning for FortisBC to scope and submit a formal project in a capital plan. For example, since the filing of FortisBC's 2012-13 CEP, two providers of SCADA circuits have contacted FortisBC and announced plans to discontinue specific services before the end of 2012. This results in a need to upgrade equipment to maintain operations; and
- Field operations staff may identify installed assets that are no longer operating correctly or at risk of imminent failure.

157.3 Please describe any reliability issues associated the Jungle MUX equipment. Does FortisBC own any Jungle MUX equipment spares? Are the communications supported by the Jungle MUX installations redundant?

Response:

FortisBC has no specific concerns with the JungleMUX equipment; the Company's experience has proven the devices to be extremely reliable. Periodic equipment upgrades are primarily due to manufacturer end-of-life for specific components or due to the need to upgrade system capacity.

FortisBC owns spare JungleMux equipment, currently stocked in Trail and Kelowna.

The JungleMux communications equipment supports full redundancy of its aggregate links. FortisBC has 31 JungleMux nodes, and 29 of these nodes have hardware redundancy, therefore at these sites, a single failure of a card or a fibre path will not interrupt communications. Presently, there is no path redundancy built into the FortisBC system as the fibre system is linear and both redundant fibres follow the same physical path.

158.0 Reference: Scada Systems Sustainment

Exhibit B-1, Tab 6, Section 5.2.2, p. 96

Cost Separation

158.1 Please provide the estimate class and accuracy of the costs shown.

Response:

The estimate developed for the SCADA Systems Sustainment project is considered equivalent to an AACE Class 3 level, with an expected accuracy range of -15% to +20%.

158.2 Please provide separate costing for the SCADA and MRS expenditures.

Response:

Please refer to the following table for the cost breakdown.

Table BCUC IR1 158.2

	2012	**2013**
	($000s)	
SCADA System Sustainment Costs	450	460
MRS System Sustainment Costs	257	273

158.3 Please explain if the MRS related costs are part of the incremental MRS costs reported elsewhere, and if not, please identify these cost separately in all other information requests related to the first-time and ongoing costs of MRS.

Response:

The MRS-related costs in the SCADA Systems Sustainment budget include all capital costs to sustain MRS requirements and are incremental to MRS costs reported elsewhere. This budget is specifically to sustain and upgrade existing infrastructure and software. If significant additions to software and/or infrastructure are required through new, updated or changed standards, or identified by audits, those costs would be identified separately.

159.0 Reference: General Plant

Exhibit B-1, Tab 6, p. 100

Trail Office Lease

159.1 Please show the calculation of the $1.4 million NPV for the purchase of the Joe Drennan building.

<u>Response:</u>

The relevant calculation showing the NPV of $1.4 million Revenue Requirement savings associated with purchasing the building and avoiding the lease payments is shown below:

Table BCUC IR1 159.1 Trail Office Lease Analysis

		Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
1	**RATE BASE**	**4,640**	**10,012**	**9,554**	**9,094**	**8,635**	**8,176**	**7,718**	**7,012**	**6,803**
2										
3	**REVENUE DEFICIENCY**									
4										
5	**Operating:**									
6	O&M Expense (Savings)	(493)	(1,974)	(1,974)	(1,974)	(1,974)	(1,974)	(1,974)	(1,974)	(1,974)
7	Capitalized Overhead	99	395	395	395	395	395	395	395	395
8		(395)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)
9	**Taxes:**									
10	Income Taxes	26	278	270	260	252	244	236	225	221
11		26	278	270	260	252	244	236	225	221
12	**Financing:**									
13	Cost of Debt	144	312	298	283	269	255	240	218	212
14	Cost of Equity	184	396	378	360	342	324	306	278	269
15	Depreciation and Amortization	-	458	459	459	459	458	458	458	458
16		328	1,166	1,135	1,102	1,070	1,036	1,004	954	939
17										
18	**TOTAL REVENUE REQUIREMENT (SURPLUS)**	(40)	(134)	(175)	(217)	(257)	(299)	(339)	(400)	(418)
19										
20										
21	**NPV OF REVENUE REQUIREMENTS (SURPLUS) 2013-21:**			**(1,437)**						
22	**AT A DISCOUNT RATE OF:**			**8%**						

160.0 Reference: General Plant

Exhibit B-1, Tab 6, pp. 100-101

Central Warehousing

160.1 Will there be operational costs associated with centralizing warehousing at Warfield? If so, how much?

Response:

Yes, there will be increased operational costs for the Warfield facility as a result of addition to the existing warehouse space associated with centralizing warehousing. However, the additional Facilities costs are expected to be minimal as a result of the space type. Based on the current assumption of an estimated 8,000 square foot addition, the Facilities operating costs increase is estimated at $1,680 per annum. The additional property tax as a result of the improvement is estimated to be between $39,810 and $77,559 per annum.

161.0 Reference: General Plant

Exhibit B-1, Tab 6, Section 6.5.6, p. 106

Table 6.5.6 - Planned Schedule AMI

161.1 Considering the planned schedule shows activities for AMI starting as early as 2009, please provide the actual amounts spent to date including the forecast for 2011.

Response:

Spent and committed expenditures to the end of July 2011 are $1.4 million. Expenditures to the end of 2011 are forecast to be $1.8 million.

161.2 In order to achieve the implementation schedule and in-service dates, what is the proposed regulatory timetable?

Response:

Based on the current implementation schedule, the proposed regulatory timetable anticipates filing of the AMI CPCN application during the latter half of 2011, with a decision anticipated during the first half of 2012.

161.3 Please identify costs to date associated with the AMI project, and confirm whether FortisBC is requesting approval for any AMI related costs in this Application.

Response:

Please see the response to BCUC IR1 Q161.1 above. FortisBC is not requesting approval for any AMI related costs in this Application. Application for recovery of deferred AMI costs will be included as part of FortisBC's CPCN submission for its AMI project.

162.0 Reference: General Plant

Exhibit B-1, Tab 6, Section 6.5.7, p. 106

Treatment of Existing Meters

162.1 As the treatment of the existing meters was not discussed in section 6.5, please explain FortisBC's position when the existing meters are taken out of service.

Response:

FortisBC is considering three alternate approaches to the treatment of existing meters within the AMI proposal. They are:

1. In accordance with US GAAP, a change in the estimate of the remaining economic life of the existing meters would require an accelerated depreciation in order to recognize that the existing meters will be removed from service over the 2013 to 2015 period. Since the Company determines its depreciation rate based on the gross book value of assets at the end of the prior year, this would mean accelerated depreciation in each of 2014, 2015 and 2016; or

2. Depreciate the existing meters based upon their current remaining life. This would mean the meters would be written off over approximately 15 years starting in 2014. This treatment would require the Commission to issue an accounting order approving an accounting treatment that varied from US GAAP; or

3. Depreciate the existing meters over a period longer than that envisioned by US GAAP, but less than the remaining economic life. For example, the existing meters could be depreciated over 5 to 10 years as agreed to by the Commission beginning in 2014. This treatment would also require the Commission to issue an accounting order approving an accounting treatment that varied from US GAAP.

From a customer rate impact perspective, option 1 has the highest impact upon rates, while option 2 has the lowest impact.

163.0 Reference: General Plant

Exhibit B-1, Tab 6, p. 108

Infrastructure Sustainment

163.1 Please explain the large jump in forecast infrastructure sustainment costs in 2011. What is the current forecast for 2011?

Response:

The primary reason for the increase in costs beginning in 2011 is due to the infrastructure that is reaching end of life. There were a number of systems implemented when Fortis Inc. acquired the utility. The infrastructure implemented to support those systems, including a backup data centre, during the years from 2005 to 2008 began reaching end of life in 2011. This cycle of replacing the oldest infrastructure will continue into the future. However due to server virtualization strategies the cost of replacing out-dated infrastructure is at least 25 percent lower than it would have been had FortisBC not used this approach.

164.0 Reference: General Plant

Exhibit B-1, Tab 6, pp. 108-109

Desktop Infrastructure Sustainment

164.1 Please explain the large and continuing escalation in actual and forecast desktop infrastructure sustainment costs since 2007.

Response:

As explained in Commission IR1 Q35.1 in the Company's 2011 Capital Expenditure Plan process, there is an increase in costs for 2011 as a number of large multifunction printing devices have reached end of life. There were a number of these devices purchased in 2005 when the business was acquired by Fortis Inc. and business operations were re-established in BC. At that time there was also additional desktop equipment required to support the re-established organization. The increase in sustaining costs from 2007 compared to 2011, and going forward, is due to this added equipment reaching end of life along with the large multifunction printing devices. The budget going forward remains relatively flat as sustainment of required Desktop Infrastructure levels out.

165.0 Reference: General Plant

Exhibit B-1, Tab 6, p. 109

Application Sustainment

165.1 Please show the actual and forecast application costs since 2007.

Response:

From 2007 through 2011 enhancement and sustainment costs were not segregated. To be clear and consistent with other areas of the business the enhancement and sustainment budgets have been segregated for 2012 and 2013. This will also make it easier to track benefits attributable to enhancement work. The tracking of sustainment and enhancements costs are aggregated for all applications, as this is more relevant due to the level of integration between applications. Thus, there is not a direct comparison to previous years, but the following table shows an estimate based on estimated sustaining work done for all systems since 2007.

Table BCUC IR1 165.1

Description	2007(e)	2008(e)	2009(e)	2010(e)	2011(f)	2012(f)	2013(f)
	($000s)						
SAP & Operational System Sustainment	370	400	410	420	435		
CIS and Customer System Sustainment	320	390	400	410	420		
AM/FM System Sustainment*			260	265	270		
Application Sustainment						1,180	1,210
Total Estimated Application Sustainment Costs	**$690**	**$790**	**$1,070**	**$1,095**	**$1,125**	**$1,180**	**$1,210**

** AM/FM sustainment costs did not begin until 2009, as the implementation was completed in 2008.*

Sustainment capital is required to ensure systems remain supported and new functionality and capabilities included in upgrades and new releases are available.

166.0 Reference: General Plant

Exhibit B-1, Tab 6, p. 110

Application Enhancements

166.1 Please show the actual and forecast application enhancement costs since 2007. What benefits are expected from the application enhancements and explain where the cost savings are shown in the 2012-2013 RRA?

Response:

Please refer to the response to BCUC IR1 Q165.1 for an explanation of costs in previous years.

Table BCUC IR1 166.1

Description	2007(e)	2008(e)	2009(e)	2010(e)	2011(f)	2012(f)	2013(f)
Total Estimated Enhancement Costs ($000s)	$622	$849	$1,246	$1,236	$1,540	$1,235	$1,242

Enhancements are reviewed and approved each year through internal processes based on safety, regulatory, legislated and customer service requirements and on cost and operational benefits. The amount available for enhancements is affected by the number of regulatory and legislative changes that need to be made in a given year.

The following is a description of some enhancements that have been proposed for 2012 and 2013:

- Enhancements to business intelligence are expected to improve reporting analysis and access to information. The benefits of these enhancements will be distributed across the organization through efficient access to data;
- Enhancements planned for the AM/FM system will allow designers to design in the field, saving time and improving accuracy. The benefits should result in reductions in overtime and contracted services for design;
- Enhancements to SAP will focus on expanding the use of the portal technology to provide more information and services through the portal, particularly for operations, as the interface is simplified and performance is good on minimal bandwidth. Benefits will be increased field time for operational leads due to the simplified mobile capabilities of portal;
- SharePoint enhancements will be focused on document management and workflow. Enhancements here will improve access to documents, as well as provide workflow for managing documents, training material and employee surveys and feedback. The benefits due to these enhancements will be time savings throughout the organization through simplified and faster access to documents, as well as automated workflows reducing time to handle forms and surveys;

Time entry enhancements, which deliver a simplified web time entry interface for field operations, have been approved for 2012 and will free up time for the administrative staff to support field operations management. This support can then be used in areas such as documentation and record keeping for front line management staff conducting field crew audits and observations. Documented audits and observations are required to ensure crews are following safe work practices and procedures. Another benefit of this project will be additional time that management can spend in the field with their staff on training and development which in turn will improve worker productivity.

The time entry enhancements will allow the Company to remove an existing temporary time administrator position, as well as alleviate the need for two additional administrative support staff that would have been required in 2012 and going forward. These positions were not included in the 2012 and 2013 revenue requirements. Efficiencies from these enhancements are also expected to decrease the time spent at offices by field workers. The additional availability of these workers has been recognized in the overall revenue requirements and capital plan in the operations area for 2012 and 2013. The value of these benefits is estimated to be $100,000 in operating expenses reductions and mitigations in 2012 and $200,000 in 2013. There is also an estimated savings in capital of approximately $145,000 in 2012 and $290,000 in 2013.

167.0 Reference: General Plant

Exhibit B-1, Tab 6, pp. 110-111

PowerSense DSM Reporting software

167.1 Please identify the cost savings to the DSM administration budget resulting from this forecast expenditure of $1.03 million in 2012.

Response:

There is no cost reduction in the DSM administration budget expected. This software will replace the current legacy system (c2000) that has very limited functionality.

As stated in the referenced section, "… this software is required to capture the appropriate customer transaction information, improve internal workflow processes to provide better customer service, advance monitoring and evaluation, and ensure optimal expenditures. This software will track interactions with each customer from project initiation to completion and provide robust reporting capabilities."

168.0 Reference: General Plant

Exhibit B-1, Tab 6, p. 112

Vehicles

168.1 In Table 6.7, please show the number and cost of vehicle replacements since 2007.

Response:

The number and cost of vehicle replacements since 2007 is shown below. Please note that the total cost is influenced by the type of units purchased and the number of lease buy-outs (primarily in 2007 and 2008) purchased at a fraction of the cost of new units.

Table BCUC IR1 168.1 Vehicle Replacements/Additions since 2007

Category	2007	2008	2009	2010	2011F
Heavy Fleet	10	9	5	2	5
Service Vehicles	7	8	3	11	9
Passenger Vehicles	16	17	9	2	5
Off-Road/Trailers	11	3	7	4	4
Total Number of Units	44	37	24	19	23
Total Cost ($000s)	4,431	1,628	2,342	1,318	2,738

STATUS OF PAST DIRECTIVES

169.0 Reference: Status of Past Directives and Negotiated Settlement Provisions

Exhibit B-1, Appendix C, p. 2

Rate Forecasts

169.1 The forecast of rate increases beyond the test period includes an expected increase of 11.4% in 2015. Please explain the drivers that are anticipated to lead to this large rate increase.

Response:

The Waneta Expansion Project constitutes approximately 7.0 percent of the total 11.4 percent customer rate increase in the year 2015.

170.0 Reference: Status of Past Directives and Negotiated Settlement Provisions

Exhibit B-1, Appendix C, p. 4

System Reliability

170.1 FortisBC was to develop a “plan” for addressing its worst performing feeders. This is said to be addressed in the LT Capital Plan, section 3.2.2. However, that section seems to dismiss the initiative of a worst performing feeder program in favour of existing assessments. Please discuss how FortisBC’s practices will adequately address the issue of upgrading worst performing feeders in a timely way.

Response:

FortisBC has implemented a number of distribution system assessment and mitigation programs which involve an evaluation of the integrity of the system’s performance and conformance to appropriate regulations. Patrols and assessments are conducted to identify deficiencies in the FortisBC electrical system which could compromise safety, service reliability, or line integrity. These predictive maintenance programs provide information in the form of data, statistics, observations, assessments, and recommendations of corrective action to be performed on the distribution system and ensure public and employee safety, provide appropriate reliability, and prevent high consequence failures. The information collected from the patrols/assessments is combined with information concerning reliability, consequence of failure (to the customer and FortisBC), public safety concerns, and the environment.

These programs include the Annual Line Patrol, the Distribution Condition Assessment and Rehabilitation programs, Unplanned and Small Capital programs, and Vegetation Management program which are described further below.

- **Annual Line Patrol program:** The Annual Line Patrol is an annual inspection done on all distribution plant as part of the regional Operations and Maintenance (O&M) budgets. Network Services determines the type of visual patrol using criteria such as safety, accessibility, reliability, known defects, outage statistics and system performance.

  Patrollers arrange with Dispatch to address all high priority action items identified during the patrol. Lower priority items are identified for inclusion in future rehabilitation programs

- **Distribution Condition Assessment and Rehabilitation programs:** The Distribution Condition Assessment program is the Company’s capital sustaining program for the distribution network. The program is based on an eight-year cycle of condition assessment (to identify above-ground issues) and test and treatment (to control below ground decay) of all of FortisBC’s distribution line facilities.

  Any deficiencies identified during the condition assessment or test and treat are documented and included in a rehabilitation package. The Condition Assessment program data is used to determine the scope of work for the Distribution Rehabilitation program for the following year.

- **Unplanned and Small Capital programs:** The unplanned growth budget and part of the small planned capital budget is used every year to accommodate reliability issues due to insufficient reclosers/switches, and off-cycle upgrades to system protection and coordination.

- **Vegetation Management program:** A brushing program has been implemented to ensure sufficient clearance is maintained between underlying vegetation and high voltage conductors.

Given the comprehensive nature of the programs described above, and the fact that there is no indication that system performance is degrading, there is no information to suggest that a wholesale change in condition assessment practices is warranted. Specifically, FortisBC believes there is no evidence to suggest that the adoption of a specific worst-performing program would provide any reliability improvements or reductions in costs compared to the Company's existing practices.

The following table shows the last four years for the 10 worst performance feeders where there is no consistency in the results due to the fact that they are influenced by many variables: bad weather and motor vehicle accidents for example, which are out of the Company's control can have a big impact in a particular year. A number of the feeders (including those which had no rehabilitation work conducted) have an improving trend line over the four year period, confirming that a worst performing feeder program may not provide the reliability benefit expected from the program for the associated investment.

Table BCUC IR1 170.1

			SAIDI Impact				**SAIFI Impact**			
Feeder	**Region**	**Length (km)**	**2010**	**2009**	**2008**	**2007**	**2010**	**2009**	**2008**	**2007**
PRI4	Princeton	100.72	0.003	0.059	0.044	0.054	0.001	0.008	0.013	0.036
NOR1	Princeton	250.03	0.072	0.187	0.129	0.000	0.025	0.026	0.034	0.000
BLU2	Castlegar	40.16	0.018	0.056	0.040	0.001	0.010	0.017	0.013	0.001
HED4	Keremeos	26.1	0.000	0.000	0.061	0.095	0.000	0.000	0.007	0.014
PLA2	South Slocan	92.09	0.029	0.075	0.004	0.022	0.014	0.018	0.002	0.012
CAS1	Castlegar	23.15	0.001	0.059	0.001	0.020	0.002	0.011	0.001	0.010
PLA1	South Slocan	56.97	0.003	0.053	0.008	0.011	0.002	0.022	0.003	0.005
OOT1	Castlegar	79.6	0.002	0.047	0.019	0.000	0.002	0.029	0.006	0.000
OSO3	Oliver	95.59	0.008	0.046	0.007	0.000	0.003	0.020	0.004	0.001
OSO1	Oliver	25.93	0.000	0.045	0.000	0.003	0.000	0.016	0.000	0.001

170.2 Please summarize and discuss the worst performing feeders and compare last year's results with current statistics.

Response:

As discussed in previous submissions, FortisBC does not currently have a specific program that addresses distribution projects based purely on reliability statistics. Instead, FortisBC utilizes the proactive maintenance programs described in the response to BCUC IR1 Q170.1 to monitor and repair based on the condition of the distribution system.

There is very little consistency to feeder performance year over year, and bad weather and motor vehicle accidents for example, which are out of the Company's control can have a large impact in a particular year.

FortisBC's service area has many long, rural distribution feeders that will always tend to have worse reliability (compared to shorter urban feeders) because they generally have increased exposure to outages

The following table shows a comparison of 2009 and 2010 (current statistics) performance metrics of the ten worst performing feeders in 2009. In most instances the feeder reliability improved the following year even in the absence of any major rehabilitation work – again diminishing the support for a worst performing feeder program.

Table BCUC IR1 170.2

Feeder	Region	Length (km)	SAIDI Impact		SAIFI Impact	
			2010	2009	2010	2009
PRI4	Princeton	100.72	0.0026	0.059	0.0011	0.008
NOR1	Princeton	250.03	0.0723	0.187	0.0249	0.026
BLU2 *	Castlegar	40.16	0.0177	0.056	0.0103	0.017
HED4	Keremeos	26.1	0.0005	0	0.0003	0
PLA2	South Slocan	92.09	0.0289	0.075	0.0144	0.018
CAS1 *	Castlegar	23.15	0.0012	0.059	0.0015	0.011
PLA1	South Slocan	56.97	0.0033	0.053	0.002	0.022
OOT1	Castlegar	79.6	0.0019	0.047	0.0016	0.029
OSO3	Oliver	95.59	0.0079	0.046	0.003	0.02
OSO1	Oliver	25.93	0.0004	0.045	0.0003	0.016

** - The CAS1 feeder had some portions rebuilt in 2009/10.*

** - The BLU2 feeder had some portions rebuilt and rehabilitated in 2009/10.*

171.0 Reference: Status of Past Directives and Negotiated Settlement Provisions

Exhibit B-1, Appendix C, p. 5

Regulatory Process

171.1 Is FortisBC prepared to report on its existing Performance Standards during the 2012-2013 test period?

Response:

Yes, for informational purposes FortisBC is able to report on its existing Performance Standards during the 2012 and 2013 test period.

171.2 Has FortisBC addressed the "criteria for meeting performance standards" in this RRA?

Response:

As referenced in item 6 of Table C.3 on page 5 of Appendix C to the 2012-13 RRA, the Negotiated Settlement Agreement reads:

> "The 2012 oral public hearing <u>or the next Performance Based Rate Application</u> review process will examine the criteria for meeting performance standards." (emphasis added)

As the 2012-13 RRA is not a PBR-based application, the Company intends to address the criteria for meeting performance standards in any future application for Performance Based Rates.

172.0 Reference: Status of Past Directives and Negotiated Settlement Provisions

Exhibit B-1, Appendix C, p. 6

Revenue Protection Activities

172.1 Section 5.4.5 of the RRA provides very little "detail" on the revenue protection activities and costs in the test period. Please provide further explanation of the program activities including how the NPV was calculated.

Response:

Section 5.4.5 of the 2012-13 RRA addresses 2011 expense which was deferred to 2012 (please see responses to BCUC IR1 questions 107.1 through 107.4). Revenue Protection 2012 expense is reflected in the Customer Service O&M budget for 2012 as presented in Tab 4, page 62, Table 4.3.4.8 of the 2012-13 RRA.

Revenue Protection activities are focused in two areas:

Power Diversion Inspections

Although FortisBC has provided additional detail on the power diversion inspections in this response, the details of the power diversion inspection process are necessarily sensitive and confidential.

Power diversion investigations are conducted based on leads from various sources by an investigator contracted by FortisBC. The investigator will review billing records from the premise to determine whether a field check to investigate potential theft is warranted.

If theft is identified, FortisBC will disconnect the premise for safety reasons and will not re-energize the service until an electrical inspection is complete and an affidavit is provided certifying that the premise is in compliance with the BC Electrical Code.

The details regarding the theft (such as the number of lights) are used to calculate the value of unmetered electricity. Invoices are issued for the value of the calculated loss and collected through normal collection processes.

The NPV savings for power diversion inspections is calculated by annualizing the calculated daily kWh loss for each site identified in the reporting year. The sum of these kWhs is priced at FortisBC power purchase costs as established under the BC Hydro Rate Schedule 3808. The annual value of loss is discounted at 8 percent over a five year window.

Third Party Contracts

The revenue protection portfolio includes oversight of third-party contracts seeking to ensure that all revenues due under the terms of the agreements are billed correctly to offset rates. The NPV savings for third party contracts are derived from the one-time productivity gains attributed to reduced crew mobilization costs due to a cost-sharing arrangement between FortisBC and a pole rental customer.

SAFETY PLAN

173.0 Reference: 2011 Safety Plan

Exhibit B-1, Appendix K, p. 1

Figure 1.0 FortisBC Injury Frequency and Severity Rates (2002-2010)

173.1 As the audit produced a 99 percent score indicating the safety system is functioning as expected, was FortisBC able to identify a key contributing factor to this significant improvement.

Response:

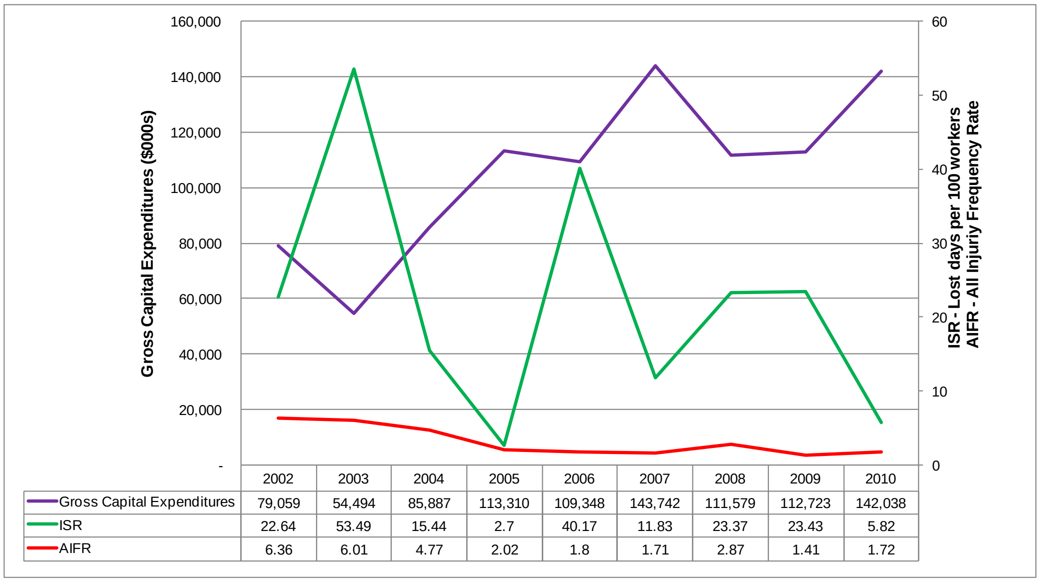
The results reflect the Health and Safety Programs which was deemed to be comprehensive during the audit, and which FortisBC strives to continually reinforce and nurture. While there was no single key contributing factor, collectively it was a combination of the various improvement strategies that were based on feedback from previous audits which were integrated into safety action plans that supported the results. Audits of this type drive the continual improvement of the safety system.

173.2 Please add the capital expenditure dollar amounts to Figure 1.0 for the years 2002-2010 and resubmit.

Response:

Please refer to Figure BCUC IR1 Q173.2 below.

Figure BCUC IR1 Q173.2



	2002	2003	2004	2005	2006	2007	2008	2009	2010
Gross Capital Expenditures	79,059	54,494	85,887	113,310	109,348	143,742	111,579	112,723	142,038
ISR	22.64	53.49	15.44	2.7	40.17	11.83	23.37	23.43	5.82
AIFR	6.36	6.01	4.77	2.02	1.8	1.71	2.87	1.41	1.72

CAPITALIZATION POLICY

174.0 Reference: Directive 16 and Capitalization Policy

Exhibit B-1, Appendix M, p. 6

FortisBC states that "Betterment is the result of enhancing the service potential of an existing item of PP&E, which could be representative of increased output, lower associated operating costs, extended useful life, or improved quality of output." (Appendix M, p. 6)

174.1 Does FortisBC know whether US GAAP has any definitions or interpretations on "betterment"? Has FortisBC obtained a third part audit opinion on the definition of "betterment" and how this relates to condition assessment activities?

Response:

FortisBC is not aware of any US GAAP definitions or interpretations on "betterment", however betterment is contained in the definition of Cost under pre-changeover CGAAP.

In Section 3061.05 of the pre-changeover CGAAP Handbook - Cost is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or **betterment** of the asset including installing it at the location and in the condition necessary for its intended use.

Management is of the opinion that betterment is the result of enhancing the service potential of an existing item of PP&E, which could be representative of increased output, lower associated operating costs, extended useful life, or improved quality of output.

This is consistent with the definition of an asset in FASB Concept Statement 6, which states that the common characteristic possessed by all assets is "service potential" or "future economic benefit", the scarce capacity to provide services or benefits to the entities that use them. In a business enterprise, that service potential or future economic benefit eventually results in net cash inflows to the enterprise.

FortisBC has not obtained a third party audit opinion on the definition of betterment.

174.2 Please provide examples of situations that would lead to "lowering the associated operating costs" and relate this to betterment of the asset.

Response:

Examples could include:

- A turbine blade efficiency upgrade that would increase the output of the generating unit and reduce power purchase costs;
- An upgrade from a manual tap changer to an automated tap changer that would enhance voltage regulation, reduce losses and improve quality of service to customers; and
- An upgrade from a manual disconnect switch to a remotely operated motorized disconnect that would reduce cost, improve reliability and enhance safety.

174.3 Please provide examples of situations that would lead to “improved quality of output” and relate this to betterment of the asset. What is defined as quality of electrical output to FortisBC customers? Reliability?

Response:

Please refer to the response to BCUC IR1 Q174.2. Quality of output in this context is system reliability including duration of outages and voltage regulation.

174.4 Is FortisBC aware of any capitalization limits that may be present in the Income Tax Act? Please confirm that FortisBC uses the same tax treatment for expensing costs as is done in the regulatory treatment of expenses.

Response:

No, FortisBC is not aware of any capitalization limits that may be present in the Income Tax Act.

FortisBC confirms that it uses the same tax treatment for expensing costs as it does for regulatory purposes, with the exception of those “Deductions” and “Additions” line items 8 through 17 adjustments on Schedule 3 – Income Tax Expense, page 32 of Tab 7 – Financial Schedules in the 2012-13 RRA.

For example, capitalized overhead is capitalized as part of capital expenditures for regulatory purposes, however it is deducted from Accounting Income on line 9 of Schedule 3 in arriving at regulatory taxable income.

174.5 Is FortisBC aware of any other utility that treats conditions assessments as a capital expense? How does FortisBC Energy treat inspections and reporting on plant conditions?

Response:

FortisBC Energy capitalizes certain major inspections which are those undertaken to assess transmission or distribution infrastructure or other major asset infrastructure or equipment, for possible required capital improvements and, accordingly, are capitalized and depreciated separately over the appropriate useful life to the next inspection date. Currently, FortisBC Energy considers two main types of inspections to be major inspections which are in-line inspections and marine crossing inspections. All other inspections are expensed.

FortisBC Energy also capitalizes certain major overhauls that are required at regular intervals over the useful life of an item of property, plant and equipment, to allow the continued use of the asset. These major overhaul costs are treated the same as major inspections whereby they are capitalized and depreciated over the appropriate useful life until the next overhaul. Currently, FortisBC Energy considers two main types of overhauls to be major overhauls which are gas turbine overhauls and gas compressor overhauls. All other overhauls are expensed.

FortisBC has not canvassed any other utilities to determine if they treat condition assessments as capital.

175.0 Reference: Directive 16 and Capitalization Policy

Exhibit B-1, Appendix M, pp. 7-12

Characterization of Urgent Repairs as Capital Expenditures

175.1 Please provide an analysis supporting the proposition that urgent repairs should be treated as operating expenses rather than capital expenditures.

Response:

The Company follows the same capitalization policy whether the repairs are urgent or part of the sustaining capital program. If urgent repairs do not meet the definition of a capital expenditure then the costs should be expensed. As an example, an urgent repair due to a winter storm might be:

- The cost of poles replaced to due to storm damage would be capitalized;
- The cost of guy tightening due to storm damage would be expensed.

Therefore, some urgent repair costs might be material expenditures and considered capital in nature, while others may not meet the capitalization criteria and should be expensed.

175.2 Please provide a survey of the eight utilities used for the minimum expenditure threshold regarding their policies on the capitalization of urgent repairs.

Response:

The Company conducted an informal survey of the eight utilities in British Columbia and other Canadian jurisdictions that were previously surveyed regarding the minimum expenditure threshold regarding their policies on the capitalization of urgent repairs. As certain of the utilities requested that the information be held in confidence, the following summary is provided.

Utility 1	Under certain circumstances urgent repairs would be capitalized. Examples include storm damage repairs and motor vehicle accidents that damage/destroy a pole;
Utility 2	Follows the same capitalization policy whether the repairs are urgent or not. Examples of capitalized urgent repairs included storm damage;
Utility 3	Some material urgent repair expenditures could be considered capital in nature. The circumstances under which repairs are made do not impact the accounting for those costs;
Utility 4	Follows the same capitalization policy whether the repairs are urgent or not. Examples of capitalized urgent repairs included storm damage repairs and motor vehicle accidents that damage/destroy a pole;
Utility 5	There is no minimum threshold regarding capitalization of urgent repairs;
Utility 6	If the urgent repair meets the criteria of the capitalization policy then it would be capitalized;
Utility 7	If the urgent repair meets the criteria of the capitalization policy then it would be capitalized; and
Utility 8	If the urgent repair meets the criteria of the capitalization policy then it would be capitalized.

176.0 Reference: Directive 16 and Capitalization Policy

Exhibit B-1, Appendix M, pp.12-13

Determination of the Minimum Threshold

176.1 Please provide a copy of the appropriate section of the Handy Whitman Cost Trends of Electric Utility Construction for the Pacific Region.

Response:

Please note that the Handy Whitman Index is protected by copyright law. FortisBC has obtained written permission to copy portions of the index for use in the regulatory proceedings associated with this Application.

E-6

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1912	1913	1914	1915	1916	1917	1918	1919	1920	1921	1922	1923	1924	1925
1	Total Plant-All Steam Generation		10	10	10	10	13	16	18	19	21	20	18	18	18	18
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		10	10	10	11	13	16	19	20	21	20	19	19	19	19
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		9	9	9	9	12	16	18	18	20	19	17	18	18	18
7	Structures & Improvements-Indoor	311	-	-	-	9	12	16	18	19	21	18	17	18	18	17
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Boiler Plant Equipment-Coal Fired	312	8	8	8	9	11	16	19	17	18	16	15	16	17	16
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		11	11	11	9	12	20	21	22	21	20	18	19	20	21
12	Turbogenerator Units	314	9	9	9	9	13	14	17	19	22	23	20	19	19	19
13	Accessory Electrical Equipment	315	14	14	14	14	15	17	20	23	26	27	24	24	24	24
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		-	-	-	9	11	14	17	17	18	17	16	16	16	16
23	Structures & Improvements	331	-	-	-	9	12	16	18	19	21	18	17	18	18	17
24	Reservoirs, Dams & Waterways	332	-	-	-	9	11	14	18	18	19	18	17	17	17	17
25	Water Wheels, Turbines & Generators	333	-	-	-	7	9	11	12	13	13	13	12	12	12	12
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		11	11	10	11	13	16	19	20	22	20	18	19	20	20
34	Station Equipment	353	16	16	15	15	17	20	25	27	31	30	28	28	29	29
35	Towers & Fixtures	354	9	9	9	9	13	16	18	18	17	16	15	15	16	15
36	Poles & Fixtures	355	6	6	6	6	7	9	10	12	14	15	14	13	13	13
37	Overhead Conductors & Devices	356	16	15	14	14	22	25	28	28	30	23	21	21	21	21
38	Underground Conduit	357	8	8	8	8	8	12	15	17	19	21	19	18	18	17
39	Underground Conductors & Devices	358	12	12	11	11	16	18	20	22	22	19	18	20	19	19
40																
41	**Distribution Plant**															
42	Total Distribution Plant		13	13	12	13	15	17	21	22	24	23	21	21	21	21
43	Station Equipment	362	16	16	16	16	17	20	23	25	29	30	28	27	28	28
44	Poles, Towers & Fixtures	364	6	7	6	6	8	9	11	12	14	14	13	13	13	13
45	Overhead Conductors & Devices	365	12	12	11	11	17	19	22	22	24	18	16	16	16	16
46	Underground Conduit	366	8	8	8	9	9	13	16	18	20	22	20	19	19	18
47	Underground Conductors & Devices	367	13	12	11	12	17	19	21	23	23	20	19	21	20	20
48	Line Transformers	368	43	43	43	43	43	46	62	64	69	70	63	60	62	61
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Services-Overhead	369	11	11	10	10	15	17	19	20	21	17	15	15	15	15
51	Services-Underground	369	10	10	10	12	14	16	18	20	21	19	16	15	15	16
52	Meters Installed	370	31	31	31	31	31	35	39	44	46	49	46	44	43	41
53	Street Lighting-Overhead	373	-	-	-	-	-	-	-	-	-	-	-	-	20	20
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	-	-	-	-	-	-	-	-	-	-	-	-	22	21
56																

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1926	1927	1928	1929	1930	1931	1932	1933	1934	1935	1936	1937	1938	1939
1	Total Plant-All Steam Generation		18	18	18	19	18	18	17	17	19	19	20	22	22	22
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		19	19	19	19	19	17	16	17	19	19	19	21	21	21
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		18	18	18	18	18	18	16	17	19	19	20	22	22	22
7	Structures & Improvements-Indoor	311	17	17	17	17	16	15	13	14	15	15	16	17	17	17
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Boiler Plant Equipment-Coal Fired	312	16	16	16	16	16	16	14	14	16	17	17	19	20	20
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		21	21	21	21	21	21	19	17	17	18	18	21	21	21
12	Turbogenerator Units	314	19	19	19	21	22	22	21	22	25	26	26	29	30	30
13	Accessory Electrical Equipment	315	24	24	24	26	25	25	23	24	26	27	28	30	30	30
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		16	16	16	17	16	15	14	15	16	16	16	17	18	18
23	Structures & Improvements	331	17	17	17	17	16	15	13	14	15	15	16	17	17	17
24	Reservoirs, Dams & Waterways	332	17	17	17	18	17	15	14	15	16	16	16	18	18	18
25	Water Wheels, Turbines & Generators	333	12	12	13	14	14	14	13	13	14	16	16	17	18	19
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		19	19	19	20	19	18	17	18	19	20	20	22	22	22
34	Station Equipment	353	29	29	29	30	29	29	27	29	31	32	32	35	35	35
35	Towers & Fixtures	354	15	15	15	15	15	14	13	13	14	15	15	17	17	17
36	Poles & Fixtures	355	13	13	13	13	13	13	12	12	12	12	13	14	15	15
37	Overhead Conductors & Devices	356	20	20	21	23	20	18	16	17	20	21	21	23	22	22
38	Underground Conduit	357	17	18	18	18	18	17	17	16	17	17	17	18	19	19
39	Underground Conductors & Devices	358	19	18	20	22	18	18	17	18	19	20	21	23	21	22
40																
41	**Distribution Plant**															
42	Total Distribution Plant		20	20	20	21	20	20	18	19	20	21	21	23	23	23
43	Station Equipment	362	26	26	26	27	27	27	25	26	28	30	30	32	32	32
44	Poles, Towers & Fixtures	364	13	13	13	13	13	12	11	12	12	12	13	15	15	15
45	Overhead Conductors & Devices	365	16	16	17	18	15	14	13	13	15	16	17	18	17	17
46	Underground Conduit	366	18	19	19	19	19	18	18	17	18	18	18	19	20	20
47	Underground Conductors & Devices	367	20	19	21	23	19	18	17	18	20	21	22	24	22	23
48	Line Transformers	368	57	53	52	56	55	53	51	52	55	55	55	60	61	61
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Services-Overhead	369	15	15	15	17	14	13	12	13	14	15	16	17	16	16
51	Services-Underground	369	16	16	15	16	15	14	12	13	15	16	16	18	17	17
52	Meters Installed	370	41	41	41	41	41	41	41	43	46	48	48	48	48	48
53	Street Lighting-Overhead	373	20	19	20	20	20	20	19	19	21	22	22	23	23	23
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	22	20	22	22	23	23	22	23	23	24	24	25	25	25
56																

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1940	1941	1942	1943	1944	1945	1946	1947	1948	1949	1950	1951	1952	1953
1	Total Plant-All Steam Generation		22	23	24	25	25	25	28	33	36	39	40	45	46	49
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		21	22	24	24	25	25	28	33	37	38	39	43	44	47
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		23	24	24	24	24	25	29	33	37	39	40	44	45	47
7	Structures & Improvements-Indoor	311	17	18	20	21	21	21	24	29	32	34	35	37	38	40
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	39	39	39	40	43
9	Boiler Plant Equipment-Coal Fired	312	20	21	22	22	22	22	25	28	33	36	38	42	43	45
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		21	22	23	23	23	23	25	29	31	32	35	38	40	42
12	Turbogenerator Units	314	30	30	30	30	30	31	35	42	45	47	48	52	52	56
13	Accessory Electrical Equipment	315	30	31	32	32	31	30	34	40	43	44	47	55	55	58
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	37	39	42	43	45
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		18	19	21	21	21	22	25	30	33	34	35	38	39	42
23	Structures & Improvements	331	17	18	20	21	21	21	24	29	32	34	35	37	38	40
24	Reservoirs, Dams & Waterways	332	17	19	21	21	21	22	25	29	33	34	35	37	39	41
25	Water Wheels, Turbines & Generators	333	20	21	22	23	23	23	26	31	34	35	37	41	43	46
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		22	23	25	25	25	26	29	34	37	38	40	45	46	49
34	Station Equipment	353	35	36	37	36	35	35	39	47	49	52	56	63	64	68
35	Towers & Fixtures	354	17	19	20	20	21	21	24	28	31	32	34	37	39	41
36	Poles & Fixtures	355	15	17	18	19	21	22	24	29	32	32	33	36	37	39
37	Overhead Conductors & Devices	356	22	23	25	26	26	26	30	35	39	39	41	47	49	51
38	Underground Conduit	357	19	21	22	23	23	24	27	31	35	35	37	39	41	43
39	Underground Conductors & Devices	358	22	25	26	26	25	25	30	35	42	46	49	61	63	62
40																
41	**Distribution Plant**															
42	Total Distribution Plant		23	25	26	26	27	28	30	37	39	41	42	47	48	50
43	Station Equipment	362	32	33	35	35	34	33	37	42	46	48	50	57	58	60
44	Poles, Towers & Fixtures	364	15	17	18	19	21	22	24	29	32	32	33	35	37	39
45	Overhead Conductors & Devices	365	17	18	20	20	20	20	23	28	30	30	32	37	38	40
46	Underground Conduit	366	20	21	23	23	24	24	27	31	34	36	37	39	41	42
47	Underground Conductors & Devices	367	23	26	28	28	26	26	31	37	44	49	52	64	66	65
48	Line Transformers	368	61	63	63	58	58	58	66	82	84	87	91	103	103	110
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	102	102	102	102	102
50	Services-Overhead	369	17	17	19	20	20	20	22	26	29	29	31	35	36	38
51	Services-Underground	369	18	20	22	23	23	23	25	29	33	35	36	42	42	41
52	Meters Installed	370	48	48	49	49	49	49	53	61	65	70	70	71	70	73
53	Street Lighting-Overhead	373	23	24	25	25	25	25	28	34	38	41	43	48	49	50
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	25	26	27	27	28	28	30	36	41	42	41	46	46	47
56																

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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	COST INDEX NUMBERS														COST INDEX NUMBERS														COST INDEX NUMBERS													
		1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
1	Total Plant-All Steam Generation	50	52	56	60	62	63	63	62	62	62	64	66	68	71	73	77	82	89	94	100	119	140	151	164	174	191	211	231	246	253	258	259	260	264	281	293	301	307	311	321	332	344
2	Total Plant-All Steam & Nuclear Gen.	-	-	-	-	-	-	-	-	-	-	-	66	68	71	73	78	83	89	94	100	119	139	151	163	174	191	210	231	246	253	258	259	260	263	281	293	301	306	310	321	332	344
3	Total Plant-All Steam & Hydro Gen.	48	50	54	56	58	59	61	60	61	61	63	65	67	70	73	77	82	88	94	100	119	139	150	162	172	189	208	228	242	249	254	255	257	260	276	288	296	301	304	315	325	337
4																																											
5	**Steam Production Plant**																																										
6	Total Steam Production Plant	49	51	58	63	65	67	66	65	64	65	66	67	69	71	73	77	81	89	96	100	117	138	150	161	174	192	212	233	247	255	264	269	270	277	295	305	314	321	326	339	351	363
7	Structures & Improvements-Indoor	41	44	47	50	51	53	55	55	56	58	60	62	64	66	69	74	77	84	92	100	117	132	140	149	161	178	203	219	230	234	241	249	253	257	265	274	279	280	285	299	311	320
8	Structures & Improvements-Semi-Outdoor	44	46	52	57	58	59	60	59	59	60	61	63	65	67	70	74	78	84	91	100	125	144	146	151	164	184	208	219	219	222	236	245	250	255	266	275	279	271	273	285	302	311
9	Boiler Plant Equipment-Coal Fired	47	49	55	62	63	66	67	66	66	67	68	70	71	73	75	79	84	89	95	100	121	143	154	165	180	198	217	238	250	256	268	276	280	289	305	317	330	339	345	359	368	379
10	Boiler Plant Equipment-Gas Fired	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed	45	47	52	57	59	62	64	65	65	66	67	68	70	73	75	79	83	89	97	100	114	130	142	154	172	190	207	231	249	247	252	258	260	270	292	297	297	304	304	315	320	336
12	Turbogenerator Units	57	58	68	75	80	79	75	70	68	67	68	69	71	72	72	75	80	89	98	100	111	129	143	156	169	186	204	227	242	254	262	265	262	268	285	293	297	304	309	321	335	348
13	Accessory Electrical Equipment	59	60	63	68	70	71	67	59	59	59	62	66	68	73	77	80	85	90	96	100	116	135	151	169	179	195	216	242	274	284	277	269	269	270	300	317	328	336	349	365	371	388
14	Misc. Power Plant Equipment	46	48	51	54	56	58	60	61	61	62	64	66	68	71	74	78	84	89	94	100	115	130	141	155	169	186	205	232	255	267	276	283	287	294	307	319	327	338	345	360	376	387
15																																											
16	**Nuclear Production Plant**																																										
17	Total Nuclear Production Plant	-	-	-	-	-	-	-	-	-	-	-	67	69	72	75	78	83	89	95	100	114	131	143	155	168	184	203	224	241	251	256	257	259	265	281	293	299	305	311	323	334	345
18	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	64	66	69	72	76	80	87	93	100	114	129	136	145	160	177	195	208	219	225	231	234	236	240	248	257	261	264	270	284	296	301
19	Reactor Plant Equipment	-	-	-	-	-	-	-	-	-	-	-	68	71	74	76	81	85	91	96	100	114	131	144	154	166	182	200	220	237	246	252	257	260	270	284	296	302	309	313	322	330	342
20																																											
21	**Hydro Production Plant**																																										
22	Total Hydraulic Production Plant	44	46	49	52	54	56	58	59	59	60	62	63	67	70	72	76	79	86	93	100	117	134	141	150	164	180	199	212	221	226	235	241	244	249	259	267	272	274	278	288	301	307
23	Structures & Improvements	41	44	47	50	51	53	55	55	56	58	60	62	64	66	69	74	77	84	92	100	117	132	140	149	161	178	203	219	230	234	241	249	253	257	265	274	279	280	285	299	311	320
24	Reservoirs, Dams & Waterways	43	45	48	50	52	54	56	57	58	59	61	63	66	70	72	75	79	85	93	100	118	134	140	148	161	177	195	205	211	215	225	231	234	240	248	255	259	259	263	274	287	292
25	Water Wheels, Turbines & Generators	47	49	56	62	65	66	66	65	64	65	66	67	69	71	73	78	83	89	95	100	114	130	144	159	173	191	212	238	252	262	271	276	276	281	300	312	320	332	333	341	350	360
26																																											
27	**Other Production Plant**																																										
28	Total Other Production Plant	-	-	-	-	-	-	-	-	-	-	70	71	73	80	84	87	91	95	97	100	110	133	147	160	169	184	199	218	235	241	244	246	249	265	302	323	330	336	343	349	345	351
29	Fuel Holders, Producers & Accessories	-	-	-	-	-	-	-	-	-	-	64	65	68	70	73	78	83	89	96	100	116	133	147	159	175	192	212	231	247	248	253	259	264	271	285	298	306	313	315	325	331	340
30	Gas Turbogenerators	-	-	-	-	-	-	-	-	-	-	74	74	77	85	89	92	95	98	99	100	107	133	148	162	168	182	195	215	231	238	241	242	245	266	314	340	346	353	361	366	355	358
31																																											
32	**Transmission Plant**																																										
33	Total Transmission Plant	50	52	56	57	59	60	60	59	59	59	61	64	67	70	73	78	83	89	93	100	123	145	158	170	175	190	213	231	244	251	252	253	255	257	281	295	304	309	311	323	337	353
34	Station Equipment	69	70	77	81	84	83	77	70	69	65	69	73	75	79	83	85	89	91	94	100	124	148	157	170	182	197	218	237	253	256	259	260	262	269	281	295	312	315	324	337	352	364
35	Towers & Fixtures	42	43	46	48	51	53	55	57	57	59	61	63	67	71	74	78	82	87	92	100	123	145	149	155	169	187	210	225	229	234	247	256	261	267	278	287	288	281	284	296	312	322
36	Poles & Fixtures	40	42	44	47	49	50	52	53	54	55	56	58	61	63	65	69	76	81	87	100	126	144	150	160	171	189	211	233	252	258	260	256	258	261	281	301	312	333	350	360	378	392
37	Overhead Conductors & Devices	52	55	61	63	63	62	63	63	65	61	64	67	70	73	73	80	89	98	99	100	117	146	172	187	179	193	220	241	251	268	258	252	252	243	311	320	323	333	318	330	340	368
38	Underground Conduit	45	47	50	52	55	57	59	61	62	63	65	67	70	73	75	79	82	89	97	100	112	128	143	156	170	185	205	226	248	254	258	255	256	263	278	291	293	295	296	304	311	318
39	Underground Conductors & Devices	63	66	65	57	57	60	61	61	61	61	66	72	73	75	73	79	82	82	92	100	134	137	143	158	160	189	221	244	269	273	267	254	275	278	293	314	364	407	416	423	424	436
40																																											
41	**Distribution Plant**																																										
42	Total Distribution Plant	51	52	55	57	59	60	61	61	61	61	63	65	68	71	74	78	83	88	93	100	120	139	150	162	172	190	208	229	246	253	254	250	251	253	267	280	287	292	295	303	311	322
43	Station Equipment	61	63	69	73	76	77	76	71	71	70	73	75	77	81	84	87	90	90	93	100	123	142	150	164	175	187	204	223	241	243	244	244	246	253	276	297	318	320	323	328	337	354
44	Poles, Towers & Fixtures	40	42	45	47	48	50	52	53	54	55	56	58	61	63	65	69	76	82	88	100	124	146	152	163	175	197	220	242	260	265	266	263	264	265	275	285	295	307	321	333	349	364
45	Overhead Conductors & Devices	40	44	48	47	48	50	52	53	53	55	57	60	63	67	71	78	87	95	98	100	115	143	166	183	181	196	221	243	261	274	273	264	263	260	302	312	315	324	318	332	343	366
46	Underground Conduit	44	46	48	50	53	55	58	59	61	62	64	66	67	69	72	76	81	87	95	100	112	127	138	150	163	180	198	217	232	245	251	249	250	255	272	296	295	290	290	298	308	316
47	Underground Conductors & Devices	67	69	68	60	60	63	65	64	64	64	69	75	77	79	76	83	86	86	99	100	124	129	138	150	160	194	224	230	233	235	233	232	240	244	249	264	275	282	286	291	293	306
48	Line Transformers	112	112	115	122	118	115	113	109	99	94	94	96	97	100	103	102	102	101	99	100	109	130	136	148	159	168	170	199	215	218	219	218	219	218	220	228	232	231	236	238	242	238
49	Pad Mounted Transformers	102	102	102	102	102	102	100	95	94	95	91	91	93	96	99	96	95	97	99	100	103	106	109	122	135	144	167	196	197	199	215	215	221	243	266	281	287	297	296	304	305	307
50	Services-Overhead	38	41	44	43	43	46	48	49	49	51	53	56	59	63	67	74	84	91	97	100	108	121	136	152	165	181	207	224	239	245	255	244	241	245	266	279	280	284	283	293	301	317
51	Services-Underground	41	41	44	43	41	43	43	43	45	47	49	54	58	61	66	71	75	78	87	100	115	108	115	123	133	145	175	194	198	216	218	196	189	201	215	231	234	226	224	225	233	241
52	Meters Installed	74	71	74	78	80	83	84	83	83	83	83	82	83	84	87	91	94	98	100	100	107	124	136	143	148	154	154	172	201	213	213	212	216	215	202	193	193	208	208	211	200	198
53	Street Lighting-Overhead	52	53	56	60	64	64	65	64	64	65	67	68	70	74	76	81	88	92	97	100	121	149	161	175	193	223	245	261	280	282	290	294	292	278	282	292	300	311	321	337	350	367
54	Mast Arms & Luminaires Installed	-	58	64	70	71	67	67	67	66	67	68	70	74	72	73	78	90	94	98	100	117	138	156	174	189	208	234	262	279	285	300	307	297	287	289	303	312	326	338	349	368	381
55	Street Lighting-Underground	51	53	54	58	61	62	63	61	61	62	62	63	68	75	72	77	89	94	98	100	120	149	163	179	196	220	240	263	285	286	294	299	297	284	287	296	304	314	324	339	351	364
56																																											

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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

PACIFIC REGION (1973=100)

COST TRENDS OF ELECTRIC UTILITY CONSTRUTION

PACIFIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	COST INDEX NUMBERS													COST INDEX NUMBERS												COST INDEX NUMBERS													
		1996	1997	1998	1999	2000	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014		2015		2016		2017	
							Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1
1	Total Plant-All Steam Generation	349	356	363	**366**	**380**	387	386	398	403	412	410	417	433	451	459	480	495	519	528	565	581	588	570	594	603	614													
2	Total Plant-All Steam & Nuclear Gen.	349	355	362	**365**	**380**	386	386	398	403	411	410	417	432	451	459	480	495	519	528	565	581	588	570	594	603	615													
3	Total Plant-All Steam & Hydro Gen.	342	349	356	**359**	**372**	378	378	389	393	401	400	408	422	440	447	467	482	505	515	551	565	573	555	578	587	598													
4																																								
5	**Steam Production Plant**																																							
6	Total Steam Production Plant	370	379	385	**392**	**411**	419	416	424	434	445	441	449	458	480	484	497	507	523	532	550	581	573	559	581	594	603													
7	Structures & Improvements-Indoor	326	333	340	**348**	**366**	374	375	382	391	397	392	403	417	440	445	456	465	480	488	508	537	541	529	551	557	569													
8	Structures & Improvements-Semi-Outdoor	321	329	334	**343**	**355**	358	363	367	369	372	372	398	405	421	427	440	448	460	486	501	514	516	491	505	507	518													
9	Boiler Plant Equipment-Coal Fired	385	393	400	**407**	**426**	434	435	441	453	457	450	455	469	490	496	510	517	529	538	556	583	590	579	601	609	621													
10	Boiler Plant Equipment-Gas Fired	-	-	-	**-**	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-													
11	Boiler Plant Piping Installed	340	343	346	**350**	**357**	362	361	368	375	381	376	386	398	441	445	460	465	471	469	497	535	556	541	555	566	584													
12	Turbogenerator Units	353	364	370	**375**	**394**	400	389	399	409	431	429	433	435	459	458	466	478	493	495	510	554	511	489	508	531	531													
13	Accessory Electrical Equipment	399	408	417	**428**	**457**	472	472	493	511	522	518	528	537	576	589	609	632	676	697	736	761	793	816	851	868	893													
14	Misc. Power Plant Equipment	392	402	410	**421**	**439**	445	446	455	464	469	463	474	488	520	524	540	547	547	551	568	606	611	605	623	629	648													
15																																								
16	**Nuclear Production Plant**																																							
17	Total Nuclear Production Plant	351	360	366	**372**	**390**	397	395	405	414	424	422	428	438	464	469	481	493	511	515	532	562	556	550	572	584	593													
18	Structures & Improvements	308	318	324	**331**	**346**	351	354	359	369	373	369	377	385	404	410	419	428	440	435	446	463	464	458	478	482	488													
19	Reactor Plant Equipment	347	353	358	**362**	**375**	380	380	387	394	399	399	402	418	444	447	460	468	480	484	496	525	521	512	530	538	547													
20																																								
21	**Hydro Production Plant**																																							
22	Total Hydraulic Production Plant	313	324	331	**337**	**346**	349	349	354	356	359	361	373	375	390	395	403	410	422	432	443	459	458	449	462	469	476													
23	Structures & Improvements	326	333	340	**348**	**366**	374	375	382	391	397	392	403	417	440	445	456	465	480	488	508	537	541	529	551	557	569													
24	Reservoirs, Dams & Waterways	298	309	317	**323**	**330**	333	336	339	342	344	346	359	363	380	386	394	399	410	421	431	439	441	433	445	449	458													
25	Water Wheels, Turbines & Generators	367	378	385	**387**	**397**	400	386	398	392	399	405	413	395	402	400	408	419	438	445	457	495	483	471	482	500	495													
26																																								
27	**Other Production Plant**																																							
28	Total Other Production Plant	362	368	379	**391**	**416**	427	402	409	420	427	428	424	432	431	438	447	458	508	519	565	588	602	628	650	661	659													
29	Fuel Holders, Producers & Accessories	348	356	366	**372**	**381**	384	386	391	399	404	403	407	432	459	466	474	484	498	501	518	556	564	548	559	558	573													
30	Gas Turbogenerators	371	375	387	**402**	**399**	401	408	415	426	433	435	424	430	416	424	431	442	505	517	575	596	613	654	677	690	680													
31																																								
32	**Transmission Plant**																																							
33	Total Transmission Plant	359	365	375	**372**	**390**	398	401	411	411	415	413	424	449	465	478	503	520	544	561	588	613	623	574	610	613	622													
34	Station Equipment	366	372	382	**388**	**410**	419	421	429	434	438	432	437	477	493	507	528	546	580	597	618	641	654	657	684	691	708													
35	Towers & Fixtures	333	341	348	**357**	**369**	373	377	384	385	388	389	415	422	434	437	455	459	472	498	513	517	526	502	520	520	542													
36	Poles & Fixtures	407	420	425	**417**	**421**	425	432	450	448	454	456	466	470	487	503	509	522	531	534	567	576	593	596	616	595	599													
37	Overhead Conductors & Devices	374	379	390	**363**	**388**	399	403	416	406	411	412	419	445	463	489	537	568	595	608	657	716	721	525	604	610	598													
38	Underground Conduit	323	331	341	**349**	**354**	358	360	374	381	390	389	398	415	448	448	463	468	485	479	499	534	548	530	543	548	560													
39	Underground Conductors & Devices	441	446	450	**458**	**459**	468	447	462	466	474	475	481	528	533	550	590	594	603	608	782	818	821	832	837	829	890													
40																																								
41	**Distribution Plant**																																							
42	Total Distribution Plant	325	329	336	**337**	**345**	350	351	366	369	376	378	383	401	417	425	452	472	503	511	570	566	588	577	600	609	623													
43	Station Equipment	352	357	372	**375**	**379**	382	383	391	383	388	387	394	444	461	468	494	506	541	559	580	602	614	615	642	650	666													
44	Poles, Towers & Fixtures	373	382	388	**391**	**397**	400	403	420	426	434	437	439	448	466	470	480	490	503	504	520	533	549	550	571	568	569													
45	Overhead Conductors & Devices	373	380	391	**382**	**404**	413	416	438	437	449	451	461	477	496	516	552	574	599	612	658	698	711	612	673	684	693													
46	Underground Conduit	321	330	338	**348**	**357**	361	362	377	389	397	394	404	406	432	433	459	461	480	476	494	503	521	520	524	526	538													
47	Underground Conductors & Devices	312	315	321	**327**	**335**	342	327	342	343	347	349	353	369	395	405	432	437	511	518	558	588	649	641	608	614	648													
48	Line Transformers	234	225	229	**230**	**231**	234	238	247	250	252	257	248	267	278	286	323	363	410	417	604	508	535	558	587	612	625													
49	Pad Mounted Transformers	320	325	327	**329**	**332**	333	351	357	365	362	362	390	460	493	542	562	653	688	818	641	758	728	666	673	652	654													
50	Services-Overhead	319	323	330	**332**	**341**	345	343	366	363	375	375	386	393	407	414	436	436	456	457	483	493	503	468	501	509	532													
51	Services-Underground	240	243	240	**238**	**250**	253	248	259	265	269	270	274	275	284	297	338	376	357	353	352	353	330	331	339	361	400													
52	Meters Installed	202	216	223	**215**	**213**	222	237	263	275	287	287	324	324	311	311	313	319	322	328	333	334	338	338	354	355	347													
53	Street Lighting-Overhead	386	395	398	**403**	**410**	415	419	435	450	474	478	482	488	505	513	529	596	617	626	642	674	740	753	781	730	741													
54	Mast Arms & Luminaires Installed	405	415	413	**413**	**419**	423	424	438	440	445	451	455	461	488	502	528	559	575	587	580	590	713	709	724	738	741													
55	Street Lighting-Underground	385	395	399	**406**	**414**	419	424	439	459	489	492	496	500	516	523	538	617	642	651	672	709	769	786	819	746	762													
56																																								

CAPITAL EXPENDITURE VARIANCES

177.0 Reference: Capital Expenditure Variances

Exhibit B-1, Appendix N

This appendix is provided in response to a Commission Panel Directive for FortisBC to provide information on how it plans to narrow the variance between approved and actual capital expenditures.

177.1 FortisBC attributes the large variances since 2008 to raw materials price volatility, labour market conditions and project timing. The Company concludes "… that its history of forecasting capital expenditures demonstrates sufficient rigour in the forecasting process despite the challenges experienced in the past number of years as noted above." Given the large variances, would it not be appropriate for FortisBC to develop a more rigorous planning and execution process?

Response:

It is important to note that FortisBC is constantly developing and refining its capital planning, estimation, and execution processes. These processes should not be viewed as unchanging, but constantly subject to refinement and improvement. In this regard, FortisBC believes that it is continually developing a more rigorous capital planning and execution process. Examples of the strategies and methodologies that reflect this continual development include:

- An extensive and evolving public consultation process to identify and address stakeholder concerns early in the project definition phase;
- Alignment with AACE estimation guidelines as per the revised CPCN guidelines;
- Competitive tender process where possible to achieve the most economical pricing;
- Use of strategic vendor alliances to achieve preferential pricing; and
- Use of variable commodity pricing for large equipment (i.e. station transformers) to achieve the lowest possible base price.

As noted in Appendix N to the 2012 – 13 RRA, variances between approved and actual capital expenditures are still likely to occur. This is driven in part by the balance that must be struck between the level of pre-approval funding for project development and estimation, and the desire for all capital projects to be executed on time and budget. Although a particular project may be planned and estimated to an extremely high degree of accuracy, the expenditures required to do so may not result in the most cost effective solution overall, and as such, would not represent prudent expenditure of project development funds. It is FortisBC's expectation that the use and continued development of the strategies and methodologies listed above will help mitigate the magnitude of the variances between approved and actual incurred capital expenditures as the Company continues to refine and improve its capital planning and execution processes.

177.2 It is often thought that a delay in a capital project in a test year has limited impact on the revenue requirement because of mid-year rate base and tax impacts. Please undertake the following hypothetical example to show the impact that a delayed capital project would have on a current year revenue requirement. Assume a $10 million transmission project had been approved as part of the 2011 revenue requirement and it was to be completed mid-year but became delayed until early 2012. After accounting for mid-year rate base, CCA and depreciation and any tax or other revenue requirement impacts, what would be the difference in revenue requirement in 2011 between the forecast of having the project completed on time and if the project had not been included in the 2011 revenue requirement. Include calculations and explanations in your response.

Response:

A hypothetical situation has been conceived where:

1. A transmission project of $10 million was expected to be completed in the current year (year 2011);
2. The project gets delayed and will now be taken up and completed during Jan – March 2012 at $ 3.3 million / month (Q1); and
3. No change in customer rates in 2011 will take place due to the above – since the rates have already been approved.

The analysis below indicates that as a result of this delay in the project implementation, there will be a reduction in revenue requirements in 2012 by $0.432 million.

However, please note that since this hypothetical project is delayed (and not cancelled), the variation in revenue requirements above will largely be a timing difference and will balance out in subsequent years.

Table BCUC IR1 177.2 Revenue Savings in 2012:

	2012 Future Year (Current Year+1) ($000s)	Relationship
Plants in Service Differential Brought Forward	(10,000)	a = (-A)
Plants in Service	10,000	b = (-a)
Less Current Year Depreciation	(344)	c = a x G
Depreciated Rate Base	344	d = a + b - c
Prior Year Utility Rate Base	(10,000)	a
Mean Depreciated Utility Rate Base	(4,828)	e = (a+d)/2
Adjustment for Capital Additions	3,750	f
Change in Mid Year Utility Rare Base	(1,078)	k
CCA %	8.0%	S
Depreciation Rate	3.4%	G
Equity Proportion	40%	H
Debt Proportion	60%	I
ROE	9.9%	J
Debt Rate	6.0%	K2
Cost of Debt	(39)	l = k * I * K2
Cost of Equity	(43)	m = k * H * J
Depreciation	(344)	c
	(426)	n = l + m + c
Income Tax	(6)	p
Total Revenue Requirement	(432)	q

Capital Adjustment Calculation:	Jan	Feb	Mar	Total	Relationship
Months in Rate Base	11.5	10.5	9.5		δ
Plants in Service ($000s)	3,333	3,333	3,333	10,000	β
Simple Average				5,000	g = b/2
Weighted Value ($000s)	3,194	2,917	2,639	8,750	h = Σ βδ/12
Capital Adjustment ($000s)				3,750	j = g-h

Income Tax Calculation:	($000s)	Relationship
Sales Revenue	(432)	q
Less Expenses (Depreciation)	(344)	c
Utility Income Before Tax	(88)	r = q - c
Deduct:		
Interest Expense	(39)	l
ACCOUNTING INCOME	(49)	s = r - l
Deduct CCA	(368)	t = (a*S/2 + b/2) * S
Add Depreciation	(344)	c
	(25)	u = s - t + c
Tax Rate	25.0%	V
Income Tax	(6)	w = u * V

178.0 Reference: Capital Expenditure Variances

Exhibit B-1, Appendix N, p. 2

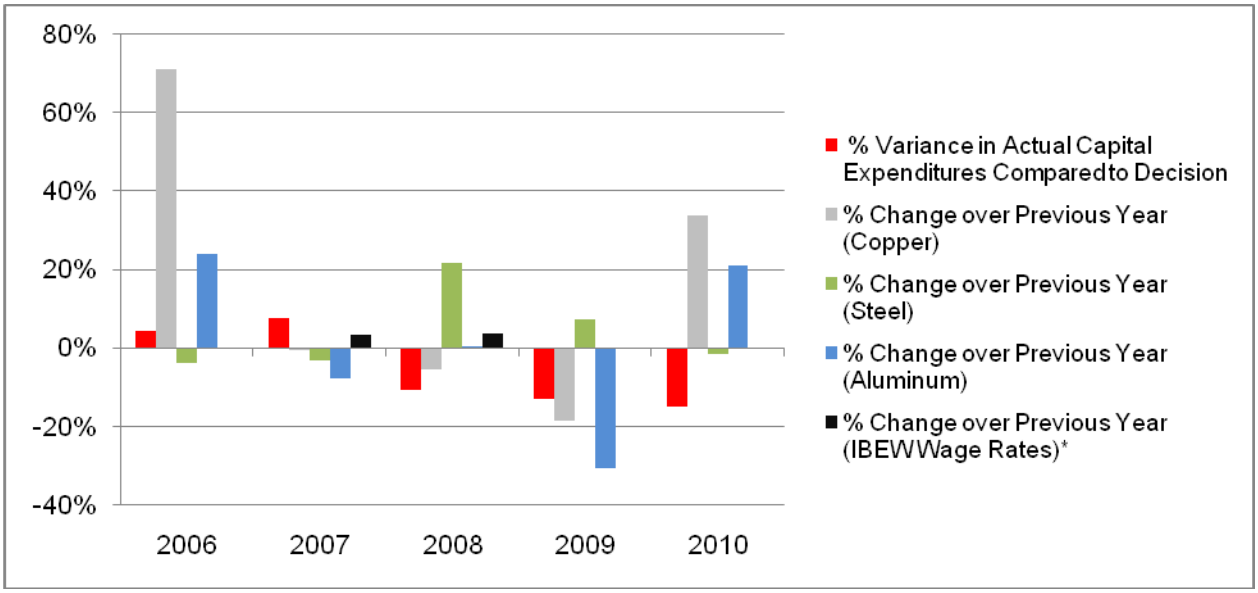
Table 1 Capital Expenditure Variances by Year

178.1 Please provide a graph of the Capital Expenditure Variances by year and add the market conditions for material and labour from the MMK Report to the graph.

Response:

Please see Figure BCUC 178.1 below. Commodity and wage indices for the period 2006 – 2009 are as provided in the Spring 2010 Report. Commodity increases for 2010 are based on the increases noted in Spring 2011 MMK Report.

Figure BCUC 178.1 – Capital Expenditure Variances and Commodity/Wage Indices by Year



* Note: MMK Reports only provide IBEW wage rate information for 2007 and 2008.

178.2 Please normalize the capital expenditure variances in the table by year using the Construction Costs Trends Annual Indices from the MMK Reports.

Response:

Please see Table BCUC IR1 178.2 below.

Table BCUC IR1 178.2 Capital Expenditure Variances Normalized from MMK Report Construction Costs Indices

	2006	2007	2008	2009	2010	2011F
Actual/Forecast	109,348	143,742	111,579	112,723	142,038	92,025
Normalized Actual (as per MMK Construction Cost Indices)	104,273	137,508	108,751	112,051	141,051	n/a
Decision	104,913	133,660	124,937	129,466	167,417	95,718
Actual Variance	4,435	10,082	(13,358)	(16,743)	(25,379)	(3,693)
Normalized Variance	(640)	3,848	(16,186)	(17,415)	(26,366)	n/a
% change in Utility Construction Costs (2010 and 2011 Spring MMK Reports)	4.9%	4.5%	2.6%	0.6%	0.7%	n/a

179.0 Reference: Capital Expenditure Variances

Exhibit B-1, Appendix N, p. 5

Spring 2010 MMK Report

179.1 Please provide a copy of the Spring 2010 MMK Report.

Response:

A copy of the Spring 2010 MMK report is provided as BCUC Appendix 179.1.

180.0 Reference: Capital Expenditure Variances

Exhibit B-1, Appendix N, p. 6

Kettle Valley Substation

180.1 As the Commission is conducting a factual review of the costs incurred on the Kettle Valley Substation project, please confirm that any expenditures that may be found not to have been prudently incurred will be adjusted in the revenue requirements and hence the rates.

Response:

The Company will comply with Commission Orders, subject to sections 99 and 101 of the Utilities Commission Act.

INTEGRATED SYSTEM PLAN & LONG TERM CAPITAL PLAN

181.0 Reference: 2012 Integrated System Plan

Exhibit B-1-1, Section 4.1, p. 6

Customer growth is expected to average 1.5% for the years 2012 to 2016.

181.1 What level of customer growth does FortisBC anticipate in the years beyond 2016? Why?

<u>Response:</u>

Yearend customer counts and annual customer growth rates for the 2011-2030 period are detailed below. The average growth of the total direct customer counts from 2017 to 2030 is 1.4 percent.

The balance of this question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

Table BCUC IR1 181.1a Forecast Yearend FortisBC Customer Count

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Total Direct
2010	97,883	11,419	7	35	1,830	1,075	112,249
2011	99,457	11,572	7	36	1,830	1,075	113,977
2012	101,320	11,837	7	36	1,830	1,075	116,105
2013	103,279	12,130	7	36	1,830	1,075	118,357
2014	105,333	12,389	7	36	1,830	1,075	120,669
2015	107,423	12,625	7	36	1,830	1,075	122,996
2016	109,459	12,825	7	36	1,830	1,075	125,231
2017	111,478	13,016	7	36	1,830	1,075	127,442
2018	113,488	13,223	7	36	1,830	1,075	129,659
2019	115,483	13,411	7	36	1,830	1,075	131,842
2020	117,476	13,582	7	36	1,830	1,075	134,006
2021	119,465	13,762	7	36	1,830	1,075	136,175
2022	121,447	13,941	7	36	1,830	1,075	138,335
2023	123,418	14,102	7	36	1,830	1,075	140,469
2024	125,402	14,280	7	36	1,830	1,075	142,630
2025	127,369	14,456	7	36	1,830	1,075	144,774
2026	129,316	14,632	7	36	1,830	1,075	146,896
2027	131,233	14,818	7	36	1,830	1,075	148,999
2028	133,149	15,001	7	36	1,830	1,075	151,098
2029	135,043	15,194	7	36	1,830	1,075	153,185
2030	136,904	15,386	7	36	1,830	1,075	155,239
2031	138,772	15,546	7	36	1,830	1,075	157,266
2032	140,625	15,726	7	36	1,830	1,075	159,300
2033	142,465	15,906	7	36	1,830	1,075	161,319
2034	144,292	16,086	7	36	1,830	1,075	163,325
2035	146,104	16,266	7	36	1,830	1,075	165,318
2036	147,903	16,445	7	36	1,830	1,075	167,296
2037	149,688	16,625	7	36	1,830	1,075	169,261
2038	151,459	16,805	7	36	1,830	1,075	171,212
2039	153,217	16,985	7	36	1,830	1,075	173,150
2040	154,961	17,165	7	36	1,830	1,075	175,074

Table BCUC IR1 181.1b Forecast Growth Rate of FortisBC's Direct Customers

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Total Direct
2010							
2011	1.6%	1.3%	0.0%	2.9%	0.0%	0.0%	1.5%
2012	1.9%	2.3%	0.0%	0.0%	0.0%	0.0%	1.9%
2013	1.9%	2.5%	0.0%	0.0%	0.0%	0.0%	1.9%
2014	2.0%	2.1%	0.0%	0.0%	0.0%	0.0%	2.0%
2015	2.0%	1.9%	0.0%	0.0%	0.0%	0.0%	1.9%
2016	1.9%	1.6%	0.0%	0.0%	0.0%	0.0%	1.8%
2017	1.8%	1.5%	0.0%	0.0%	0.0%	0.0%	1.8%
2018	1.8%	1.6%	0.0%	0.0%	0.0%	0.0%	1.7%
2019	1.8%	1.4%	0.0%	0.0%	0.0%	0.0%	1.7%
2020	1.7%	1.3%	0.0%	0.0%	0.0%	0.0%	1.6%
2021	1.7%	1.3%	0.0%	0.0%	0.0%	0.0%	1.6%
2022	1.7%	1.3%	0.0%	0.0%	0.0%	0.0%	1.6%
2023	1.6%	1.2%	0.0%	0.0%	0.0%	0.0%	1.5%
2024	1.6%	1.3%	0.0%	0.0%	0.0%	0.0%	1.5%
2025	1.6%	1.2%	0.0%	0.0%	0.0%	0.0%	1.5%
2026	1.5%	1.2%	0.0%	0.0%	0.0%	0.0%	1.5%
2027	1.5%	1.3%	0.0%	0.0%	0.0%	0.0%	1.4%
2028	1.5%	1.2%	0.0%	0.0%	0.0%	0.0%	1.4%
2029	1.4%	1.3%	0.0%	0.0%	0.0%	0.0%	1.4%
2030	1.4%	1.3%	0.0%	0.0%	0.0%	0.0%	1.3%
2031	1.4%	1.0%	0.0%	0.0%	0.0%	0.0%	1.3%
2032	1.3%	1.2%	0.0%	0.0%	0.0%	0.0%	1.3%
2033	1.3%	1.1%	0.0%	0.0%	0.0%	0.0%	1.3%
2034	1.3%	1.1%	0.0%	0.0%	0.0%	0.0%	1.2%
2035	1.3%	1.1%	0.0%	0.0%	0.0%	0.0%	1.2%
2036	1.2%	1.1%	0.0%	0.0%	0.0%	0.0%	1.2%
2037	1.2%	1.1%	0.0%	0.0%	0.0%	0.0%	1.2%
2038	1.2%	1.1%	0.0%	0.0%	0.0%	0.0%	1.2%
2039	1.2%	1.1%	0.0%	0.0%	0.0%	0.0%	1.1%
2040	1.1%	1.1%	0.0%	0.0%	0.0%	0.0%	1.1%

182.0 Reference: 2012 Integrated System Plan

Exhibit B-1-1, Section 4.5.1.1, pp. 17-18

Security of Assets, Prevention and Mitigation Programs

> "Historically copper theft was minor with issues being dealt with as they arose. In the past two years the increase in frequency of breaks-ins and copper theft has resulted in increased security at specific job sites and greater vigilance on the part of operations crews. This problem has escalated to the point where these activities contributed to one of FortisBC's Power Line Technicians being injured."

182.1 Please describe the circumstances surrounding the identified injury.

Response:

In 2010, suspected criminals installed a braided copper cable over an energized FortisBC transmission line in a possible attempt to check if the line was energized and to thereafter steal the copper transmission conductor. However, due to the improper application of the cable, the line remained energized. A Power Line Technician (PLT) was dispatched to investigate an unrelated distribution circuit interruption in the same area some time after the copper cable was placed on the transmission line. While investigating, the PLT noticed the object over the transmission line and unfortunately received a shock from the energized short circuit cable hanging from the transmission line.

182.2 What actions can FortisBC take to curb this theft? For example, has FortisBC partnered with municipalities and the police to limit the sales options for stolen copper?

Response:

Yes, FortisBC works with police and local governments in order to utilize recycling bylaws that limit the sales potential of stolen copper, and to gain the most current information of illegal activities in this regard. The Company is working directly with the metal recycling industry and scrap metal dealers to limit the market for stolen metal. As well, the Company participates in joint investigations with the police to facilitate information sharing and theft resolution. New tamper resistant locking materials and mechanisms are being installed on high risk equipment and non copper grounding material is being tested in on selected location for possible new construction standards.

183.0 Reference: 2012 Integrated System Plan

Exhibit B-1-1, Section 4, p. 19

Section 4.5.1.2 provides a five year plan to enhance security.

183.1 What actions are other utilities taking to enhance security? Has the CEA provided any recommendations to member utilities?

<u>Response:</u>

The CEA has not provided recommendations to member utilities on security enhancement; however, FortisBC has met with industry peers and the company understands that many utilities are contemplating the same measures that FortisBC is, including Smart Metering to assist in the reduction of power theft, new grounding standards to reduce copper theft, and the standards under North American Electric Reliability Corporation (NERC) and the BC Mandatory Reliability Standards (BC MRS). The CEA on behalf of the utilities is working with government to have electrical infrastructure declared critical infrastructure to allow stiffer criminal charges for theft. Furthermore, FortisBC reviews security related reporting from CSIS and the RCMP that are relevant to the electric industry business.

184.0 Reference: 2012 Integrated System Plan

Exhibit B-1-1, Chapter 4.6, pp. 23-24

In sections 4.6 and 4.6.1, FortisBC discusses customer expectations from various surveys but does not demonstrate how FortisBC will use the information.

184.1 What actions is FortisBC taking and planning to take over the study period to address consumer attitudes towards the utility and the environment?

<u>Response:</u>

FortisBC continually strives to provide superior service to its customers and improve their perception of the utility. With respect to the top drivers cited by the CEA:

1. **The price paid for electricity.** FortisBC is always looking for ways to reduce the cost of electricity. It does this in numerous ways, including:
    a. Helping customers manage the bills with an extensive DSM program and improved consumption information via the AMI project;
    b. Ensuring effective maintenance of existing assets with an Asset Management program;
    c. Buying out the Trail office lease; and

   d. Continuing to ensure the availability of cost effective long-term, reliable power by evaluating and determining the best plan for meeting FortisBC's load and peak demand forecasts over the next 30 years.

2. **The perception that the Company cares about its customers and that it listens to and acts upon their concerns.** FortisBC will continue to demonstrate its concern for customers by continuing to engage them in open dialog and incorporate their feedback as it implements its 2012 Integrated System Plan.

3. **The perception that the Company is efficient and well-run.** The Company will continue to demonstrate that it is efficient and well-run by delivering the 2012 ISP commitments on time and at the lowest reasonable cost.

4. **The accuracy of billing.** FortisBC already reads over 98 percent of its meters on time, but will further improve that percentage and the accuracy of bills by implementing the proposed Advanced Metering Infrastructure project.

Projects such as the Advanced Metering Infrastructure program (which helps customers reduce use and which will reduce GHG emissions from meter reading vehicles), the DSM program (which helps customers reduce energy use), the continual exploration of new green vehicle technologies, and FortisBC's ongoing work with many environmental groups and programs, including the Osprey program, all help to address consumer attitudes towards FortisBC and the environment.

185.0 Reference: 2012 Integrated System Plan

Exhibit B-1-1, Chapter 4.6.1.3, p. 28

> "In addition to the political structure which encourages public involvement in making land use decisions, the advancement of technology over the last five years has allowed much greater mobilization of interest groups."

185.1 How is FortisBC planning to respond to this development of technology to engage the interested public during the next several years?

<u>Response:</u>

FortisBC is planning to respond to the development of technology to engage the interested public through the following types of activities:

- Explore use of online tools for public and stakeholder engagement to complement traditional consultation methods and provide more ways to solicit feedback from and engage with customers and stakeholders;

- Use of social media – (eg. Twitter or social media networking sites) to notify followers of FortisBC business about events and milestones in the consultation process, and to provide an additional forum for feedback;
- Continue to conduct webinars and post video of presentations where appropriate so customers and stakeholders have another avenue to receive information, ask questions, and provide feedback without having to physically attend an open house;
- More online advertising to notify followers of FortisBC business about events; and
- Online feedback surveys.

186.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 1, p. 1

FortisBC 2012 Long Term Capital Plan

"The Company is not seeking Commission approval of specific projects and associated expenditures discussed in the 2012 Long Term Capital Plan. Rather, as stated in Section 8 of the Application, the Company is seeking Commission's acceptance of its Integrated System Plan, of which this Long Term Capital Plan is part, to be in the public interest under Section 44.1(6) of the Utilities Commission Act. The Long Term Capital Plan, together with the Long Term Resource Plan and Long Term DSM Plan, provide the contextual framework for the Company's 2012-2013 Revenue Requirements and 2012-2013 Capital Expenditure Plan applications. As it has done previously, the Company expects to review the Long Term Capital Expenditure Plan in conjunction with subsequent Capital Expenditure Plans and to prepare and file updates and seek specific Commission approval as appropriate."

186.1 Please describe the process FortisBC proposes for the Commission denying, or being able to deny, recovery at a later date of specific expenditures or projects contained within the ISP if the ISP were to be given approval during the current regulatory process.

Response:

As quoted in the preamble, FortisBC is not seeking approval of expenditures for specific capital projects presented as the part of the ISP. FortisBC is seeking approval that the ISP is in the public interest, and recognizes that a public interest determination by itself does not ensure cost recovery for the initiatives and projects described in it. Specific project expenditure approvals are being sought in the 2012-13 Capital Plan. Expenditures beyond 2013 will be the subject of future Capital Expenditure Plans or CPCN applications, as appropriate. The Company does not intend to undertake the construction of any of the projects in the ISP until such approvals have been obtained.

Generally, there is a presumption of prudency for capital expenditures allowed pursuant to a CPCN in the absence of evidence to the contrary. In the event of cost overruns, normal prudency review processes would be open to the Commission.

187.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 1.1.1, p. 3

Generation Condition Based Maintenance

> "Currently, minimal information is tracked with respect to direct health of equipment and thus asset condition information is not generally used for scheduling of maintenance activities."

187.1 Please confirm the above statement that FortisBC Generation typically does not use asset condition for scheduling maintenance. How does this compare to standard industry practice?

Response:

Presently, Generation's equipment maintenance scheduling is time-based. FortisBC has initiated a project in 2011 referred to as "Plant Automation" that will increase the information available with respect to equipment health. This information will be tracked and trended over an extended period of time and analyzed periodically with equipment condition in mind.

It is FortisBC's understanding that the implementation of condition-based maintenance (as a supplement to time-based maintenance) is a common trend in the industry.

187.2 Does FortisBC expect that condition-based maintenance will increase or decrease maintenance frequency? If the response is increase, please reconcile this with FortisBC actual failure rate and reliability statistics compared against industry averages.

Response:

FortisBC anticipates that the adoption of condition based maintenance to supplement its time based program will result in decreases to the frequency of some routine repetitive maintenance tasks at the plants although it is conceivable that the frequency of some tasks may increase as well. If condition data suggests an increase in maintenance activities, the need for this increase would be balanced against the risk of failure, impact to reliability and safety and cost prior to implementation.

188.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 1.1.3, p. 5

Asset Management Development

> "FortisBC is proposing a staged approach to the development of an Asset Management solution. Expenditures of $785,000 in 2012 and 2013 are proposed to accommodate the development of a project team comprising internal and external resources. This project team will examine FortisBC's existing Asset Management processes and provide a comprehensive report and project cost estimate recommending changes and mapping out an implementation plan."

188.1 Please provide the complete project scope and cost for all years for the Asset Management Development.

Response:

Please refer to the response to BCUC IR1 Q108.3. The scope and cost for the years beyond 2013 have not been defined as these are proposed to be developed during the first stage of the implementation in 2012-13.

188.2 How does FortisBC propose to address future asset maintenance if separate incremental expenditures are not approved for the development of an Asset Management strategy?

Response:

If the development of a formal Asset Management system is not approved, FortisBC would continue to address maintenance and capital investment decisions using current assessment methods and budgeting practices.

188.3 Please explain why development of an Asset Management strategy requires separate incremental expenditures outside the normal O&M budget? Should this not be expected as a standard business practice in a modern utility?

Response:

Please see the response to BCUC IR1 Q108.1.

188.4 Please advise if FortisBC has approached BC Hydro to perform asset management services for FortisBC's equipment base. As BC Hydro has made significant investments in developing asset management procedures, processes, software and equipment life expectancy curves, please discuss whether there are any economies or efficiencies to be gained by contracting this service to BC Hydro.

Response:

FortisBC has not approached BC Hydro as a potential provider of Asset Management services at this time. However, FortisBC has had discussions with BC Hydro on its implementation of Asset Management strategies. The result of those discussions (as with other utilities, consultants and vendors) has led the company to the next step in the process. The first part of the next phase of this project is to identify and evaluate options for Asset Management and propose a cost-effective solution and implementation plan. Collaboration with BC Hydro either as a service or information provider will be investigated in this process. Any selected solution will have to demonstrate that is in the best interests of both the rate-payers and the Company.

189.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 1.2, pp. 6-8

Smart Grid, Definitions

FortisBC states that "In order to facilitate comparison with other utilities in North America, FortisBC intends to use the "Smart Grid Characteristics" defined by the United States Department of Energy. In the coming years, funding recipients in the United States will use these defined categories to present plans and progress." …. (Tab 2, p. 13)

189.1 Please provide an explanation of the funding provided by the United States government.

Response:

In 2007, the United States government established stimulus funding for Smart Grid development and research through the passage of the Energy Independence and Security Act. This Act authorized funding of $100 million USD for each of fiscal years 2008 through 2012. This funding was allocated specifically for demonstration projects focused on advanced technologies for use in power grid sensing, communications, analysis, and power flow control. The legislation also noted that the funding and associated projects were to leverage off existing Smart grid deployments. Utilities were eligible to receive a federal contribution up to 50% of the project cost for Smart Grid demonstration project. Other provisions in the legislation authorized a "matching fund" which would reimburse utilities for up 20% of the cost of qualifying Smart Grid technology investments. Further funding was authorized in the American Recovery and Reinvestment Act of 2009.

Qualifying investments eligible for federal funding include (but are not limited to):

- Smart meters;
- Monitoring and communications devices to enable Smart Grid functions;
- Equipment to allow Smart Grid functions to be operated and coordinated between multiple electric utilities;
- Devices to support the integration of distributed generation;
- Devices to support the integration of electric or hybrid-electric vehicles;
- Design and manufacture of intelligent appliances; and
- Smart Grid software.

189.2 Please explain why FortisBC is not using the smart grid definition in BC's Clean Energy Act Smart Meters and Smart Grid Regulation.

Response:

The definition and characteristics of "Smart Grid" vary widely depend on the source of the definition. Government bodies, utilities, vendors and special interest groups have all employed different definitions which share and overlap to varying degrees. FortisBC looked to the Smart Grid definitions of the US Department of Energy as their definition appeared to be among the broadest and well developed, thus covering all possible interpretations of the "Smart Grid".

The BC Clean Energy Act and Smart Grid Regulation are somewhat narrower in scope and have a primary focus on the deployment of smart meters and distribution transformer meters (referred to in the Act as smart grid system devices). The Act does reference the support for integration of distributed generation and electric vehicles however no specific requirements are cited.

Notwithstanding the chosen source for a reference Smart Grid definition, FortisBC takes significant guidance from the definitions and intent contained in the Act and Regulations. Numerous projects in the Capital Expenditure Plan and Long Term Capital Plan support the provisions of both these government documents.

Part 5, section 17 (6) of the Clean Energy Act states "If a public utility, other than the authority, makes an application under the Utilities Commission Act in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority."

189.3 Please provide an explanation of FortisBC's interpretation of "must consider the government's goal of having smart meters, other advanced meters and a smart grid in use <u>with respect to customers</u> (emphasis added)…"

<u>Response:</u>

FortisBC believes that section 17 (6) needs to be read in its entirety, which states that "… the commission must consider the government's goal of having smart meters, other advanced meters and a smart grid in use <u>with respect to customers other than those of the authority</u>".

Other subsections of section 17 of the Clean Energy Act addresses BC Hydro's duties and responsibilities. Section 17(6) discusses an application for smart meters, other advanced meters or a smart grid filed by a public utility, rather than BC Hydro. The wording of section 17(6) suggests the following. First, unlike the subsections of section 17 governing BC Hydro's duties and responsibilities, section 17(6) does not mandate a public utility (other than BC Hydro) to file an application for a smart meter under the Utilities Commission Act, evidenced by using the phrase "if a public utility … makes an application…." Second, the government appears to have a goal of providing smart meters and other advanced meters and a smart grid in use for customers who are not BC Hydro's customers.

190.0 Reference: Long-Term Capital Plan

Exhibit B-1-1, Section 2.2, pp. 12-13

Project Estimation Methodology - Indirect Costs

FortisBC states that "All project cost estimates were developed in 2010 dollars and include an annualized, constant 2 percent inflation rate based on the Consumer Price Index (CPI)." (Exhibit B-1-1, Tab 2, p. 13)

FortisBC states that "Currently the forecast for 2012 for CPI is 2.2 percent followed by 1.9 percent in 2013." (Exhibit B-1, Tab 4, p. 43)

FortisBC states that "Labour inflation for 2012 and 2013 is forecast at 3 percent annually for non-union (executive and exempt) employees. The 3 percent increase for non-union labour inflation is the increase required to achieve FortisBC's compensation philosophy of establishing compensation at the median of its defined peer group." (Exhibit B-1, Tab 4, p. 34)

190.1 Please provide justification for using a constant 2% inflation rate for project cost estimates when FortisBC's internal staff costs are ranging between 3% to 5% as shown in Table 4.3.2.1 Labour Inflation (2007-2013) (Tab 4, p.34)

Response:

Project estimates include a wide variety of cost components including internal labour, external contractors, vehicle charges, equipment and various commodity materials. Each of these components is affected by differing degrees of cost inflation. In addition, the relative proportion of these cost components varies from project to project. Determining, assigning, and tracking inflation factors for individual project cost components would be very cumbersome. On that basis, FortisBC uses a constant 2 percent inflation rate (which approximates CPI) as it is considered a representative proxy for these various inflation factors once they are blended together over a longer term.

190.2 Please explain how FortisBC incorporates commodity and labour cost inflation and escalation into project cost estimates.

Response:

Please refer to the response to BCUC IR1 Q190.1.

191.0 Reference: Long-Term Capital Plan

Exhibit B-1-1, Section 2.2, pp.12-13

Project Estimation Methodology - Standardized Cost Estimate Format

191.1 Does FortisBC currently use a standardized project estimation methodology or a capital budgeting template in determining all the components that make up a project estimate? If so, please provide a copy.

Response:

Yes, FortisBC has developed an estimating methodology for Transmission, Distribution, Station and Generation assets. Please refer to BCUC IR1 Appendix 191.1 for the estimating guideline developed for Transmission and Distribution as well as a sample project cost sheet which has been developed for larger projects or projects that contain multiple assets.

191.2 Would FortisBC be amenable to working with Commission staff to develop a standardized table format for all cost estimates?

Response:

FortisBC would be amenable to working with Commission staff to develop the criteria and general categories which are considered during the development of the Company's project cost estimates.

192.0 Reference: Long-Term Capital Plan

Exhibit B-1-1, Section 2.2.2, pp. 14-16

Transmission and Distribution costs of removal

"The forecast amounts reflect the expected expenditures of removing existing infrastructure less any salvage credits for scrap material sold or returned to inventory for reuse." (p. 14)

"Cost of removal forecasts are established, where applicable, for individual projects included in (1) generation, (2) transmission and distribution and (3) general plant…" (p. 15)

"Project costs in this Long Term Capital Plan are presented <u>inclusive</u> of costs of removal." (p. 16) [emphasis added]

192.1 Are removal or salvage costs always included in all the estimates for capital expenditures in the Application and proposed CPCN's? Is this treatment consistent with past practices?

Response:

Yes, Costs of Removal (COR) are included in the estimates for capital expenditures and are consistent with practices used since FortisBC's 2011 Capital Expenditure Plan filing.

192.2 Please describe other types of treatments for capturing Cost of Removal and why FortisBC has not considered it: Cost of removal to be captured in a deferral account or separate trust account for future use? Accumulate carrying costs in favour of ratepayers? Adjusted annually when new information becomes available?

Response:

There are several treatments to capture or recover cost of removal, including the following:

1) defer collection to a future period (by way of updated depreciation study);
2) collect when incurred (period expense); or
3) incorporate a provision for negative net salvage in depreciation rates.

The Company outlined its current and proposed continued practice of charging costs of removal incurred to accumulated depreciation in the 2012-13 RRA, which is the first option identified above. This method adjusts future depreciation rates in the amount of the actual deferred costs of removal.

The second option is sometimes referred to as the “pay as you go” method, and the removal costs are collected from customers as they are actually incurred, presumably with a deferral account if variances from forecasts are significant. While this method may be easier to explain and administer, the costs are not appropriately borne by the customers who are using the assets.

The third method of collecting negative net salvage in depreciation rates is generally used by many utilities and is recommended by the depreciation consultant, Gannett Fleming. This third method incorporates a provision for negative net salvage and records actual costs of removal against the provision when incurred. Despite the Company’s acknowledgement that including a provision for negative net salvage is the most appropriate method of collecting removal costs, implementing the recommended salvage accrual rate would result in a significant increase to customer rates. As a result, in order to manage rate increases for the term of the 2012-13 RRA, FortisBC proposed not to incorporate the recommended salvage accrual rates at this time and is proposing to reconsider for inclusion in a subsequent revenue requirements application.

Only under the third method of including a provision for negative net salvage in depreciation rates would there be the potential for a separate trust account for future use or the ability to accumulate interest income in favour of ratepayers. Since FortisBC opted to continue to recognize the actual cost of removal against accumulated depreciation and defer collection to a future period (first method) in order to mitigate the customer rate impacts, there is no opportunity to move these costs to a separate trust account or earn carrying costs.

192.3 Please describe the US GAAP treatment and interpretation for Cost of Removal.

Response:

Under US GAAP, the predominant practice of rate-regulated utilities is to include in current depreciation rates the estimated cost a utility expects to incur in removing assets in the future. These amounts create a regulatory liability, where actual costs of removal are recorded against the regulatory liability when incurred. Accounting Standards Codification (ASC) 980-405-25-1(b) provides the related US GAAP guidance.

The Company has prepared its 2012-13 RRA based on the assumption that subsequent depreciation studies adjust future depreciation rates in the amount of the deferred costs of removal so that any costs of removal that are charged to accumulated depreciation will be drawn down and reflected in future depreciation expense. If the Commission approves FortisBC's proposal to continue recognizing actual costs of removal against accumulated depreciation, similar to prior years' revenue requirements applications, with the clear expectation of recovering these costs from customers through future depreciation expense, such treatment would generally be permitted under US GAAP ASC 980 *Regulated Operations* due to the effects of rate regulation.

192.4 Please explain why a capital project costs should include the cost of removal. Does this mean that FortisBC is allowed to earn a return on the cost of removal when it the project is capitalized into rate base?

Response:

The cost of removing an asset from service is a real cost to the Company. In instances where assets are replaced or upgraded before they fail, costs of removal are required to be incurred as a result of removing old assets to be replaced with new assets. Therefore, these capital project costs should include a related cost of removal. Since the costs of removal are charged to accumulated depreciation when incurred, they increase rate base and would earn a return just as any other approved capital expenditure would. Subsequent depreciation studies adjust future depreciation rates in the amount of the deferred costs of removal so that any costs of removal that are charged to accumulated depreciation will be drawn down and reflected in future depreciation expense.

192.5 Is the future cost of removal recorded at its present value in the initial capital project costs?

Response:

No. The forecast cost of removal in any given year is recorded in that year's nominal dollar amount.

> "In estimating the cost of removal component for transmission rehabilitation, distribution rehabilitation, rebuilds and small planned capital projects, the Company applies a ratio of 30 percent to engineering, project management, supervision, construction labour and vehicles charges to the salvage of facilities.
>
> For transmission and distribution Urgent Repair projects, a ratio of 50 percent of these components is used…" (p. 15)

192.6 Please explain the rationale behind the 30% and 50% estimates above. Please clarify whether the statements above are suggesting that the cost of removal is approximately 30% or 50% of the project costs? Does this mean that the total project is generally 30% - 50% higher to accommodate the future cost of removal?

Response:

For distribution and transmission rehabilitation and rebuild projects, the work is quite similar from an installation and removal standpoint. In general, a new pole or structure is to be installed where an existing one is to be removed. In most cases this involves moving the existing structure and attached facilities enough to put the new pole or structure in. The old pole or structure is then removed. The work to install the new structure as well as a portion of the alteration to stand-off existing facilities to safely place the new structure is considered "new construction". The remainder of the alteration costs as well as the removal of the old facility is considered "cost of removal" (COR). This COR component is considered to be 30 percent of the non-material related costs of a rehabilitation / rebuild project.

For Transmission / Distribution Urgent Repairs projects, FortisBC considers that a ratio of 50 percent of the cost components is more representative since these are typically short duration projects where a crew is called to replace damaged facilities. For these short duration projects the time to install the new facilities compared to removing and cleaning up the damaged facilities is considered to be approximately equal.

The 30 percent or 50 percent factor is only applied to engineering, labour, vehicles, supervision, and third party costs. Material, land, and brushing costs are not typically included in the cost of removal.

Projects costs are not higher to accommodate future cost of removal. Cost of removal is based on the costs at the time of removal. FortisBC does not "build in" additional costs into new construction to accommodate future salvage or removal.

192.6.1 Provide a sample calculation using the above ratios.

Response:

The following is a listing of how the COR is allocated for the individual components for Transmission Rehabilitation / Distribution Rehabilitation projects:

- Engineering – 30% of this component is considered design work to establish the salvage of facilities;
- Land & Brushing – 0% is used for COR since these projects rarely require land negotiations or brushing to accommodate salvaging of facilities;
- Material – 0% is used for COR since these projects rarely require material to accommodate salvaging of facilities;
- Project Management/Supervision – 30% of this work is required for the safe removal of facilities as well as administration/record-keeping functions to retire these assets;
- Third Party Expense – 30% of this component is required to remove facilities. This includes flaggers, backhoe rental charges, etc;
- Construction Labour – 30% of this work is allocated to accommodate the removal of facilities; and
- Construction Vehicles – 30% of the vehicle charges are allocated in driving to and from the facility location and time for the specific salvage component of the work.

Transmission and Distribution Urgent Repairs utilize the same calculation but with a 50% factor for cost of removal instead of 30%.

193.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.4.4, p. 38

Upper Bonnington Unit 1 to Unit 4 (The Old Plant)

193.1 Please describe any discussions held with BC Hydro to decommission the Old Plant and replace the Canal Plant Agreement entitlement with a power purchase contract.

Response:

Discussions have not been held with BC Hydro regarding any changes to the Canal Plant Agreement concerning the old units at Upper Bonnington.

193.2 Please provide the actual generation of the Old Plant by month for the five-year period from 2006 to 2010.

Response:

The actual monthly generation of Upper Bonnington Unit 1 to 4 for the period 2006 to 2010 is provided in the following table.

Table BCUC IR1 193.2 Upper Bonnington Generation (MWH)

2006	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	-	-	2,052	4,322	3,289	-	-	-	-	-	9,662
Unit 2	-	-	-	-	833	2,287	1,277	-	-	774	-	-	5,172
Unit 3	-	-	-	-	1,603	3,351	2,568	-	-	-	-	-	7,522
Unit 4	-	-	-	-	1,872	4,061	2,602	(1)	-	-	-	1	8,535
2006 Total	-	-	-	-	6,360	14,020	9,736	(1)	-	774	-	1	30,891
2007	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	51	542	4,496	4,195	568	-	-	-	60	-	9,913
Unit 2	-	-	44	435	3,622	3,506	3,014	-	-	-	-	-	10,621
Unit 3	-	-	-	422	3,600	3,497	3,123	-	-	-	-	-	10,642
Unit 4	-	(1)	-	508	4,220	3,680	533	-	-	-	-	-	8,939
2007 Total	-	(1)	95	1,907	15,937	14,878	7,238	-	-	-	60	-	40,115
2008	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	(60)	-	1,809	4,287	2,108	-	-	-	-	-	8,144
Unit 2	-	-	-	0	1,467	3,410	1,714	-	-	-	-	-	6,591
Unit 3	-	-	-	0	1,483	3,442	1,573	-	-	-	-	-	6,498
Unit 4	-	-	-	0	1,614	4,219	1,776	-	-	-	-	-	7,609
2008 Total	-	-	(60)	1	6,372	15,359	7,170	-	-	-	-	-	28,842
2009	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	115	189	1,885	-	657	4,235	-	-	-	-	-	-	7,082
Unit 2	-	80	1,575	406	521	3,451	0	-	-	-	-	-	6,035
Unit 3	-	1	1,571	-	-	1,490	-	67	839	-	-	-	3,967
Unit 4	-	1	-	-	676	4,125	-	-	-	-	-	-	4,802
2009 Total	115	271	5,031	406	1,855	13,301	0	67	839	-	-	-	21,885
2010	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	-	1	-	3,920	1,211	-	-	-	-	-	5,132
Unit 2	-	-	-	1	25	3,379	447	-	-	213	-	-	4,064
Unit 3	-	-	-	-	1	3,093	863	-	-	-	-	-	3,957
Unit 4	-	-	-	1	-	3,657	1,083	-	-	-	-	-	4,741
2010 Total	-	-	-	2	25	14,049	3,604	-	-	213	-	-	17,893

193.3 Please provide a Net Present Value (NPV) analysis of the characteristics of repowering the Old Plant from the BC Hydro perspective (using the average actual generation of the Old Plant for the five-year period 2006 to 2010). Please provide the NPV for capital costs of $40 million, $50 million and $60 million, and please state all other assumptions such as discount rates, analysis timeframe, and value of power generated given the actual monthly generation from the previous question.

<u>Response:</u>

FortisBC is unable to provide a reasonable analysis to respond to this question, as it greatly over simplifies the numerous variables which need to be considered with respect to future work on Upper Bonnington Units 1 to 4. For instance, the use of actual generation in this analysis does not consider the value of the entitlement energy available under the Canal Plant Agreement and which forms a key part of the Company's long term resource planning. Secondly, the Company is not prepared to estimate the value of the actual energy provided to BC Hydro as this value can vary considerably depending on the specific needs of that organization. A further consideration is the discount rate which can be affected by a number of factors and can greatly affect the outcome of such an analysis.

Any decisions to embark on a major investment in the repowering of the old units at Upper Bonnington would be the subject of a future regulatory filing. A further review of this type of analysis can be completed at that time.

194.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.5.1.1, pp. 45-54

All Plants Concrete and Structural Rehabilitation Program

"Although difficult to accurately estimate, FortisBC anticipates a considerable increase in the amount of deterioration at the generation facilities should the concrete and structural rehabilitation be delayed."

194.1 Please discuss the cost of the proposed rehabilitation as a function of the amount of deterioration. For instance, is the majority of the cost of rehabilitation driven by the set-up and isolation required for the work, and less for the actual steel and concrete repairs, or vice versa? Will a rapid increase in deterioration only marginally increase the cost of the proposed projects?

<u>Response:</u>

A project can vary from 10 to 25% set-up cost leaving the repair portion of the costs in the 75 to 90% range. Thus a rapid increase in deterioration will translate into a rapid increase in project cost.

194.2 Please provide the estimated cost of the concrete and steel rehabilitation projects if all work was to be deferred for 5 years and 10 years.

Response:

High level estimates of the increased costs are as follows:

- All projects as scheduled: 100% of costs as allocated;
- All projects delayed until 2015 but completed by 2030: 155% of costs as allocated;
- All projects delayed until 2015 and completed by 2035: 170% of costs as allocated;
- All projects delayed until 2020 but completed by 2030: 175% of costs as allocated; and
- All projects delayed until 2020 and completed by 2040: 205% of costs as allocated.

Note: Percentages based on estimated growth in scope in today's dollars and do not include any allowance for inflation.

195.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.5.1.5, pp. 54-55

Corra Linn Spillgate and Spillway Concrete Rehabilitation

195.1 Please provide a detailed line item cost estimate for this project.

Response:

A detailed line item cost estimate for this project is not yet available as the Company is engaged in preliminary work to finalize the scope of work and construction methods.

195.2 Since spillway and spillway gate rehabilitation is such an infrequent activity, please explain why a gate isolation system is necessary, rather than other approaches such as temporary bulkhead. Please discuss the options to gate isolation that have been considered and their relative costs.

Response:

Although the options for spillway gate isolation are still under development, the following conceptual options have been considered:

1. Installation of a monorail crane with the crane rail attached to the existing spillway gate towers along with the saw cutting of stop log slots into the concrete spillway piers. Estimated direct cost of $5.5 million;
2. No isolation – spill water for approximately two months per gate. This option was deemed to be infeasible due to loss of the reservoir which affects fish habitat, shoreline and adjacent generation facilities (both FortisBC and BC Hydro);
3. Construction of a temporary needle beam isolation system in conjunction with saw cutting of beam pockets into the existing piers. Estimated direct cost of $4 million; and
4. Construction of temporary arch beam isolation system. Three each required due to irregularities on piers at gates #1 and #14. Estimated direct cost of $3.5 million.

These estimated costs are based on AACE class 5 estimates. A refinement of these options along with higher level estimates will be the subject of a future regulatory filing.

196.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.5.3.3, p. 66

All Plants Fire Safety

196.1 Please provide the most recent assessment of the generating facilities from FortisBC's insurer.

Response:

FortisBC has attached a November 2010 Risk Control Report as BCUC IR1 Appendix 196.1.

196.2 Please comment on the risks associated with fire in these, mostly, concrete facilities.

Response:

The risk of fire is still present due to operational equipment such as governor hydraulics, station service transformers, power and control cables, switch gear, mobile equipment, lube oil systems and the generators themselves.

Fires associated with the above equipment could present a trap to employees if they are working within locations where egress may be challenging, or unavailable depending on the location of the fire.

197.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.7.3, pp. 77-79

FERC Order 890

> "Electric utilities and transmission organizations in Canada are not subject to FERC jurisdiction and are not required to implement FERC Order 890. However, certain Canadian organizations have modified their planning processes to voluntarily comply with those requirements of the FERC Order that are most applicable in Canada. The transmission planning group at FortisBC is reviewing the requirements vis-à-vis its existing planning process to determine the extent to which the process already meets the requirements, as well as changes in the process to incorporate those FERC requirements that are most relevant in British Columbia and most beneficial to FortisBC stakeholders."

197.1 Please provide the terms of reference, framework, or any results from the review of FERC Order 890.

Response:

The transmission planning group at FortisBC conducted a preliminary review, which showed no significant gaps between FERC requirements and the FortisBC planning process.

Additional results will be provided when a detailed review is completed.

197.2 Please comment on how the assessment is determining benefits for FortisBC stakeholders.

Response:

In this context, "stakeholders" refers primarily to FortisBC's relationship with its neighbouring utilities and transmission customers. As an interconnected utility member of WECC, FortisBC believes it is good utility practice to consider the principles of FERC Order 890. As discussed on page 77 of the Long Term Capital Plan, three of the prime principles of this Order are coordinated, open, and transparent communications and transmission planning on a local and regional level.

In further support of this belief, FortisBC is a founding member of the recently formed BC Coordinated Planning Group (BCCPG). The BCCPG is a forum for enabling the coordination of transmission planning activities with the aim of ensuring a high degree of reliability of the electric system. Within BC, the BCCPG enables coordination and, where appropriate, integration of the transmission planning functions of transmission owner members. Outside BC, the BCCPG represents the interests of its transmission owner members to the Western Interconnection through participation in the WECC's Transmission Expansion Planning Policy Committee

(TEPPC) as well as the Sub-Regional Coordination Group (SCG). Further information can be found on the BCCPG website: http://bccpg.com.

198.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.7.5, pp. 80-81

Transmission Planning Studies

> "In the current FortisBC study cycle, the load flow analysis was carried out for years 2012, 2016 and 2020 both for winter and summer peak load conditions. In addition, load flow analysis was also performed for 2012 light load conditions. The transient stability analysis was carried out for year 2012 winter peak, summer peak and light load conditions. Longer term studies of the bulk system out to the planning horizon were also conducted to determine the need for future large transmission upgrades."

198.1 Please provide electronic copies of all the studies identified above, including exception and summary reports.

Response:

The methodology and results of all studies for years 2012, 2016 and 2020 are described in the 2011 Load Flow and Transient Stability Analysis provided as BCUC IR1 Appendix 5.1. These studies are performed annually, as required by WECC standards, and include detailed power flow and dynamic simulation studies.

Longer term planning studies are not performed annually but rather when deemed necessary due to system changes. The most recent long term study was performed in 2009. The results of these studies are not always compiled into a formalized report.

199.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.7.6, pp. 82-85

Reliability Studies

199.1 Please provide the 2005 to 2010 SAIFI and SAIDI data shown in Figures 2.7.6(c) and 2.7.6(d) in tabular format, and provide a comparison to BC Hydro's statistics for the same time period.

Response:

Please refer to Figures BCUC IR1 Q199.1a and Q199.1b for FortisBC SAIFI and SAIDI data as shown in Figures 2.7.6(c) and 2.7.6(d) of the Company's 2012 Long Term Capital Plan. The SAIDI and SAIFI data shown below and in the 2012 Long Term Capital Plan are reported on a calendar year and are not normalized for major events.

FortisBC could not find non-normalized calendar-year SAIDI and SAIFI for BC Hydro in the public domain, and therefore has not provided a comparison for FortisBC and BC Hydro reliability data based on the data provided in the 2012 Long Term Capital Plan.

Figure BCUC IR1 Q199.1a – FortisBC Actual Non-Normalized SAIFI (2005-2010)

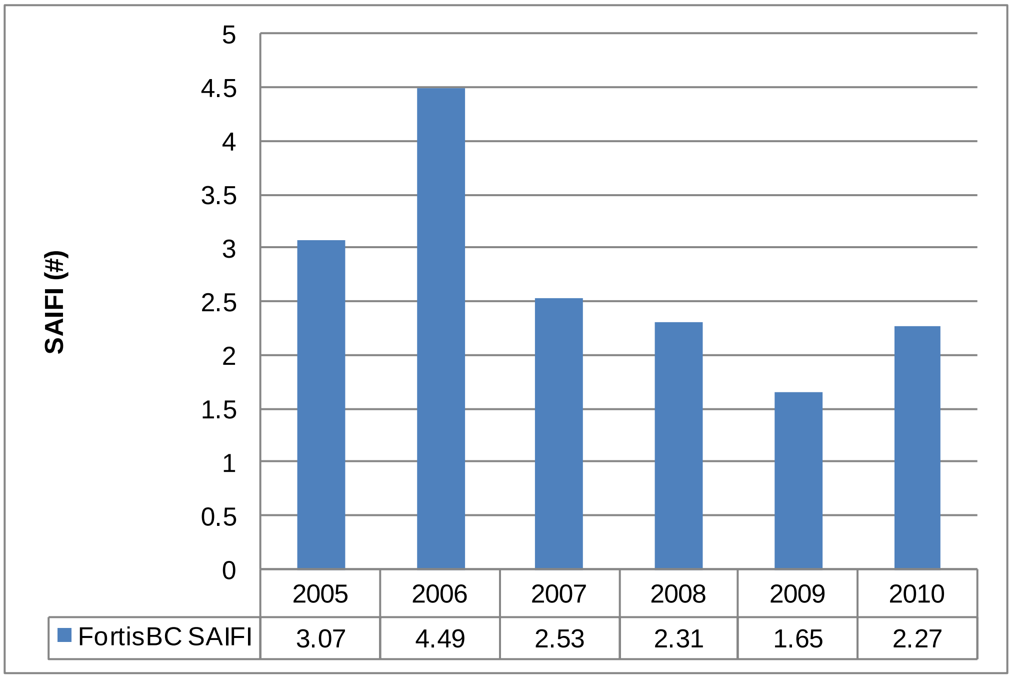
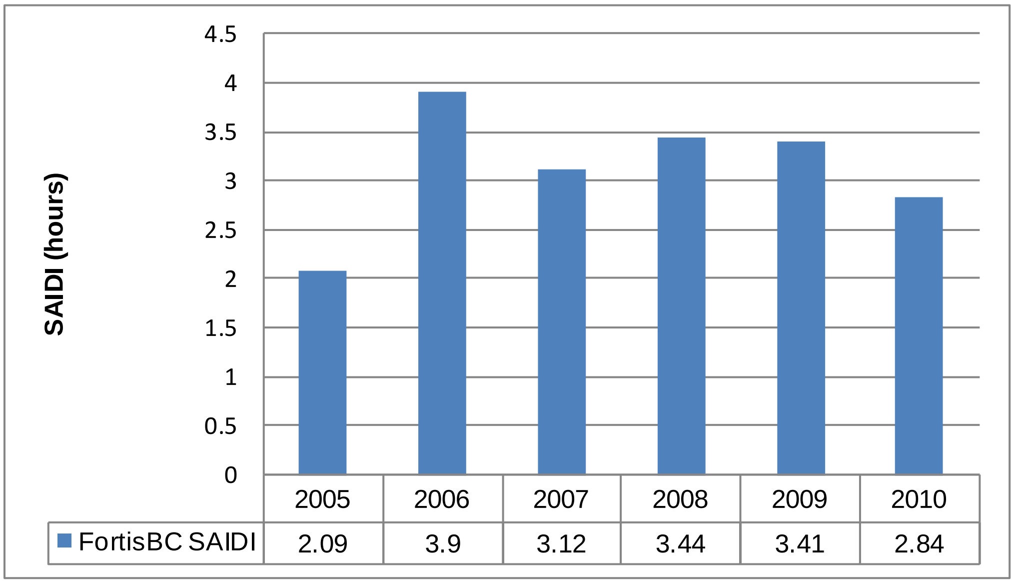


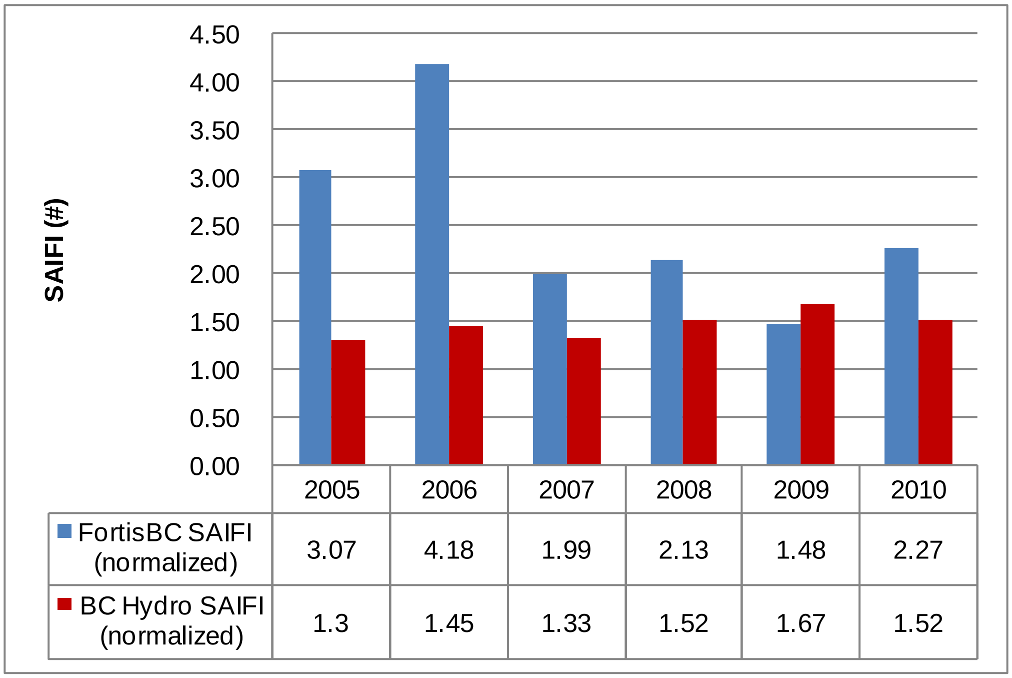
Figure BCUC IR1 Q199.1b – FortisBC Actual Non-Normalized SAIDI (2005-2010)



	2005	2006	2007	2008	2009	2010
🟦 FortisBC SAIDI	2.09	3.9	3.12	3.44	3.41	2.84

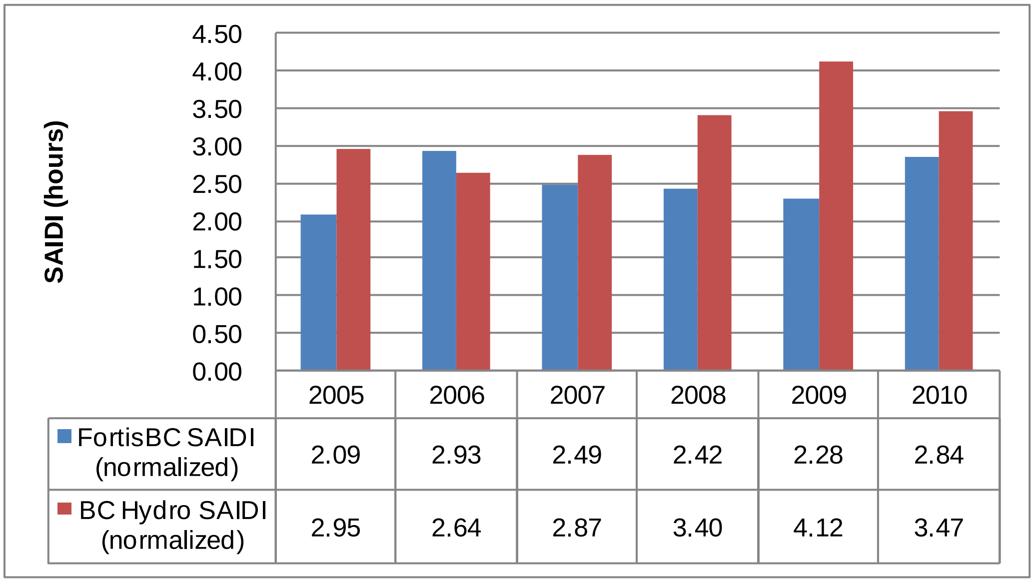
FortisBC provides the following comparison of FortisBC's normalized, calendar-year SAIDI and SAIFI data with BC Hydro's normalized SAIDI and SAIFI data provided in its F2009/F2010, F2011 and F2012/F2014 Revenue Requirements Applications.

Figure BCUC IR1 Q199.1c – Comparison of FortisBC and BC Hydro Actual Normalized SAIFI (2005-2010)



	2005	2006	2007	2008	2009	2010
🟦 FortisBC SAIFI (normalized)	3.07	4.18	1.99	2.13	1.48	2.27
🟥 BC Hydro SAIFI (normalized)	1.3	1.45	1.33	1.52	1.67	1.52

Figure BCUC IR1 Q199.1b – Comparison of FortisBC and BC Hydro Actual Normalized SAIDI (2005-2010)



BC Hydro SAIDI calculated from its SAIFI and CAIDI data filed in its F2009/F2010, F2011 and F2012/F2014 Revenue Requirements Applications.

200.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.7.8.1, p. 86

Radial Configuration

> "In some cases, a substation may have two transmission line sources, however only one supply line is used at any given time. If both transmission lines run in a common corridor, then this is generally considered a radial supply configuration (as a forced outage to both adjacent circuits is considered a credible event)."

200.1 Please provide additional support for this definition of radial configuration. Please provide other references where two circuits on a single corridor are considered as a "radial configuration."

Response:

The statement cited in the reference is not intended to imply that FortisBC formally defines a substation with two sources of supply in a common corridor as being a "radial supply". Rather, the statement is intended to clarify that a station with this configuration shares some of the characteristics of a classical radial configuration, namely that a single initiating event (i.e. forest fire or lightning strike) can simultaneously fault both transmission lines resulting in a station outage. As an example, prior to 2006 the normal source of supply for the Kelowna area was the two 230 kV lines which originate at the BC Hydro Vernon Terminal. These lines share a common right-of-way and had previously experienced multiple simultaneous outages resulting in a complete outage to all of Kelowna. Thus, these two lines were exhibiting a reliability level similar to single radial transmission line. The resulting major outages were part of the justification for the FortisBC's Okanagan Transmission Reinforcement project.

As further clarification, FortisBC confirms that it plans to a single-contingency (N-1) level in its transmission planning studies. More extreme conditions (N-2 and higher) are examined as required under BC Mandatory Reliability Standards requirements, but no projects have been proposed to support a level of reliability beyond N-1.

200.2 Have any projects in FortisBC's long term capital plan being justified in whole or in part on the above interpretation of "radial configuration"?

<u>Response:</u>

FortisBC confirms that no projects in the Long Term Capital Plan are proposed on the basis of the above interpretation.

201.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.7.8.3, p. 87

Meshed Configuration

"No manual reconfiguration of the system is necessary and no customer outages occur. This is referred to as N-1 (single-contingency) "all outages" reliability. The FortisBC bulk transmission system must meet this level of reliability in order to comply with legislated mandatory reliability standards (described above in Section 2.7.4)."

201.1 Please provide additional support for this definition of meshed configuration as it applies to the bulk transmission system. Does this interpretation of the bulk transmission system include the Kelowna loops?

<u>Response:</u>

Following is the definition of the "bulk power system" as contained in the BC Mandatory Reliability Standards Regulation (BC Reg 32/2009):

"bulk power system" means

(a) electrical generation facilities and transmission facilities, including interconnections with neighbouring systems, that are generally operated at voltages of 100 kilovolts or greater, and

> (b) transmission facilities that are generally operated at voltages of less than 100 kilovolts and that are, on their own or in combination with other generation, transmission or distribution facilities, material to reliability
>
> but excludes radial transmission facilities, regardless of voltage, serving only end-users of electricity with one transmission source;

Further, as per the approved BC Mandatory Reliability Standard TPL-002-0 ("System Performance Following Loss of a Single BES Element"), loss of customer load or curtailment of firm transfers is not permitted following the loss of a single bulk power system element.

Given the above requirements, FortisBC must plan, construct and operate the Company's non-radial transmission system facilities (132 kV and higher) such that the loss of a single transmission element does not result in a loss of load or curtailment of transfers. The resulting system configuration is consistent with the definition of "meshed configuration" as described in the Long Term Capital Plan.

Currently the Kelowna 138-kV sub-transmission system is operated radially with multiple open points and so in FortisBC's interpretation is not included in these requirements.

201.2 Have any projects on FortisBC's long term capital plan been justified in whole or in part on the above interpretation of "meshed configuration" as a requirement under the Mandatory Reliability Standards?

Response:

First, it should be noted that the BC Mandatory Reliability Standard TPL-002-0 does not require the establishment of two sources of supply to any given location. However, the standard does require that where such a configuration exists, and where it is operated non-radially, that it must comply with the requirements of TPL-002-0. On that basis, a number of projects contained in the Long Term Capital Plan are required for FortisBC's existing meshed transmission system to remain compliant as customer load continues to grow. By definition, FortisBC classifies these projects as Transmission Growth. Following is a list of these future projects required to maintain compliance with standard TPL-002-0:

1. Kelowna Bulk Transformer Capacity Addition;
2. 42 Line Meshed Operation (Huth and Oliver);
3. Capacitors at Bentley Terminal;
4. DG Bell Static VAR Compensator;
5. DG Bell 230 kV Ring Bus;
6. DG Bell Second 230/138kV Transformer;

7. Vaseux Lake Third 500/230kV Transformer; and
8. Boundary Area Supply

202.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.8.5, pp. 104-106

South Okanagan Area Upgrade

> "There are three related projects scheduled to address reliability and capacity concerns in the South Okanagan area over the next 20 years. The completion of these projects will ensure FortisBC maintains compliance with BC Mandatory Reliability Standards, and continues to meet the growing capacity demands."

202.1 For the referenced projects being driven in whole or in part as a requirement under the Mandatory Reliability Standards, please describe and discuss the specific standards as they apply to each project.

Response:

These projects are required to comply with the BC Mandatory Reliability Standard "TPL-002-0 – System Performance Following Loss of a Single Bulk Electric System Element (Category B)". This standard requires that there be no loss of demand following an event resulting in the loss of a single element.

During normal operations, the interconnection to BC Hydro at Princeton is open and all of FortisBC's 43 Line customer load is supplied from the FortisBC system. In the event of an outage of 40 Line or the Bentley T1 transformer, the entire load in Similkameen, Oliver and Boundary areas must then be supplied via the 11 Line path from Warfield. Under these conditions the supply capability of the 11 Line path is approximately 110 MW. Loads above this level will result in a voltage collapse in the Similkameen, Oliver and Boundary areas (please refer to the load forecast for these areas provided in the response to BCUC IR1 Q203.1). In order to prevent this voltage collapse, either a Remedial Action Scheme is required to shed an appropriate amount of load or the load in the Similkameen must be transferred to the BC Hydro system during peak load periods by closing the Princeton tap and opening 43 Line at the Bentley end. Even with this modified configuration, this option is exhausted by 2017 when the winter peak load again exceeds the supply capability of the 11 Line path and load shedding is again required.

The meshed operation of 42 Line prevents the voltage collapse by providing voltage support during the outage of 40 Line or the Bentley T1 transformer. It increases the supply limit of the 11 Line path in a contingency to approximately 150 MW. It also delays the reconductoring of 52 and 53 Lines which otherwise is required in 2012. As the load in the area continues to grow, eventually the installation of capacitor banks at Bentley is required to increase the contingency supply limit to 165 MW (by providing the required reactive support to prevent a voltage collapse).

202.2 Do the BC Mandatory Reliability Standards require system changes to achieve compliance or are they a mechanism by which compliance and non-compliance is reported and monitored?

Response:

The BC Mandatory Reliability Standards provide an ongoing mechanism by which compliance and non-compliance is reported and monitored. For example, requirement R1 of Standard TPL-002-0 describes in detail the annual system assessments that must be performed to identify compliance and non-compliance, while requirement R3 mandates the documentation and reporting of the assessments. Therefore, the answer to the second part of the question is affirmative.

The outcome of these compliance assessments is that FortisBC develops and proposes solutions to either achieve or maintain compliance with the standards. In this case, the projects discussed in the response to BCUC IR1 Q202.1 have been proposed to maintain compliance with BC Mandatory Reliability Standard TPL-002-0. Requirement R2 of the standard mandates the description of investment plans and implementation schedules required to achieve compliance.

203.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.8.5.1, pp. 106-107

42 Line Meshed Operation (Huth to Oliver)

203.1 Please provide a summary report for the above referenced project which describes the peak loads that were considered in the analysis, and the voltage levels that resulted in the Boundary and Oliver areas without the proposed meshing of 42 Line.

Response:

Table BCUC IR1 203.1 below details the winter and summer peak loads for the Oliver, Similkameen and Boundary areas that were used in the analysis. The critical condition (i.e. an outage of 40 Line or the Bentley T1 transformer) results in a voltage collapse both during winter and summer peak periods when the area load exceeds specific levels. Please also refer to the 2011 Load Flow and Transient Stability Analysis provided as BCUC IR1 Appendix 5.1, with specific reference to sections 4.1 and 4.2 as well as the Automatic Contingency Analysis Report in Appendix B of the 2011 Load Flow and Transient Stability Analysis.

Table BCUC IR1 203.1

	WINTER PEAK (2010 LOAD FORECAST)																				
	Based on FortisBC Distribution 2010 Load Forecast																				
COMPONENT	**LOAD (MW)**																				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Oliver	53.0	54.0	55.3	56.6	57.1	57.4	57.7	58.2	58.6	59.0	59.4	59.8	60.2	60.6	61.0	61.4	61.8	62.1	62.5	62.9	63.2
Similkameen	41.8	42.6	43.2	43.4	43.8	44.1	44.5	44.8	45.0	45.3	45.6	45.9	46.2	46.5	46.7	47.0	47.3	47.5	47.8	48.0	48.3
Boundary	50.3	50.7	51.3	51.6	51.9	52.1	52.3	52.6	52.8	53.0	53.3	53.5	53.7	53.9	54.1	54.3	54.5	54.7	54.9	55.1	55.3
Total	**145.1**	**147.3**	**149.8**	**151.6**	**152.7**	**153.6**	**154.6**	**155.6**	**156.5**	**157.4**	**158.3**	**159.2**	**160.1**	**161.0**	**161.9**	**162.7**	**163.5**	**164.4**	**165.2**	**166.0**	**166.8**

	SUMMER PEAK (2010 LOAD FORECAST)																				
	Based on FortisBC Distribution 2010 Load Forecast																				
COMPONENT	**LOAD (MW)**																				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Oliver	56.0	57.2	58.2	59.3	59.9	60.7	61.1	61.6	62.1	62.6	63.1	63.6	64.1	64.6	65.1	65.6	66.0	66.5	67.0	67.4	67.9
Similkameen	34.4	34.7	35.1	35.1	35.6	36.0	36.2	36.5	36.7	37.1	37.3	37.6	37.8	38.1	38.4	38.6	38.9	39.2	39.4	39.6	39.9
Boundary	39.7	40.1	40.4	40.3	40.8	41.4	41.7	41.9	42.2	42.6	42.9	43.2	43.5	43.8	44.2	44.5	44.7	45.0	45.3	45.6	45.9
Total	**130.0**	**132.0**	**133.7**	**134.8**	**136.3**	**138.1**	**139.0**	**140.0**	**141.1**	**142.3**	**143.3**	**144.4**	**145.5**	**146.6**	**147.7**	**148.7**	**149.7**	**150.7**	**151.7**	**152.7**	**153.8**

204.0 Reference: Long Term Capital Plan
Exhibit B-1-1, Section 2.8.5.3, p. 107
Reconductor 52 Line and 53 Line

204.1 Please supply the load growth projections upon which the need for this project is based, and provide the actual load history back to 2007.

<u>Response:</u>

The need for this project is driven by summer peak load conditions. The summer peak forecast for the load potentially supplied by 52 and 53 Line combined is given in the table below. A portion of this area load is also supplied by 42 Line from the Oliver substation which mitigates any potential overload at peak times. However, in 2020 following a single contingency (the outage of either 52 Line or 53 Line) the flow on the other line is forecast to exceed the 73.6 MVA summer emergency rating of the 477 kcmil ASC conductor. Refer also to BCUC IR1 Appendix 204.1 for a load flow diagram showing the overloaded element.

Table BCUC IR1 204.1 Summer Peak: Load Connected to 52 Line and 53 Line

SUBSTATION	ACTUAL (MVA)				FORECAST (MVA)									
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Huth	24.8	24.2	23.5	23.6	16.8	17.0	17.2	17.4	17.6	17.8	17.9	18.1	18.2	18.4
Kaleden	3.7	3.9	4.3	3.9	5.0	5.1	5.5	5.6	6.3	6.3	6.4	6.4	6.5	6.5
OK Falls	11.4	6.6	8.7	7.4	8.4	8.6	8.6	8.8	8.7	8.9	9.0	9.0	9.1	9.2
Summerland	12.7	12.5	13.6	12.5	13.6	13.8	14.0	14.2	14.3	14.4	14.6	14.7	14.8	14.9
Waterford	18.4	16.9	17.7	16.7	17.0	17.2	17.5	17.7	17.8	18.0	18.2	18.3	18.5	18.6
West Bench	5.6	8.3	6.2	8.9	8.6	8.9	9.0	9.1	9.2	9.2	9.4	9.4	9.5	9.6
Trout Creek	5.3	5.3	5.6	5.6	6.4	6.5	6.4	6.6	6.6	6.7	6.7	6.8	6.8	6.9
Total	82.0	77.7	79.5	78.6	75.7	77.0	78.2	79.3	80.5	81.3	82.1	82.8	83.5	84.2

205.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.8.6, p. 109

Meshing Kelowna Loop

> "Presently the Kelowna 138 kV transmission system is operated with normally open points. This operating configuration can result in widespread and lengthy outages following a single contingency."

205.1 Please explain why the outages would be "lengthy" for single contingencies. Although the system is not meshed, is it capable of being remotely operated to open and close connection points?

Response:

Yes, the substations in the Kelowna area are equipped with SCADA remote control and this can be used to remotely reconfigure the open and closed connection points. However, a critical component of the SCADA control network is the communications system which is used to provide that remote control functionality. Ideally this would be a highly reliable system that is available at all times to allow the System Control Centre dispatchers to quickly and efficiently reconfigure the transmission system when needed. Unfortunately, the existing communications system for the Kelowna distribution substations is an aging wireless system that has reached end of life and can no longer be depended on to perform remote operations when needed. It is for that reason that FortisBC has proposed a project to complete a highly-reliable fibre optic network in Kelowna and then transfer the SCADA communications to that system (please refer to Section 5.1.1 "Kelowna 138 kV Loop Fibre Installation" in the 2012-13 CEP).

Following are two transmission outage reports which illustrate how communications failures resulted in lengthy outages due to the inability to remotely reconfigure the transmission system:

- 2008/08/17 - Outage Report #87 – 50 Line (Sexsmith/Glenmore/Recreation substations) – outage duration 30 minutes – 15,689 customers (3,890 customer/hours) – "While restoring the system SCC lost all communications to the Kelowna area which caused the restoration of 50 line to take longer."; and
- 2006/06/09 - Outage Report #44 – Bell Terminal and 51 Line (Recreation/Saucier/OK Mission/Bell substations) — outage duration 1-1/2 hours - ~25,000 customers (32,000 customer/hours) - "[communications] failure at the Benvoulin office caused a delay in customer restoration due to communications failing at the substation RTUs."

206.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.8.7, pp. 109-110

Summerland Substation Transformer Upgrade

206.1 Please explain why the upgrade is necessary in 2014 if the transformer nameplate capacity of 20 MVA is not reached until 2019 as shown in Figure 2.8.7?

Response:

The nameplate capacity of the Summerland transformer is 20MVA. However the Wholesale Service Agreement between FortisBC and the City of Summerland states that when load exceeds 95 percent of the contracted demand limit (20MVA Winter, 16MVA Summer), then FortisBC, at its own cost, must upgrade the facility such that the load does not exceed 95 percent of the contracted demand limit. 95 percent of 20MVA amounts to 19MVA and the winter load at the Summerland substation is forecast to exceed 19MVA in 2014.

206.2 Is the District of Summerland responsible for any portion of the cost of the upgrade? Why or why not?

Response:

The District of Summerland is not responsible for any portion of the cost of this particular upgrade. Please also refer to the response to BCUC IR1 Q206.1.

207.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.8.8, pp. 110-111

Beaver Valley South Solution

207.1 Please discuss whether FortisBC has analyzed the possibility of off-loading feeders from Beaver Park Substation by transferring load to the new substation recently constructed for the Waneta Expansion Project construction after the construction is finished in 2016? If not, why not?

Response:

Using the station at the Waneta Expansion site was investigated and modeled to offload some of the Beaver Park substation load.

The Waneta Expansion site station is a small substation located at the end of a rural single phase distribution line where there is very little load and no new development is occurring. The station is not owned by FortisBC and an agreement to purchase or utilize the site would need to be negotiated on appropriate commercial terms. If FortisBC were to purchase or utilize this station, then the distribution feeder would have to be upgraded to three-phase construction to interconnect it with the existing system. Currently, FortisBC has no specific driver to upgrade this section of line and therefore this cost, along with the expected commercial costs of the Waneta Expansion site station, was deemed more appropriately spent towards the Beaver Valley South Solution.

Notwithstanding the above discussion, FortisBC will continue to monitor development in the area and will pursue an opportunity to utilize the substation capacity and upgrade the distribution feeder if this option proves to be in the interest of FortisBC customers.

208.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.8.22, pp. 123-126

New Central Okanagan Substation

208.1 Please discuss the feasibility and provide a cost comparison for replacing the transformers at each substation instead of the proposed project.

Response:

The scope of the New Central Okanagan Substation is initially only to replace the existing Kaleden substation. The Kaleden substation is a very old legacy station on a small parcel of land that is unable to accommodate a larger transformer, additional distribution feeders and the required control building. Access to the station is difficult due to the property location and site topography and there is no room for the placement of a mobile transformer. The station's tight proximity to the highway and hillside on either side of the station make site expansion very awkward, expensive and aesthetically unpleasing. As area load continues to grow, particularly due to development on the Penticton Indian Band (PIB) land just southwest of Penticton, upgrades to distribution facilities in the area and additional substation capacity will be required. At this time, FortisBC has proposed the new Central Okanagan Substation project as a prospective cost-effective solution which would satisfy the long-term needs for the area. In the future, other legacy substations such as West Bench initially, then Trout Creek, and finally OK Falls could be transferred onto a supply from the new substation.

Given the timing of this project, no comparison estimates for the replacement of the transformers and land expansion at the existing sites are available. Further studies will be conducted to confirm the most economical and reasonable solution closer to the time the project is required.

209.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.9.5, pp. 135-136

30 Line Lake Crossing Rehabilitation

209.1 Please confirm the expenditure years in Table 2.9.5(f).

Response:

The two years shown in the Table 2.9.5(f) should read 2015/2016 and not 2012/2013. Please refer to Errata 2.

210.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.10.4.3, p. 143

Switchgear Replacement Program (13 kV)

210.1 Please confirm the year of the Playmor Substation 25 kV Upgrade project.

Response:

The Playmor Substation Distribution Transformer Addition currently has an in-service date of 2027. This year was inadvertently referenced as 2029 on page 143 of the Long Term Capital Plan (refer to Errata 2).

211.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.10.4.5, pp. 144-146

DG Bell 138 kV Breaker Addition

> “Currently, the DG Bell T1 and T2 transformers, the mobile transformer connection and the capacitor bank are all included in the same protection zone. A fault with one piece of equipment will cause all units in this zone to experience an outage.”

211.1 Please confirm the capacitor bank has its own independent breaker and a fault in the capacitor bank will be cleared by that breaker and not affect the node.

Response:

Yes, the capacitor bank has its own circuit breaker and a fault in the capacitor bank itself will be cleared by this circuit breaker. This is not the case for either of the DG Bell T1 or T2 transformers or the mobile connection. A fault on any of these three pieces of equipment will result in an outage to the node (both transformers and the capacitor bank). The sentences also refer to the fact that a fault on the node itself (the bus-work, switches, instrument transformers, etc.) will result in the simultaneous loss of the DG Bell T1 and T2 transformers as well as the capacitor bank (and possibly the mobile transformer if installed).

211.2 Please provide the outage statistics for this node since 2006.

Response:

The outage statistics for the DG Bell T1/T2 node are listed in the table below.

Table BCUC IR1 211.2

Outage Date	Number of Customers Affected	Outage duration (seconds)	Customer Hours Lost
3-Mar-06	3,525	1,730	1,694
3-Mar-06	3,525	2,597	2,543
9-Jun-06	3,397	4,656	4,393
29-Jun-06	3,399	553	522
30-Aug-06	3,534	3,202	3,143
29-Jun-07	3,491	4,475	4,340
26-Aug-07	3,491	2,930	2,841
	Totals	**20,143**	**19,477**

211.3 Please provide an estimate of the SAIFI, SAIDI or CAIDI improvement associated with this proposed project.

Response:

The historic SAIDI and SAIFI figures for the load supplied from the DG Bell Terminal are dependent on:

- the nature of the events which caused the outages;
- the operating configuration of the system at the time;
- the response of the protection equipment;
- the mobilization time of the operations personnel responding to the events; and
- the effects or damage resulting from the outage on the system.

The DG Bell 138 kV Breaker Addition will improve the functionality of the protective equipment, and add the ability to sectionalize the DG Bell T1 and T2 transformers. It is difficult to quantify an improvement in SAIDI or SAIFI resulting from this project as it is difficult to adequately address all of the various combinations of factors which contribute to these metrics.

As well, not all equipment outages contribute to reportable statistics. For example, some equipment outages do not result in a loss of customer load due to system redundancy. Also, outages of less than one minute do result in a customer interruption but are not included in the reportable statistics. For many types of customer equipment, short duration outages can be just as disruptive as long outages.

For these reasons, FortisBC does not consider the impact on the system statistics as representative of the benefits provided by this future project.

211.4 How long has the DG Bell Substation been in this configuration?

Response:

The DG Bell capacitor bank was installed as part of the Okanagan Transmission Reinforcement (OTR) project in 2011. The DG Bell T2 transformer was added in 2005 and hence T1 and T2 have operated in the same protection zone since that time.

212.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.10.4.6, p. 146

Osoyoos Substation 63 kV Breaker Additions (2)

212.1 Please provide the outage statistics for this Osoyoos Substation since 2006.

Response:

The outage statistics for the Osoyoos substation are listed in the table below.

Table BCUC IR1 212.1

Outage Date	Number of Customers Affected	Outage duration (seconds)	Customer Hours Lost
6-Jan-06	2,517	381	266
29-Apr-06	2,518	302	211
9-Dec-06	2,505	28,440	19,790
19-Aug-08	2,507	5,074	3,533
5-Aug-10	1,561	1,790	776
27-Sep-10	1,563	3,226	1,401
27-Sep-10	1,563	1,031	448
	Totals	**40,244**	**26,425**

212.2 Please provide an estimate of the SAIFI, SAIDI or CAIDI improvement associated with this proposed project.

Response:

The historic SAIDI and SAIFI figures for the Osoyoos substation are dependent on:

- the nature of the events which caused the outages;
- the operating configuration of the system at the time;
- the response of the protection equipment;
- the mobilization time of the operations personnel responding to the events; and
- the effects or damage resulting from the outage on the system.

Currently, a major fault in one of the Osoyoos transformers will be detected by the 44 Line protection equipment at the Oliver substation and hence result in an outage to all load supplied via 44 Line. This includes all Pine Street substation load, as well as all Osoyoos substation load. In other words, a fault in a single transformer at Osoyoos will result in the loss of four distribution transformers (two at Pine Street and two at Osoyoos). The high-side breaker addition at Osoyoos will improve the functionality of the protective equipment, and add the ability to sectionalize the Osoyoos T1 and T2 transformers. This will ensure that only the faulted transformer is isolated and the other three transformers will remain online and supplying load. This resulting arrangement is consistent with all other FortisBC dual transformer substations which have some form of high-voltage fault isolation equipment.

It is difficult to quantify an improvement in SAIDI or SAIFI resulting from this project as it is difficult to adequately address all of the various combinations of factors which contribute to these metrics. For these reasons, FortisBC does not consider the impact on the system statistics as representative of the benefits provided by this future project.

212.3 How long has the Osoyoos Substation been in this configuration?

Response:

The Osoyoos substation has operated in this configuration since the early 1980s.

213.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.10.4.7, pp. 147-148

Bulk Oil Breaker Replacement Program

213.1 Please explain why it is necessary to replace all the bulk oil breakers rather than the just those that are un-maintainable or otherwise at risk. Are some bulk oil circuits still maintainable, and easily retrofitted with oil containment in high risk areas?

Response:

The newest bulk oil circuit breakers in the FortisBC system will be 33 to 38 years old, with an average age of 40 to 45 during the time frame of this program. They were purchased near the end the industry's transition from bulk oil to minimum oil and SF6 circuit breaker technology. As a result, parts are difficult to source, and often must be specially made. In addition, oil containment facilities are difficult to retrofit in existing installations, because of the civil and physical construction required while working in an energized substation. Many of the bulk oil circuit breakers are also located in higher risk sites located in residential areas.

214.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 2.10.5, pp. 150-153

Transformer Replacements

214.1 Please provide a time frame for the reconfiguration of 11 Line to 138 kV operation and the associated projects.

Response:

FortisBC is unable to provide a time-frame as the voltage conversion of 11 Line to 138 kV will be an event-driven reconfiguration driven by the failure of one of the A.S. Mawdsley T1 or T2 transformers. If and when a transformer failure occurs, FortisBC will evaluate the options at that time to determine if it is more cost-effective to reduce the operating voltage of the line to 138 kV or to simply replace the failed A.S. Mawdsley transformer with a similar-rated unit.

215.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 3, pp. 157-159

Distribution Voltage Conversion

> "FortisBC work procedures are very similar between 12.47 and 25 kV systems, with the exception of limits of approach. FortisBC's usual distribution hot work (live line) procedures cannot be used on 25 kV lines, but must instead be completed using transmission procedures."

215.1 Please reconcile the two sentences above, as the first states the procedures are very similar, and the second sentence implies they are not.

<u>Response:</u>

. The second statement is in error and should read:

> "FortisBC's usual distribution hot work (live line) procedures cannot be used on <u>lines exceeding 25 kV</u>, but must instead be completed using transmission procedures."

Please refer to Errata 2.

216.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 3.1.7, pp. 165-166

Kaleden Feeder 1 Capacity Upgrades

216.1 Please explain whether the feeder is being re-conductored to 13 kV or 25 kV standards in anticipation of an upcoming change to the Kaleden Substation.

<u>Response:</u>

The Kaleden Feeder will be re-conductored to a 25 kV standard.

217.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 4.2.1, pp. 175-178

Fibre Optic Backbone Infrastructure

> "FortisBC has no control over the availability or reliability of third-party providers' circuits. Generally, standard service level agreements will not provide guaranteed availability sufficient to achieve end to end up times specified in WECC standards or in FortisBC's internal policies. Furthermore, FortisBC believes that in an emergency situation, where it is imperative that the power system continues to operate, a third- party will not prioritize its work based on the needs of FortisBC to the detriment of this critical infrastructure."

217.1 Please discuss whether dark fibre leased from fibre owned by others but installed on the FortisBC infrastructure achieves similar reliability and availability as FortisBC owned fibre.

Response:

Leased dark fibre owned by others but installed on FortisBC infrastructure is expected to achieve the same reliability and availability as that owned by FortisBC. This is a function of the extremely low probability of a physical fibre failure.

The quoted text does not refer to leased dark fibre, but to leased services. Please refer to BCOAPO IR1 Q36.1 for a discussion on leased facilities versus leased services.

218.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 4.3.1.2, p. 187

Kootenay Remedial Action Scheme (RAS) - Install Redundant Backup System

218.1 Please describe any existing redundancies in the current RAS system. Explain the drivers for adding additional redundancy and quantify the expected increases in system reliability indices.

Response:

FortisBC does not see an immediate need for installation of equipment to make the Kootenay Remedial Action Scheme fully redundant. The project has been included in the 2012 Integrated System Plan based on anticipated future Mandatory Reliability Standards that will make it more difficult to take the RAS system out of service for maintenance. FortisBC will continue to monitor the drivers for this work and will apply in a future submission if and when a need arises.

This project is generally driven by the need to be able to take the system out of service for maintenance or upgrades and not by the need to increase reliability or availability numbers. For this reason the system reliability increase has not been quantified.

219.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 4.3.1.3, p. 188

Syncrophasor Data Collection Platform

219.1 Please provide further information regarding BC Energy Plan Real Time Phasor initiative.

<u>Response:</u>

The 2007 BC Energy Plan noted that (referring to BC Hydro):

> “British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle “snapshots” of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.”

The Energy Plan also sets out the following direction:

> ““Policy Action #12: 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.”

Finally, the BC government also provided policy direction through the Utilities Commission Act Amendment (Bill 15) to “encourage public utilities to use innovative energy technologies that facilitate […] the fulfillment of their long-term transmission requirements”.

The future addition of synchrophasor data collection equipment contributes to the development of the Smart Grid in British Columbia and would allow FortisBC to participate in this initiative to operate the transmission system more efficiently and more reliably.

220.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 5.1, pp. 197-198

Kootenay Long Term Facilities Strategy

220.1 Please provide the business case and calculation of long term savings from the Kootenay Long Term Facilities Strategy.

Response:

Facilities is currently working through the options and details of the Kootenay Long Term Facilities Strategy. As stated in the 2012-13 Capital Plan, FortisBC will file a CPCN application providing the business justification and financial analysis for the proposed project.

221.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 5.7, pp. 206-207

Hybrid Vehicles

221.1 Please provide an assessment of the cost effectiveness and suitability of the 7 hybrid low emission passenger vehicles and the hybrid low emission service truck.

Response:

FortisBC owns five and leases three hybrid vehicles. They are performing well, and the Company has not seen an increase in maintenance costs. According to a recent BCAA report, payback of the higher incremental purchase price through fuel savings is very sensitive to kilometers driven in the year and fuel prices, and for most hybrids is still marginal, however the Company should experience a 37 percent reduction in Greenhouse gas emissions with the hybrid units compared to conventionally powered vehicles.

222.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 5.8, p. 207

Metering Changes

222.1 Why is there a large increase in metering changes in 2011, 2012, & 2013? Wouldn’t the AMI project provide an opportunity to delay and reduce costs in these years?

Response:

The meter change budget is comprised of two categories.

The first category is the budget required to purchase new meters that fail during the routine meter testing program as well as the meters that fail under the meter compliance program. Measurement Canada requires that these programs achieve compliance with the Electricity and Gas Inspection Act. The number of meters that are removed each year is based on; 1) the seal due date of an individual meter, and 2) the due date of a group of meters, which varies from year to year. Another factor that will impact the changes is the number of meter groups that fail when presented for testing.

The budget also covers the cost for new metering equipment for customer growth as well as meters that are vandalized or damaged in the field.

Commission approval of the AMI project will provide the opportunity for FortisBC to apply to Measurement Canada for dispensation. If approved, the routine meter test and compliance programs would cease, along with the associated costs, until the seal period of the AMI meters are due. An application, for dispensation, to Measurement Canada would not occur unless a project to replace the FortisBC meter fleet was approved. FortisBC does not believe that a deferral of the meter exchanges would be granted without certainty that the project will proceed.

223.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 5.9, p. 207

Telecommunications

223.1 Please update the 2011 forecast expenditure and explain why it is so much higher than other years?

Response:

The 2011 forecast expenditure for General Plant Telecommunications is higher than in other years due to a required upgrade of FortisBC’s radio dispatch consoles. These consoles are critical to the safe operation of the electric grid by facilitating voice communications between the System Control Centre and field personnel. The existing radio consoles, purchased approximately 12 years ago, are at the end of their service life and are being replaced with new technology. The forecast expenditure for 2011 has not changed.

224.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Section 5.11, p. 209

Furniture and Fixtures

224.1 Why is the 2014 forecast expenditure on Furniture and Fixtures so much higher than other years?

Response:

The 2014 forecast for Furniture and Fixtures is higher than other forecast years as it considers reconfiguration of the Trail Office building to an open office plan which will require acquisition of new furniture. An open plan with space standard provides for more efficient use of the building footprint and will reduce the overall space requirement.

225.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Appendix K, p. 4

ISP Consultation Report

FBC states: “A total of 54 people signed in to the four open houses and FortisBC received 39 exit surveys and four written responses …”

225.1 This seems to be a small representation considering the extensive advertising for the open houses. Does FBC consider the findings representative of its customers?

Response:

No, participants that elect to attend the public open houses are not necessarily representative of all FortisBC customers. Typically public open houses do not have a large number of participants, so FortisBC additionally conducted “supergroup” (large focus groups) research with an additional 115 attendees randomly selected from the FortisBC customer list and recruited to increase the amount of feedback received and to provide findings better representative of all customer groups.

226.0 Reference: Long Term Capital Plan

Exhibit B-1-1, Appendix K, p. 6

ISP Consultation Report

FBC states: "89 per cent say social and environmental components such as visual screening, special environmental treatment or other community specific amenities should be considered when determining future capital project budgets. Only 50 per cent of these respondents are willing to pay higher rates for these components."

226.1 How does FortisBC interpret this? Since less than half the total respondents are willing to pay at higher rates, would FortisBC consider charging affected parties for these amenities if they want them? For example, a BCUC Inquiry determined that the transmission lines along Boundary road in Vancouver/Burnaby could be undergrounded if the two municipalities contributed to the cost.

Response:

FortisBC would interpret this to mean that while people accept that social and environmental components should be considered, they are less willing to pay higher rates to address these components.

The Company believes however that recent FortisBC projects approved by the BCUC which did incorporate social and environmental mitigation components have experienced a more streamlined permitting and regulatory process. The nominal cost of these measures (which are in line with those requested in Section 4.6.1.2, page 25 of the 2012 ISP) likely reduced overall project costs by minimizing schedule impacts and other costs had the Company been required to utilize a more expensive project alternative.

Note that in certain circumstances, the Company does charge the requesting party of the amenity when the request can be directly attributable to them. For example, a developer may want an underground service instead of the standard overhead service. In this case, the Company will charge the developer for the incremental cost of the underground infrastructure when compared to the standard overhead construction.

If the BCUC does not decide that a budget can be included in capital projects to address social and environmental considerations, FortisBC would consider working with affected parties to otherwise fund these costs. Since FortisBC does not have a legislative authority to force payment, an agreement would be required with parties willing to carry the cost of social and environmental considerations. And if those parties are not willing to pay those costs, those components may not be able to be substantially addressed.

227.0 Reference: 2012 Long Term Capital Plan

Exhibit B-1-1, Appendix K, p. 7

ISP Consultation Report

Regarding AMI, FortisBC states that “If in-home displays are optional, most customers would pay up to $50 for the technology.”

227.1 How does FBC interpret this information for the development of AMI? Is FortisBC considering charging customers directly for some or all of the in-house display option? Would this hurt the conservation impact of AMI? How would FortisBC treat the incremental cost above the $50?

Response:

FortisBC will consider this information when developing the proposed PowerSense DSM program (which is contingent on approval of the AMI project) that will provide incentives for customers to purchase in-home displays (IHD). FortisBC will estimate the number of customers that are expected to purchase an IHD when estimating the conservation impact of AMI. FortisBC is considering the provision of “free” IHD’s for low-income customers only, again as part of the PowerSense DSM program.

(LONG-TERM) LOAD FORECAST

228.0 Reference: Load Forecasting

Exhibit B-1-1, Long Term Capital Plan, Section 2.1, p. 9; Appendix B, pp. 1-8

Distribution Loads

> "In preparing the Distribution Load Forecast (found at Appendix B), Load is forecast first at the distribution feeder level, then built up to the transformer level using historical coincident factors. Where appropriate, the Distribution Load Forecast is adjusted to reflect information available through the relevant official community plans and through ongoing discussions with regional or municipal planners and local developers."

228.1 Please provide a restated version of the tabular data provided in Exhibit B-1-1, Appendix B to include apparent and real power (KVA) for the period 2010 to 2031. Segmented by year and substation, please also include the corresponding number of user accounts, population and energy sales (GWh) serviced by each substation.

<u>Response:</u>

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

228.1.1 For the above question, please include historical data for the period 1990 to 2010. Copies of tabular and graphical data are requested in the form of an electronic spreadsheet.

<u>Response:</u>

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

228.2 Please describe any clear trends in the relationship between apparent power (KVA), the number of customer accounts, population and the energy sales (GWh) for the three geographic regions serviced by FortisBC (Okanagan, Kootenay, and Boundary regions) from 1990 to 2010.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

228.2.1 Please also discuss consistency or differences between historical trends (1990 to 2010) to forecasted trends (2011 to 2031).

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

228.3 For the period 1990 to 2031, please provide linear graphs that summarize the annual percent (%) variation in the number of user accounts, population, energy sales, and apparent power for the Okanagan, Kootenay and Boundary regions. Please provide a copy of the data and graphs in the form of an electronic spreadsheet.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

229.0 Reference: Load Forecasting

Exhibit B-1-1, Long Term Capital Plan, Section 2.1, p. 10; Appendix B, p. 9

Peak Loads

> "To this end the Company provides a "1-in-20" load forecast, which produces forecast peak loads that are expected to be higher than the actual peak loads in 19 out of 20 years. Its success rate is therefore expected to be 95 percent. The "1-in-20" winter and summer peak demand forecasts for the period 2011-2040 is included in Appendix B."

229.1 FortisBC uses a peak load forecast that is based on a 5% probability (i.e., 1-in-20 assumption). Please provide a benchmark comparison of the peak load assumption used by other peer group utilities in Canada including BC Hydro.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

229.1.1 What financial impact would a peak load forecast based on a 10% probability (1-in-10) have on the FortisBC's Long-Term Capital Plan and customer rates?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

229.2 For the FortisBC service regions during the period 1990 to 2031, please provide graphical and tabular data that summarizes energy demand (MW) for the following: (a) summer peak levels, (b) winter peak levels, (c) 1-in-20 peak levels, (d) annual average. Please provide a copy in the form of an electronic spreadsheet.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

230.0 Reference: Kelowna Area Spatial Load Forecast

Exhibit B-1-1, Long Term Capital Plan, Section 2.1.1, p. 10; Appendix C, pp. 1-59

FortisBC Inc.'s Preliminary 2009 RRA, September 26, 2008, Tab 5, p. 15

FortisBC Inc.'s 2006 RRA, November 24, 2005, Tab 6, p. 4

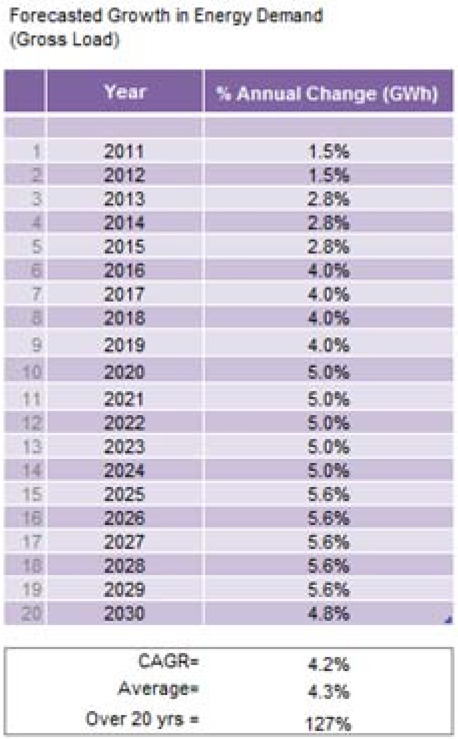
Growth Assumptions

"FortisBC engaged an engineering consultant to develop a spatial electric load forecast for the Kelowna area. A report on the methodology and results is included in Appendix C -Spatial Electric Load Forecasting, Kelowna, BC. Results to date have provided meaningful information of urban expansion patterns in the Kelowna area, as shown in Figure 2.1.1."

230.1 The load forecast presented in Appendix C provides a summary of the assumed growth rates between 2010-2030. The data suggests that the FortisBC service region will experience a compound annual growth rate (C AGR) of 4.2% between 2011 and 2030 resulting in a total growth of 127% over the same period. Historical data from 2002 to 2008 indicate a significantly lower grow rate:

<u>Response:</u>

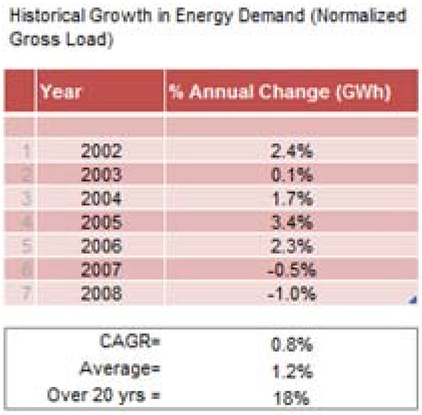
This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.



Forecasted Growth in Energy Demand (Gross Load)

	Year	% Annual Change (GWh)
1	2011	1.5%
2	2012	1.5%
3	2013	2.8%
4	2014	2.8%
5	2015	2.8%
6	2016	4.0%
7	2017	4.0%
8	2018	4.0%
9	2019	4.0%
10	2020	5.0%
11	2021	5.0%
12	2022	5.0%
13	2023	5.0%
14	2024	5.0%
15	2025	5.6%
16	2026	5.6%
17	2027	5.6%
18	2028	5.6%
19	2029	5.6%
20	2030	4.8%

CAGR=	4.2%
Average=	4.3%
Over 20 yrs =	127%



Historical Growth in Energy Demand (Normalized Gross Load)

	Year	% Annual Change (GWh)
1	2002	2.4%
2	2003	0.1%
3	2004	1.7%
4	2005	3.4%
5	2006	2.3%
6	2007	-0.5%
7	2008	-1.0%

CAGR=	0.8%
Average=	1.2%
Over 20 yrs =	18%

230.2 Please confirm whether the data presented in the above tables are correct. If not, please provide a revised version.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

230.2.1 Please describe what aspects of the Spatial Load Forecast were used by FortisBC in their 30 year load forecast which is summarized in Exhibit B-1-2, Section 4, p. 42.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

230.2.2 Please discuss and reconcile the difference between the forecasted growth in energy demand from 2012-2030 with the historical trends in growth rates from 2002-2008.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

LONG TERM RESOURCE PLAN

231.0 Reference: Energy and Capacity Supply / Demand Gaps

Exhibit B-1-2, Section 1.2.2, p. 3

Load Forecast

FortisBC states "the forecast energy sales for each customer class is reduced by a forecast of annual DSM savings and other non-DSM savings including Customer Portal Information and Residential Inclining Block and Advanced Metering Infrastructure (AMI)."

FortisBC also states "Other adjustments include savings from the RIB rate beginning in 2012, the Customer Information Portal (CIP) beginning in 2015, and the AMI-based revenue protection programs starting in 2013. A sale increase by the AMI-based revenue protection programs will be offset by a reduction in losses so that the total impact of the AMI-based programs on the gross load is zero." (Exhibit B-1, Tab 3, Appendix 3C, p. 3C-2)

231.1 Please provide a detailed description of the Customer Portal Information (and also please confirm the name of the program), including: a) which customer classes it will be applied to; b) how it will lead to energy savings; and c) the methodology used by FortisBC to forecast the energy savings from this program for the period 2015 to 2040.

Response:

The proposed Customer Information Portal (CIP) would be implemented if the AMI project were approved. The CIP would be accessed by residential customers using a secure login on the FortisBC website.

From there, the customers would have access to historical consumption and account information. Hourly consumption data from the customer's AMI meter is expected to be available the next day on the website.

a) The savings have been applied to the residential customer class;

b) Near real-time consumption information is expected to incent customers to reduce their consumption. This effect has been demonstrated in numerous studies throughout North America, and FortisBC expects that effect to be magnified as conservation rates are implemented; and

c) The savings were based on the following assumptions: 1) 15% of customers will regularly use the CIP, 2) those customers that regularly use the CIP will reduce their energy consumption by 2%.

231.2 Please provide a detailed description of the AMI-based revenue protection programs, including: a) which customer classes it will be available to; b) why these programs will lead to increased energy sales as well as reduction in losses; and the methodology used by FortisBC to forecast the increases in energy use from these programs for the period 2013 to 2040.

Response:

a) 99 percent of the energy theft identified within the last 5 years has been found in the residential sector of FortisBC. Most of this energy is consumed in the illegal production of marijuana within residences. The load forecast impact of the AMI based revenue protection program for the present applies to the residential class only; and

b) Stolen energy is energy provided by FortisBC but not paid for directly by the customers using the electricity. This unbilled energy is presently included in the gross load purchased annually and accounted for in system losses versus revenue. As AMI technology will provide additional tools to identify energy theft more of these customers will be identified and move from unmetered to metered energy. The result will be a gradual increase in sales revenue and a corresponding decline in system losses while gross load will remain unchanged. The assumption made in this application for the years 2013 - 2017 is that unmetered energy will become metered consumption. Beginning in 2018 and continuing until 2022 the prediction is that these customers will either find more efficient ways to consume electricity or will move off the electric grid to alternate sources of energy. The impact on the load forecast in the latter period is a gradual decline in sales revenue and a corresponding reduction in gross load.

231.3 Please explain the methodology used by FortisBC to forecast the residential energy savings resulting from the RIB from 2012 to 2040 and clearly identify the underlying assumptions.

Response:

In response to BCUC IR1 Q21.3 in the FortisBC Residential Inclining Block (RIB) Rate Application currently before the Commission, the Company stated,

The elasticity numbers used in the Application are meant to be long-term - they don't occur immediately. In the opinion of the Company, there is no useful method of estimating how much applies each year.

Due to the uncertainty that exists in the elasticity assumptions, this statement holds true. The elasticity calculations for each year reflect eventual savings as a result of the rate change and will not necessarily all occur in the same year as the rate is changed. So while elasticity savings are shown by year in the RIB Application, as requested, they reflect the savings that will occur over time associated with the change in rates for each year. FortisBC, as previously stated, is not able to estimate how much of the savings will occur in any given year.

Assumptions used to derive the energy savings are as follows:

In the RIB Rate Application, savings associated with the RIB rate were estimated under three different scenarios. The scenarios reflect elasticity numbers of 0.05/0.10, 0.10/0.20, and 0.20/0.30 to provide a range of estimates given the uncertainty associated with the savings. Usage was broken down into two categories: usage facing block 1 and usage facing block 2. For bills with usage below the threshold, their usage was considered to be facing block 1. For bills that exceeded the threshold, their total usage was considered to be facing block 2. The percent in each category differed based on the various thresholds considered.

The lower elasticity number in each scenario was applied to the usage facing block 1 and the higher elasticity number was applied to the usage facing block 2. For 2011 the rate change was set at the equivalent flat rate versus the RIB rates for block 1 and 2. For subsequent years the rate change was set using the previous year’s comparable rate, for example, the 2012 block 1 rate versus the 2011 block 1 rate. Savings were then estimated for each block individually by multiplying the rate change times the elasticity number times the usage in the block. Savings in the two blocks were added together and compared to total residential usage to get the percent savings.

The RIB energy savings in 2012-13 RRA match the estimated conservation from the minimum elasticity assumption for the preferred RIB rate option as shown in the “Conservation Impact” column of Table 7-2 in FortisBC’s RIB Application.

RIB savings were assumed to reduce residential load by a total of 1.9 percent, starting at 0.22 percent in 2012 and increasing incrementally until the full 1.9 percent is realized in 2017 as the 1.9 percent savings resulting from 2011 rates would likely not all be achieved until 2017. After 2017, no incremental savings from RIB are assumed.

231.3.1 Please explain why the RIB energy savings in this Application diverge greatly from the RIB conservation estimates provided by FortisBC in the FortisBC Residential Inclining Block Rate Application (RIB Application). (References: FortisBC RIB Rate Application, Exhibit B-5, BCUC IR1 Q19.2; Exhibit B-8, Panel IR Q5.2)

Response:

The RIB energy savings in 2012-13 RRA match the estimated conservation from the minimum elasticity assumption for the preferred RIB rate option as shown in the “Conservation Impact” column of Table 7-2 in the RIB Application. Please see the response to BCUC IR1 Q231.3 above.

231.3.2 Please explain why FortisBC is able to provide annual forecasts for RIB savings from 2013 to 2040 in this Application but it is unable to provide estimates of annual energy savings for 2012 to 2015 for each of the options under consideration in the RIB Rate Application.

Response:

Please see the response to BCUC IR1 Q231.3 above.

231.4 Please provide in tabular form, for each customer class, annual data on DSM savings, and other non-DSM savings including Customer Portal Information, Residential Inclining Block (RIB) and Advanced Metering Infrastructure (AMI) for the 30-year planning period (2010 to 2040). Please also provide in electronic format.

Response:

Three tables are presented below:

1- Annual cumulative DSM energy savings (MWh),

2- Annual cumulative of total non-DSM energy savings (RIB, AMI, and CIP) before losses (MWh), and

3- Annual cumulative of total non-DSM energy savings (RIB, AMI, and CIP) after losses (MWh).

All non-DSM savings are for the residential sector only. Note that in each year in the 2013-2017 period, the AMI-based programs’ annual impact on the residential gross load is zero as sale increases (negative savings) and loss reduction due to the AMI program offset each other. After

2017, sale increases due to AMI start diminishing (and reach zero in 2022), hence the main long-term benefits are from loss reductions.

The data is also provided in electronic form.

Cumulative DSM Energy Break-out (MWh)

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Net	Loss	Gross
2010	-	-	-	-	-	-	-	-	-
2011	5,432	4,066	4,495	1,243	373	343	15,952	1,544	17,496
2012	15,431	11,549	12,769	3,530	1,059	873	45,212	4,376	49,587
2013	24,457	19,224	20,674	5,876	1,763	1402	73,396	7,103	80,499
2014	33,762	27,136	28,823	8,295	2,488	1969	102,474	9,917	112,391
2015	43,831	35,698	37,640	10,911	3,273	2580	133,934	12,962	146,896
2016	54,443	44,722	46,934	13,670	4,101	3223	167,093	16,171	183,264
2017	63,844	52,716	55,167	16,113	4,101	3773	195,715	18,941	214,656
2018	72,009	59,658	62,317	18,235	4,101	4265	220,586	21,348	241,935
2019	80,173	66,601	69,467	20,357	4,101	4758	245,458	23,756	269,213
2020	88,338	73,543	76,617	22,479	4,101	5250	270,329	26,163	296,492
2021	96,502	80,486	83,767	24,602	4,101	5742	295,200	28,570	323,770
2022	104,667	87,428	90,917	26,724	4,101	6235	320,072	30,977	351,048
2023	112,831	94,371	98,067	28,846	4,101	6727	344,943	33,384	378,327
2024	120,996	101,313	105,217	30,968	4,101	7219	369,815	35,791	405,605
2025	129,160	108,256	112,368	33,090	4,101	7712	394,686	38,198	432,884
2026	137,325	115,198	119,518	35,212	4,101	8204	419,557	40,605	460,162
2027	145,489	122,141	126,668	37,334	4,101	8696	444,429	43,012	487,441
2028	153,654	129,083	133,818	39,456	4,101	9189	469,300	45,419	514,719
2029	161,818	136,026	140,968	41,578	4,101	9681	494,171	47,826	541,998
2030	169,983	142,968	148,118	43,700	4,101	10173	519,043	50,233	569,276
2031	178,147	149,911	155,268	45,822	4,101	10665	543,914	52,640	596,555
2032	186,312	156,853	162,418	47,944	4,101	11158	568,786	55,047	623,833
2033	194,476	163,796	169,568	50,066	4,101	11650	593,657	57,454	651,111
2034	202,641	170,738	176,718	52,188	4,101	12142	618,528	59,862	678,390
2035	210,805	177,681	183,868	54,310	4,101	12635	643,400	62,269	705,668
2036	218,970	184,623	191,018	56,432	4,101	13127	668,271	64,676	732,947
2037	227,134	191,566	198,168	58,554	4,101	13619	693,142	67,083	760,225
2038	235,299	198,508	205,318	60,677	4,101	14112	718,014	69,490	787,504
2039	243,463	205,451	212,468	62,799	4,101	14604	742,885	71,897	814,782
2040	251,628	212,393	219,618	64,921	4,101	15096	767,757	74,304	842,061

Residential Non-DSM Savings - Before Losses (MWh)

Year	RIB	AMI	CIP	Total	AMI Loss
2011	-	-	-	-	-
2012	2,842	-	-	2,842	-
2013	7,861	(2,286)	-	5,574	2,286
2014	13,077	(4,662)	-	8,414	4,662
2015	18,499	(7,132)	2,038	13,404	7,132
2016	24,120	(9,694)	4,155	18,581	9,694
2017	26,805	(12,344)	4,232	18,693	12,344
2018	27,294	(10,056)	4,310	21,548	12,570
2019	27,780	(7,676)	4,386	24,490	12,793
2020	28,264	(5,206)	4,463	27,520	13,016
2021	28,747	(2,648)	4,539	30,638	13,239
2022	29,228	-	4,615	33,843	13,460
2023	29,708	-	4,691	34,399	13,681
2024	30,188	-	4,767	34,954	13,902
2025	30,667	-	4,842	35,510	14,123
2026	31,142	-	4,917	36,059	14,342
2027	31,611	-	4,991	36,602	14,558
2028	32,076	-	5,065	37,141	14,772
2029	32,538	-	5,138	37,676	14,985
2030	32,994	-	5,210	38,203	15,195
2031	33,446	-	5,281	38,727	15,403
2032	33,898	-	5,352	39,250	15,611
2033	34,346	-	5,423	39,769	15,817
2034	34,791	-	5,493	40,284	16,022
2035	35,232	-	5,563	40,795	16,225
2036	35,670	-	5,632	41,302	16,427
2037	36,105	-	5,701	41,806	16,627
2038	36,536	-	5,769	42,305	16,826
2039	36,965	-	5,837	42,801	17,023
2040	37,389	-	5,904	43,293	17,219

Residential Non-DSM Savings - After Losses (MWh)

Year	RIB	AMI	CIP	Total
2011	-	-	-	-
2012	3,117	-	-	3,117
2013	8,621	-	-	8,621
2014	14,342	-	-	14,342
2015	20,289	-	2,235	22,524
2016	26,455	-	4,557	31,011
2017	29,399	-	4,642	34,041
2018	29,935	2,514	4,727	37,176
2019	30,468	5,117	4,811	40,396
2020	30,999	7,810	4,895	43,703
2021	31,529	10,591	4,978	47,098
2022	32,057	13,460	5,062	50,579
2023	32,583	13,681	5,145	51,409
2024	33,110	13,902	5,228	52,240
2025	33,635	14,123	5,311	53,069
2026	34,156	14,342	5,393	53,891
2027	34,670	14,558	5,474	54,702
2028	35,180	14,772	5,555	55,507
2029	35,687	14,985	5,635	56,307
2030	36,187	15,195	5,714	57,095
2031	36,683	15,403	5,792	57,878
2032	37,178	15,611	5,870	58,659
2033	37,670	15,817	5,948	59,435
2034	38,158	16,022	6,025	60,205
2035	38,642	16,225	6,101	60,968
2036	39,122	16,427	6,177	61,727
2037	39,599	16,627	6,253	62,479
2038	40,073	16,826	6,327	63,226
2039	40,542	17,023	6,401	63,967
2040	41,008	17,219	6,475	64,702

232.0 Reference: Load Forecast

Exhibit B-1-2, Long Term Resource Plan, Section 1.2.2, p. 3

Line Losses & System Use (Line Losses)

232.1 Please provide a benchmark comparison of Line Losses expressed as percentage of transmission and distribution billed sales of peer group utilities that include Pacific Gas & Electric (PG&E), Sask Power, Manitoba Hydro, Hydro Quebec, and BC Hydro.

Response:

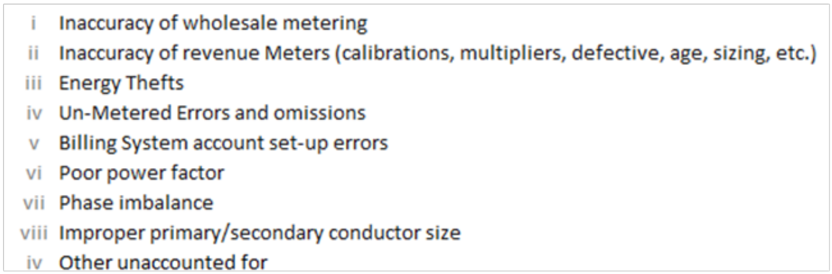
This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

232.2 Please describe and quantify initiatives undertaken by FortisBC over the past 5 years, or planned over the next 5 years, that have resulted in reduced Line Losses and system use, or that have the potential to reduce such losses and system use.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

232.3 Resistance to the flow of electrical current in the distribution and transmission system is not solely responsible for Line Losses. Other causes of line loss typically can include:



i Inaccuracy of wholesale metering
ii Inaccuracy of revenue Meters (calibrations, multipliers, defective, age, sizing, etc.)
iii Energy Thefts
iv Un-Metered Errors and omissions
v Billing System account set-up errors
vi Poor power factor
vii Phase imbalance
viii Improper primary/secondary conductor size
iv Other unaccounted for

232.3.1 For the period 2000 to 2010, please provide a Line Loss report (tabular data) segmented by year and cause of loss.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

232.3.2 Please provide copies of engineering/economic studies undertaken by FortisBC in the past 10 years relating to line losses. If no studies have been conducted, please indicate whether FortisBC has any plans to perform such a study as part of a future regulatory filing (e.g. Cost of Service Analysis “COSA”).

Response:

No formal studies have been conducted to determine line losses since insufficient information is available to properly apportion known system losses between various causes. Once the Advanced Metering Infrastructure project is completed (and thus sufficient information was available to properly allocate system losses), FortisBC would be amenable to developing such a study for filing in a future application.

232.3.3 If line losses were reduced from 8.8% to 7.8% during the period 2012-2040, what impact would it have on FortisBC’s long-term capital plan? What impact would it have on customer rates?

Response:

FortisBC is unable to determine the effect that the suggested loss reduction would have on the 2012 Long Term Capital Plan for two reasons:

a) It is important to note that loss estimates are only available as a percentage of energy sales (MWh) and not as a percentage of peak load (MW). To calculate the system losses at the time of the system peak it would be necessary to have full customer consumption information during the short interval of the system peak. Since most customers are only read either monthly or bi-monthly the necessary consumption information at the time of the peak is unknown. Only with the detailed consumption information provided by the Advanced Metering Infrastructure project would it be possible to determine the system losses in near real-time. Since capital projects are typically driven by peak load conditions there is no information available to determine the effect that a loss reduction would have on the timing for any given project; and

b) Since losses are not evenly distributed through the system, it is not clear how an overall 1 percent loss reduction would impact the peak demand on individual system assets.

Thus, again it is not possible to determine the effect that an overall loss reduction would have on the timing for any given project.

If line losses were reduced by 1 percent as indicated above, the Rate Impact for 2012-13 (period under consideration) would be reduced as indicated in the Table below:

Table BCUC IR1 232.3.3

Customer Rate Impact Variance Analysis	2012	2013	2012-13 Cumulative
Base Case Rate Impacts (As per 2012-13 RRA)	4.0%	6.9%	11.2%
Rate Impact with reduced system loss by 1%	3.4%	6.8%	10.4%
Variance from Base Case	-0.6%	-0.1%	-0.7%

233.0 Reference: Resource Options and Strategies

Exhibit B-1-2, Section 1.3.1, p. 9

Build Strategy

FortisBC states that "The Company then refined its resource option rankings by running the resource options that passed initial UCC and UEC **econometric screening** through a set of filters that represent key FortisBC priorities and requirement." (Emphasis added)

233.1 Please explain what FortisBC means by "the initial UCC and UEC econometric screening".

Response:

The initial UCC and UEC econometric screening refers to a process completed in the FortisBC 2010 Resource Options Report contained in Appendix C of the 2012 Long Term Resource Plan (Exhibit B-1-2). As per the FortisBC 2010 Resource Options Report:

- **Unit Capacity Cost (UCC)** UCC is defined as the annual cost of providing Dependable Capacity using each resource option, expressed as $/MW-month. Annual costs include the interest on debt, return on equity, and amortization, which are derived from the project capital cost. Annual costs also include the fixed operating costs that must be spent to keep the project's dependable capacity available regardless of the amount of energy generated each year. UCC is used to rank resources being considered to address capacity requirements. If a capacity shortfall has been identified, the UCC metric can be used to assemble a portfolio of lowest cost capacity resources to address that need.

- **Unit Energy Cost (UEC)** UEC is defined as the annualized cost of generating a unit of electrical energy using a specific resource option, expressed as $/MWh. The UEC calculation divides the all-in capital, fixed operating, and variable operating costs by the total amount of energy expected to be generated over the resource's anticipated service life. UEC is used to rank resources under consideration to address energy requirements. If an energy shortfall has been identified, the UEC metric can be used to develop a lowest cost energy resource portfolio to address that need.

The FortisBC 2010 Resource Options Report calculated a UCC and UEC for each resource option available. These resources were subsequently sorted and ranked in order of the most desirable UCC and UEC values. A summary of the results is located in Table 5.2 of the FortisBC 2010 Resource Options Report located in the 2012 Long Term Resource Plan, Appendix C. The resource options in Table 5.2 of the FortisBC 2010 Resource Options Report were then filtered to remove resource options that were not available to FortisBC (e.g. BC Hydro's resource options Mica 5 & 6, Revelstoke, etc.). Remaining resource options were included in the evaluation for inclusion in Exhibit B-1-2, Section 1.3.1, Table 1.3.1.

234.0 Reference: Governmental Policy and Legislation Regarding the Environment

Exhibit B-1-2, Section 2.4, p. 15

Canadian Federal Legislative / Regulatory Framework

FortisBC states that "On March 10, 2008, the Government of Canada published further details of the "Turning the Corner" regulatory framework. This updated plan includes mandatory reductions for industry, along with additional new measures to address two of Canada's key emitting sectors: oil sands and electricity. The details of the plan include: …"

234.1 Please provide an update on the Canadian government implementation of its "Turning the Corner" regulatory framework.

Response:

The Federal Government's "Turning the Corner" Webpage has not been updated since 2008. However, it refers to Canada's Action on Climate Change Fact Sheet for more information on Canada's current action on climate change, including information on proposed vehicle emissions regulations and our Canada-U.S. collaboration on the Clean Energy Dialogue.

Canada's Action on Climate Change Fact Sheet is available at:

http://www.climatechange.gc.ca/default.asp?lang=En&n=D43918F1-1

235.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 2.6, p. 27

Stakeholder Consultation Regarding PRM

"96 percent of customers support holding a Planning Reserve Margin, with 60 percent willing to pay higher rates for the Planning Reserve Margin."

235.1 Please discuss the context of and amount of information that was provided to stakeholders regarding the potential short-term (2012 and 2013) and medium-term (2014 to 2021) costs of carrying PRM.

Response:

While the direct costs of carry PRM were not discussed in the ISP open houses, the approximate rate increase as a result of PRM was discussed. The estimated rate increase of approximately 3% due to "Other Power Purchase", which includes the expected costs of the PRM, was provided to the stakeholder. This is shown on slide 22 of the presentation, in Appendix K of the 2012 Long Term Capital Plan (2012 Integrated System Plan, Volume 1). The Company believes that showing the cost as a percentage rate increases provides better information to the stakeholders than giving out dollar amounts. The stakeholders do not always know the correlation between the dollar amount and their electricity bill.

235.2 Please confirm that 40 percent of the stakeholders were unwilling to pay higher rates for the Planning Reserve Margin.

Response:

As shown in Appendix K of the 2012 Long Term Capital Plan (2012 Integrated System Plan, Volume 1), 30% of stakeholder said they were "likely not" and 9% were "definitely not" willing to pay higher rates for the planning margin.

236.0 Reference: Electricity Market

Exhibit B-1-2, Section 3, p. 29

FortisBC states that "FortisBC feels its strategy of making market purchases to close the gap between its supply and demand has generally been successful."

236.1 What criteria does FortisBC use to affirm that its strategy of making market purchases has generally been successful (e.g., average cost of market purchases, number of outages)?

<u>Response:</u>

FortisBC believes the current market based strategy has been generally successful since the Company has been able to meet its peak demand at reasonable costs and without having to resort to measures such as public emergency appeals for conservation except on a very occasional basis.

The Company's cost of spot market purchases to meet peak load requirements is higher than the overall average cost of market power. This is to be expected since the Company's other resources mean that the Company's exposure to resource shortfalls is limited to only a small number of hours per year in the short to medium term. Since the Company is therefore purchasing power at the times of greatest overall regional demand, the price will be higher than the average price. The alternative of obtaining a new resource to meet this load would be at a much higher cost over the short to medium timeframe.

To the Company's knowledge, there has never been a customer outage due to a lack of overall supply. A cold weather event that resulted in a public appeal for conservation occurred in January 2004. In this event, there was insufficient power available to be purchased on the real-time markets at any price.. This occurred due to a change in the weather forecast between the day ahead trading (which was actually 5 days ahead due to industry holiday schedule accommodation) and real-time. The public appeal for conservation was an import part of meeting load for that day along with voltage reduction and assistance from Teck.

The Company will continue to monitor the risks to determine the suitability of continuing to rely on market based power to meet peak load demands.

237.0 Reference: Supply and Demand

Exhibit B-1-2, Section 3.1, p. 30

Available Market Supply

FortisBC states that "The Preferred Strategy is based on current price and load forecasts, which will be reviewed regularly. The renewal of the BC Hydro PPA may also impact the timing and nature of the Preferred Strategy if the final terms are different than what has been assumed in the 2012 Resource Plan. The Company will monitor these conditions and if they change, it may impact the timing and the nature of the Company's strategy. Any changes will be reflected in FortisBC's next Resource Plan."

237.1 How regularly does FortisBC plan to review the price and load forecasts?

Response:

FortisBC typically updates its load and price forecasts twice a year.

237.2 Considering that negotiations between FortisBC and BC Hydro to renew the BC Hydro PPA have been ongoing since 2005, what are the probabilities that the terms of the renewed BC Hydro PPA are different than those assumed herein?

Response:

FortisBC and BC Hydro remain in very active discussions regarding the terms of under which the PPA would be renewed and are attempting to come to a negotiated solution. Therefore, the Company respectfully declines to provide further details at this time. Please also see the response to BCUC IR1 Q251.3.1.

237.3 When does FortisBC plan to file its next long-term Resource Plan?

Response:

FortisBC plans to file a Long-Term Resource Plan approximately every five years. If there is a significant event that would prompt a material revision in the Long-Term Resource Plan, FortisBC may file an earlier update to the Resource Plan.

238.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 3.1.2.1, pp. 30-31

Market Shortages of Capacity

> "In a more recent example, during a regional cold spell that occurred in November 2010 FortisBC purchased a 150 MW block of energy in the day-ahead market to address an anticipated extreme load demand. When FortisBC attempted to purchase an additional 10 MW in the real-time market the following day there was no supply available for purchase in the market (at any price). A similar situation occurred the following week. If during any of these times FortisBC's largest single supply unit (Brilliant) had become unavailable, the Company would have had to draw upon excess BC Hydro PPA capacity (estimated at approximately $1 million) to avoid shedding load."

238.1 Please confirm that FortisBC's current contractual arrangements for on-demand capacity purchases.

Response:

FortisBC's only on-demand capacity contractual arrangement is under the BC Hydro PPA. BC Hydro is obligated to supply on-demand up to 170 MW of capacity at the Okanagan interconnection and 30 MW of capacity at the Princeton interconnection for all hours. FortisBC will pay the applicable capacity ratchet charges. Capacity received above the nominations of 170 MW at the Okanagan interconnection and 30 MW at the Princeton interconnection is considered Excess Capacity. Under the current terms of the PPA BC Hydro will make "reasonable efforts" to supply Excess Capacity to FortisBC above the nominated amounts. However, the cost of Excess Capacity is large. Excess Capacity will cost the Company approximately $70,000/MW.

238.2 Please confirm the duration for which a new capacity demand level is set once an excess capacity charge is triggered under the BC Hydro PPA.

Response:

Once an excess capacity charge is triggered under the BC Hydro PPA, the Company is required to pay the excess capacity charge in that month, plus 75% of the excess capacity charge in each month for the next 11 months.

239.0 Reference: Supply and Demand

Exhibit B-1-2, Section 3.1.2.2, p. 31

Transmission Interconnection Constraints

Exhibit B-1-2, Appendix B, Section 4.2.3, pp. 16-17

Transmission Availability and Constraints

FortisBC states that "The British Columbia / Alberta and the British Columbia / United States transmission interconnections often operate at their maximum available transfer limits; therefore wheeling additional power between utilities in the region is frequently not possible."

239.1 Please elaborate on how often each of these transmission interconnections operate at their maximum available transfer limits and what the underlying causes are.

Response:

It is FortisBC's understanding from its own trading experience on the British Columbia / United States interconnection and also based upon recent conversations with power traders active on the British Columbia / Alberta interconnection, that these interconnections are often operated at maximum transfer limits, especially during Heavy Load Hours during the winter and summer peak load periods. During much of the year price differentials between Alberta, BC and the US Pacific Northwest create an incentive to trade power between the regions.

Several very active traders have acquired large Firm and Conditional Firm positions on these interties, effectively leaving limited or no ability for other parties to acquire Firm transmission rights. Excess capacity only becomes available on these interconnections on a spot basis when the parties holding the firm capacity rights determine that market conditions are not favourable for them to trade power on the interconnections.

The BC / Alberta interconnection is often further constrained below its nominal transfer capacity because of system limitations that vary depending upon system loading and transmission facility outages internal to Alberta.

239.2 Please provide an analysis showing the south to north congestion of the transmission path with the US correlated against the times when FortisBC would need to rely on imports for emergency supply.

Response:

"Emergency supply" periods for FortisBC are by definition unpredictable. Such emergencies are very likely caused by regional weather extremes, such as an unforeseen lengthy cold snap, or by an unexpected generation outage or transmission outage of sufficient size to negatively impact FortisBC. In either case, there is a danger that the cause of the emergency will similarly impact FortisBC's neighbouring utilities, thus exacerbating the emergency supply situation.

FortisBC has not performed a correlation analysis between the available transmission capacity, the times when FortisBC will potentially require emergency supply, and the forecast price of the supply alternatives. Attempting to conduct an analysis with this many degrees of freedom is complex and costly with little certainty that the analysis' conclusions would provide reliable information given the number of assumptions incorporated into the analysis.

239.3 Please confirm that FortisBC has access rights on Teck's 71 Line to access the US market. Please describe the conditions of this access right.

Response:

FortisBC has indefinite rights to use Teck's 71 Line, which has a total capacity of 370 MW year round.

These rights allow FortisBC to import over the Northern Intertie (i.e. the US to BC path). However, they do not provide any transmission rights to move power to the Northern Intertie on the US side.

240.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 3.1.3.5, pp. 33-34

Alberta Energy Markets

Exhibit B-1-2, Appendix B, Section 4.3, pp. 17-20

Competition with Neighbouring Jurisdictions

240.1 Please confirm that the BC – Alberta transmission path is highly constrained.

Response:

Yes, the BC – Alberta transmission path is highly constrained. See response to BCUC IR1 Q239.1 for analysis of BC-Alberta transmission path constraints.

In addition to the detail analysis shown in to BCUC IR1 Q239.1, the Company's discussions with power marketers, and attempts to use the path, have all confirmed that there are significant transmission constraints.

240.2 Please provide an analysis which correlates the amount and direction of congestion on the BC – Alberta transmission path against the times when FortisBC is likely to require emergency supply, and comment on what this correlation suggest for FortisBC and participants in the Alberta market to be price competitors for the same resource.

Response:

Please see the responses to BCUC IR1 Q239.2, Q273.1 and Q273.1.1

241.0 Reference: Market Pricing

Exhibit B-1-2, Section 3.2, pp. 34-35

Hydrology

FortisBC states that “Overall WECC market prices are predominantly driven by three key factors: hydrology, natural gas prices and transmission constraints.”

FortisBC also states that “Hydroelectric generation comprises over 30 percent of WECC capacity and almost 55 percent of the capacity in the NWPP region. The total available annual energy from this generation is dependent upon the amount and timing of precipitation in the various WECC drainage basins. Precipitation during maximum water years can be 50 percent greater than in minimum water years, therefore precipitation can materially affect regional market supply and pricing.”

241.1 Given the prominence of hydroelectric generation in the WECC region and the significance of hydrology as a key variable influencing WECC market prices, please elaborate on the type of analysis FortisBC is currently undertaking or planning to undertake in the near future to assess the potential impacts of climate change through changes in precipitation patterns on: 1) FortisBC’s hydroelectric generation capacity over the next 30 years given; and 2) the WECC region’s hydroelectric generation capacity over the next 30 years.

Response:

FortisBC has not undertaken its own studies on the impacts of climate change on hydrologic or hydrogeologic conditions in the WECC affecting hydroelectric power generation. FortisBC is aware; however, that BC Hydro is working with the University of Victoria’s Pacific Climate Impacts Consortium to examine potential future impacts of climate change on hydroelectric generation. FortisBC has also reviewed work done by the Northwest Power and Conservation Council appended to their 6th Power Plan. Since the preparation of the 6th Power Plan, Fortis BC understands that additional studies are being undertaken by US federal agencies in cooperation with the University of Washington’s Climate Impact Group. These studies, however, are not yet complete.

Climate change may impact WECC hydroelectric generation. In general, a review of the reports referred to above reveals that climate change modellers are expecting higher annual temperatures that will result in a shift toward increased rain and decreased snowfall during winter months, decreases in snowpack and glacier sizes, and a potential shift in timing of the spring peak runoff. Modelling results, however, appear to remain uncertain as to the overall impact on hydroelectric generation. Some results predict overall drying impacts with reduced stream and river flows available for generation, while other results show moistening trends and improved generation availability. Further, Fortis BC understands that the assumptions that went into the NPCC's 6th Power Plan were limited by the accuracy of the rainfall forecasts, the flood control rules that formed inputs to the models and operational rules with respect to hydro facilities in Canada and the US.

Since FortisBC's core hydroelectric generation resources are Canal Plan Agreement facilities, any changes in hydrological conditions due to climate change should not impact FortisBC's energy and capacity entitlements. Therefore, FortisBC is of the view that embarking on its own assessment of the impacts of climate change on hydroelectric generation will not add value to its integrated resource planning process at this time. Rather, FortisBC intends to continue monitoring the results of climate change studies and forecasts already being undertaken and assessing the results for definitive trends and implications. This approach is consistent with the recommendation of the 6th Power Plan for the Northwest Power and Conservation Council[3].

242.0 Reference: Cost of Energy and Capacity in British Columbia

Exhibit B-1-2, Section 3.3, p. 38

Figure 3.3.2-A – BC Wholesale Market Energy Curves vs. BC New Resources Market Energy Curve ($CAD/MWh)

FortisBC states that "In the specific context of the forecast energy and capacity price curves presented in Section 4, the forecasts have three general timeframes: […] Long term: More than ten (10) years."

242.1 Based on Figure 3.3.2-A, please indicate what is FortisBC's **Long-Run** Marginal Cost (LRMC) of New Supply for 2012 (as opposed to the marginal cost of energy in the near to medium term). Please also provide justification.

<u>Response:</u>

FortisBC defines long-run marginal cost as the cost to acquire additional power where existing resources are insufficient to meet load requirements. As outlined in the Resource Plan, in the near to medium term FortisBC expects to meet incremental requirements through increased market purchases. Therefore, in the short to medium term, the determination of long-run

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[3] Page L-2 of the 6th Power Plan, Appendix L.

marginal cost could be based on the forecast of the market price of power and not the cost of new construction.

The Resource Plan contains a BC Wholesale Market Energy Curve in the FortisBC Energy & Capacity Market Assessment conducted by Midgard (Appendix C of the Resource Plan). As outlined in Table 242.1, the LRMC based on incremental market purchases is $84.94.

BC Hydro calculates its LRMC from new resources as $124.3/MWh. This is based on projects granted contracts under its 2008 Clean Power Call, so their LRMC is a fair representation of the BC Hydro avoided costs. The $124.3/MWh represents an adjusted weighted average levelized firm energy price, using a nominal 8% discount rate (which assumes 2.1% inflation). The price is adjusted for the costs to deliver energy to the lower mainland, including transmission upgrades. The corresponding plantgate price is $111.3/MWh. The BCH LRMC price is based on firm delivery, which has a built-in capacity component. There is additional non-firm energy acquired under this call which is priced significantly lower which is not included in the BC Hydro calculation of LRMC (approximately $57/MWh).

FortisBC does not have an equivalent energy call to base a calculation of LRMC from new resources. In addition, as discussed in the Resource Plan, FortisBC expects to meet incremental requirements primarily through additional energy purchases under the BC Hydro 3808 contract and market purchases and is not planning to acquire new resources in the near to medium term.

Nevertheless, a LRMC from new resources could to be developed from a forecast of the cost of potential new resources. The Resource Plan contains a preliminary estimate of the cost of BC new resources in the Midgard Resource Options Report (Appendix C of the Resource Plan). A reasonable proxy for the cost of new resources in the long term is to use the BC New Resources Market Energy Curve presented as Table 5.2-A in the Midgard 2011 FortisBC Energy and Capacity Market Assessment (Appendix B of the Resource Plan).

Using the projections contained in the Midgard Report, and a nominal discount rate of 8%, FortisBC has calculated a levelized value for its LRMC, for use in this Application, of $111.96 per MWh. Table 242.1 provides a summary of the LRMC discussed in this Application.

1 **Table BCUC IR1 242.1 Long Run Marginal Cost**

Reference	Definition	Value
FortisBC RIB Application - Exhibit B8 Q7.1, 7.2	Marginal Cost (defined as Short Term Avoided Costs over 2012 to 2015 period (based on primarily avoided 3808 Energy Purchases with minor amount of market purchases and surplus sales)	$38.04 /MWh (energy only)
FortisBC 2012 Resource Plan – Appendix B: Midgard 2011 FortisBC Energy and Capacity Market Assessment	LRMC (define as the cost to acquire additional power through market purchases where the existing resources are insufficient to meet load requirements).	$84.94/MWh (6% real)
FortisBC 2012 Resource Plan – Appendix C: Midgard Resource Option Report	LRMC New Construction – Similkameen UEC	$97/MWh (6% real)
FortisBC 2012 Resource Plan – Appendix B: Midgard 2011 FortisBC Energy and Capacity Market Assessment	BC New Resources Market Energy	$111.96/MWh (8% nominal)
Clean Power Call RFP– Report on the RFP Process – August 3, 2010	BCH LRMC (Clean Power Call) Delivered to LML	$124.30/MWh (8% Nominal)
Clean Power Call Request For Proposals – Report on the RFP Process – August 3, 2010	BCH LRMC (Clean Power Call) Plantgate	$111.3/MWh (8% Nominal)

2

3

242.2 Given FortisBC's response in the question above, please justify the variance, if any, between FortisBC's LRMC and BC Hydro's LRMC of 13.2 cents/kWh in F2012 (Reference: BC Hydro RIB Rate Re-Pricing Application, Exhibit B-1, p. 2).

Response:

The 13.2 cents/kWh referred to above is in 2012 dollars. Converting it into 2009 dollars is 12.4 cents/kWh, which is equivalent to the figure shown for BC Hydro Marginal cost in Table BCUC IR1 242.1 in response to BCUC IR1 Q242.1.

Please see the response to BCUC IR1 Q242.1.

243.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 3.4.1, p. 39

Assessment of Potential Risks

> "The energy and capacity market price comparisons provided in Section 3.3 do not take into account the potential long-term cost implications of the risk factors and trends discussed in Sections 3.1.2 and 3.1.3, such as Renewable Portfolio Standards, Demand Side Management and transmission constraints. Although these trends are presently impossible to quantify they should be recognized as factors which could materially increase the cost of procuring both energy and capacity from the Wholesale market in the medium term to long term future."

243.1 Please confirm that the outcomes associated with the risk factors are equally likely to decrease wholesale market prices in the medium term to long term.

Response:

No, the outcomes associated with the risk factors are not symmetric. Most of the identified risks would tend to increase market costs should they occur. It will not commensurately reduce market costs if any or all of these risks do not occur. The probability that wholesale market prices will decrease in the medium to long term is materially less than the probability that wholesale market prices will increase during that period. In other words, market prices are far more likely to increase by 50% than they are to decrease by 50%.

243.2 Please comment on the supply potential of conventional and unconventional natural gas reserves to significantly disrupt the future cost of capacity.

Response:

It is the Company's view that increases in the supply potential of unconventional natural gas reserves identified in recent years have resulted in lower natural gas commodity price forecasts, which is likely to result in the development of new gas fired generation capacity in various jurisdictions in North America. For the purposes of FortisBC's Long Term Resource Plan, however, the Company believes that the supply potential and its subsequent impact upon future natural gas prices has been appropriately factored into the electricity market price projections found in Appendix B of the Resource Plan.

Midgard's electricity price forecast was developed taking into consideration the following sources of information, which in turn had already embedded the impact of the supply potential of conventional and unconventional gas reserves gas into the respective price forecasts. Specifically:

- In its 2011 IRP Technical Advisory Committee Summary Brief: Natural Gas Price Forecast (January 2011), BC Hydro developed a natural gas price forecast, which included the effects of shale gas supply potential on the market;
- In its 2011 IRP Technical Advisory Committee Summary Brief: Electricity Spot Market Price Forecast (January 2011), BC Hydro developed a Mid-C electricity price forecast, which included the impacts of its natural gas price forecast.

The BC Hydro Mid-C electricity price forecast was then converted into a FortisBC forecast electricity price by adding transmission wheeling costs (from Mid-C to the FortisBC Service Area) and foreign exchange costs.

In this way, the effects of unconventional gas are embedded in Midgard's electricity price forecast.

In any case, the price of fuel (natural gas) is not a variable used in the calculation of Unit Capacity Cost (UCC) (see Appendix C, Section 2.2, page 7 of 82 for discussion of UCC). UCC is a measure to assess only the installation costs of new capacity resources and does not consider the cost of generating energy using those resources. The price of natural gas does not have a direct impact upon the cost of installing a capacity resource (e.g. SCGT or CCGT). The BC New Resources Market Capacity Curve is based upon UCC calculations.

References:

BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: Natural Gas Price Forecast (January 2011)

BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: Electricity Spot Market Price Forecast (January 2011)

BC Hydro, 2011 IRP Presentation to the Technical Advisory Committee, Meeting #2 – Day 1 (January 2011)

243.3 Please comment on the following announcement by the proponents of the Canada to Northern California transmission project to let the studies lapse, and its potential effect to stranded resources in the Northwest:

> "Over the last four years, Avista Corporation (Avista), BC Hydro, and Pacific Gas and Electric Company (PG&E) have jointly sponsored the Canada-Pacific Northwest-Northern California (CNC) Transmission Project. This Project consists of 500 kV HVAC and HVDC segments from British Columbia through the Pacific Northwest to Northern California. The Project has achieved WECC Phase 2 status with a Planned Rating of 3000 MW in the north-to-south direction, and studies indicate that a rating of 2000 MW in a south-to-north direction is possible.
>
> Since the Sponsors originally conceived of this Project, the supply of and need for renewable resources has evolved. As such, the Sponsors have decided to let the current study agreements for the Project lapse. Each of the Sponsors believes that expansion of transmission capacity is needed to access renewable resources. In fact, Avista and BC Hydro plan to continue with the possible implementation, including the continuation of the WECC rating process, for the original HVAC segment between British Columbia and the northeast Oregon. PG&E is continuing to explore the need for regional transmission to access renewable resources."

Response:

The announcement suggests the delay or postponing of the project to expand transmission between the three regions.

Additional interregional transmission capacity allows the incremental levelization of market prices across the interconnected regions. In other words, high demand in one region may be satiated by high supply from an interconnected region, hence mitigating price rises in the high demand region while commensurately raising prices in the high supply region.

In the event there are low marginal cost stranded resources in the Pacific Northwest (for example, excess hydroelectric generation during the spring freshet), additional interregional transmission capacity electricity would enable previously stranded electrical energy to be sold to a wider array of buyers. A lack of additional transmission capacity will result, within the short run, all else being equal, in lower electricity energy prices within the surplus region.

Similarly, during the winter season when hydroelectric generation in the Pacific Northwest is constrained due to low streamflows and regional loads are coincidentally high due to winter heating and lighting requirements, additional interregional transmission capacity would enable less constrained access to surplus wintertime generation resources in the US Southwest, thereby reducing winter energy costs in the generation deficient region (Pacific Northwest). A lack of additional transmission capacity will result, within the short run, all else being equal, in higher electricity energy prices within the generation constrained region (Pacific Northwest).

244.0 Reference: Load Forecast

Exhibit B-1-2, Section 4, p. 41

FortisBC states that "Based on recent trends and the results of residential end use surveys, it is assumed that residential use per customer before DSM will remain constant over the forecast period."

244.1 How are the RIB-related impacts taken into account in relation to the use per customer (UPC)? Please clarify whether it is the UPC forecast before DSM and RIB that remain constant or before DSM but after RIB?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.2 Please confirm that the forecast period is the next 30 years, from 2011 to 2040 and provide a justification for forecasting a constant UPC for the next three decades.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.2.1 Please provide the trends and the results of residential end use surveys that support this conclusion.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.2.2 Please also provide the historical residential UPC for the last 30 years.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

FortisBC states that "The commercial class is comprised of many diverse sectors including commercial enterprises, school, hospitals, other public buildings as well as small industrial sites. As such the energy use in this class has been found to be well correlated with provincial real gross domestic product growth and has been forecast on that basis."

244.3 Please explain why the energy used by schools, hospitals and other public buildings is a function of economic activity as measured by GDP?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.3.1 What is the correlation coefficient between commercial load and GDP? Please specify the period over which it is calculated.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

FortisBC states that “Industrial loads are forecast based partly on survey data supplied by customers, and where customer information is not available, by forecast GDP growth rates in each industrial sector. In the long term, composite GDP growth rates of industrial sectors are used to escalate the entire industrial load. Out of 24 listed sectors by CBOC, only 12 sectors contribute to the FBC’s industrial load growth rates, with 95 percent of growth determined by five sectors: agriculture, forestry, manufacturing, utilities, and commercial service.”

244.4 What percentage of industrial customers provided survey data? For the customers having provided survey data, have they provided their load forecast for the 30-year period ending in 2040?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.5 Please explain what FortisBC means by “composite GDP growth rates” of industrial sectors and how they are calculated. Do these composite GDP growth rates correspond to the 24, 12 or 5 industrial sectors listed above?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.6 Please provide the list of the 12 sectors contributing to FBC's load growth with their respective share.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

FortisBC states that "Irrigation loads are forecast to be constant on a before DSM basis while lighting loads grow based on a trend analysis."

244.7 Please provide a justification for the forecast methods for irrigation and lighting load. Please provide historic data or any other data supporting FortisBC's forecasts.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

244.8 Please discuss FortisBC's forecast that irrigation loads will remain constant over the next 30-year period in light of increasing average temperature and changed precipitation patterns resulting from climate change.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

FortisBC states that "When considered on a before DSM basis, gross load is forecast to increase at an annual average rate of 1.8 percent in the first ten years of the forecast and by 0.8 percent in the **final thirty years of the forecast**." (Emphasis added)

244.9 Please confirm that FortisBC meant "final twenty years".

Response:

Confirmed. The statement should read: "When considered ….and by **1.2** percent in the final **twenty** years of the forecast".

Please refer to Errata 2.

244.10 Please explain why the before-DSM load growth is forecast to increase by only 0.8 percent in the final twenty years as compared to 1.8 percent in the first 10 years? What factors are responsible for the significant reduction in the growth rate of the load forecast in the latter part of the period?

Response:

The statement should read: “When considered… and by 1.2 percent in the final twenty years of the forecast”. Please refer to Errata 2.

The balance of this question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

245.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 4, pp. 41-44

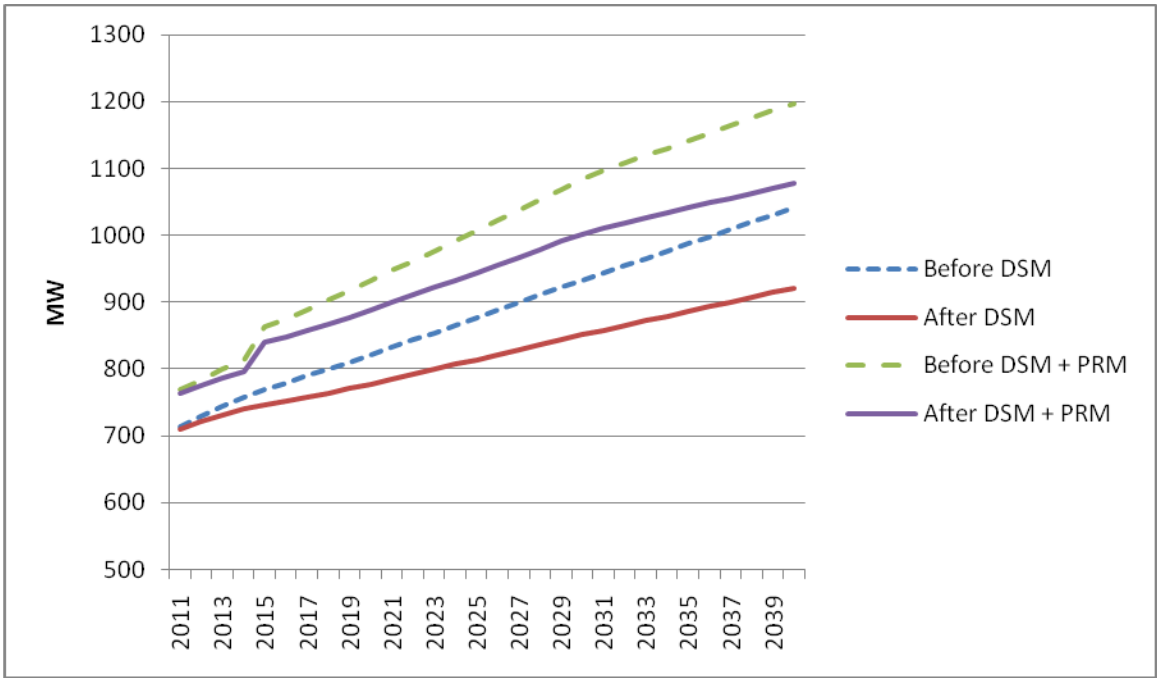
Load Forecast, Figures 4.2 and 4.3

245.1 Please confirm whether Figures 4.2 and 4.3 include the proposed planning reserve margin, and please provide the corresponding figures showing a comparison with and without the planning reserve margin.

Response:

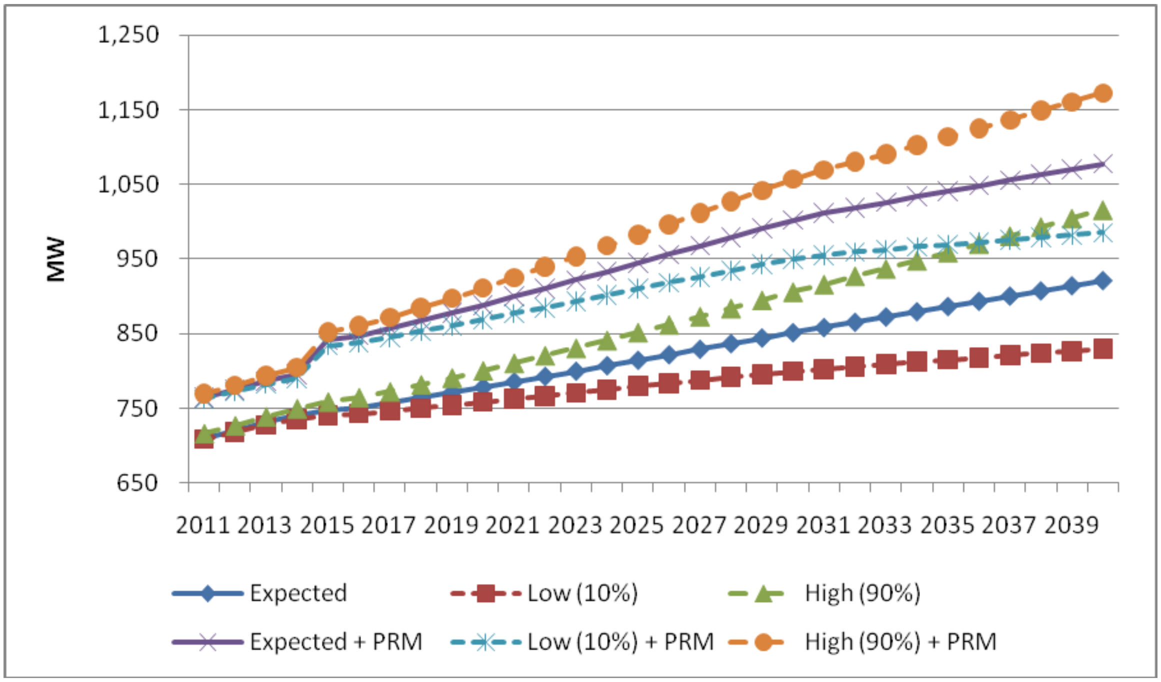
Figures 4.2 and 4.3 do not include the proposed Planning Reserve Margin. Figures showing the comparison with and without PRM are as follows.

1 **Figure BCUC IR1 245.1a**



2

3 **Figure BCUC IR1 245.1b**



4

246.0 Reference: Load Forecast

Exhibit B-1-2, Long Term Resource Plan, Section 4.0, pp. 42-44

Energy Requirement (GWh) and Annual System Peak (MW)

246.1 Please provide a revised version of Figures 4.1 and 4.2 which include historical data commencing from 1990. Please provide these graphs and associated data in the form of a fully functional spreadsheet.

Response:

Revised figures for Figures 4.1 and 4.2 which include historical data commencing from 1990 are as follows. The figures and associated data have also been attached to these responses as BCUC IR1 Electronic Attachment 246.1.

Figure BCUC IR1 246.1a

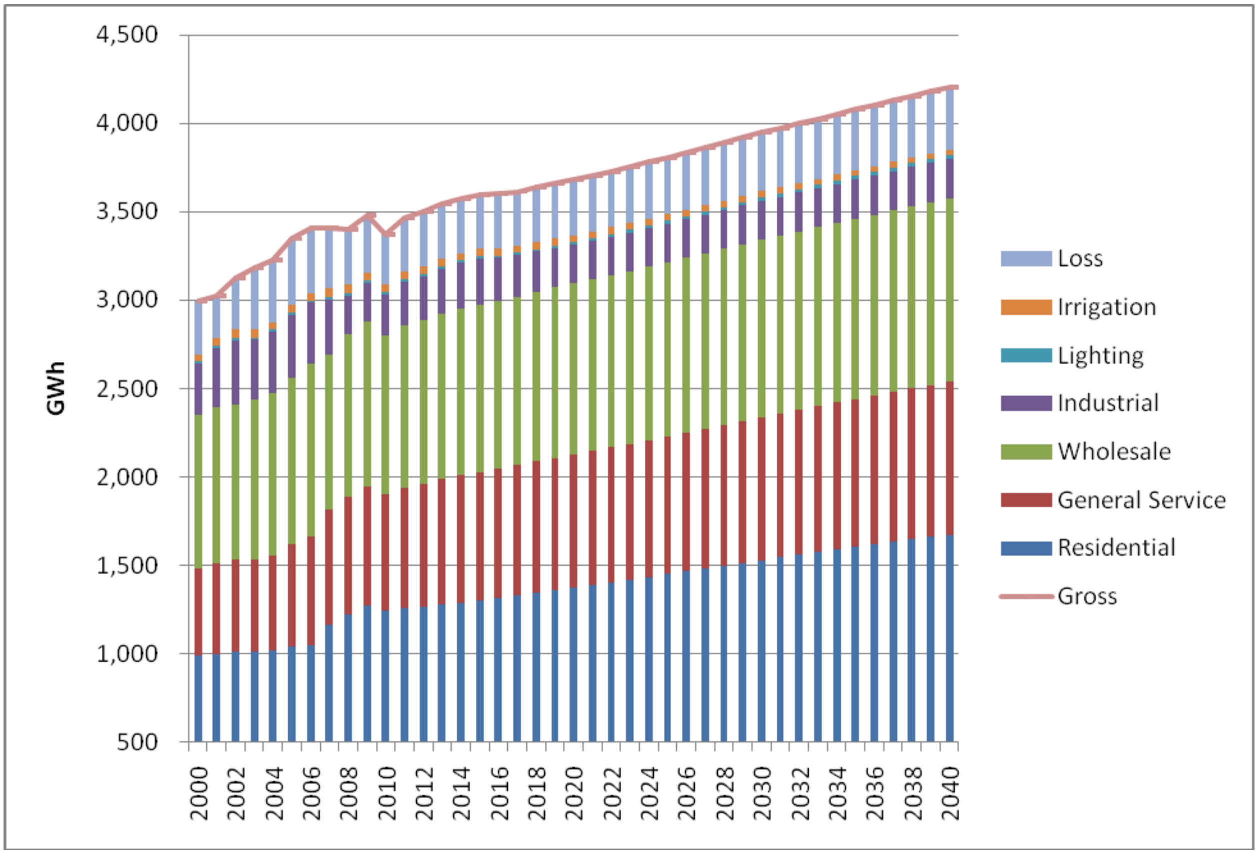
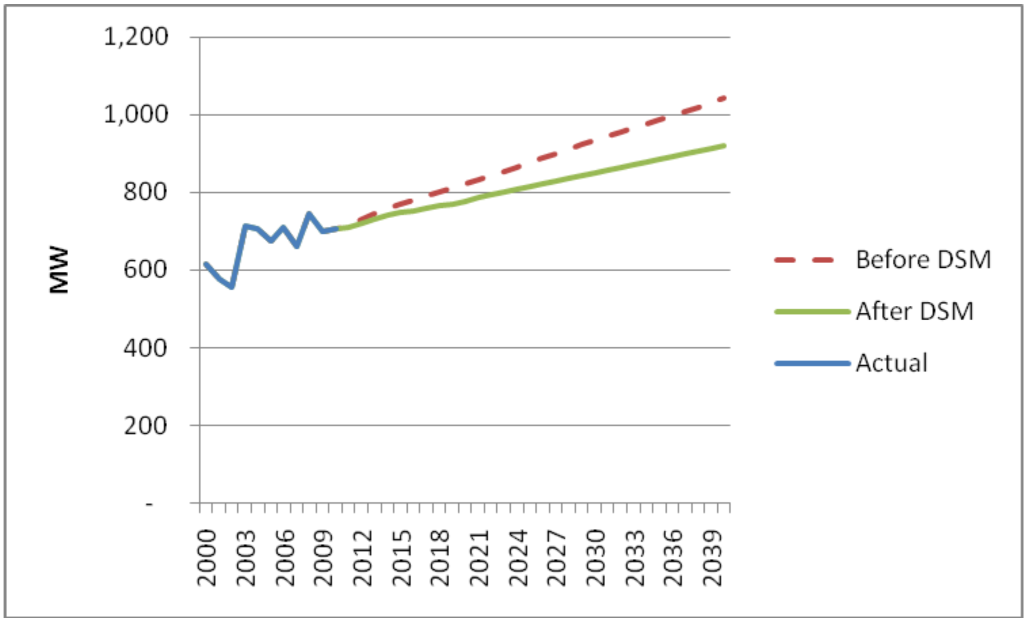


Figure BCUC IR1 246.1b



247.0 Reference: Load Forecast

Exhibit B-1-2, Long Term Resource Plan, Section 4.0, pp. 41-44

Forecast Accuracy

247.1 To better understand FortisBC's forecasting capabilities, please provide graphical and tabular data that compares forecasted load demand (GWh) to actual load demand for the past 10 RRA filings submitted by FortisBC to the Commission.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

247.1.1 For the above question, please calculate the mean absolute percent error (MAPE) of the past 10 forecasts and discuss whether there is a natural bias towards over or under forecasting energy demand (GWh).

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

247.1.2 Please provide any additional information that FortisBC considers helpful in demonstrating the accuracy of previous short-term and long-term load forecasts.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

247.2 Please provide the 80% confidence intervals associated with FortisBC's energy requirements forecast (GWh) in the following format:

Domestic Energy Sales[1]

	F2012		F2013		F2015		F2020		F2030	
(GWh)	Low	High	Low	High	Low	High	Low	High	Low	High
Residential										
General Service (Commercial)										
Industrial										
Wholesale										
Other[2]										
Total Domestic Energy Sales Range										

Notes:

1 High and low based on 80 per cent confidence interval.

2 Other category includes: Irrigation and Lighting

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

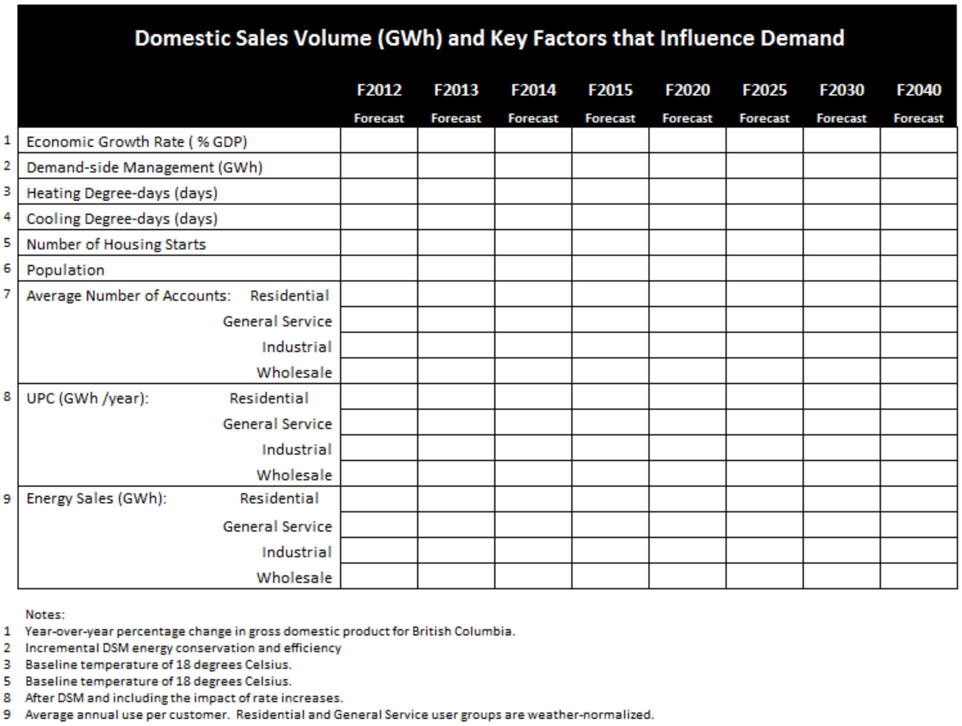
248.0 Reference: Load Forecast

Exhibit B-1-2, Long Term Resource Plan, Section 4.0, p. 41

Forecast Accuracy

> "FortisBC's load forecast is prepared annually and is composed of individual forecasts for each of the residential, wholesale, industrial, commercial and irrigation and lighting classes and well as system losses and DSM savings. The methodology is primarily econometric in nature with survey data also employed. Forecasts of provincial housing starts and provincial Gross Domestic Product (GDP) by sector are primary drivers of sales."

248.1 Please summarize the key factors that influence energy demand in the following format:



Domestic Sales Volume (GWh) and Key Factors that Influence Demand

			F2012 Forecast	F2013 Forecast	F2014 Forecast	F2015 Forecast	F2020 Forecast	F2025 Forecast	F2030 Forecast	F2040 Forecast
1	Economic Growth Rate (% GDP)									
2	Demand-side Management (GWh)									
3	Heating Degree-days (days)									
4	Cooling Degree-days (days)									
5	Number of Housing Starts									
6	Population									
7	Average Number of Accounts:	Residential								
		General Service								
		Industrial								
		Wholesale								
8	UPC (GWh /year):	Residential								
		General Service								
		Industrial								
		Wholesale								
9	Energy Sales (GWh):	Residential								
		General Service								
		Industrial								
		Wholesale								

Notes:
1 Year-over-year percentage change in gross domestic product for British Columbia.
2 Incremental DSM energy conservation and efficiency
3 Baseline temperature of 18 degrees Celsius.
5 Baseline temperature of 18 degrees Celsius.
8 After DSM and including the impact of rate increases.
9 Average annual use per customer. Residential and General Service user groups are weather-normalized.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

248.1.1 Please provide a revised version of the above table that includes actuals from 1990 to 2011. Please provide in the form of an electronic spreadsheet.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

248.1.2 Please provide electronic copies of the documents/reports, including those provided by BC Stats and Conference Board of Canada, which were used to derive inputs to FortisBC's load forecast.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

248.2 FortisBC employs well understood quantitative/statistical methods to derive the load forecasts for residential, commercial, industrial, and wholesale user groups. Forecasts are sometimes subject to consensus overrides based upon judgment. For the forecast period 2012 to 2015, please confirm whether FortisBC has applied a consensus overrides to any of the input variables or results? If "yes", please describe those overrides.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

249.0 Reference: Load Forecast

Exhibit B-1-2, Long Term Resource Plan, Section 4.0, p. 42

Climate Change

249.1 Temperature is an important factor which affects peak loads and energy consumption. Please confirm whether FortisBC's 30-year load forecast assumes historical Heat Degree Days (HDD) and Cooling Degree Day (CDD) or whether the impact of climate change has been taken into consideration.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

249.1.1 Please confirm what values for HDD and CDD were used in the 30-year load forecast.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

249.2 If climate change has been taken into consideration in the 30-year load forecast, please provide a description of the methodology employed.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

249.3 Alternatively, if the impact of climate change has not been included in the forecast, please provide a discussion and analysis which support that decision.

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

249.3.1 Given the likely increase in average temperature caused by climate change over the next 30 years, what are the anticipated impacts of the most likely increase in average temperature on energy use in winter and in summer? What will be the impacts on the winter and summer peak demand and the resulting capacity constraints?

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

249.4 Please provide tabular data of the HDD and CDD for the Kelowna region from 1980 to 2010. Please assume a baseline temperature of 18 ˚C for both HDD and CDD. Also provide the statistical correlation between the total HDD/CDD and the energy demand (GWh) for each of the major user groups (Residential, Commercial, Industrial, Wholesale).

Response:

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural order (Order G-111-11), the load forecast is not subject to the initial Information Request process.

250.0 Reference: FortisBC's Own Resources

Exhibit B-1-2, Section 5.1.1, pp. 45-46

FortisBC states that "In 2005 BC Hydro and the Entitlement Parties (FortisBC Inc., Teck Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation and Waneta Expansion Limited Partnership) entered into renewed CPA, which amended and extended the original Canal Plant Agreement for a further 30 year term."

FortisBC also states that "FortisBC is currently studying the optimal method of ensuring that the Upper Bonnington plant continues to contribute to the Company's existing generation resources."

250.1 The renewed Canal Plant Agreement expires in 2035, that is, five years before the end of the planning period covered by the 2012 Long Term Resource Plan. Please explain how this has been taken into account in this Resource Plan.

Response:

The 2005 Canal Plant Agreement was renewed for a term not less than 30 years. However, it will not terminate unless one of the parties gives at least five years notice of termination. Since notice cannot be given until December 31, 2030, 2035 is the earliest the CPA could terminate, but it is not required to terminate at that time. The 2012 Long Term Resource Plan assumes that the Canal Plan Agreement will continue in force throughout the planning period.

250.2 When does FortisBC plan to complete the study on the Upper Bonnington Plant and does FortisBC plan to submit this study to the Commission upon completion?

Response:

FortisBC has completed the assessment of the Upper Bonnington Repowering Project. The assessment demonstrated value to maintain this generation resource for the benefit of customers. The assessment also confirmed that the units are operating satisfactorily and as such this project is not required at this time. The Company will continue to review this assessment on a regular basis as unit performance, O&M costs, power costs and other operational factors change over time. Further information can be found at Section 2.4.4, pp. 38, 2012 Integrated System Plan). FortisBC did not prepare a formal study of this facility and does not plan to submit anything further to the Commission at this time.

250.2.1 Given that the four generating units at the Upper Bonnington Plant are now due for refurbishment or replacement how has their generation output been taken into account for the planning period of this 2012 Resource Plan?

Response:

The Resource Plan assumes that there will be no change in supply from the four Upper Bonnington Plant units. Provided these units remain available for service (either through maintenance of the existing old units or repowering), the CPA entitlement energy will be available to FortisBC.

251.0 Reference: Long and Medium Term Contractual Resources

Exhibit B-1-2, Section 5.1.2, pp. 46-49

BC Hydro PPA

FortisBC states that “The BC Hydro PPA represents an important resource for FortisBC, providing approximately 32 percent of FortisBC’s annual capacity needs on a planning basis in 2011.”

251.1 What percentage share of FortisBC’s energy requirement is supplied by the BC Hydro PPA?

Response:

The BC Hydro PPA is forecast to provide 20% of FortisBC’s energy requirements in 2011, and 28% of FortisBC’s energy requirements in 2012 and 2013.

FortisBC states that “The BC Hydro PPA is FortisBC’s allocation of Heritage Assets. FortisBC and BC Hydro are currently in discussions regarding the renewal of the PPA when it expires in 2013.”

251.2 In a letter to FortisBC dated October 27, 2009, the Commission asked if BC Hydro and FortisBC (the Parties) would agree to a one-year extension to the BC Hydro PPA and on January 8, 2010, both Parties responded that they were not opposed to extending the term of the PPA by one year. Please confirm whether the PPA expires in 2013 or 2014.

Response:

The PPA expires in October 2013. At this time both FortisBC and BC Hydro are in agreement that the preferred course of action is to come to agreement on a renewed PPA without extending the existing PPA by an additional year. However, if agreement with BC Hydro on a renewed PPA is not reached and the matter must be referred to the Commission, then the Company believes it will be necessary to extend the PPA to 2014 to allow for appropriate review.

> FortisBC states that “For the purpose of this Resource Plan, FortisBC has assumed the BC Hydro PPA will be renewed on comparable terms to the existing PPA and will be available to the end of the planning period of this Resource Plan. Although many terms and conditions of the BC Hydro PPA have been agreed to in principal, there are still key terms and conditions which are outstanding. Specific issues such as the term of the PPA, the amount of energy available under the PPA, and the cost of energy under the PPA can have impacts on the timing and nature of the energy resource requirements described in this Resource Plan.”

251.3 Please clarify what is meant by "comparable terms." Has FortisBC assumed that the renewed PPA would include the current export restriction?

Response:

Principally, what FortisBC means by “comparable terms” in the context of the Resource Plan discussion of the PPA renewal is that all associated energy with the 200 MW cap will be continue to be available to the Company at average embedded rates.

FortisBC has assumed that the current export restrictions will remain in force for all current generation resources. However, the Company expects that the renewed PPA will exempt the Waneta Expansion surplus capacity, thereby allowing that surplus to be sold provided it is not fueled with PPA power.

251.3.1 Please provide a detailed explanation of the outstanding issues around: 1) the term of the PPA; 2) the amount of energy available under the PPA; and 3) the cost of energy under the PPA. Please elaborate on FortisBC's position on each one and the obstacles to concluding the negotiations.

Response:

FortisBC and BC Hydro remain in very active discussions around the outstanding PPA issues and while no agreement has yet been reached, the parties are attempting to come to a negotiated solution. While the Company can confirm that term, amount of energy, and cost of energy under the PPA continue to be principal issues, the discussions are not limited to these concerns and any negotiated resolution will likely require compromise and trade-offs. It should be recognized that any disclosure of FortisBC's position at this time could seriously prejudice these discussions. In addition, if no agreement is reached, it may be necessary for the Commission to make a determination on the appropriate renewal terms based on submissions from both BC Hydro and FortisBC. Therefore, the Company respectfully declines to provide further details at this time.

251.4 If negotiations on the renewed PPA conclude before the submission of the next Resource Plan, does FortisBC plan to submit an update to the 2012 Long-Term Resource Plan or otherwise indicate which areas of the plan will be impacted by the renewed PPA?

Response:

FortisBC has not planned to submit an update before the next Long-Term Resource Plan, but is prepared to do so if the changes in the new PPA are material. This Resource Plan update or briefing on impacted areas may be part of any submission to the Commission for approval of the renewed PPA.

252.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 5.1.2.1.4, pp. 48-49

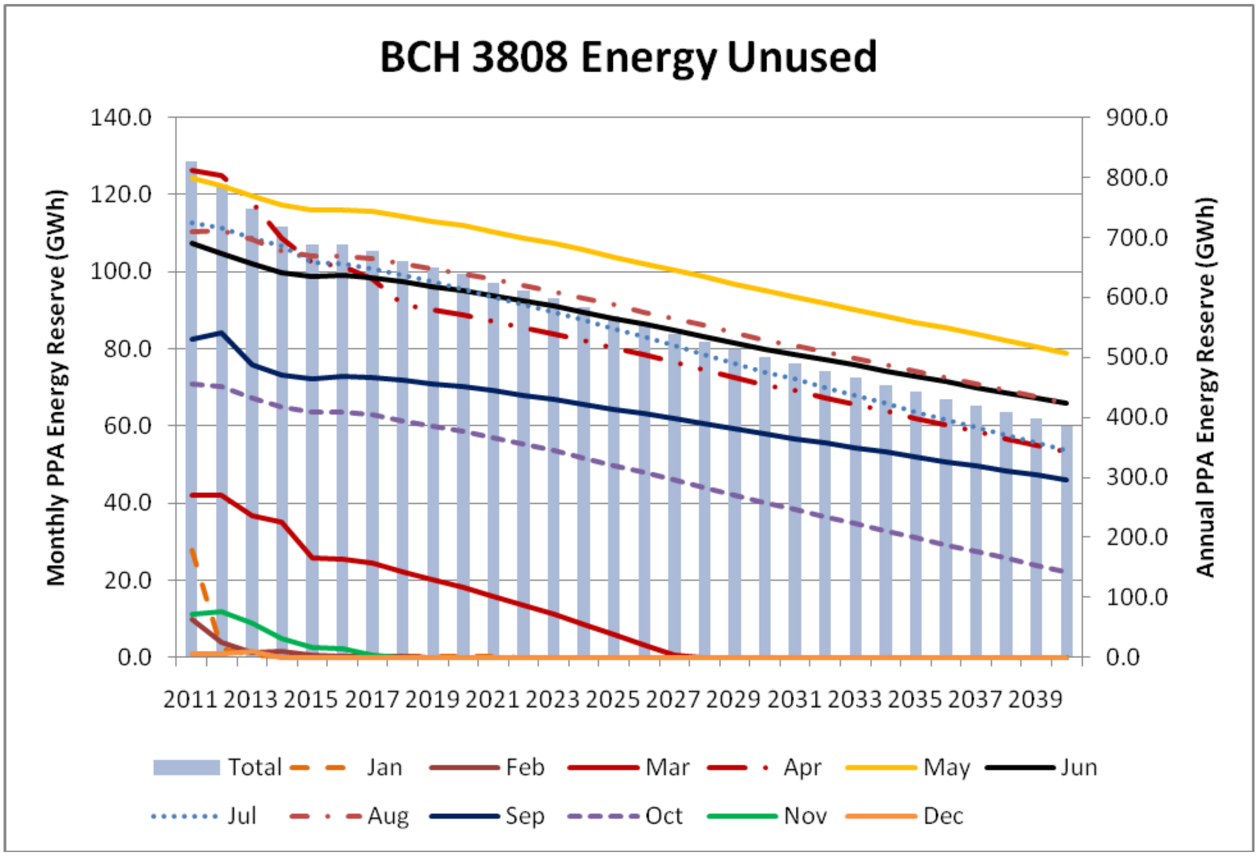
BC Hydro PPA and Implications for the 2012 Resource Plan, Figure 5.1.2.1.4-A

252.1 Please confirm that the BC Hydro PPA energy ceiling is not reached until after 2040 under the assumption that only forecast load growth is driving utilization.

Response:

Assuming the PPA is renewed on similar terms, FortisBC can confirm the total annual energy associated with the 200 MW of capacity is not forecast to be reached until after 2040. However, in certain months FortisBC will be hitting monthly energy limits associated with the 200 MW of capacity much earlier. In fact, in December, the energy associated with the December PPA capacity is already fully utilized, and by 2018 the energy associated with the PPA ceiling in November, December, January and February would also be effectively fully utilized. Please refer to the below figure.

Figure BCUC IR1 252.1



252.2 Please provide a figure similar to Figure 5.1.2.1.4-A showing the effect of a pumped storage hydro facility on the PPA energy utilization, assuming that the first energy to be used for the pumped storage operation is PPA energy.

Response:

The Pumped Storage Hydro (PSH) option in this plan has been presented at a conceptual level, using an indicative opportunity for the Okanagan with an installed capacity of 180 MW. The capacity of the project was sized based on an 8 hour generation cycle where the reservoir is filled during a suitable time during the remainder of the day. If and when a PSH facility will be constructed has not been determined.

An analysis of the impact of a Pumped Storage Hydro facility on PPA energy usage has not been conducted. Assuming that pumped storage is being used entirely to serve load, there will be no PPA energy available to be used for pumped storage in the winter. There will be minimal amounts which will be available to be used in the shoulder seasons and summer.

There may be restrictions on using PPA energy for pumped storage hydro to support sales. Please see the response to BCUC IR1 Q252.3.

252.3 Please comment on whether there are any restrictions on the use of PPA energy to supply a pumped storage hydro facility.

Response:

Under the Current PPA, FortisBC is restricted from selling energy while taking PPA energy.

Pumped storage for resale using PPA energy may violate the arbitrage principles implied in the Heritage Contract. There should be no restrictions on pumped storage to meet load using PPA energy, just as there would be no restrictions from using storage capability behind a dam or charging a battery.

253.0 Reference: Long and Medium Term Contractual Resources

Exhibit B-1-2, Section 5.1.2, pp. 49-50

Brilliant Power Purchase Agreement

FortisBC states that "In 2010, such costs were $36.45/MWh. During the second 30 years of the term of the Brilliant PPA, amounts payable by FortisBC will be adjusted using a market price mechanism based on the depreciated value of the Brilliant plant and then-prevailing operating costs."

253.1 Please describe how the costs would likely differ from the $36.45/MWh in the second 30-year period.

Response:

Based on the projected payment schedules provided under the BPPA, these power purchase costs would be expected to continue to increase over the 60 year term, except for a market price mechanism effective 2026 to re-evaluate the second 30-year period pricing. Pursuant to BCUC Order G-36-96, one of the intents of the market pricing mechanism adjustment is to ensure that FortisBC's customers are not unfairly locked into a power purchase arrangement that is significantly above market prices. The costs to be paid by FortisBC under the second 30-year period of the BPPA will primarily depend on a comparison of two factors that drive the market price mechanism. The first will be an evaluation of the market cost to purchase the quantity and quality of capacity and energy that would be necessary to replace the entitlement provided by the BPPA under the Canal Plant Agreement in an open market transaction. The second factor considers the combined capital charges, sustaining charges and operational and maintenance charges of the Brilliant Plant. The evaluation of these two factors is made each year subsequent to 2026. Due to the differing variables that affect the market factor and the capital and operating costs of the Brilliant Plant, an accurate comparison of the second 30-year period pricing as compared to the 2010 costs of $36.45/MWh cannot be reasonably determined today.

253.2 Similarly, with respect to the Upgrade Amendment, please describe how the costs would likely differ from the $26.55/MWh in the second 30-year period.

Response:

The pricing associated with the Upgrade Amendment would be subject to the same market pricing adjustment mechanism described in the response to BCUC IR1 Q253.1.

254.0 Reference: Long and Medium Term Contractual Resources

Exhibit B-1-2, Section 5.1.2, pp. 50-51

Waneta Expansion Capacity Purchase

254.1 What is the difference between the Waneta Expansion Limited Partnership and the Waneta Expansion Power Corporation?

Response:

The Waneta Expansion Power Corporation is a subsidiary of Columbia Power Corporation and Columbia Basin Trust which held legal title to the Waneta Expansion Assets.

The Waneta Expansion Limited Partnership is a partnership of Fortis Inc. (51% ownership), CPC Waneta Holdings Ltd. (32.5% ownership) and CBT Waneta Expansion Power Corp. (16.5% ownership).

On October 1, 2010, all assets related to the Waneta Expansion were transferred from the Waneta Expansion Power Corporation to the Waneta Expansion Limited Partnership.

FortisBC states that "The capacity entitlements obtained by FortisBC under WAX CAPA begin in 2015 and vary by month (see Table 5.1.2.4-A)."

254.2 Will the monthly capacity entitlements presented in Table 5.1.2.4-A remain the same throughout the planning period of the 2012 Long-Term Resource Plan?

Response:

The Company is not expecting any material changes in the capacity amounts available under the WAX CAPA throughout the planning period.

254.3 Are there separate costs for energy and capacity?

Response:

There is no energy associated with the WAX capacity entitlements acquired. The capacity will be used with other Canal Plan Agreement entitlement energy obtained from other Canal Plant Agreement facilities in conjunction with the Company's CPA storage accounts.

254.4 Please describe the duration for which the capacity associated with the WAX CAPA is available in each month.

Response:

There is no duration associated with the WAX capacity acquired. As long as the WAX units are in service the contracted amounts of capacity will be available to the Company for short-term dispatch. However, as the Company is not buying any energy through the WAX CAPA agreement, long-term duration will in practise be limited by the amount of Canal Plant Agreement entitlement energy available in the FortisBC CPA storage accounts.

254.5 Please describe if the WAX CAPA was negotiated to include reserves, similar to the Brilliant Tailrace capacity agreement with Columbia Power Corporation, and if not, why not?

Response:

Operating Reserves are required to be held on the WAX CAPA generation by FortisBC. There would have been no advantage to the Company to negotiate a WAX CAPA agreement whereby the capacity values were net of reserves since that would have just resulted in a higher per MW cost with no overall change in cost.

255.0 Reference: Long and Medium Term Contractual Resources
Exhibit B-1-2, Section 5.1.3, p. 51
Powerex Capacity Power Block

FortisBC states that "FortisBC purchased a five-year seasonal capacity block from Powerex (the Powerex Capacity Purchase Block, or Powerex CPB) that temporarily addresses FortisBC's seasonal winter capacity requirements. The contract will terminate in 2015, coinciding with the commencement of the WAX CAPA."

255.1 Please provide a table with the monthly capacity blocks purchased from Powerex for the 5-year period.

Response:

The 5-year Powerex capacity contract is valid until February 2016 as shown in the table below. However, the Company has the right to terminate the contract when new generation is brought online. The Company plans to terminate the contract to coincide with the commencement of the WAX CAPA.

Table BCUC IR1 255.1

	Powerex Capacity Blocks (MW)			
Year	January	February	November	December
2010	0	0	50	125
2011	150	75	50	125
2012	150	75	50	125
2013	150	75	50	125
2014	150	75	50	125
2015	150	75	50	125
2016	150	75	0	0

255.2 Please elaborate on the risk that the WAX CAPA will not be able to deliver capacity in time and once the Powerex CPB will have expired?

Response:

If the Waneta Expansion in-service date should be delayed, the Company expects to continue on with the existing Powerex blocks that extend through to November of 2016. If the Waneta Expansion is delayed past that point, either the Powerex blocks will be extended or other market based arrangements will be made.

255.2.1 Please explain how FortisBC would manage that situation if it were to happen and what mitigating strategies it would implement.

Response:

The Powerex arrangement extends beyond the expected in-service date for Waneta Expansion, although the Company has the right to terminate the arrangement once WAX is completed. If the Waneta Expansion in-service date should be delayed, the Company expects to continue on with the existing Powerex arrangement that extends through to November of 2016 after which the first month replacement capacity would be required is November of 2016. If the Waneta Expansion is delayed past that point, the Company would seek to extend the Powerex blocks or other market based arrangements will be made.

The Company is kept appraised of the construction progress of the project, and as a result will be able to assess if there is to be significant delay in the in-service date with sufficient notice to put in place alternative arrangements to bridge any gap and therefore believes that it largely will be able to mitigate this risk.

256.0 Reference: Resource / Load Balance Analysis

Exhibit B-1-2, Section 5.2, p. 52

FortisBC states "Contracted Resources: Brilliant, the Brilliant Upgrades and the WAX PPA are all contracted long-term, and are secure for the term of this 2012 Resource Plan." (Emphasis added)

256.1 Please clarify what WAX PPA refers to in the above statement as opposed to WAX CAPA

Response:

The sentence should have read: "FortisBC states "Contracted Resources: Brilliant, the Brilliant Upgrades and the WAX CAPA are all contracted long-term, and are secure for the term of this 2012 Resource Plan."

257.0 Reference: Application of Planning Reserve Margin (PRM)

Exhibit B-1-2, Section 5.2.1.1, pp. 53-57

FortisBC's PRM

FortisBC states that "The following criterion is applied as the basis for PRM design:

PRM = 5% of Load Responsibility + the Single Largest Utilized Contingency".

FortisBC also states that "[it] has chosen to modify the PRM calculation methodology recommended by Midgard in order to reduce ratepayer impacts."

257.1 Please provide the formula used by FortisBC to calculate the PRM and explain how the Midgard formula has been modified.

Response:

FortisBC uses the formula of 5 percent of Load Responsibility + the Single Largest Utilized Contingency. After the WAX CAPA is available, the Single Largest Utilized Contingency is the amount of WAX CAPA that FortisBC is using to meet load, if it is larger than a Brilliant unit. In some scenarios, the amount of WAX CAPA used to meet load was less than the largest unit at the Waneta Expansion. Since the Waneta Expansion units are much larger than any other unit on FortisBC's system (estimate of 167 MW compared to 37.5 MW at Brilliant, FortisBC's next biggest generator), FortisBC believes that it is necessary to only carry planning reserve margin on the WAX CAPA that is being used to meet load. Midgard agrees with these assumptions.

Where FortisBC and Midgard differ is in the calculation of Utilized Contingency. FortisBC assumes that the amount of WAX CAPA being used to meet load is divided evenly between two units. Midgard assumes that that amount of WAX CAPA being used to meet load uses the first unit completely before using the second unit.

The Company believes that its method is a more accurate representation of how its system works under the Canal Plant Agreement.

257.1.1 Please provide examples to demonstrate how the FortisBC modified PRM calculation method will reduce ratepayer impacts as compared to the Midgard calculation method. Please use examples that can be compared to the PRM scenarios provided by Midgard in Figure 6.4-A on page 23 of Appendix D.

Response:

FortisBC's calculation of PRM produces a smaller level of PRM than the Midgard analysis, due to the treatment of the Single Largest Utilized Contingency as described in BCUC IR1 Q257.1. A smaller PRM requirement will result in reduced cost to the ratepayer.

FortisBC Modified PRM Calculation Methodology Example 1:

If FortisBC is using 100 MW of WAX CAPA to meet load in December when the WAX CAPA is 312.1 MW, the FortisBC single largest unit (SLU) would be equal to half of the amount used to meet load, or 50 MW.

Midgard would use the amount of the first WAX unit that is used as the SLU. Since the WAX CAPA in December is 312.1 MW, each WAX unit is assumed to deliver 156 MW. If FortisBC is using 100 MW to meet load, Midgard assumes that this all comes from the first unit (since 100 MW < 156 MW). Midgard calculates the SLU as 100 MW. In this scenario, the Midgard PRM calculation would be 50 MW higher than FortisBC.

FortisBC Modified PRM Calculation Methodology Example 2:

If FortisBC is using 200 MW of WAX CAPA to meet load in December when the WAX CAPA is 312.1 MW, the FortisBC SLU would be equal to half of the amount used to meet load, or 100 MW. Midgard would use the amount of the first WAX unit that is used as the SLU. Since the WAX CAPA in December is 312.1 MW, each WAX unit is assumed to deliver 156 MW. If FortisBC is using 200 MW to meet load, Midgard assumes that the first unit is being used completely at 156 MW, and the second unit is being used 44 MW (200 – 156). Midgard calculates the SLU as 156 MW. In this scenario, the Midgard PRM calculation would be 56 MW higher than FortisBC.

The following additional examples utilize scenarios described in Section 6.4 of Appendix D of the 2012 Long Term Resource Plan, the Midgard Planning Reserve Margin Report.

Midgard Planning Reserve Margin Methodology Scenario 1

In this scenario, the amount of WAX CAPA used to meet load is less than a Brilliant unit and a Brilliant unit is the SLU. This scenario is the same under both FortisBC and Midgard assumptions.

Midgard Planning Reserve Margin Methodology Scenario 2:

In this scenario, the amount of WAX CAPA used to meet load is increasing to about the amount of a Brilliant unit (37.5 MW). This scenario is different between Midgard and FortisBC, since FortisBC assumes that the amount of WAX used to meet load is divided equally between two units, while Midgard assumes that the WAX CAPA is used by one unit until it has been used completely. In the FortisBC analysis, if the WAX CAPA used to meet load is less than 75 MW, then the Brilliant unit (37.5 MW) will still be the SLU. Under the MIdgard analysis, if the WAX CAPA used to meet load is greater than 37.5 MW, the amount of WAX CAPA used to meet load is the SLU. For any amount of WAX CAPA used to meet load between 37.5 MW and 75 MW, Midgard PRM calculations will use the amount of WAX used, and FortisBC will use a Brilliant Unit. Midgard's PRM calculation will be greater than FortisBCs.

Midgard Planning Reserve Margin Methodology Scenario 3

In this scenario, the amount of WAX CAPA used to meet load is more than 37.5 MW and less than one half of the total WAX CAPA for that month. Under the FortisBC analysis, the amount of WAX CAPA used to meet load would have to be greater than 75 MW for ½ of the WAX CAPA to be greater than a Brilliant Unit. For WAX CAPA used to meet load between 75 MW and up to one half of the total WAX CAPA for that month, FortisBC calculates the SLU as one half of the amount of WAX CAPA used to meet load. Midgard calculates the SLU as the amount of WAX CAPA used to meet load. Midgard's PRM calculation will be greater than FortisBCs.

Midgard Planning Reserve Margin Methodology Scenario 4

In this scenario, the amount of WAX CAPA used to meet load is larger than ½ of the WAX CAPA. In the FortisBC analysis, one half of the WAX CAPA used to meet load is considered the SLU. Midgard assumes that since a full unit has been used to meet load, a full unit (1/2 of WAX CAPA) is the SLU. Midgard's PRM calculation will be greater than FortisBC. See FortisBC Example #2 for an example of this scenario.

In all scenarios, FortisBC's calculation of the single largest utilized contingency is less than Midgard's calculations. This creates a smaller PRM, which will cost less, and will therefore have a smaller effect of FortisBC's ratepayers.

FortisBC states that "Although it is uncommon to change PRM on a monthly basis, the majority of FortisBC's supply resources vary by month and therefore it is prudent that FortisBC adapt its PRM requirements to match."

257.2 Please provide in tabular form the monthly capacity contributions of each of FortisBC's supply resources (FBC Plants, BCH PPA, Brilliant PPA (incl. upgrade), WAX CAPA, Powerex CPB, Wholesale Market)

Response:

The monthly capacity contributions of each of FortisBC's supply resources are as follows:

Table BCUC IR1 257.2a

FortisBC Usable Resource - Pre WAX

Usable Resources	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
FortisBC	220	216	209	205	196	186	197	212	216	217	224	223
Turbine Upgrade	4	4	4	4	4	4	4	4	4	4	4	4
Brilliant Base	129	129	129	124	112	105	112	122	125	126	129	129
Brilliant Upgrade	19.8	19.8	19.9	20.0	19.8	19.5	19.7	20.1	19.6	19.7	20.1	20.0
CPA Operating Reserve (4.5%)	-17	-17	-16	-16	-15	-14	-15	-16	-16	-17	-17	-17
BCH 3808 PPA	200	200	200	200	200	200	200	200	200	200	200	200
Brilliant Tailrace Capacity	4.4	3.0	1.0	2.5	6.0	6.0	5.7	3.6	0.9	0.9	3.4	4.8
Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125
Total Resources	**711**	**631**	**547**	**540**	**522**	**507**	**523**	**545**	**550**	**551**	**614**	**689**

Table BCUC IR1 257.2b

FortisBC Usable Resource - Post WAX

Usable Resources	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
FortisBC	220	216	209	205	196	186	197	212	216	217	224	223
Turbine Upgrade	4	4	4	4	4	4	4	4	4	4	4	4
Brilliant Base	129	129	129	124	112	105	112	122	125	126	129	129
Brilliant Upgrade	19.8	19.8	19.9	20.0	19.8	19.5	19.7	20.1	19.6	19.7	20.1	20.0
CPA Operating Reserve (4.5%)	-17	-17	-16	-16	-15	-14	-15	-16	-16	-17	-17	-17
BCH 3808 PPA	200	200	200	200	200	200	200	200	200	200	200	200
Brilliant Tailrace Capacity	4.4	3.0	1.0	2.5	6.0	6.0	5.7	3.6	0.9	0.9	3.4	4.8
WAX CAPA	304	304	289	133	70	54	169	319	324	211	320	312
WAX CAPA Operating Reserve (7%)	-21	-21	-20	-9	-5	-4	-12	-22	-23	-15	-22	-22
Total Resources	**844**	**838**	**816**	**664**	**587**	**557**	**680**	**842**	**851**	**748**	**861**	**855**

FortisBC also states that "For reference, the PRM held by nearby utilities is listed in Table 5.2.1.1-C. This table demonstrates that the recommended PRM for FortisBC is **comparable** to the current industry practice in the region." [emphasis added]

257.3 FortisBC's PRM levels are low when compared to other industry practices in the region for half the year. For instance, for the months of April, May, June, August, September and October, the PRM is in the range of 5 percent to 9 percent, which is lower than the utility's lowest PRM at 10%.

257.3.1 Given the above, please elaborate further on FortisBC's proposed PRM levels when compared to regional industry practice.

Response:

It is anticipated that FortisBC's PRM requirement will differ from other utilities due to the different conditions in each utility. No two utilities are exactly alike, and the PRM requirements will be different. FortisBC's PRM is designed to cover 5% of load and the loss of the single largest contingency, consistent with WECC's recommendation.

Please refer to the response to BCUC IR1 Q23.1

257.3.2 Does FortisBC's modified PRM calculation method still meet the WECC recommendations for minimum PRM? If so, please explain why. If not, please explain why not.

Response:

Yes, FortisBC's modified PRM calculation methodology still meets WECC recommendations for minimum PRM because it covers 5% of load plus the largest risk on the system, which is consistent with the WECC recommendations.

Please also see page 16 of the 2012 Long Term Resource Plan, Appendix D – Midgard Planning Reserve Margin Report.

258.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 5.2.1.1, pp. 53-58

Application of Planning Reserve Margin (PRM)

Exhibit B-1-2, Appendix E

FortisBC Inc. Planning Reserve Margin Study

258.1 Please provide detailed calculations of how the forecast annual costs associated with the Planning Reserve margins are derived for each year from 2012 to 2021.

Response:

Forecast PRM costs from 2014 to 2020 are presented and discussed in BCUC IR1 Q17.3 and 2012 and 2013 in BCUC IR1 Q19.1. No estimate is currently available for the year 2021.

Midgard prepared the estimate of PRM costs for FortisBC, which includes detailed calculations of how they forecast annual costs. This information is provided in BCUC IR1 Appendix 258.1. Midgard's forecast of costs are based on the assumptions in the memorandum and the current forecast of FortisBC requirements. Note that in the February memorandum, Midgard utilized the load forecast available at the time, which has since been updated in the Resource Plan.

The Company will seek to minimize the costs of procuring resources to meet its system requirements, including PRM, by optimizing its own portfolio and other contracted or owned resources on an on-going basis.

258.2 Please describe if the planning reserve margin is more efficiently held by BC Hydro, and simply contractually arranged for as a separate service from BC Hydro.

Response:

At this time, it is the Company's understanding that BC Hydro does not offer a PRM service, however it is possible that PRM is more efficiently held by BC Hydro and contractually arranged for as a separate service. FortisBC will investigate this possibility as it evaluates the most efficient ways of procuring PRM.

258.3 Please provide an analysis of the incremental costs to BC Hydro of providing a planning reserve margin to FortisBC as compared to FortisBC providing its own planning reserve margin.

Response:

FortisBC does not have any direct knowledge of the incremental cost to BC Hydro of providing a planning reserve margin. However, it is expected that the cost of new capacity will be similar for both FortisBC and BC Hydro.

BC Hydro may have flexibility from its existing resources to provide a certain amount of planning reserve margin to FortisBC without having to construct new units. It may be possible to blend the planning reserve margin of both utilities to achieve overall savings as the single largest unit should be common to both utilities.

Please refer to the response to BCUC IR1 Q258.2.

258.4 Please describe the changed circumstances that make it now prudent for FortisBC to carry separate planning reserve margin in light of the fact that it has been prudent, acceptable and cost-effective not to carry planning reserve margin up to now.

Response:

Please see Section 5 of the FortisBC Planning Reserve Margin Report by Midgard Consulting Inc. (Exhibit B-1-2, Appendix D, pp. 11 - 15) for a full discussion on the need for planning reserve margin.

To summarize the referenced section, FortisBC is very unusual among Canadian (and North American) electric utilities in that for many years its firm resource stack has been inadequate to meet its expected peak load-serving requirements. Peak requirements, including any reserve requirements, have been met by spot purchases and seasonal purchases of energy blocks and call-options. Effectively the market has been used as a repository of Planning Reserve Margin.

FortisBC has determined that relying on others to provide Planning Reserve Margin will not be prudent in the long run for a number of reasons:

- The existing large (>7,000 MW) and rapidly growing volume of non-firm generating resources such as wind, solar and run-of-river hydro, will erode the winter peak capacity surplus in the Pacific Northwest region, since capacity must be held in reserve to firm these intermittent resources. FortisBC's greatest capacity requirements occur when regional capacity surpluses are most impacted by this phenomenon;
- NERC is projecting negative capacity margins in the Canadian Sub-region of the WECC by 2019;

- The one-time capacity surplus created by the permanent closure of Direct Service Industry loads in the US Pacific Northwest region has now been fully allocated;
- Most utilities in the region are counting upon very aggressive Demand Side Management programs to avoid a large compounding proportion of their status quo load growth requirements. If these programs fail to achieve the aggressive targets (e.g.: 66% for BC Hydro) then regional capacity margins will be commensurately reduced;
- The Pacific Northwest region is highly dependent on regional hydrology to meet its annual electric energy requirements. Extended droughts (which have occurred historically) will negatively impact capacity margins throughout the region. Utilities will meet their own capacity requirements before providing capacity to FortisBC during difficult hydrology conditions; and
- Transmission throughout the region is becoming increasingly constrained, as loads grow and remote generation (such as wind and run-of-river hydro) continued to be added. Although several major transmission expansion projects have been announced, to date very little new transmission has actually been added, and many of the announced projects have faced extended permitting delays. Congested transmission can reduce FortisBC's access to the market during capacity shortages.

258.5 Please provide the active spreadsheet model with the detailed calculations for the monthly planning reserve margin data shown in Table 1 through Table 6 of Appendix E.

<u>Response:</u>

Please refer to BCUC IR1 Electronic Attachment 258.5, which has been filed separately due to the file size of the electronic attachment.

259.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 5.2.1.2, pp. 58-61

Capacity Resource/Load Gaps

259.1 Please provide Figures 5.2.1.2-A, 5.2.1.2-B, and 5.2.1.2-C and the associated tables without the planning reserve margin component in the Forecast load requirement.

Response:

The requested Figures and associated tables without the PRM requirement are as follows:

Figure BCUC IR1 259.1a 2016 Monthly Capacity Load/Resource Balance

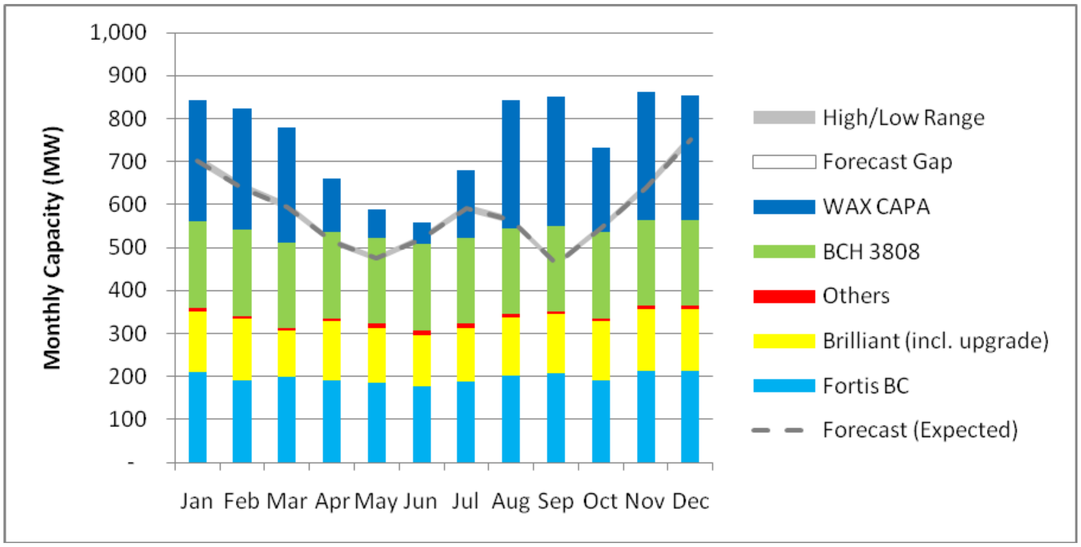


Table BCUC IR1 259.1a 2016 Monthly Capacity Load/Resource Balance

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Gaps (MW)												
Expected	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)												
Expected	703	639	595	514	474	521	590	563	462	545	639	751
High	715	650	606	523	482	530	600	572	470	554	650	764
Low	695	632	589	508	469	515	583	556	457	538	632	743
Resources (MW)												
Fortis BC	210	192	200	192	187	178	188	203	206	191	214	213
Brilliant (incl. upgrade)	142	143	107	137	126	119	126	135	139	139	143	143
Others	9	7	5	7	10	10	10	8	5	5	8	9
BCH 3808	200	200	200	200	200	200	200	200	200	200	200	200
WAX CAPA	283	282	269	124	65	50	157	296	301	197	298	290

Figure BCUC IR1 259.1b 2020 Monthly Capacity Load/Resource Balance

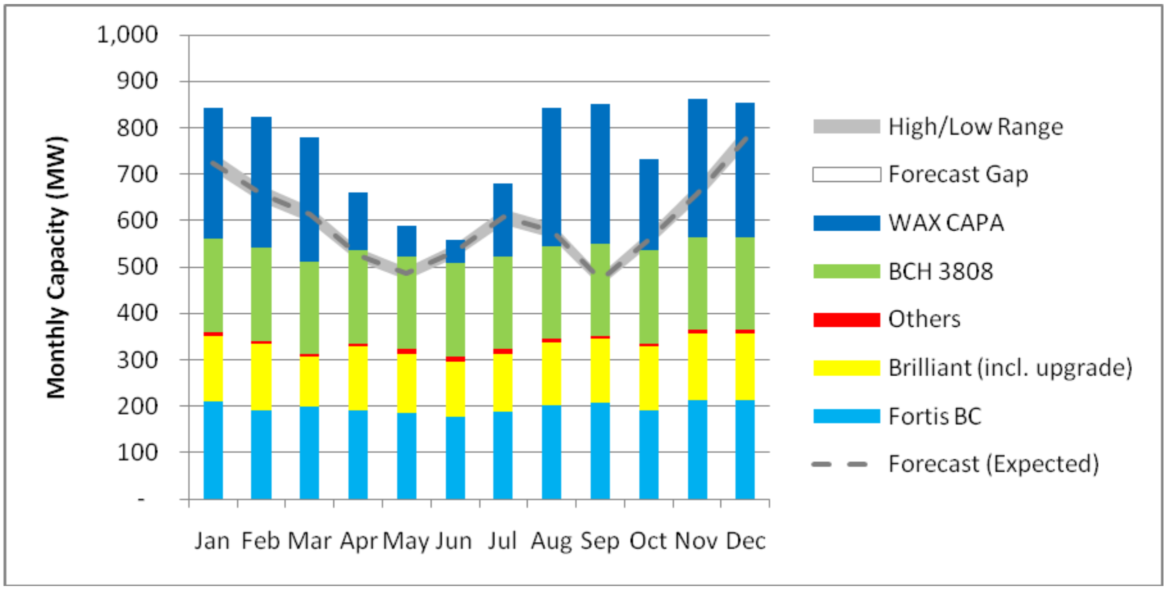


Figure BCUC IR1 259.1b 2020 Monthly Capacity Load/Resource Balance

2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Gaps (MW)												
Expected	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)												
Expected	725	657	613	526	486	534	607	578	472	559	659	778
High	746	676	630	542	500	549	624	594	485	576	678	800
Low	707	640	597	513	473	520	592	563	460	545	642	758
Resources (MW)												
Fortis BC	210	192	200	192	187	178	188	203	206	191	214	213
Brilliant (incl. upgrade)	142	143	107	137	126	119	126	135	139	139	143	143
Others	9	7	5	7	10	10	10	8	5	5	8	9
BCH 3808	200	200	200	200	200	200	200	200	200	200	200	200
WAX CAPA	283	282	269	124	65	50	157	296	301	197	298	290

Figure BCUC IR1 259.1c 2030 Monthly Capacity Load/Resource Balance

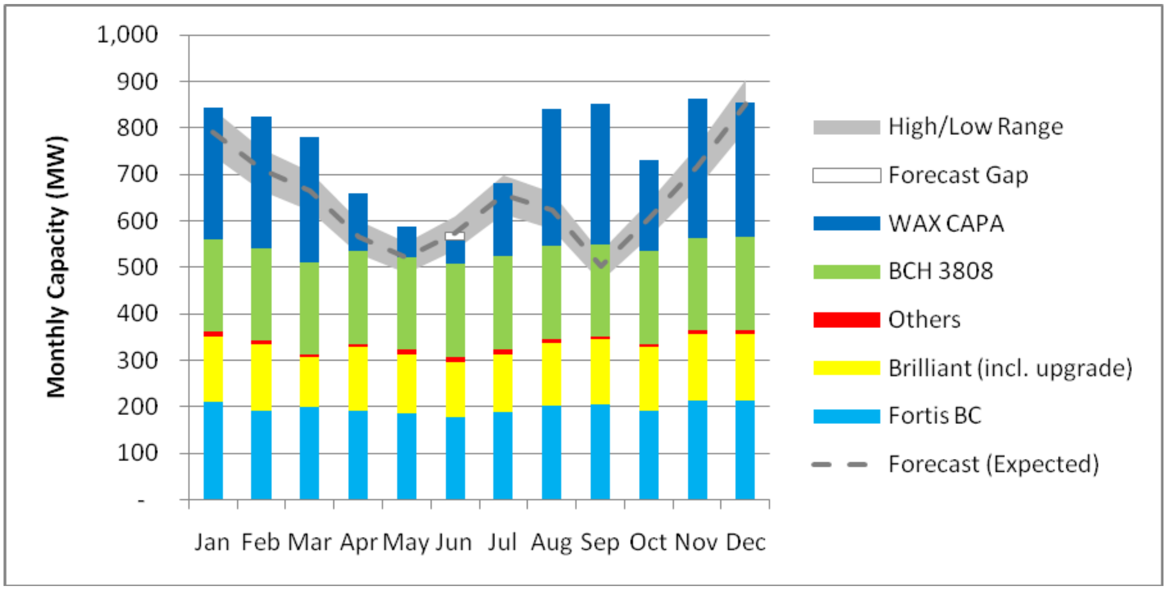


Figure BCUC IR1 259.1c 2030 Monthly Capacity Load/Resource Balance

2030	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Gaps (MW)												
Expected	0	0	0	0	0	17	0	0	0	0	0	0
High	0	0	0	0	0	53	19	0	0	0	0	50
Low	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)												
Expected	792	711	665	567	522	574	658	623	502	604	716	851
High	842	756	708	602	555	611	699	662	534	642	762	905
Low	742	666	623	531	489	538	616	584	470	565	671	797
Resources (MW)												
Fortis BC	210	192	200	192	187	178	188	203	206	191	214	213
Brilliant (incl. upgrade)	142	143	107	137	126	119	126	135	139	139	143	143
Others	9	7	5	7	10	10	10	8	5	5	8	9
BCH 3808	200	200	200	200	200	200	200	200	200	200	200	200
WAX CAPA	283	282	269	124	65	50	157	296	301	197	298	290

Figure BCUC IR1 259.1d 2040 Monthly Capacity Load/Resource Balance

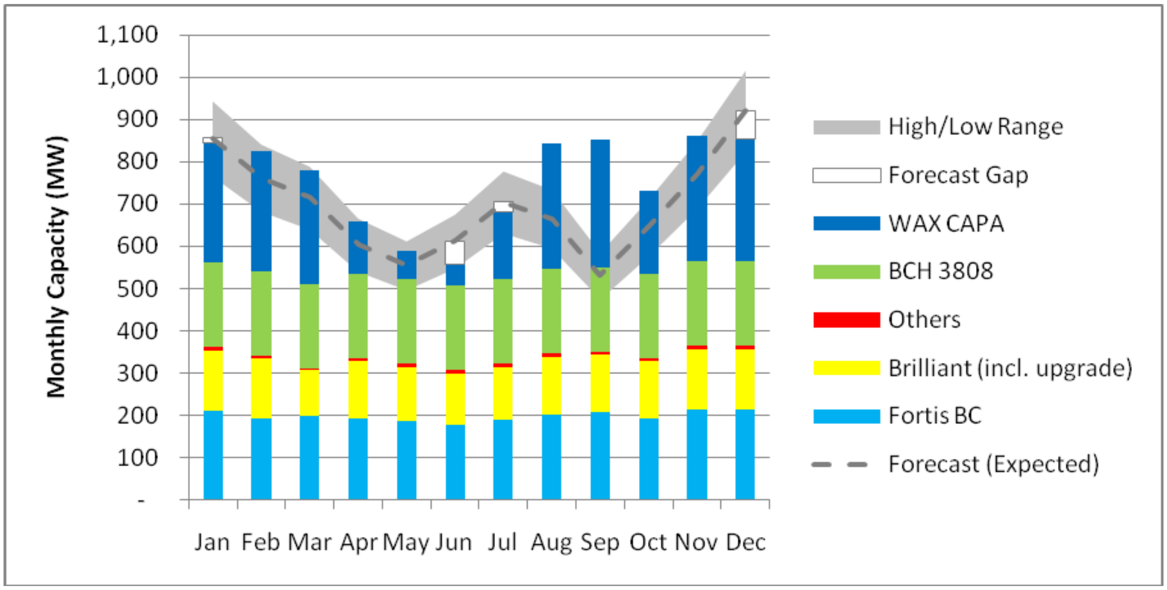


Table BCUC IR1 259.1d 2040 Monthly Capacity Load/Resource Balance

2040	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Gaps (MW)												
Expected	11	0	0	0	0	55	25	0	0	0	0	66
High	99	17	9	7	25	118	97	0	0	0	0	161
Low	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)												
Expected	855	763	715	604	555	612	705	665	531	645	771	921
High	943	841	789	666	612	675	778	734	585	711	850	1,016
Low	765	683	640	540	497	548	631	595	475	577	689	824
Resources (MW)												
Fortis BC	210	192	200	192	187	178	188	203	206	191	214	213
Brilliant (incl. upgrade)	142	143	107	137	126	119	126	135	139	139	143	143
Others	9	7	5	7	10	10	10	8	5	5	8	9
BCH 3808	200	200	200	200	200	200	200	200	200	200	200	200
WAX CAPA	283	282	269	124	65	50	157	296	301	197	298	290

260.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 5.2.1.3, pp. 61-63

Capacity Gap Summary

260.1 Please provide Figures 5.2.1.3-A, 5.2.1.3-B, 5.2.1.3-C and 5.2.1.3-D without the planning reserve margin component in the Forecast load requirement.

Response:

The requested Figures without the PRM requirements are as follows:

Figure BCUC IR1 260.1a 2016 Forecast Gap + High/Low Spread

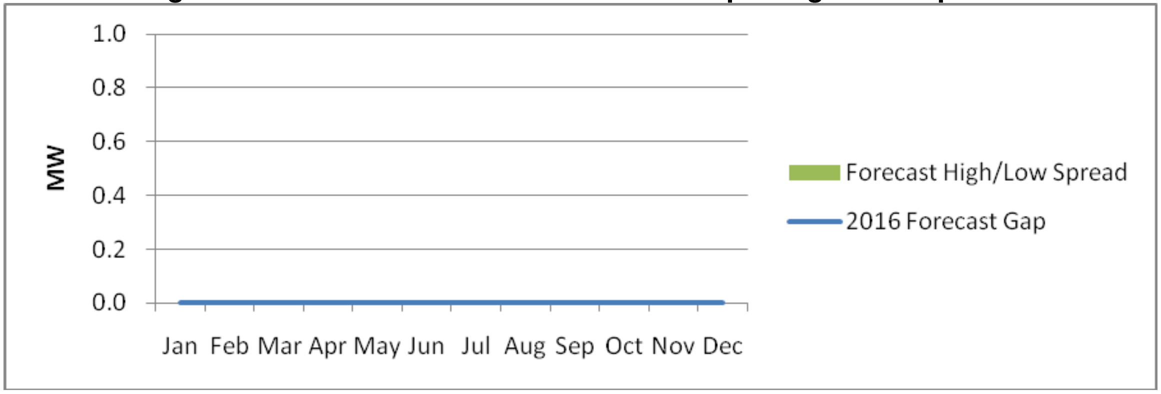


Figure BCUC IR1 260.1b 2020 Forecast Gap + High/Low Spread

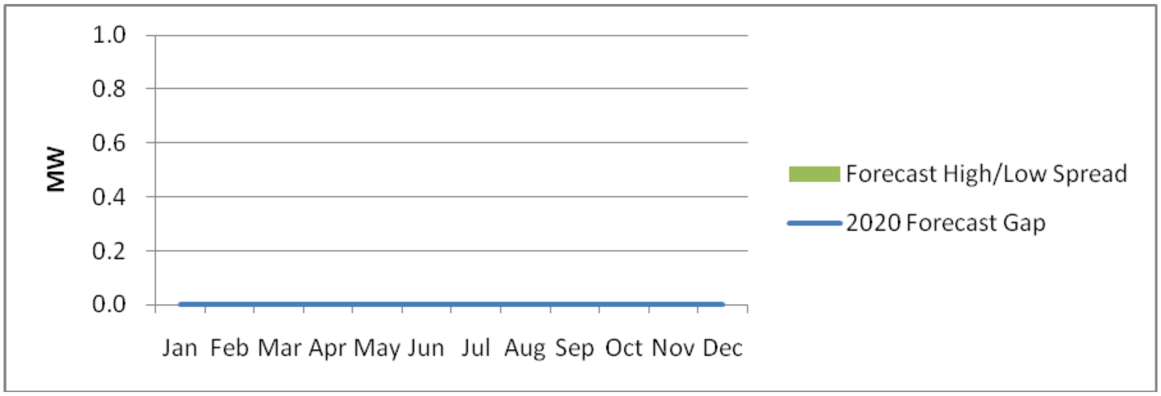


Figure BCUC IR1 260.1c 2030 Forecast Gap + High/Low Spread

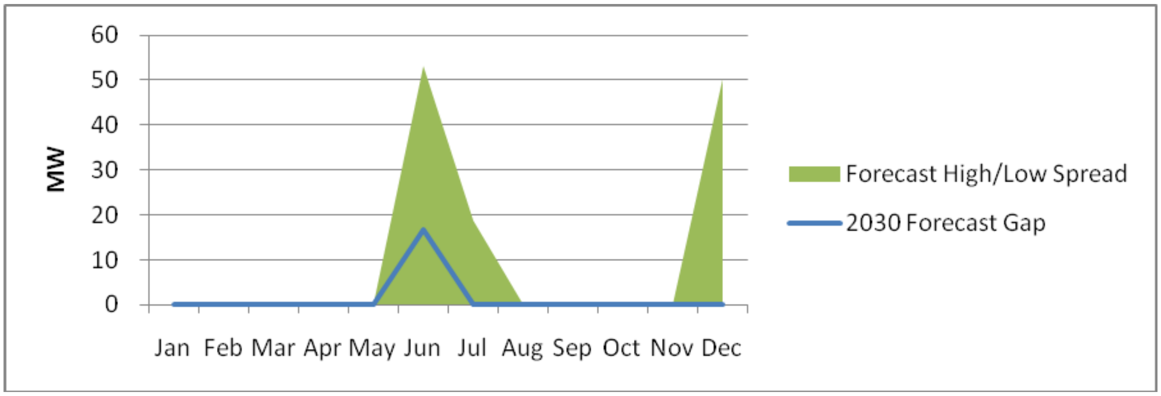
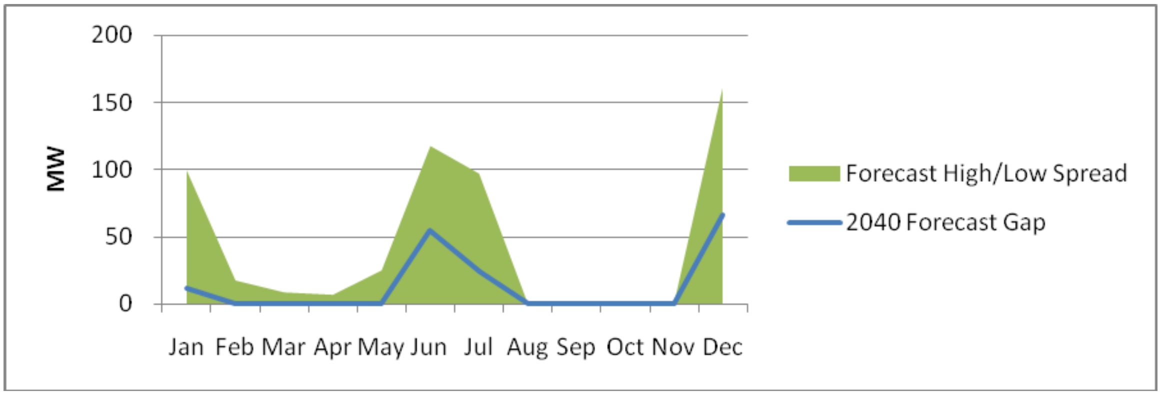


Figure BCUC IR1 260.1d 2040 Forecast Gap + High/Low Spread

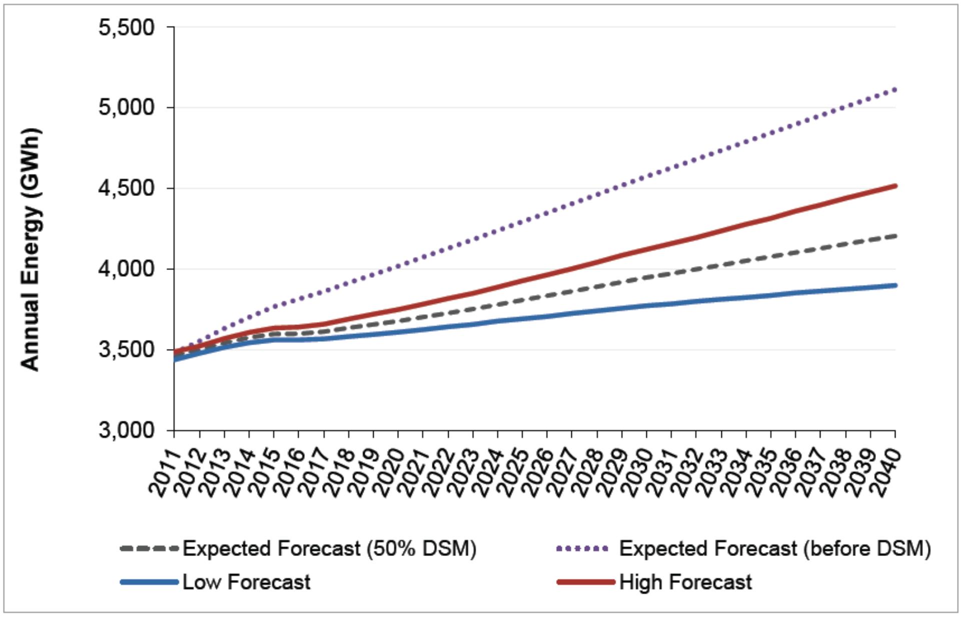


261.0 Reference: Key Input Parameters

Exhibit B-1-2, Section 5.2.2.1, p. 64

Figure 5.2.2.1-A FortisBC Load Forecast (GWh)

Figure 5.2.2.1-A - FortisBC Load Forecast (GWh)



FortisBC states that "FortisBC prepares a Monte Carlo forecast to determine a high forecast which has a 90 percent probability of not being exceeded and a low forecast with a 10 percent probability of not being reached. The Monte Carlo analysis considers probability distributions for each customer class and performs repeated simulations of the load forecasting model. The high, low and expected peaks after DSM are shown below." (Exhibit B-1-2, Section 4, p. 43)

FortisBC also states that "However, given the inherent non-firm nature of DSM resources, and the long lead time required to implement alternative supply resources, the Company has considered a probabilistic approach which targets 50 percent DSM effectiveness with an 80 percent confidence interval that projected demand avoidance will fall within the range of 28 percent to 72 percent of status quo load growth." (Exhibit B-1-2, Section 5.1.4, p. 52)

261.1 Please clearly explain the difference between the two probabilistic approaches (Monte Carlo and around DSM) and how they relate to each other.

Response:

The probabilistic approach for DSM is also the Monte-Carlo method, in which DSM is integrated into the load forecasting model and its performance as a percentage (e.g. 80%, 100%, 120%, etc.) of the planned DSM target (in percent of incremental load growth, e.g. 50%, 52%, 66%, etc.) in each year is assumed to follow a normal probability distribution function with mean 100% and standard deviation 21.7%.

For example, a randomly generated performance of 90% of a target of 50% in a year will yield a DSM equal to 90%*50% = 45% of the load growth in that year.

261.2 Please show separately on the graph the effect of the Monte Carlo simulation and the effect of the probabilistic analysis around DSM and that the combination of the two results in what we see in Figure 5.2.2.1-A.

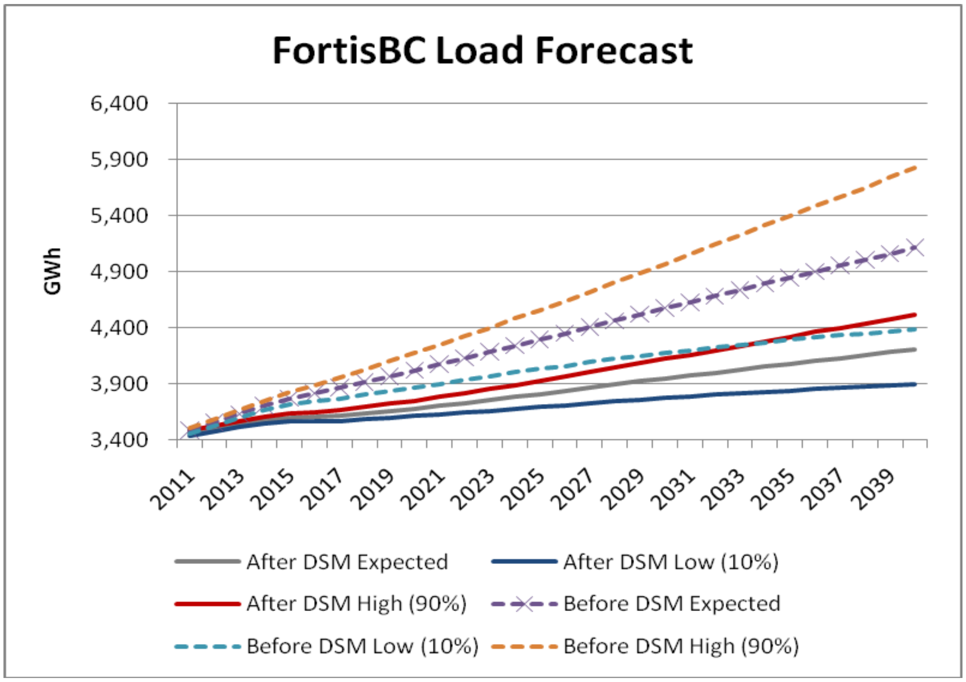
Response:

Please note that there was an error in the description of the DSM range in Exhibit B-1-2, Section 5.1.4, p. 52. The phrase "…within the range of 28 percent to 72% of status quo growth" should read, "…within the range of 36 percent to 64 percent of status quo load growth". Please refer to the response to BCUC IR1 Q281.1 for further information on this correction, as well as Errata 2.

The probabilistic approach around DSM mentioned in the paragraph above is the same Monte-Carlo simulation used to determine the high/low demand forecast after DSM as DSM savings are directly integrated into the load forecasting model as explained in the response to BCUC IR No. 281.3. In other words, the high/low range of the after-DSM energy forecast as shown in Fig. 5.2.2.1.A is a direct output from the Monte-Carlo simulation (i.e. the range of DSM and other savings were not simulated separately and then superimposed on the high/low range of the before DSM load forecast). In fact, in each Monte-Carlo simulation run, the DSM saving, and therefore the after DSM load, is determined by the simulated load combined with the simulated DSM performance in a single operation.

Nevertheless, as shown in the following graph, a comparison of the high/low ranges resulting from Monte Carlo simulations performed with and without taking into consideration DSM savings can be used to see the impact of DSM on the overall forecast.

1 **Figure BCUC IR1 261.2**



2

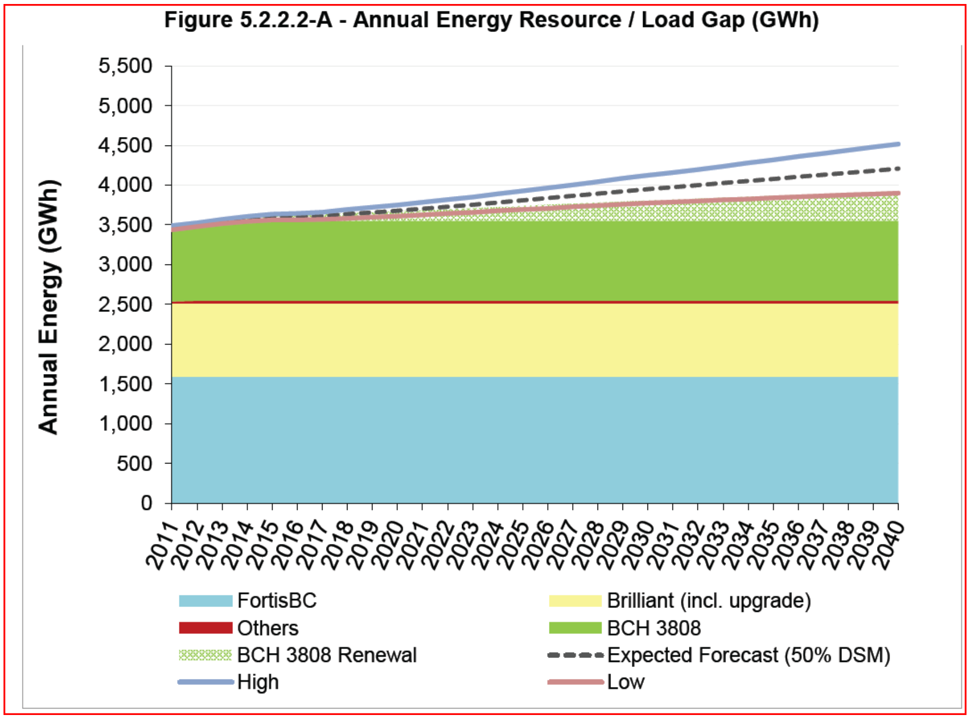
3

4

262.0 Reference: Energy Resource / Load Gap

Exhibit B-1-2, Section 5.2.2.2, p. 65

Figure 5.2.2.2-A Annual Energy Resource / Load Gap (GWh)



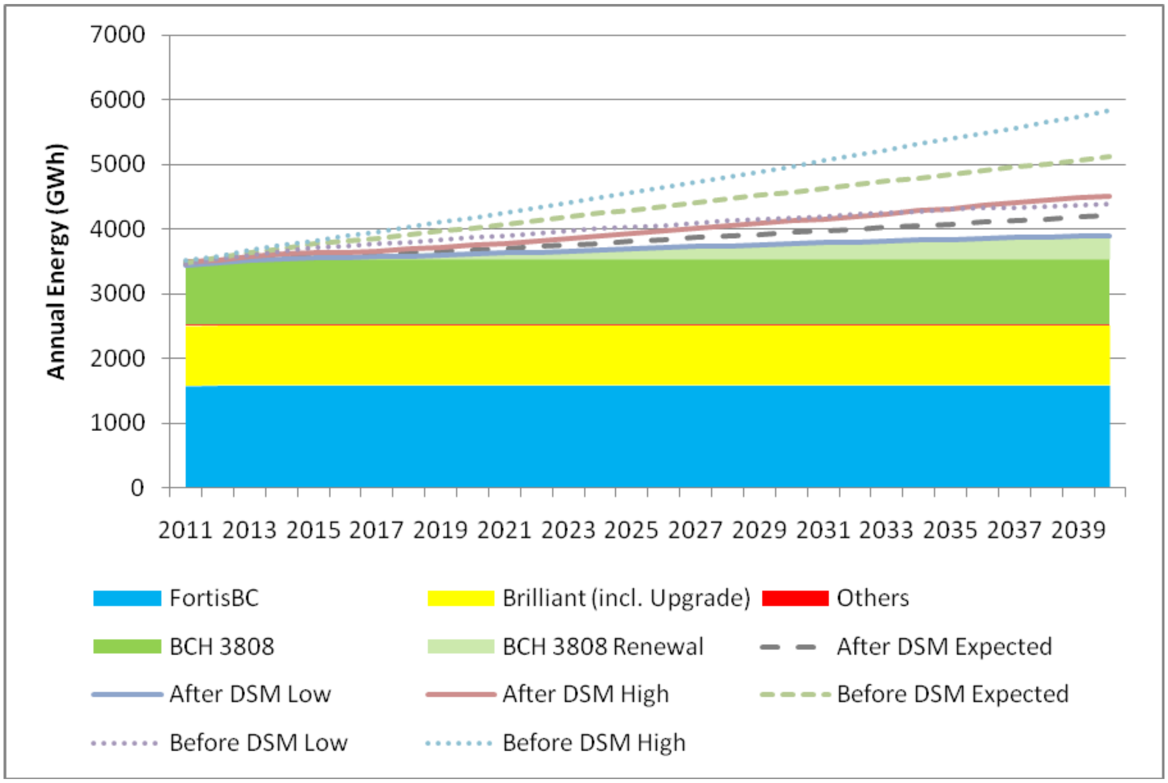
FortisBC states that "Figure 5.2.2.2-A shows how FortisBC's energy demand will grow into the future with and without DSM."

262.1 Please provide an amended graph that shows the load forecast without DSM.

Response:

Figure BCUC IR1 262.1 below shows the load forecast without DSM.

Figure BCUC IR1 262.1 Annual Energy Resource/Load Gap (GWh)



263.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 6, pp. 68-69

Table 6-A - Expected Energy and Capacity Gaps in the Short, Medium and Long Terms

263.1 Please confirm whether Table 6-A includes the planning reserve margin, and if so, please provide a similar table without the planning reserve margin.

<u>Response:</u>

Yes, the capacity gap column in Table 6-A discusses the gaps which include the requirement for planning reserve margin (PRM).

The revised Table 6-A assuming no PRM required is as follows.

Table BCUC IR1 263.1

Time Period	Capacity Gap	Energy Gap
Short term (2011 – 2015)	Increasing capacity deficits through to 2014, by which time deficits are present in 8 months and range from 3 MW (October) to 75 MW (March). However deficits disappear in 2015 following the commissioning of WAX.	A small energy gap exists, starting at 5 GWh in 2011.
Medium term (2016 – 2020)	No capacity gap is expected.	Gap increasing to a 35 GWh by 2020.
Long term (2021 – 2040)	No deficit is observed until 2027. Gaps are mainly in June and December, but eventually expanding to July (2035) and January (2039). Winter max deficit of 0 MW by 2030 and 66 MW by 2040; summer max deficit of 17 MW by 2030 and 55 MW by 2040. By 2040, 4 percent of December super peak hours have a capacity gap.	Gap increasing to approximately 310 GWh by 2040.

264.0 Reference: Resource Options Ranking and Evaluation Criteria

Exhibit B-1-2, Section 6.1.2, pp. 73

Evaluation Criteria

FortisBC states that “FortisBC further refined its resource option rankings by putting the resources options that passed initial economic screening through a final set of filters that represent key FortisBC resource option priorities and requirements: 1. Appropriate Size; 2. Environmental Impacts and **Adherence to the Directives of the *Clean Energy Act***; 3. Appropriate Energy Shape (Energy Resource Evaluation Only); 4. Comparative Resource Economics Test.” (Emphasis added)

Section 2 of the *Clean Energy Act* (CEA) stipulates British Columbia’s Energy Objectives, including:

2(k) to encourage economic development and the creation and retention of jobs; and

2(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources.

264.1 Please evaluate the capacity resource options in Table 6.1.2-A and the energy resource options in Table 6.1.2-B using the following additional criteria (consistent with the CEA): 1) job creation/retention and 2) community benefits.

Response:

FortisBC has not yet developed detailed project scopes for the various capacity and energy resource options to enable evaluation of either 1) job creation/retention or 2) community benefits at this time.

A socio-economic assessment, including job creation, job retention, and community benefits will be part of the evaluation of any resource options at the time that detailed project scopes are being developed.

264.2 For each of the capacity resource options in Table 6.1.2-A and the energy resource options in Table 6.1.2-B, please elaborate on the degree of difficulty in obtaining the social contract for permitting and siting each of the facility.

Response:

All new projects will face a high degree of scrutiny during their permitting. The sizing and routing of the transmission lines required to interconnect the projects will also impact the environmental review and permitting process.

The following table provides a general breakdown of the anticipated degree of difficulty to obtain the social contracts – i.e.: local and regional public opinion support – necessary for permitting and siting:

Resource	Degree of Difficulty	Comments / Obstacles
SCGT	Moderate	Although primarily operated as a peaking/reserve resource, as a gas fired resource, development of a SCGT will need to address the environmental concerns related to greenhouse gases and other air pollutants. This is of particular concern when a unit is located within or near a populated area, especially when there are airshed constraints.
Similkameen Storage Hydro	Moderate to High	Three concerns regarding social contract: 1) Development of a hydroelectric project on a historically un-regulated reach of a river 2) Impacts upon the wildlife and aquatic environment 3) Hydroelectric reservoir permitting process is complex

Resource	Degree of Difficulty	Comments / Obstacles
PSH	Moderate to High	PSH requires an upper and lower reservoir – either natural or man-made. As previously mentioned, reservoirs are not simple to permit.
CCGT	Moderate to High	Development of CCGT plants will need to address environmental concerns related to greenhouse gases and other air pollutants. CCGT plants are generally run much more often than SCGT plants, have a more continuous local airshed impact and will likely attract a higher degree of scrutiny.
ROR	Moderate	Although regarded as the most environmentally friendly form of hydroelectric generation, impacts to the river's diversion reach and other site specific factors relating to civil works must be considered. Transmission may also become an issue.
Biomass	Low to Moderate	Biomass energy is considered to be a green resource. Assuming the fuel source is forestry waste, greenhouse gas emissions would be modest, although the trucking of the fuel could exacerbate the emissions. (Municipal waste as the fuel source would result in a 'High' rating.)
Wind	Low to Moderate	Two key concerns regarding social contract: 1) Visual pollution and noise impacts 2) Environmental impacts associated with the very large physical footprint and the impact upon wildlife, especially birds and bats In addition, the Transmission footprint is generally larger than other resources, both due to the internal collector system and the typically large distances between suitable sites and major load centres.

265.0 Reference: Key Attributes of FortisBC's Preferred Build Strategy Resource Options

Exhibit B-1-2, Section 6.1.3.1, pp. 75-76

Simple Cycle Gas Turbines

FortisBC states that "Since SCGTs generate greenhouse gases, obtaining the social contract needed to permit and site SCGTs is often difficult. However, once permits are obtained SCGTs can be constructed in a relatively short period of time."

FortisBC also states that "These facilities can be located close to load centers and therefore this option involves minimal transmission impacts and may defer otherwise necessary transmission reinforcements to the load center."

265.1 Would the SCGT be located in the FortisBC service territory? If not, where would it be located and would new transmission infrastructure be required?

Response:

The SCGT has been presented at a conceptual level in the resource plan. At this stage of the planning process FortisBC has not determined specific sites for the resource options identified in Table 6.1.1-A and Table 6.1.1-B (with the exception of the Similkameen hydroelectric project which is located at a specific location on the Similkameen River). Given that siting options have not been explored, transmission costs/benefits have not been evaluated.

265.2 Please describe the permitting process, and costs associated to it, that FortisBC would need to go through in connection to the construction and operation of the SCGT (e.g., which permits FortisBC would need to obtain from which authority).

Response:

The potential SCGT in the Resource Plan has been presented at a conceptual level. At this stage of the planning process FortisBC has not determined the permitting process, and costs associated to it, that FortisBC would need to go through in connection to the construction and operation of the SCGT.

265.3 Please describe the stakeholders consultations that FortisBC would undertake to specifically obtain the social contract needed to permit and site the SCGT. How has FortisBC factored in its failed effort to obtain approval for a single cycle turbine in Oliver into its assessment of this option?

Response:

The potential SCGT in the Resource Plan has been presented at a conceptual level. At this stage of the planning process FortisBC has not determined the stakeholder consultations that FortisBC would undertake to specifically obtain the social contract needed to permit and site the SCGT. FortisBC has not factored in its failed effort in 1988 to obtain approval for a single cycle turbine in Oliver into its assessment of this option.

265.4 Aside from GHG emissions, please list all other air emissions from a SCGT and their impact on the air quality where the facility would be located. What can be done to reduce the emission of these air pollutants?

Response:

The potential SCGT in the Resource Plan has been presented at a conceptual level. At this stage of the planning process FortisBC has not determined the other air emissions from a SCGT, their impact on the air quality where the facility would be located, and what can be done to reduce the emissions of these air pollutants.

266.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 6.1.2, pp. 73-75

Resource Option Ranking and Evaluation Criteria

266.1 Please discuss whether all criteria should be given the same weight. For instance, one project could be rated a 1 for gap closure/size and 3 for resource economics, and a second project rated vice versa, yet they would be rated equal. Of greater concern is where the first project was rated a 2 in resource economics, yet significantly more expensive that the second project, yet the selection criteria would give preference to the first project.

Response:

It is valid to designate equal weighting to each criterion for the purposes of ranking. The ranking and evaluation criteria were designed as a simple tool to filter out resource options that poorly met the needs of FortisBC. It was not designed to determine which project should be built.

It is important to emphasize that the criterion - gap closure and size, environmental impacts, resource economics, energy shape - are independently ranked. Any one criterion is not obviously more significant than the others.

In response to the scenario proposed in part two of the question, the following table is provided for illustration:

Table BCUC IR1 266.1

Resource	Gap Closure/Size	Project Economics	Total
A	1	2	3
B	3	1	4

Concern was expressed regarding the fact that resource A ranks better than resource B, given the assumption that resource A is “significantly more expensive” than resource B. Although one resource may be less costly to construct based upon the ”per unit” MW or MWh basis, if the size of the resource added is larger than required to address the FortisBC gap, then the resource may actually be more costly as measured on a “FortisBC required” MW or MWh basis. Resource B is not necessarily the better resource option for FortisBC simply because it has a more favorable “per unit” project economics score.

266.2 Please identify the amount of investigative spending that has been expended, and is forecasted to be expended in 2012 and 2013, on each of the projects identified in Table 6.1.1-A and Table 6.1.1-B and the intended disposition of these amounts.

Response:

FortisBC has conducted some preliminary investigations of potential PSH sites and identified two potential sites. The costs of identification and preliminary investigation of the sites is $0.227 million. The Company is not seeking to amortize the balance of $0.2 million during the period under review and will seek disposition in a subsequent filing.

FortisBC also incurred investigative small hydro costs of $0.051 million for the Similkameen hydroelectric project. These were expensed to O&M in 2010.No spending is planned for 2012 and 2013 for any of the projects identified in the tables.

266.3 Please clarify if any approval is being sought for previously expended amounts, or forecasted expenditure amounts with regard to each of the projects identified in Table 6.1.1-A and Table 6.1.1-B.

Response:

No approvals are being sought in this Application for previously expended amounts, or forecast expenditure amounts with regard to each of the projects identified in Table 6.1.1-A and Table 6.1.1-B.

266.4 Please discuss the green house gas emissions associated the combined cycle generating stations and the use of that threshold in determining if a resource is "clean" or "dirty".

Response:

The 2007 Energy Plan included Policy items 18 and 19, which requires new and existing natural gas and oil generation plants connected to the integrated grid to have zero net GHG emissions. This means that the proponents of these generation projects would have to invest in other initiatives that would offset the GHG emissions generated by these projects, unless the technology was available to eliminate or capture and store the emissions from the plant.

Therefore, it is the Company's view that any new CCGT in developed in BC that arrangements or technology in place that would offset or eliminate GHG emissions would by definition, be "clean".

266.5 Please explain if a co-owner of a combined cycle generating station, for example BC Hydro, has been investigated to tailor the size of FortisBC's share of a combined cycle generating station to match the load/resource gap. If not, why not?

Response:

The CCGT option in this plan has been presented at a conceptual level. Significant capacity gaps do not appear in the short to medium term. At this stage of the planning process we have not yet have had the opportunity to investigate if a co-owner of a combined cycle generating station would allow FortisBC to to tailor the size of its share of a combined cycle generating station to match the load/resource gap.

266.6 Please provide a comparison of the potential environmental permitting challenges of the Similkameen Hydroelectric project, the Pumped Storage Hydro project and a combined cycle generating station, and reconcile this against the "3" rating for the combined cycle generating station environmental impacts. Please explain how criteria other than GHG emissions were considered in the evaluation of the environmental impacts of the projects.

Response:

Environmental permitting challenges were not incorporated in the environmental impacts ranking criterion due to the fact that the project evaluations were largely based upon generic projects. Unless further information, such as site specific environmental concerns, impacted stakeholders, and project layouts are known, accurate assessment of permitting challenges is difficult and will not necessarily result in reliable conclusions.

The following factors were considered in the evaluation of the environmental impact criterion:

- Greenhouse Gas Emissions;
- Fuel type (renewable vs. non-renewable);
- Typical distance from load centers (transmission implications and well as GHG output footprint);
- Physical project footprint;
- Ability to comply with the following Clean Energy Act directives:
    - To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
    - To reduce BC greenhouse gas emissions;
    - To reduce waste by encouraging the use of waste heat, biogas and biomass; and
    - To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia.

References

British Columbia Bill 17 – 2010 Clean Energy Act

266.7 Please provide additional description if the siting options for each of the projects identified in Table 6.1.1-A and Table 6.1.1-B, and explain how transmission support costs/benefits have been included in the evaluation of UEC and UCC for each option. For instance, if a suitably sited resource could defer the need for a $40 million static VAR compensator at the DG Bell substation, it could significantly alter its economics relative to other projects.

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process FortisBC has not determined specific sites for the resource options identified in Table 6.1.1-A and Table 6.1.1-B (with the exception of the Similkameen hydroelectric project which is located at a specific location on the Similkameen River). Given that siting options have not been explored, transmission costs/benefits have not been included in the UEC and UCC calculations.

FortisBC agrees that if a suitably sited resource could defer the need for a $40 million static VAR compensator at the DG Bell substation, it could significantly alter its economics relative to other projects.

267.0 Reference: Key Attributes of FortisBC's Preferred Build Strategy Resource Options

Exhibit B-1-2, Section 6.1.3.1, pp. 76-77

Pumped Storage Hydro

FortisBC states that "This capability also enables the electric system to absorb and balance significant amounts of customer-owned distributed generation resources, such as small wind mills or roof-top solar panels."

267.1 What is FortisBC's forecast over the planning period of the share of customer-owned distributed generation in the overall resource mix (energy and capacity)?

Response:

The Company has not produced a forecast of customer-owned distributed generation.

FortisBC states that "PSH facilities involve long lead times for siting, permitting and construction due to the requirement for water storage sites, therefore development activities must be pursued prudently long in advance of actual project commissioning."

267.2 What are the sites considered for the PSH? Are they located in the FortisBC service territory?

Response:

For commercially sensitive reasons, FortisBC respectfully declines to provide location details of prospective PSH sites at this time. It is worth noting that for one site, on Nicola Lake near Merritt, BC, the Company did commence the procedure to obtain a water licence. Since the original application, given further investigation, the Company has determined that the Nicola site is no longer suitable and has terminated the application process.

In general though, potential PSH development sites would be chosen for a) topographical attractiveness (existing "significant" lower reservoir and good head), b) proximity to existing transmission, and c) proximity to FBC load center.

267.3 Does FortisBC anticipate opposition to siting?

Response:

Hydroelectric reservoir permitting is complex. PSH requires an upper and lower reservoir, either natural or man-made. Depending on the site chosen, there may be opposition to siting. FortisBC will hold stakeholder and First Nations consultations in order to determine how it can minimize potential opposition to siting as part of the feasibility assessment of any PSH projects it identifies in the future.

267.4 Please describe the potential land impacts from constructing this facility and the strategies to mitigate them.

Response:

The PSH option in this plan has been presented at a conceptual level. At this stage of the planning process FortisBC has not determined specific sites for the resource options identified in Table 6.1.1-A and Table 6.1.1-B (with the exception of the Similkameen hydroelectric project which is located at a specific location on the Similkameen River). Given that siting options have not been determined, potential land impacts from constructing this facility and the strategies to mitigate them have not been properly evaluated.

268.0 Reference: Key Attributes of FortisBC's Preferred Build Strategy Resource Options

Exhibit B-1-2, Section 6.1.3.1, pp. 77-78

Similkameen Hydroelectric Project

FortisBC states that "This project would potentially increase Similkameen River stream flows during the dry summer months by storing freshet water, thereby improving summertime water availability for downstream users and aquatic life in both Canada and the United States.

268.1 Please describe the potential land impact upstream of the dam and strategies to mitigate them.

Response:

The potential Similkameen Hydroelectric Project identified in the Resource Plan has been presented at a conceptual level. At this stage of the planning process, upstream land impacts for this project have not been assessed in any great detail. From the information available, it is apparent that the project would be constructed on a stream located in a very deep valley with steep valley walls. As a result, it is anticipated that the potential upstream land impact would be negligible.

If FortisBC decides the project warrants further evaluation, the exact nature of potential land impacts from such a project would be evaluated as part of the project development and through mechanisms such as the environmental assessment. At that time, mitigation strategies would be developed and implemented.

269.0 Reference: Key Attributes of FortisBC's Preferred Build Strategy Resource Options

Exhibit B-1-2, Section 6.1.3.1, pp. 78-79

Combined Cycle Gas Turbines

FortisBC states that "Since CCGTs are base load resources that continuously generate greenhouse gases, obtaining the social contract needed to permit and site CCGTs is often difficult. However, once permits are obtained, CCGTs can be constructed in a relatively short period of time. It is reasonable to expect that FortisBC would be required to purchase carbon offsets to compensate for greenhouse gas emissions."

FortisBC also states that "Rapid deployment: CCGTs can be rapidly developed once environmental permitting is complete."

269.1 Would the CCGT be located in the FortisBC service territory? If not, where would it be located and would new transmission infrastructure be required?

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process FortisBC has not determined specific sites for the resource options identified in Table 6.1.1-A and Table 6.1.1-B (with the exception of the Similkameen hydroelectric project which is located at a specific location on the Similkameen River). Given that siting options have not been explored, transmission costs/benefits have not been evaluated.

269.2 Please describe the permitting process, and costs associated to it, that FortisBC would need to go through in connection to the construction and operation of the CCGT (e.g., which permits would FortisBC need to obtain and from which authority).

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process the permitting process that FortisBC would need to go through in connection to the construction and operation of the CCGT, and costs associated to it, have not been evaluated.

269.3 Please describe the environmental permitting process, and costs associated to it, that FortisBC would need to go through to obtain approval for construction of a CCGT.

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process the environmental permitting process that FortisBC would need to go through to obtain approval for construction of a CCGT, and costs associated to it have not been evaluated.

However, the proposed CCGT project would trigger a provincial environmental assessment under the British Columbia Reviewable Projects Regulation of the Environmental Assessment Act because the nameplate capacity of the project would be greater than 50 MW. As such, the environmental permitting process would involve the Environmental Assessment Office (EAO) and include the following steps:

1. Pre-application: A project description is submitted to the EAO to determine the Terms of Reference for the Application for a Project Approval Certificate. This process requires a First Nation and stakeholder consultation to identify the potential social, environmental and economic impacts and concerns. Baseline and impact

studies are initiated based on the Term of Reference. The timelines and cost of the pre-application stage are highly variable and dependant on the location selected and the various social and environmental implications of that location. Generally for CCGT projects the contentious environmental issues often include water consumption and water temperature, air-shed impacts and emissions, noise and visual impacts of the plant. Secondary concerns may include archeological and ecological/habitat concerns. All issues will require consultation, assessment and mitigation during the pre-application stage of the permitting process. This information is combined in a report and submitted as an Application for Project Approval.

2. Submission and Review of Application: When completed, the Application for Project Approval is submitted to the EAO where it is evaluated for completeness over 30 days and then distributed for public consultation and review by regulatory agencies. The EAO then prepares a report to the Minister to summarize the outcome of their review. This process is 180 days.
3. Decision stage: The Minister decides whether the project is approved, rejected or more work is required. This decision process is 45 days.

The costs of the pre-application phase is the most variable and highly dependent on the sensitivity of the location selected for the power plant.

269.3.1 What is the likely time period for the environmental permitting process to be complete?

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process the environmental permitting process that FortisBC would need to go through to obtain approval for construction of a CCGT, and costs associated to it have not been evaluated.

It is very difficult to predict all the variables that would impact the deployment of CCGTs. A time estimate from EAO website information is: “a typical environmental assessment process generally takes 16 to 20 months to complete.”

269.3.2 Would the CCGT option still be considered a rapid-deployment option given the response above?

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process the environmental permitting process that FortisBC would need to go through to obtain approval for construction of a CCGT, and the likely time period for the environmental permitting process to be complete, has not been evaluated.

However, although development of a CCGT option must address GHG concerns, each of potential resource options will have specific environmental, land impact and stakeholder concerns to address prior to obtaining necessary permitting. The advantage of the CCGT is that once permitted, the construction period is relatively short as compared to many other options,

Given these responses, the CCGT option would still be considered a rapid-deployment option.

269.4 Aside from GHG emissions, please list all other air emissions from a CCGT and their impact on the air quality where the facility would be located. What can be done to reduce the emission of these air pollutants?

Response:

The CCGT option in this plan has been presented at a conceptual level. At this stage of the planning process the other air emissions from a CCGT, their impact on the air quality where the facility would be located, and what can be done to reduce the emission of these air pollutants have not been evaluated.

269.5 Even if offsets were purchased, please explain how a CCGT is consistent with the following CEA's energy objectives: c), d), g) h) and m).

Response:

The *Clean Energy Act* Section 2 objectives listed above are:

(c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and the use of clean or renewable resources;

(g) to reduce BC greenhouse gas emissions;

> (h) To encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
>
> (m) to maximize the value, including the incremental value of the resources being clean or renewable resource, of BC's generation and transmission assets for the benefit of BC.

The 2007 BC Energy Plan included Policy items 18 and 19, which requires new and existing natural gas and oil generation plants connected to the integrated grid to have zero net GHG emissions. This means that the proponents of these generation projects would have to invest in other initiatives that would completely offset the GHG emissions generated by these projects, unless the technology was available to eliminate or capture and store the emissions from the plant.

By offsetting its GHG footprint through the purchase of carbon offsets of allowances under a cap and trade program, a CCGT would be carbon neutral, and would qualify as "clean". Therefore it would be consistent with 2(c), 2(g) and 2(h).

As stated in Appendix F of the Resource Plan and in response to BCUC IR1 Q278.1, policy items 2(d) and 2(h) are not directly applicable to FortisBC. Irregardless of the applicability of these objectives to FortisBC, since there has effectively been no market penetration of CCGT's in BC, it could be argued that a CCGT supported by carbon offsets is an innovative clean energy technology for BC. In addition, by building a carbon neutral CCGT, Fortis BC will likely reduce electricity imports which will have a component of "dirty" electricity from natural gas or coal generators, thereby addressing 2(h).

Policy Item 2(m) would be satisfied if the CCGT, including offset purchases, was cost competitive with other clean resources.

> FortisBC states that "In the FortisBC context, CCGTs are typically large relative to the forecast energy gaps. For example, a 243 MW CCGT can be expected to generate approximately 1,900 GWh68 of energy annually."

269.6 Is a 243-MW-facility the smallest economic size that can be commissioned? If so, please explain why. If not, please explain how FortisBC has evaluated this facility size for this Resource Plan.

Response:

Smaller CCGT plants are available, but the UEC would be much higher than for larger CCGT plants. For example, in the BC Hydro 2008 Long Term Acquisition Plan Appendix F1 (Page 8 & 9 of 216), the UEC for a 50 MW facility ($131/MWh) is 25 % higher than the UEC for a 250MW facility ($105/MWh), assuming a 6% Discount Rate. The UEC difference between the 50 MW and 250 MW options increases to 28% using an 8% Discount Rate ($136/MWh vs. $106/MWh, respectively).

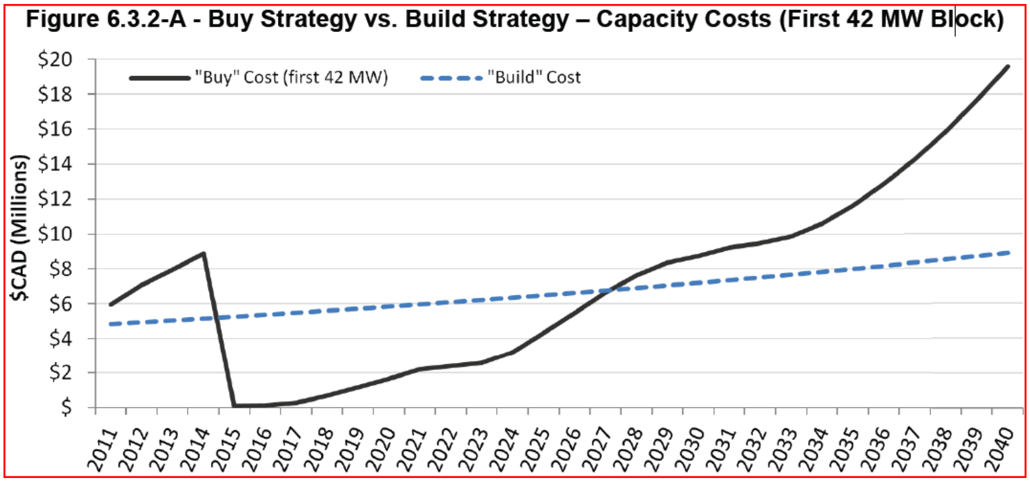
Applying an assumed 25% adder to the UEC of $90/MWh (@ 6% discount) calculated for a 243 MW CCGT in the FortisBC - 2010 Resource Options Report prepared by Midgard Consulting Inc., the expected comparable UEC for a 50 MW CCGT would be $113/MWh. This would rank worse than the UEC for all other resource options except higher cost Wind in the resource stack shown in Table 6.1.1-B of the 2012 Long Term Resource Plan (Page 71).

As a result, it was determined that a 250 MW or larger CCGT represents an economically competitive energy resource when compared with the other energy resource options available to FortisBC. Therefore, FortisBC has selected a 250 MW facility for consideration as a resource option.

270.0 Reference: Capacity Cost Comparison

Exhibit B-1-2, Section 6.3.2, pp. 80-81

Figure 6.3.2-A Buy Strategy vs. Build Strategy – Capacity Costs (First 42 MW Block)



270.1 For the Build Strategy, please specify which discount rate was used for these calculations: 6% or 8%?

Response:

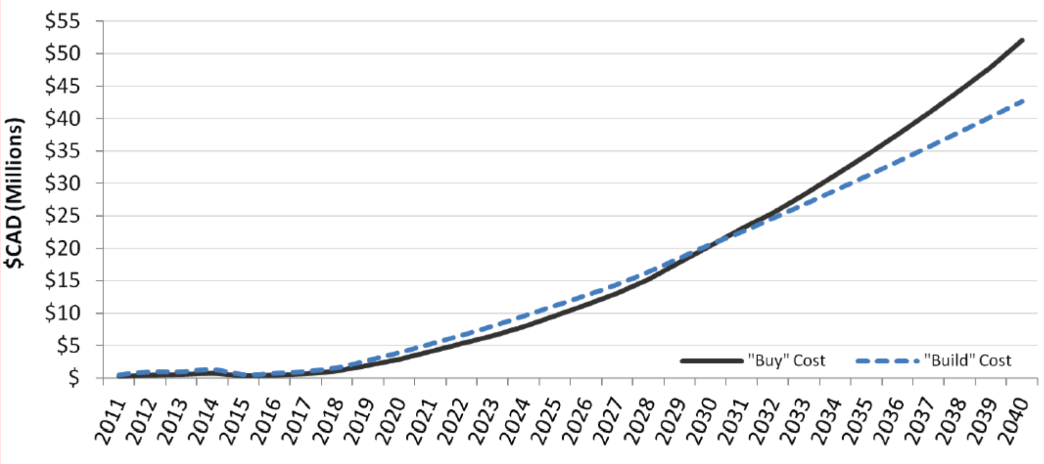
The Build Strategy costs were developed from the BC New Resources Market Capacity Curve, which utilized an 8% real discount rate. Further details can be found in the Section 6.2 of the Midgard Energy and Capacity Market Assessment in Appendix B of the 2012 Long Term Resource Plan.

271.0 Reference: Energy Cost Comparison

Exhibit B-1-2, Section 6.3.3, pp. 81-82

Figure 6.3.3-A Buy vs. Build– New Clean Energy Resources

Figure 6.3.3-A - Buy vs. Build – New Clean Energy Resources



271.1 Given that the terms “New Clean Energy Resources” refer to various energy resources with very different UEC (see Exhibit B-1-2, Table 6.1.1-B, p. 71 and Table 6.1.2-B, p. 75), please explain how the “Build” Cost curve in Figure 6.3.3-A was put together.

Response:

UEC was not used in the derivation of the BC New Clean Energy Resources Curve. Rather, a three step process was used to create the “Build” Cost curve:

1) The most recent BC Hydro Standing Offer Program (SOP) price was used as the starting point of the curve. Section 5.2 (Exhibit B-1-2, Appendix B, page 26 of 54) provides the reasoning as to why the current SOP price offering is representative of the current cost of new resources. In brief, when BC Hydro performed its recent review and update of its SOP, it selected a price that was sufficiently high to encourage IPP participation while low enough to ensure that only the most competitive projects would be viable (e.g. target of 500 GWh of new generation). FortisBC believes that the work done by BC Hydro is fundamentally sound and appropriately represents the cost of new resources in BC.

   The SOP is available to new clean energy resources;

2) The 2011 SOP price was escalated at 50% CPI (as per the terms within the SOP contract) for each year in the 2011 to 2040 planning horizon; and

3) The “Build” cost curve (expressed in Millions of Canadian dollars) was calculated by taking the product of the respective energy price (as described above) and the expected energy gap (taken from Table 5.2.2.3-A of Exhibit B-1-2, page 66) for each year.

272.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 6.3.5, p. 84

Solutions Summary

272.1 Please revise Table 6.3.5-A to reflect no planning reserve margin amount.

Response:

The revised Table 6.3.5-A assuming no PRM required is as follows.

Table BCUC IR1 272.1

Time Period	Expected Capacity Gap	Capacity Solution
Short term (2011 – 2015)	Increasing capacity deficits through to 2014, by which time deficits are present in 8 months and range from 3 MW (October) to 75 MW (March). However deficits disappear in 2015 following the commissioning of WAX.	• Wholesale market purchases as required • Continue assessment of potential capacity resources.
Medium term (2016 – 2020)	No capacity gap is expected.	Continue assessment of potential capacity resources.
Long term (2021 – 2040)	No deficit is observed until 2027. Gaps are mainly in June and December, but eventually expanding to July (2035) and January (2039). Winter max deficit of 0 MW by 2030 and 66 MW by 2040; summer max deficit of 17 MW by 2030 and 55 MW by 2040. By 2040, 4 percent of December super peak hours have a capacity gap.	Anticipate building new resources by mid-late 2020s • Additional new capacity resources required in the mid-late 2030s.

273.0 Reference: Preferred Resource Strategy

Exhibit B-1-2, Section 6.4, pp. 84-85

FortisBC states that "Consequently, if FortisBC finds that in practice its market purchases are correlated with Wholesale market price spikes, it may be prudent to shorten its timelines for building new generation assets."

273.1 Given that FortisBC has been relying on the Wholesale market for the past two decades, please provide the correlation coefficient between FortisBC's market purchases and the Wholesale market price spikes over the period 1990-2010.

Response:

FortisBC has does not have the historic data in a suitable format to perform this requested analysis. However, based on past buying practices, the Company believes that historically there would be a high correlation between market purchases used to meet peak demand and wholesale market price spikes. Typically the Company's peak demand periods are the same peak demand periods for neighbouring utilities, which creates upward pressure on wholesale market prices.

273.1.1 Please provide the reasons why FortisBC expects it could be different over the short to medium term.

Response:

FortisBC is currently purchasing capacity from the market to meet peak demand for several months of the year. The addition of the Waneta Expansion Capacity Purchase Agreement to its resource stack in 2015 will satisfy the majority of the Company's expected peak capacity needs for the short to medium term.

274.0 Reference: Combined Build and Buy

Exhibit B-1-2, Section 6.4.1, pp. 85-87

Table 6.4.1 – FortisBC Preferred Strategy; Figure 6.4.1-A – FortisBC – Preferred Strategy Energy Gap Closure

274.1 In the "Capacity Solution" column, under the short-term (2011-2015) timeframe, please explain what FortisBC mean by "early assessment" of capacity resource options.

Response:

The ranking and evaluation criteria in the Midgard Resource Options Report (Appendix C) were designed as tools to help select resource options that best meet the needs of FortisBC. The ranking does not determine the actual order in which to build projects, but does provide a portfolio of potential resource options that should be considered for development.

The early assessment of capacity resource options referred to in the short term section of Table 6.4.1 means further screening or a prefeasibility level of assessment to assist in the evaluation and prioritization of the preferred projects. At this stage in planning it may still not be possible to prioritize the preferred resource options. As specific needs, capacity gaps, and energy gaps become more apparent in the future, further assessment will establish the ultimate priority of the preferred projects.

274.1.1 Are the three capacity resource options listed in order of priority? If so, please explain how the priority was determined. If not, please explain how the priority would be determined.

Response:

The three capacity resources options identified are listed in the order of ranking received in Exhibit B-1-2, Section 6.1.2, pages 73 through 75. Note that the SCGT received the best ranking and that Pumped Storage hydro and the Similkameen hydroelectric project receiving an equal ranking (and therefore are interchangeable). That being said, the ranking and evaluation criteria were designed as tools to help select resource options that best meet the needs of FortisBC. The ranking does not determine the actual order in which to build projects, but does provide a portfolio of potential resource options that should be considered for development.

At this stage in planning (long-term 30 year horizon), it is not possible to prioritize the preferred resource options that have been identified. As specific needs, capacity gaps, and energy gaps become more apparent in the future, further effort will be required to establish the ultimate priority of the preferred projects.

274.2 In the “Capacity Solution” column, under the medium-term (2016-2020) timeframe, please explain what is involved in “being prepared” to accelerate the commissioning of one or more capacity resources.

Response:

At this stage in planning, specific needs, capacity gaps, and energy gaps have become more apparent, and the priority of the preferred project(s) should be clear. Given there are long lead times on certain aspects of project development, “being prepared to accelerate” basically means that FortisBC has conducted enough screening, feasibility analysis, environmental assessment and permitting that development of the generation project can be accelerated if needed.

274.3 In the “Capacity Solution” column, under the long-term (2021-2040) timeframe, are the three capacity resource options listed in order of priority? If so, please explain how the priority was determined. If not, please explain how the priority would be determined.

Response:

Please see response to BCUC IR1 Q274.1.1.

274.4 Please specify the year corresponding to Figure 6.4.1-A.

Response:

Figure 6.4.1-A refers to the year 2020. Please note that the figure title is incorrect, and should be: ” Figure 6.4.1-A – 2020 Preferred Strategy Capacity Gap Closure for 2020”

275.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Section 6.4.1, pp. 85-88

Combined Build and Buy

275.1 Please revise Table 6.4.1-A and Figure 6.4.1-A to reflect no planning reserve margin amount.

Response:

The following table shows no PRM required amount.

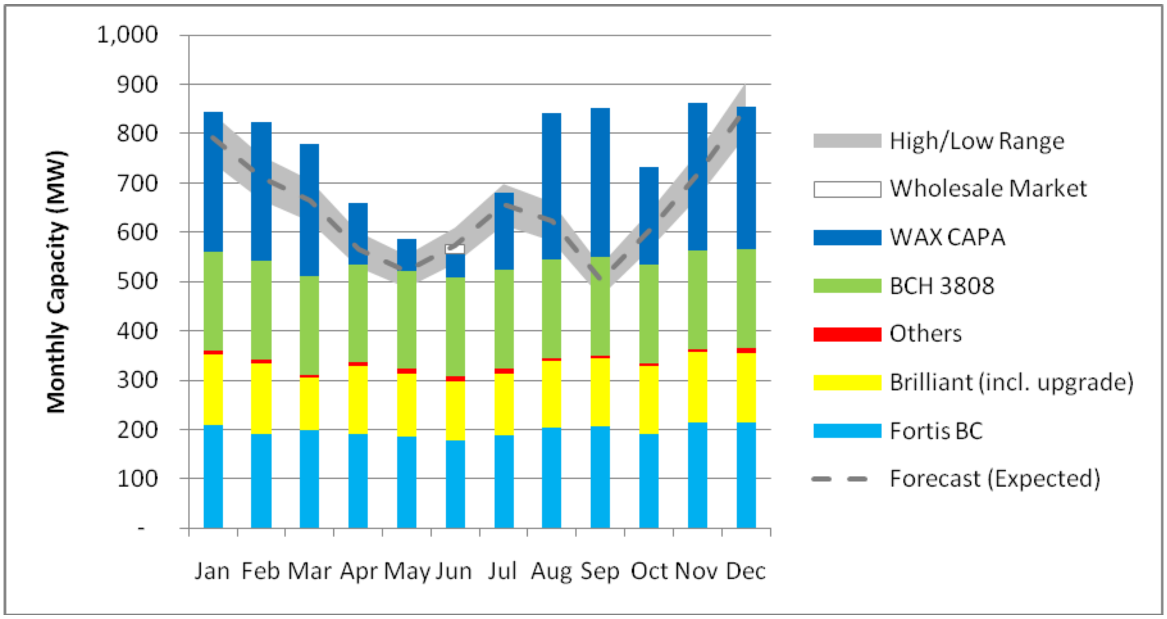
Table BCUC IR1 275.1a

Time Period	Capacity Solution	Energy Solution
Short term (2011 – 2015)	• Wholesale market purchases of Capacity (Buy Strategy) as required • Early stage assessment of capacity resource options: i. SCGT ii. PSH iii. 60 MW Similkameen Hydroelectric Project	Wholesale market purchases of Energy (Buy Strategy) • Early stage assessment of energy resource options: i. 234 GWh/year Similkameen Hydroelectric Project
Medium term (2016 – 2020)	• Wholesale market purchases of Capacity (Buy Strategy) as required • Continued feasibility assessment of capacity resource options: i. SCGT ii. PSH iii. 60 MW Similkameen Hydroelectric Project	• Wholesale market purchases of Energy (Buy Strategy) • Early stage development of energy resource options: i. 234 GWh/year Similkameen Hydroelectric Project ii. 200 – 500 GWh New Clean Energy Resources
Long term (2021 –	• New Resources (Build Strategy) capacity resources by mid-late 2020s. One or more of:	• New Resources (Build Strategy) energy resources. One or both of: i. 234 GWh/year

2040)	i. 1-2 x 42 MW SCGT ii. 100 - 200 MW PSH iii. 60 MW Similkameen Hydroelectric Project • Additional New Resources (Build Strategy) capacity resource in the mid-late 2030s. • Wholesale market purchases (Buy Strategy) remain an option to fill small residual gaps after capacity resource are commissioned.	Similkameen Hydroelectric Project ii. New Clean Energy Resources • Wholesale market purchases (Buy Strategy) remain an option to fill small residual gaps after energy resources are commissioned.

The Following is Table 6-4-1-A revised to show no PRM amount. Please note that the title of Figure 6.4.1-A is incorrect in the Resource Plan, and should be changed to “Figure 6.4.1-A - FortisBC – Preferred Strategy <u>Capacity</u> Gap Closure for 2020”.

Table BCUC IR1 275.1b



276.0 Reference: Community Energy Development Program

Exhibit B-1-2, Section 6.5, pp. 88-89

Clean Energy Act Goals

FortisBC states that "The FortisBC CEDP concept is aligned with the Clean Energy Act goals:

- to foster innovative technologies that support energy conservation and the use of clean or renewable resources and distributed generation;
- to encourage local economic development and the creation and retention of jobs; and
- to foster the economic growth of First Nation and rural communities through the development and operation of clean or renewable resources."

In Appendix F of the Resource Plan, FortisBC indicates that the three CEA objectives above listed are "not applicable" to FortisBC's 2012 Resource Plan.

276.1 Please explain why these objectives are not applicable to FortisBC's Resource Plan.

Response:

The goals referred to above are Provincial goals set by government. Government's instruments to achieve those goals include regulation, taxes, grants, incentive programs, and direction to government owned corporations such as BC Hydro.

Unlike electricity self-sufficiency, where section 6(4) of the Clean Energy Act specifically includes public utilities other than BC Hydro, the objectives listed above do not specifically direct other utilities to achieve them. However, these are important issues for British Columbia, and FortisBC believes it has a role to play in helping the Province achieve these objectives. FortisBC, at its own discretion, may propose to the BCUC cost-effective programs that align with the Provincial goals within the *Clean Energy Act*.

276.2 Please reconcile the fact that FortisBC states these objectives are not applicable with FortisBC's desire to establish a program that would meet these same objectives.

Response:

Although FortisBC does not believe all the Provincial goals specified in the Clean Energy Act direct the Company to achieve then, that does not mean FortisBC disagrees with the objectives. FortisBC, at its own discretion, may propose to the BCUC cost-effective programs that align with the Provincial goals within the Clean Energy Act.

FortisBC also states "FortisBC will continue to investigate the concept, potential design and costs of the CEDP. If, in the Company's opinion, the concept has merit, FortisBC will submit the final design FortisBC CEDP to the BC Utilities Commission for review and acceptance."

276.3 What is FortisBC's timeframe to investigate the CEDP concept, design it and evaluate its costs?

Response:

FortisBC has not established a specific timetable for evaluating the merits of a CEDP, nor has it committed to establishing a CEDP and submitting it to the BCUC for review and acceptance. However, FortisBC expects to complete its evaluation of the potential benefits of a CEDP before submitting its next Resource Plan.

277.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Appendix B, Section 6.2.1.2 - Results of the 2010 Resource Options Report, pp. 29-30

Efficiency and GHG Comparison

277.1 Please provide the efficiencies and GHG generation for the resource options outline in Table 6.2.1.2-A: Competitive Unit Capacity Cost Resource Options (CAD 2010).

Response:

Please see the table below for a breakdown of resource efficiency and GHG generation.

Table BCUC IR1 277.1

Resource	Efficiency	GHG output
Simple Cycle Gas Turbine	36.6 – 36.9%	500 tonnes CO_2 equivalent/GWh
Combined Cycle Gas Turbine	48.3 – 49.7%	365 tonnes CO_2 equivalent/GWh
Potential Pumped Storage Hydro	80%	0 tonnes CO_2 equivalent/GWh
Similkameen – Small Hydro with Capacity	87%	0 tonnes CO_2 equivalent/GWh

Reference:

FortisBC 2010 Resource Option Report

277.2 Provide comparative costs of these resource options to taking capacity from other sources either purchase from others or BC Hydro's RS 3808.

Response:

The new resource capacity options available to FortisBC, as shown in Table 6.2.1.2-A (Exhibit B-1-2, Appendix B, Page 30) are replicated below:

Table 6.2.1.2-A: Competitive Unit Capacity Cost Resource Options (CAD 2010)

Project	Dependable Capacity (MW)	Capital Cost (k$)	UCC @6% ($/MW-month)	UCC @8% ($/MW-month)
Simple Cycle Gas Turbine	39	44,269	8,481	10,163
Combined Cycle Gas Turbine	243	329,445	10,624	12,708
Potential Pumped Storage Hydro	180	340,000	13,668	17,412
Similkameen - Small Hydro with Capacity	60	283,117	29,274	38,003

The alternatives to the Company developing one of these resources are to contract with an IPP to build the resource, buy the power from the wholesale market or to negotiate to increase purchases from BC Hydro.

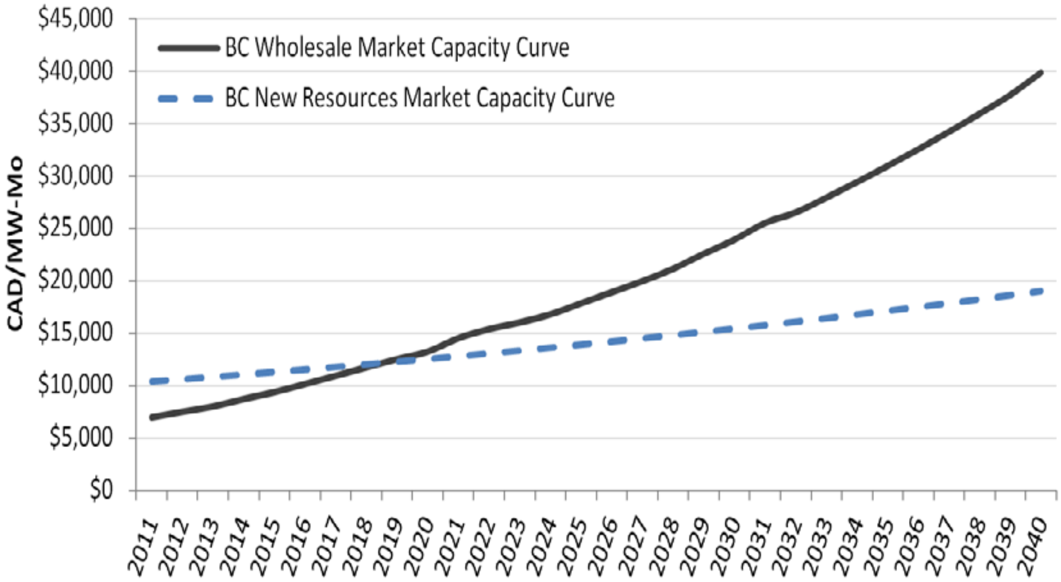
BC Hydro RS3808 is fully utilized as a capacity resource during the months of November, December, January and February and therefore additional capacity from this resource is unavailable at any price during the key winter peak period. Additional capacity at RS3808 is not expected to be available.

The price of capacity from the wholesale market equates to the BC Wholesale Market Capacity Curve, which is detailed in Figure 6.1.1-A (Exhibit B-1-2, Appendix B, Pages 26 - 28).

The price of capacity from an IPP would be as per the BC New Resources Market Capacity Curve. However, this price is derived from the SCGT price in the table above and it is believed that the Company's cost to develop a SCGT would be approximately the same.

For a graphical comparison of the BC Wholesale Market Capacity Curve and the BC New Resources Market Capacity Curve, please refer to Figure 3.3.3-A (Exhibit B-1-2, Section 3.3.3, page 39) and as replicated below. Based on current assumptions and market forecasts, it is believed that the cost of wholesale market power for capacity will exceed the cost of SCGT based new construction after approximately 2020. The cross over time frame for pumped storage hydro would be much later.

Figure 3.3.3-A BC Wholesale Market vs. BC New Resources Market Capacity ($CAD/MW-month)



277.3 As the SCGT can be used in smaller sizes and in a peaker plant mode, did FortisBC consider the CCGT and SCGT combined option for meeting the capacity and energy gaps?

Response:

The potential new resource options in the 2012 Long Term Resource Plan have been presented at a conceptual level. At this stage of the planning process FortisBC has not determined the optimal mix of potential new resources. A SCGT has been identified as a potential capacity option, and a CCGT has been identified as a potential energy options in Table 6.1.3-A of the Resource Plan, so a CCGT and a SCGT combined option is a possible solution for meeting the future capacity and energy gaps.

277.4 Please provide FortisBC point of view on the potential of time-shifted arbitrage of heritage energy by selecting pump storage hydro as a resource option.

Response:

FortisBC does not believe that storing energy constitutes arbitrage. The arbitrage principle is specifically intended to avoid or limit the amount of arbitrage of embedded cost power resulting from selling electricity.

Please also refer to the response to BCUC IR1 Q252.3

278.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Appendix F

Clean Energy Act Objectives

278.1 For each of the energy objectives that FortisBC declares “not applicable” (i.e., energy objective (b), (d), (f), (h), (i), (l), (n) and (p)), please provide a justification of why each of them is not applicable in the context of the 2012 Resource Plan.

<u>Response:</u>

The energy objectives referred to are:

(b) To take demand side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for the year 2020 by at least 65%;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and the use of clean or renewable resources;

(f) to ensure the authorities rates remain among the most competitive of rates charged by public utilities in North America;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(l) to maximize the value, including the incremental value of the resources being clean or renewable resource, of BC’s generation and transmission assets for the benefit of BC;

(n) to be a net exporter of electricity from clean or renewable resources with the intension of benefitting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in BC;

(p) to ensure the Commission, under the Utilities Commission Act, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

The goals in Section 2 of the *Clean Energy Act* referred to above are Provincial goals set by government. Government’s instruments to achieve those goals include regulation, taxes, grants, incentive programs, and direction to government owned corporations such as BC Hydro.

Unlike electricity self-sufficiency, where section 6(4) of the Clean Energy Act specifically includes public utilities other than BC Hydro, smart meters where section 17(6) addresses public utilities other than the authority, and greenhouse gas reductions and clean energy resources addressed by Section 18 and 19 respectively, the objectives listed above do not specifically direct other utilities to achieve them. For example Clean Energy Act objectives 2(d), 2(h), 2(i), 2(l) and 2(n), as well as others listed above, all fall under this category. Some of the other objectives may only be partly applicable.

In the Clean Energy Act definitions, "authority" has the same meaning as in section 1 of the Hydro and Power Authority Act; which is the British Columbia Hydro and Power Authority. Clean Energy Act Objective 2(b) has the authority reducing its expected increase in demand for the year 2020 by at least 65%. Objective 2(f) is to ensure the authorities rates remain among the most competitive. Objective 2(p) relieves the commission from regulating the authorities' rates with respect to expenditures for export.

Although FortisBC does not believe all the Provincial goals specified in the Clean Energy Act direct the Company to achieve then, that does not mean FortisBC disagrees with the objectives. FortisBC, at its own discretion, may propose to the BCUC cost-effective programs that align with the Provincial goals within the Clean Energy Act.

279.0 Reference: Long Term Resource Plan

Exhibit B-1-2, Appendix H

Monthly Capacity Gaps

279.1 Please revise Appendix H to reflect no planning reserve margin amount.

<u>Response:</u>

The revised Appendix H assuming no PRM is required is as follows:

CAPACITY GAP (ASSUMING EXPECTED FORECAST) (MW)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	0	0	56	0	0	0	41	0	0	0	9	38
2012	0	0	73	0	0	0	44	31	0	0	0	31
2013	0	6	68	0	0	2	52	38	0	0	9	42
2014	0	14	75	0	0	7	59	10	0	3	16	51
2015	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	4	0	0	0	0	0	0
2028	0	0	0	0	0	8	0	0	0	0	0	0
2029	0	0	0	0	0	13	0	0	0	0	0	0
2030	0	0	0	0	0	17	0	0	0	0	0	0
2031	0	0	0	0	0	20	0	0	0	0	0	3
2032	0	0	0	0	0	24	0	0	0	0	0	10
2033	0	0	0	0	0	28	0	0	0	0	0	17
2034	0	0	0	0	0	32	0	0	0	0	0	25
2035	0	0	0	0	0	36	1	0	0	0	0	32
2036	0	0	0	0	0	40	6	0	0	0	0	39
2037	0	0	0	0	0	43	10	0	0	0	0	46
2038	0	0	0	0	0	47	15	0	0	0	0	53
2039	5	0	0	0	0	51	20	0	0	0	0	60
2040	11	0	0	0	0	55	25	0	0	0	0	66

CAPACITY GAP (ASSUMING LOW FORECAST) (MW)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	0	0	55	0	0	0	39	0	0	0	8	36
2012	0	0	71	0	0	0	42	29	0	0	0	29
2013	0	3	65	0	0	0	49	35	0	0	6	38
2014	0	10	71	0	0	4	55	7	0	0	12	46
2015	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0

CAPACITY GAP (ASSUMING HIGH FORECAST) (MW)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	0	0	61	0	0	0	45	0	0	0	14	44
2012	0	3	78	0	0	0	49	35	0	0	5	37
2013	0	12	74	0	0	7	57	43	0	2	15	49
2014	0	21	82	0	0	14	66	17	0	10	24	60
2015	7	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	3	0	0	0	0	0	0
2023	0	0	0	0	0	9	0	0	0	0	0	0
2024	0	0	0	0	0	15	0	0	0	0	0	0
2025	0	0	0	0	0	21	0	0	0	0	0	0
2026	0	0	0	0	0	27	0	0	0	0	0	7
2027	0	0	0	0	0	34	0	0	0	0	0	18
2028	0	0	0	0	0	40	3	0	0	0	0	28
2029	0	0	0	0	0	46	11	0	0	0	0	39
2030	0	0	0	0	0	53	19	0	0	0	0	50
2031	8	0	0	0	0	59	26	0	0	0	0	61
2032	18	0	0	0	0	66	34	0	0	0	0	72
2033	28	0	0	0	0	72	42	0	0	0	0	83
2034	38	0	0	0	0	79	50	0	0	0	0	94
2035	48	0	0	0	0	85	57	0	0	0	0	105
2036	58	0	0	0	1	91	65	0	0	0	0	116
2037	68	0	0	0	7	98	73	0	0	0	0	127
2038	79	0	0	0	13	104	81	0	0	0	0	138
2039	89	8	0	0	19	111	89	0	0	0	0	149
2040	99	17	9	7	25	118	97	0	0	0	0	161

DEMAND SIDE MANAGEMENT

280.0 Reference: Executive Summary

Exhibit B-1, Tab 1, p. 7; Exhibit B-1, Tab 3, Appendix 3A, pp. 3A-1 - 3A-2; Exhibit B-1, Tab 3, Appendix 3C, p. 3C-2 – 3C-5; Exhibit B-1, Tab 6, p. 117; Exhibit B-1-2, Section 1, pp. 1, 14-16

Demand Side Management Projected Energy Savings

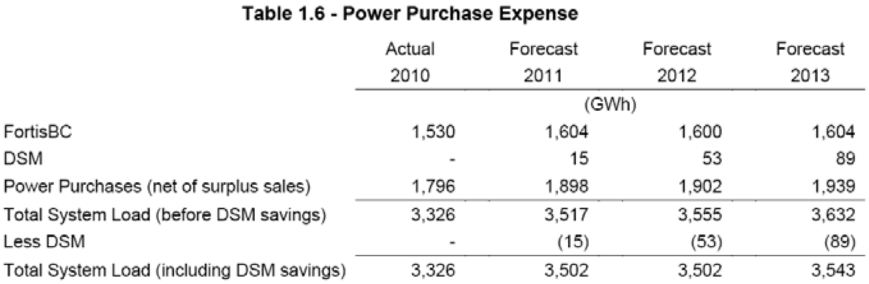


Table 1.6 - Power Purchase Expense

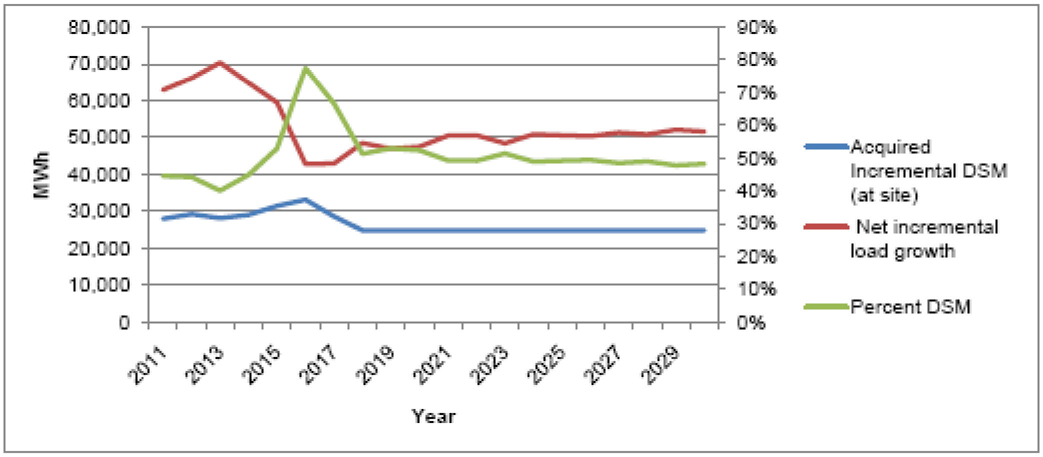
	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		(GWh)		
FortisBC	1,530	1,604	1,600	1,604
DSM	-	15	53	89
Power Purchases (net of surplus sales)	1,796	1,898	1,902	1,939
Total System Load (before DSM savings)	3,326	3,517	3,555	3,632
Less DSM	-	(15)	(53)	(89)
Total System Load (including DSM savings)	3,326	3,502	3,502	3,543

(Exhibit B-1, Tab 1, p. 7)

FortisBC states “The first five years of the 2012 DSM Plan (2012-2016) are an extension of the approved

2011 DSM Plan, thereafter a constant savings target is used as a placeholder for future DSM activities.” (Exhibit B-1-2, Section 1, p. 1)

Figure 3.2.4 – Acquired DSM vs. Load Growth Forecast



(Exhibit B-1-2, p. 16)

FortisBC also states “The individual years’ DSM load offset ranges considerably from 40-77 percent, primarily due to a decrease in forecast load growth, before levelling out in 2018.” (Exhibit B-1-2, p. 16)

280.1 Please explain why the DSM Energy Savings in Table 1.6 increases from 15 to 89 GWh from 2011 to 2013 if only a slight spending increase is requested between those years.

Response:

The DSM figures shown in Table 1.6 are cumulative acquired DSM savings, inclusive of DSM programs, conservation rate impact and AMI portal savings, whereas the figures shown in Figure 3.2.4 are the annual target DSM program savings. Please see the response to Q280.5.1 for a disaggregation of Table 1.6.

The difference between “acquired” and “target” DSM savings is due to timing issues. For example the 2011 DSM program has a revised target of approximately 32 GWh of savings, but only about 15 GWh will actually be acquired in 2011. This is due to the fact that measures are implemented throughout the year, so only approximately half of the savings are actually realized in that year.

For example, a residential heat pump with energy savings of 6 MWh per year, will realize about 3 MWh of acquired savings in its first year of operation if installed July 1. The full 6 MWh of savings will be realized in subsequent years.

280.2 Please provide the data in tabular format that were used to create Figure 3.2.4 above.

Response:

Please refer to the below table.

Table BCUC IR1 280.2

Year	Acquired DSM Savings	Net load growth (MWh)	Per cent DSM
2011	28,004	62,881	45%
2012	29,260	66,149	44%
2013	28,184	70,363	40%
2014	29,078	64,848	45%
2015	31,460	59,489	53%
2016	33,159	42,799	77%
2017	28,622	42,971	67%
2018	24,871	48,486	51%
2019	24,871	46,988	53%
2020	24,871	47,537	52%
2021	24,871	50,490	49%
2022	24,871	50,596	49%
2023	24,871	48,434	51%
2024	24,871	50,854	49%
2025	24,871	50,596	49%
2026	24,871	50,362	49%
2027	24,871	51,339	48%
2028	24,871	50,816	49%
2029	24,871	52,076	48%
2030	24,871	51,618	48%
2031	24,871	47,313	53%
2032	24,871	49,836	50%
2033	24,871	49,683	50%
2034	24,871	49,530	50%
2035	24,871	49,377	50%
2036	24,871	49,224	51%
2037	24,871	49,072	51%
2038	24,871	48,919	51%
2039	24,871	48,767	51%
2040	24,871	48,615	51%
Overall:	**779,809**	**1,550,030**	**50%**

280.3 Please explain the spike in Percent DSM seen in 2016 in Figure 3.2.4.

Response:

The acquired DSM savings is expected to reach a peak in 2016 of 33,159 MWh at the same time that the Net Load Growth forecast reaches its lowest level at 42,799 MWh, resulting in the 77% load growth offset in 2016. These two factors result in the spike shown in Figure 3.2.4.

280.4 Please explain how the constant savings figure of 28 GWh/year for 2017 and beyond was derived.

Response:

Setting the annual DSM target to 28 GWh/year ensured the Company met the cumulative 50% load growth offset target in the BC Energy Plan. As shown in the tabular response to Q280.2, the cumulative acquired DSM savings are 50% of the net load growth for the planning period ending in 2040.

280.5 Please show the incremental DSM savings for the years 2010-2040 that were factored into the Long Term Energy Forecast in Table A-2 of Exhibit B-1, Tab 3, p. 3A-2. In other words, please show the difference between the Gross columns in the Tables A-1 and A-2 of Exhibit B-1, Tab 3, pp. 3A-1 and 3-A-2 with other losses subtracted. Please include 2010 for Table A-1 and show in the following format:

	Table A-1 Gross (GWh)	**Table A-2 Gross (GWh)**	**Other Losses**	**Difference (Incremental DSM savings)**
2010		3,370		
2011	3,483	3,465		18
2012	3,555	3,502		53
2013	3,632	3,543		89

Response:

Please see the table below.

Table BCUC IR1 280.5

Year	Table A1 Gross (GWh)	Table A2 Gross (GWh)	Other Savings (GWh)	Difference (Incremental DSM Savings) (GWh)
2010	-	3,370	-	
2011	3,483	3,465	-	17
2012	3,555	3,502	3	50
2013	3,632	3,543	9	80
2014	3,703	3,577	14	112
2015	3,769	3,599	23	147
2016	3,816	3,601	31	183
2017	3,863	3,614	34	215
2018	3,916	3,637	37	242
2019	3,967	3,658	40	269
2020	4,020	3,679	44	296
2021	4,075	3,704	47	324
2022	4,130	3,729	51	351
2023	4,184	3,754	51	378
2024	4,239	3,781	52	406
2025	4,295	3,809	53	433
2026	4,350	3,836	54	460
2027	4,406	3,864	55	487
2028	4,462	3,892	56	515
2029	4,519	3,921	56	542
2030	4,576	3,949	57	569
2031	4,628	3,973	58	597
2032	4,682	4,000	59	624
2033	4,737	4,026	59	651
2034	4,791	4,053	60	678
2035	4,845	4,079	61	706
2036	4,899	4,105	62	733
2037	4,953	4,130	62	760
2038	5,007	4,156	63	788
2039	5,060	4,182	64	815
2040	5,114	4,207	65	842

280.5.1 Please reconcile these incremental DSM energy savings with those shown in Tables 1.6 and Figure 3.2.4 in the preamble above.

Response:

Table 1.6 numbers are the cumulative DSM savings, including DSM programs and non-program savings. The non-program savings include savings from AMI and implementing the RIB rate.

Breakdown of DSM in table 1.6, with Jan 1, 2011 as DSM baseline:

Table BCUC IR1 280.5.1

	2011	2012	2013
Total DSM Savings	15	53	89
DSM (non-program savings)	-	9	17
DSM (Programs)	15	44	72

In terms of the 2011 the apparent discrepancy (between the 32 GWh forecast and 15 GWh acquired), is due to timing issues (see response to Q280.1).

For forecasting and resource planning purposes, DSM is plan is broken down into monthly figures. The annual acquired incremental is calculated based on DSM savings above that which was reported each month the year before, which is the method to determine the numbers in figure 3.2.4. It is a rolling 12-month arithmetic summation, as follows:

Annual incremental acquired savings:

∑ (Jan 2011-Jan 2010) + (Feb 2011 – Feb 2010) + (month 2011 – month 2010).

A similar method is used in table 1.6; except that table 1.6 uses January 1st, 2011 as the baseline. Therefore instead of adding the incremental savings of each month (as above) to the remainder of the prior year, DSM is added as above the baseline. As per the following equation:

∑ (Jan 2011 savings - Jan 1, 2011) + (Feb 2011 - Jan 1, 2011) + (MONTH 2011 - Jan 1, 2011)

280.6 Please show the incremental DSM savings for the years 2010-2040 that were factored into the Long Term Peak Forecasts in Table A-3 of Exhibit B-1, Tab 3, p. 3A-4. In other words, please show the difference between the Gross columns in the Tables A-3 and A-4 of Exhibit B-1, Tab 3, pp. 3A-3 and 3-A-4. Please show in the following format:

	Table A-3 Gross (GWh)		Table A-4 Gross (GWh)		Other Losses		Difference (Incremental DSM savings)	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2010	661	577	661	577			0	0
2011	715	563	710	560			5	3

Response:

Please see the table below.

Table BCUC IR1 280.6

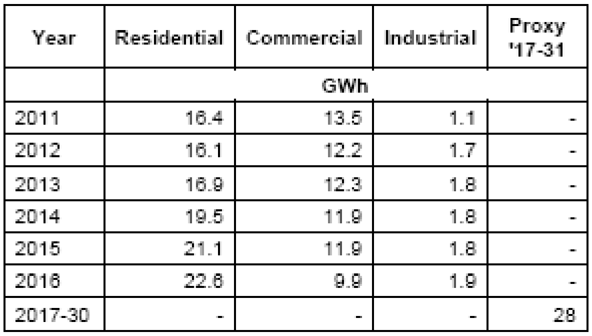
	Table A3 Gross (MW)		Table A4 Gross (MW)		Other Savings (MW)		Difference (Incremental Savings) (MW)	
Year	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2010	719	669	719	669	-	-	-	-
2011	715	563	710	560	-	-	5	3
2012	730	575	721	567	-	-	9	7
2013	745	587	731	575	-	-	13	11
2014	758	598	741	582	-	-	18	16
2015	770	609	747	588	-	-	23	21
2016	780	616	751	590	-	-	28	26
2017	789	624	758	593	-	-	32	30
2018	800	632	764	598	-	-	36	34
2019	810	640	771	603	-	-	40	38
2020	821	649	778	607	-	-	43	42
2021	832	657	785	612	-	-	47	45
2022	843	666	792	617	-	-	51	49
2023	854	675	799	622	-	-	55	53
2024	865	684	807	627	-	-	59	57
2025	877	692	814	632	-	-	63	61
2026	888	701	821	637	-	-	66	64
2027	899	710	829	642	-	-	70	68
2028	910	719	836	647	-	-	74	72
2029	922	728	844	652	-	-	78	76
2030	933	737	851	658	-	-	82	80
2031	944	745	858	662	-	-	85	83
2032	955	754	865	667	-	-	89	87
2033	965	763	872	672	-	-	93	91
2034	976	772	879	677	-	-	97	95
2035	987	780	887	681	-	-	101	99
2036	998	789	894	686	-	-	105	102
2037	1,009	797	901	691	-	-	108	106
2038	1,020	806	908	696	-	-	112	110
2039	1,030	814	914	700	-	-	116	114
2040	1,041	823	921	705	-	-	120	118

280.6.1 Please explain in detail the methodology used to determine the incremental DSM energy savings that are subtracted from peak load.

Response:

The DSM program energy savings are converted to Peak Power savings by taking the energy conservation measure's (ECM) annual operating hours and dividing them into the ECM kWh savings to yield the nominal kW savings. The kW savings of the ECM were then distributed by a monthly load distribution profile and applied to the peak load forecast.

Table 3.2.3 – Savings Targets



Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.4	13.5	1.1	-
2012	16.1	12.2	1.7	-
2013	16.9	12.3	1.8	-
2014	19.5	11.9	1.8	-
2015	21.1	11.9	1.8	-
2016	22.6	9.9	1.9	-
2017-30	-	-	-	28

(Exhibit B-1-2, p. 15)

FortisBC also states "There is a significant drop in the energy savings forecast in the 2012-13 plan years, primarily due to an extraordinary industrial project expected to occur in 2011. When the extraordinary project is subtracted from the 2011 savings target of 39,722, the underlying "base" savings target is 32,282 MWh." (Exhibit B-1, Tab 6, p. 117)

280.7 Please explain why the projected DSM Energy Savings in Table 1.6 do not match the Savings Targets in Table 3.2.3 and why the projected Savings Targets in Table 3.2.3 do not match the savings target in the narrative at Exhibit B-1, Tab 6, p. 117.

Response:

A corrected version of Table 3.2.3 is provided below as Table BCUC IR1 280.7. Please also refer to Errata 2.

Table BCUC IR1 280.7

Year	Residential	Commercial	Industrial	Proxy ’17-31
	GWh			
2011	16.2	13.5	2.5	-
2012	16.1	13.4	2.5	-
2013	16.9	12.0	2.6	-
2014	15.8	14.9	2.8	-
2015	16.7	15.8	2.9	-
2016	17.6	16.6	3.1	-
2017-‘30	-	-	-	28

280.8 Where in the load forecast is the “significant drop in energy savings forecast in 2012-2013” reflected?

Response:

The statement was intended to explain the drop, in the 2011 DSM energy savings, from the 39.7 GWh approved plan, to 32.3 GWh forecast for comparison purposes to the 2012-13 DSM targets. The significant drop in forecast savings occurs in 2011 and is reflected in the DSM figures that were input into the load forecast.

280.9 Please provide the detailed methodology FortisBC uses to derive DSMt.

Response:

FortisBC used the same methodology described in Exhibit B-1-1, 2012 Long-Term DSM Plan, Section 2, pp. 6-12.

280.10 For the years 2011-2040 please provide:

i. the correct DSM Savings Targets; and

ii. the actual DSM energy savings that were inputs into the load forecast.

Response:

Please see the revised Table 3.2.3, in response to BCUC IR1 Q280.7, which shows the DSM plan targets by year.

The total annual DSM plan targets, which are the annualized first-year energy savings, are shown in the first column on the right in response to 280.10(i).

The DSM energy savings on which the load forecast was indirectly based are shown in the second column on the right in response to 280.10(ii). The Annual Acquired savings are the forecast incremental DSM energy savings achieved during that calendar year from the DSM programs implemented. Please see the responses to BCUC IR1 Q281.3 and Q281.4 for a more detailed description of how DSM was incorporated into the load forecast.

Table BCUC IR1 280.10

Year	Residential	Commercial	Industrial	Proxy ’17-31	(i) DSM Savings Targets	(ii) Annual Acquired savings
	GWh					
2011	16.2	13.5	2.5	-	32.3	30.7
2012	16.1	13.4	2.5	-	32.0	32.2
2013	16.9	12.0	2.6	-	31.5	31.0
2014	15.8	14.9	2.8	-	33.5	31.6
2015	16.7	15.8	2.9	-	35.4	34.6
2016	17.6	16.6	3.1	-	37.2	36.4
2017	-	-	-	28	28.0	31.4
2018-‘30	-	-	-	28	28.0	27.3

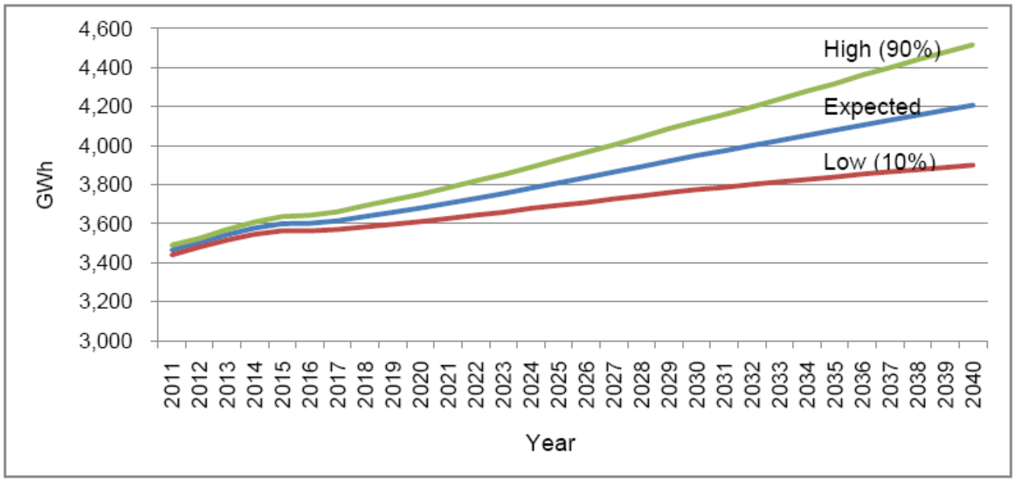
281.0 Reference: Load Forecast

Exhibit B-1, Tab 3, Appendix 3E, pp. 3E-2 – 3E-3; Exhibit B-1-2, Section 5.1.4, p. 52

Demand Side Management Projected Energy Savings

FortisBC states “Based on the 1991-2010 data, DSM performance is modeled as a normally distributed random variable with mean 100 percent and standard deviation 21.73 percent. Therefore, if an incremental DSM target for a year is 50 percent of the year’s load growth, then for 95 percent of the time, DSM performance will be in the range (28.27%, 71,73%), where 28.27% = 50%*(100% - 2*21.73%) and 71.73% = 4 50%*(100% + 2*21.73%).” (Exhibit B-1, Tab 3)

Figure E-1 - After DSM Gross Energy



FortisBC also states "FortisBC has set a target to avoid 50 percent of annual load growth via DSM measures. However, given the inherent non-firm nature of DSM resources, and the long lead time required to implement alternative supply resources, the Company has considered a probabilistic approach which targets 50 percent DSM effectiveness with an 80 percent confidence interval that projected demand avoidance will fall within the range of 28 percent to 72 percent of status quo load growth." (Exhibit B-1-2, p. 52)

281.1 Please provide the historical DSM performance (actual DSM savings achieved in 1991-2010) in tabular and histogram format.

Response:

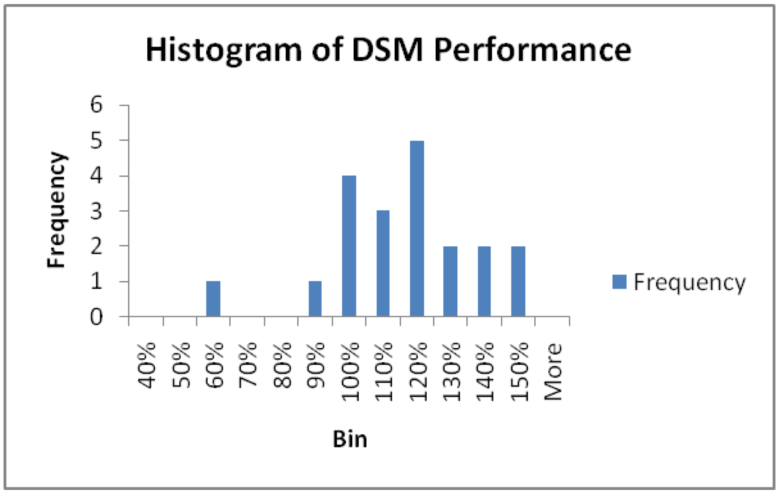
Exhibit B-1-2, p.52 should read "…with an 80 percent confidence interval that projected demand avoidance will fall within the range of **36** percent to **64** percent of status quo load growth." Please refer to Errata 2.

The low and high ends of 28% and 72% in the application are associated with the 95% range, not 80% range. For the 80% range, the low end P10 is 50%*(1-1.28*21.73%) = 36.09% and the high end P90 is 50%*(1+1.28*21.73%) = 63.91%.

FortisBC answers questions under BCUC IR No. 1 281.0 with this correction.

The historical DSM performance is the ratio between actual and planned DSM in each year.

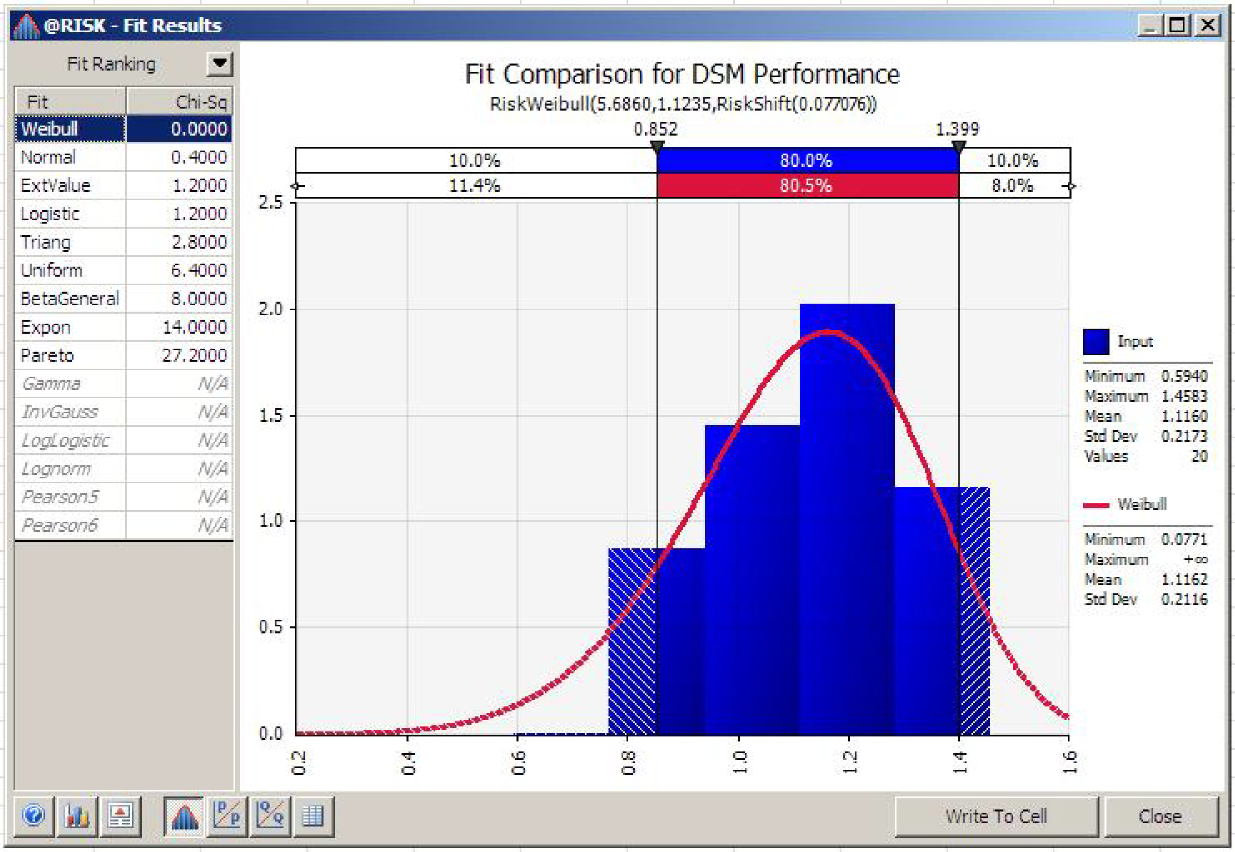
	Planned DSM (GWh)	Actual DSM (GWh)	Performance (%)
1991	13.3	7.9	59%
1992	15.6	16.3	104%
1993	26.1	24.1	92%
1994	14.2	12.9	91%
1995	18.3	15.6	85%
1996	16.3	17.0	104%
1997	14.4	14.2	99%
1998	13.6	13.1	96%
1999	11.6	13.5	116%
2000	12.0	17.5	146%
2001	12.5	16.9	135%
2002	14.1	16.3	116%
2003	15.6	18.5	119%
2004	14.7	21.3	145%
2005	19.0	23.9	126%
2006	20.4	23.1	113%
2007	21.8	27.9	128%
2008	19.5	27.3	140%
2009	25.3	28.4	112%
2010	27.5	28.8	105%
	Standard deviation		21.73%



281.1.1 Is the actual data normally distributed or was it modeled that way for forecast purposes?

Response:

The normal probability distribution ranks high among possible probability distribution functions (see below for an output of distribution fitting using @RISK 5.0). Although it is not at the top, it was still selected due to the common practice of fitting the normal probability distribution to data.



Fit	Chi-Sq
Weibull	0.0000
Normal	0.4000
ExtValue	1.2000
Logistic	1.2000
Triang	2.8000
Uniform	6.4000
BetaGeneral	8.0000
Expon	14.0000
Pareto	27.2000
Gamma	*N/A*
InvGauss	*N/A*
LogLogistic	*N/A*
Lognorm	*N/A*
Pearson5	*N/A*
Pearson6	*N/A*

Input	
Minimum	0.5940
Maximum	1.4583
Mean	1.1160
Std Dev	0.2173
Values	20

Weibull	
Minimum	0.0771
Maximum	+∞
Mean	1.1162
Std Dev	0.2116

281.2 In the probabilistic approach, were both ends of the range (28.27% and 71.73%) both given equal probabilities? If not, what probabilities were assigned? If so, isn't it more probable that 28.27% of target will be achieved than 71.73%? Please explain.

Response:

The normal distribution is assumed, so the distribution is symmetrical. There is 10% probability that the DSM as percentage of incremental load growth will be lower than 36% and 10% probability that performance will be higher than 64%.

281.3 It appears that FortisBC determined the DSM savings target and applied a probability range of 28.27% - 71.73% to determine the DSM energy savings that are included in the After DSM Gross Energy forecast. Please confirm that this approach was taken and the confidence interval that was used. If not, please clarify the steps in the probabilistic approach FortisBC uses to project DSM energy savings.

Response:

Please see the response to BCUC IR1 Q281.1 for a correction of the confidence interval used.

DSM performance is an output of the Monte-Carlo simulation. However, as DSM is directly integrated into the load forecasting model, there is no intermediate step to calculate DSM in order to calculate the after DSM load. In fact, the after DSM load range is a direct output from the simulation.

Putting it another way, in each Monte-Carlo simulation run, the DSM saving will be determined by the simulated load combined with the simulated DSM performance in a single operation.

281.3.1 Please clarify how the Achievable Energy Savings from the Conservation Potential Review were included in the after DSM load forecasts.

Response:

Achievable Energy Savings were converted to annual plan figures (DSM targets) by applying ramp rates to each measure, as described on pp. 9-11 of the 2012 long term DSM Plan, which included an illustrative example at the top of page 11. The annual DSM targets were then converted to acquired DSM savings i.e. DSM forecast, for load forecasting purposes. The DSM forecast is then subtracted from the before DSM load forecast to arrive at the after DSM load forecast.

281.3.2 Please clarify how cost effectiveness of DSM was included in the after DSM load forecasts.

Response:

The 50 percent DSM target used in the load forecast is assumed to be cost-effective based on the cost-effectiveness tests applied to the 2012-2013 DSM plan.

281.4 Please specify to which DSM savings forecast(s) FortisBC has applied the probabilistic approach. Please reference specific Tables and Figures.

Response:

The savings forecast to which the probabilistic approach is based is the percentage of load DSM expects to meet each year (shown below). This simulates both risk in meeting targets and the target itself.

Table BCUC IR1 281.4

Year	% Of Gross Load Growth
2010	
2011	15.5%
2012	44.2%
2013	40.1%
2014	44.8%
2015	52.9%
2016	77.5%
2017	66.6%
2018	51.3%
2019	52.9%
2020	52.3%
2021	49.3%
2022	49.2%
2023	51.4%
2024	48.9%
2025	49.2%
2026	49.4%
2027	48.4%
2028	48.9%
2029	47.8%
2030	48.2%
2031	52.6%
2032	49.9%
2033	50.1%
2034	50.2%
2035	50.4%
2036	50.5%
2037	50.7%
2038	50.8%
2039	51.0%
2040	51.2%

281.4.1 Please provide the range of DSM savings forecast for the years 2010-2040 showing the forecast with 28.27% achieved and 71.73% achieved.

Response:

Please also see the response to BCUC IR1 Q281.1.

The high/low range forecast of cumulative DSM (in GWh) is shown below.

Table BCUC IR1 281.4.1

DSM Energy (GWh)		
	Low (10%)	High (90%)
2011	13	22
2012	32	68
2013	60	102
2014	87	139
2015	114	180
2016	131	237
2017	151	279
2018	169	316
2019	187	354
2020	204	391
2021	219	425
2022	239	466
2023	255	504
2024	273	543
2025	289	583
2026	304	619
2027	318	660
2028	335	700
2029	348	737
2030	364	778
2031	377	819
2032	388	862
2033	399	905
2034	412	946
2035	426	988
2036	437	1,032
2037	447	1,077
2038	452	1,122
2039	464	1,166
2040	475	1,212

281.4.2 What is the cumulative DSM energy savings over the 2011-2020 period if 28.27% of DSM is achieved?

<u>Response:</u>

The cumulative DSM in the low scenario is 204 GWh.

282.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 1, p. 1

Projected Energy Savings

FortisBC states "The DSM programs include savings for an IHD (in-home display) measure that is dependent upon approval of the Company's Advanced Metering Infrastructure CPCN application to be filed later in 2011."

282.1 Please show, in tabular format, the projected DSM energy savings for all applicable years with and without the savings from an in-home display measure.

<u>Response:</u>

The IHD measure is expected to be introduced in 2013, with plan savings of 100 MWh.

Table BCUC IR1 282.1

Programs	**<u>2013</u> Plan incl. IHD** *<u>MWh</u>*	**<u>2013</u> Plan excl. IHD** *<u>MWh</u>*
Residential	16,946	16,846
General Service	11,980	11,980
Industrial	2,580	2,580
Sub-total Programs:	**31,506**	**31,406**

283.0 Reference: Rate Base

Exhibit B-1, Tab 5, p. 11

Demand Side Management Deferred Charges and Credits

283.1 The total approved amount of DSM programs is included in the rate base on which the revenue requirement is calculated, such that spending less than the total approved amount results in a "benefit" to the shareholders. Please provide the amount of such "benefit" in each of 2008, 2009, 2010 and projected for 2011. Please confirm the shareholder benefits when there is under spending of the approved amounts in the DSM programs to the extent amounts are included in the forecasts of the RRA.

Response:

FortisBC interprets the shareholder "benefit" referred to in the question to be the shareholder's equity return on rate base associated with the variance in the DSM deferral account from the balance embedded in rates.

A variance in the DSM deferral account balance, or in any single component of rate base, does not necessarily result in the shareholder earning more than its approved return on equity in the year of expenditure.

The table below shows that over the period 2008 – 2011, revenue requirements would have been reduced by a maximum of $7,000 in 2011 and in total by $9,000, had the actual DSM balances been known at the time of rate-setting.

Table BCUC IR1 283.1

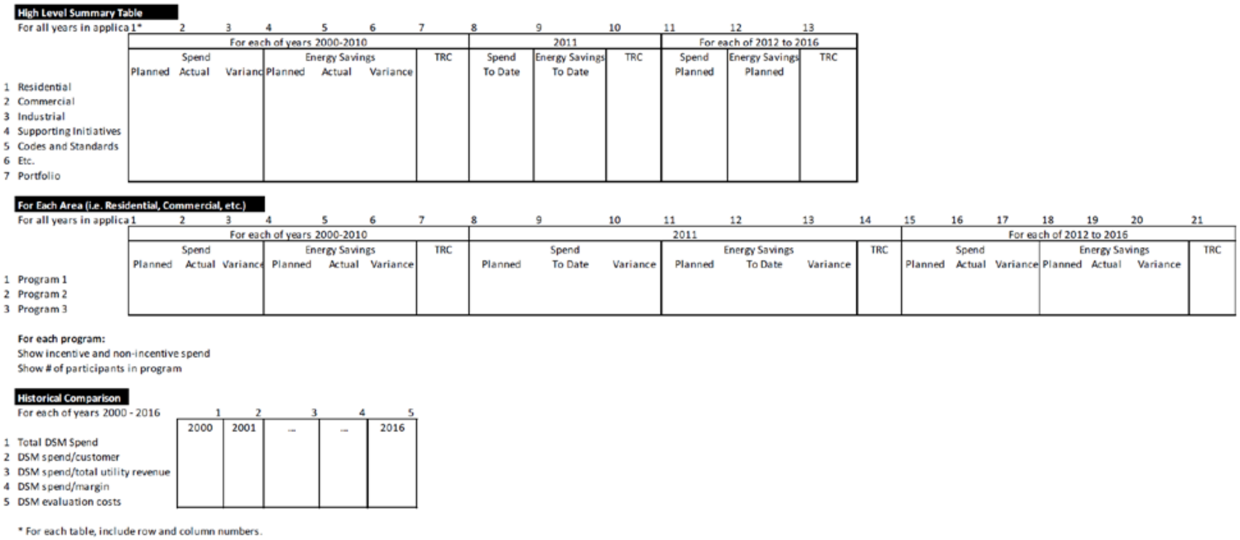
	Mid-Year DSM Balance	2008	2009	2010	2011 F
			($000s)		
1	Actual	6,494	7,385	8,275	10,448
2	Approved	6,408	7,412	8,376	10,621
3	Variance	87	(27)	(101)	(173)
4	Return on Equity	9.19%	8.87%	9.90%	9.90%
5	Equity Component	40%	40%	40%	40%
6	Weighted Return (Line 4 x Line 5)	3.68%	3.55%	3.96%	3.96%
7	Impact on Revenue Requirement (Line 3 x Line 6)	3	(1)	(4)	(7)
8	Cumulative Impact on Revenue Requirement				(9)

284.0 Reference: 2012-2013 Capital Plan

Exhibit B-1, Tab 6, p. 116

Demand Side Management

284.1 Please provide a working Excel spreadsheet showing the following:



High Level Summary Table

For all years in applica	1*	2	3	4	5	6	7	8	9	10	11	12	13
	For each of years 2000-2010							2011			For each of 2012 to 2016		
	Spend			Energy Savings			TRC	Spend	Energy Savings	TRC	Spend	Energy Savings	TRC
	Planned	Actual	Varianc	Planned	Actual	Variance		To Date	To Date		Planned	Planned	
1 Residential													
2 Commercial													
3 Industrial													
4 Supporting Initiatives													
5 Codes and Standards													
6 Etc.													
7 Portfolio													

For Each Area (i.e. Residential, Commercial, etc.)

For all years in applica	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	For each of years 2000-2010							2011							For each of 2012 to 2016						
	Spend			Energy Savings			TRC	Spend			Energy Savings			TRC	Spend			Energy Savings			TRC
	Planned	Actual	Variance	Planned	Actual	Variance		Planned	To Date	Variance	Planned	To Date	Variance		Planned	Actual	Variance	Planned	Actual	Variance	
1 Program 1																					
2 Program 2																					
3 Program 3																					

For each program:
Show incentive and non-incentive spend
Show # of participants in program

Historical Comparison

For each of years 2000 - 2016	1	2	3	4	5
	2000	2001	...	...	2016
1 Total DSM Spend					
2 DSM spend/customer					
3 DSM spend/total utility revenue					
4 DSM spend/margin					
5 DSM evaluation costs					

* For each table, include row and column numbers.

Response:

The tables are provided for the years 2005 (actual) through 2013 (plan) inclusive. Data for prior years (2000-04) are not readily available, and arguably are of little comparative value. Tables for the years 2014-16 inclusive are not available until such time as they are prepared and filed in the next CEP.

A working spreadsheet is attached as BCUC IR1 Electronic Attachment 284.1.

285.0 Reference: 2012-2013 Capital Plan
Exhibit B-1, Tab 6, p. 116
Demand Side Management

285.1 Please complete the table below for the years 2000-2011:

Year	2000 (Complete for each of years 2000-2011)						
Sector / Program	Utility Program Costs			Planning and Evaluation			Total Utility Costs
	Direct Incentives	Direct Information	Program Labour	Program Development	Planning & Admin.	Monitoring & Evaluation	
Residential							
Building Envelope							
Heat Pumps							
Residential Lighting							
New Home Program							
Appliances							
Electronics							
Water Heating							
Low Income & Rental							
Behavioural							
Residential Sub-total							
Commercial							
Lighting							
Building and Process Improvements							
Computers							
Municipal							
Irrigation							
Commercial Sub-total							
Industrial							
EMIS							
Industrial Efficiencies							
Industrial Sub-total							
Total							

Response:

The requested tables are provided for the years 2005 (actual) through 2013 (plan) inclusive. Data for prior years (2000-04) are not readily available, and arguably are of little comparative value. Tables for the years 2014-16 inclusive are not available until such time as they are prepared and filed in the next CEP.

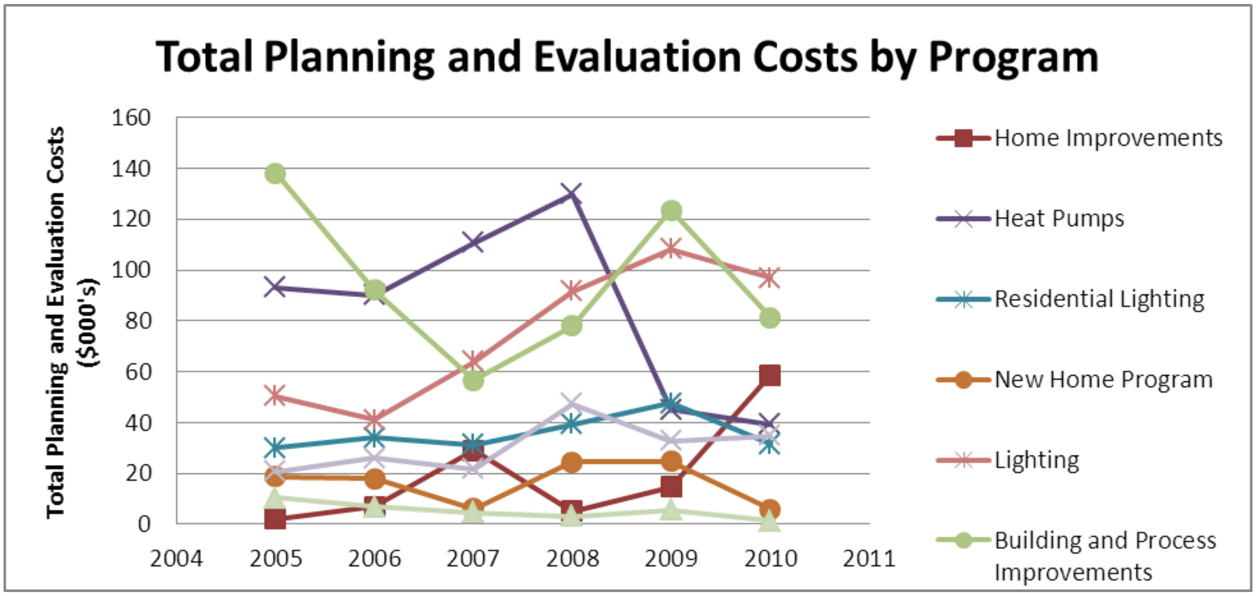
A working spreadsheet of the requested tables is attached as BCUC Electronic Attachment 285.1.

285.2 Please show in graph form, for each program and sector, the total planning and evaluation costs (combined program development , planning and administration and monitoring and evaluation) for the years 2000-2011.

Response:

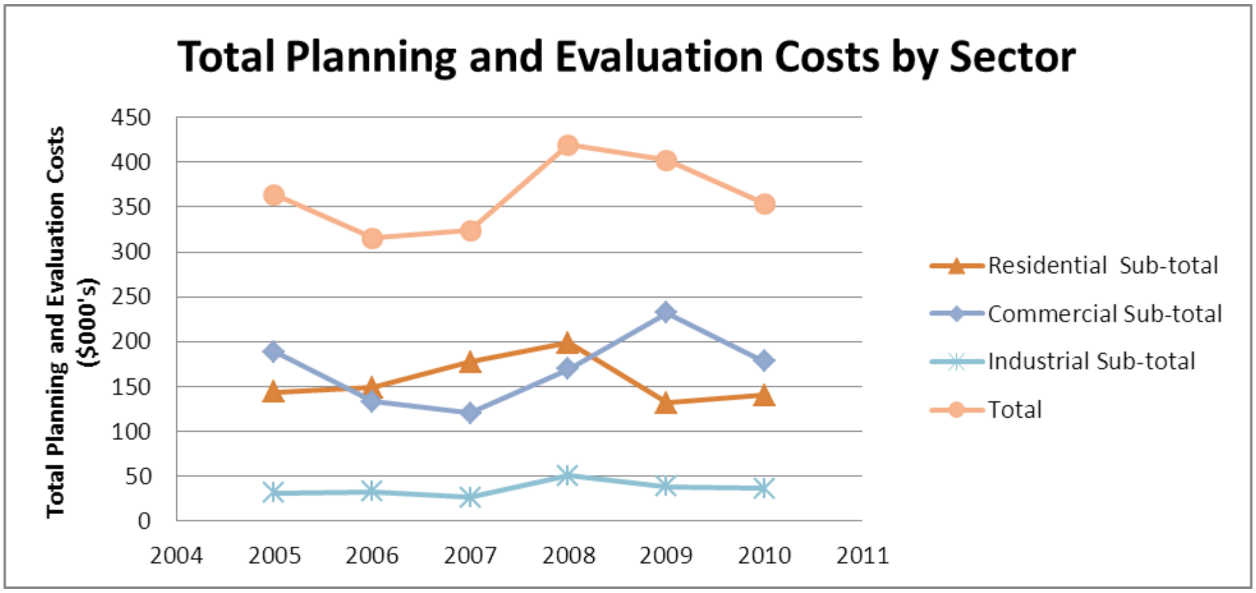
The following chart, which shows the P&E costs by program, exhibits considerable variance due to the fact that P&E costs are allocated to programs based on the programs' energy savings. Data was not readily available prior to 2005, and 2011 data is not yet available.

Figure BCUC IR1 285.2a



For clarity the sector spend was not included in the above chart. The following chart shows the P&E costs by sector, and in total, which reduces the program variance considerably:

Figure BCUC IR1 285.2b



285.3 Please identify any year over year change of 10% or greater in total planning and evaluation costs (combined program development, planning and administration and monitoring and evaluation) for a specific program or for a sector.

Response:

The following table illustrates the year over year difference in P&E (Planning & Evaluation) expenditures by program and sector, in per cent:

Table BCUC IR1 285.3a

	% change year/year				
	2006	2007	2008	2009	2010
		greater than 10%			
Residential					
Home Improvements	218%	314%	-82%	189%	300%
Heat Pumps	-3%	23%	17%	-65%	-13%
Residential Lighting	13%	-8%	26%	21%	-34%
New Home Program	-4%	-66%	296%	0%	-76%
Residential Sub-total	**3%**	**19%**	**12%**	**-34%**	**6%**
Commercial					
Lighting	-18%	56%	43%	18%	-11%
Building and Process Improvements	-33%	-38%	38%	58%	-34%
Commercial Sub-total	**-29%**	**-9%**	**41%**	**37%**	**-23%**
Industrial					
EMIS	-33%	-36%	-28%	76%	-76%
Industrial Efficiencies	26%	-17%	119%	-31%	6%
Industrial Sub-total	**6%**	**-21%**	**94%**	**-24%**	**-6%**
Total	**-13%**	**3%**	**29%**	**-4%**	**-12%**

The allocation of total P&E costs to individual programs, which is based on the yearly program energy savings, results in many highlighted cells that representing a change greater than ten per cent. Since individual program energy savings vary by year, depending on customer participation rates, thus the P&E allocation and year over year variance varies significantly.

P&E costs have traditionally been allocated across programs to smooth out the effect of periodic comprehensive M&E reports, and because it is difficult to track the P&E staff time in three categories over more than 10 programs.

Despite the volatility in per cent from year to year by program, and to a lesser extent by sector, the overall P&E expenditure has not fluctuated nearly as much. For reference the following annual P&E expenditures are extracted from BCUC IR1 Q284.1:

Table BCUC IR1 285.3b

2006 (Actual)	2007 (Actual)	2008 (Actual)	2009 (Actual)	2010 (Actual)
$ 314	$ 324	$ 419	$ 402	$ 354

285.4 Please explain any year over year change of 10% or greater.

Response:

Please refer to the response to BCUC IR1 Q285.3 above.

286.0 Reference: 2012-2013 Capital Plan

Exhibit B-1, Tab 6, p. 116

Demand Side Management

286.1 For all new residential, commercial, industrial, lighting or irrigation programs that are planned to be introduced in 2011 or 2012, please provide the following:

Program Name	
Energy Savings per Installation (Average Annual Energy Savings per Measure) (kWh):	
Energy Savings Determination Methodology	1. Give any algorithms or engineering analyses used to determine savings. 2. List the data and sources of data (e.g. DEER, ASHRAE etc.) reviewed to determine the savings per installation. 3. List the range of savings considered. 4. List any assumptions made in choosing the energy savings per measure. 5. Provide the energy savings per installation used by other utilities. 6. If a code or standard is in place for the measure, provide the calculation showing how the proposed energy savings per measure was determined.
Measure Lifetime (years)	
Measure Lifetime Determination Methodology	1. List the data and sources of data reviewed to determine the measure lifetime. 2. List the range of measure lifetimes considered. 3. List any assumptions made in choosing the measure lifetime. 4. Provide the measure lifetime used by other utilities.

Incremental Cost ($)	
Incremental Cost Determination Methodology	1. List the data and sources of data reviewed to determine the incremental cost. For retrofit measures, give the full installed cost (including labour) of both the standard unit and the efficient unit. 2. List the range of incremental costs considered. 3. List any assumptions made in choosing the incremental cost. 4. Provide the incremental cost used by other utilities.

Response:

There are a considerable number of new or enhanced programs proposed for 2011-13, based on the 2010 CDPR. The CDPR sources for DSM measure elements (measure cost, unit savings, EML etc) were referenced in the report, and included reputable sources such as BC Hydro and OPA. Since the 2010 CDPR report was filed, tested and accepted in the 2011 CEP filing, and since the effort required to respond to this question in full is considerable, illustrative examples follow:

Program Name	Freezer Pick-up
Energy Savings per Installation (kWh):	775 kWh/yr
Energy Savings Determination Methodology	See the 2010 CDPR, based on a deemed measure from the Ontario Power Authority.
Measure Lifetime	8 (eight) years.
Measure Lifetime Determination Methodology	OPA deemed measures list.
Incremental Cost ($)	$140
Incremental Cost Determination Methodology	OPA deemed measures list.

The Company has since researched additional opportunities including a heat pump maintenance measure which will enhance the existing heat pump installation program. The requested data for that measure is as follows:

Program Name	heat pump maintenance (tune-up)
Energy Savings per Installation (kWh):	360 kWh/yr
Energy Savings Determination Methodology	1. N/A 2.North West Energy Council, Bonneville Power Authority and the Energy Trust of Oregon. Savings from a 2005 study by the Energy Trust of Oregon: Baylon, David, et al. Analysis of Heat Pump Installation Practices and Performance. For the Heat Pump Working Group. Oregon. 2005 Other Utilities with program: Rocky Mountain Power, Pacific Power, Oregon Energy Trust and many utilities across the states. Some of these programs run for only new installations as commissioning programs. 3. Range of measure savings considered was 183-709 kWh/yr as per the above study of 450 participants within a 95% confidence level. 4. Assumptions: - An average annual savings from the above mentioned field study is used as an estimate including a 20% free ridership. - Heat pumps of all ages will have similar savings. - Heat pumps that are not serviceable to regain performance will be replaced by new heat pumps. 5. 360kWh/yr used by North West Energy Council Participants 6.N/A
Measure Lifetime	2 (two) years.
Measure Lifetime Determination Methodology	1. See energy savings determination methodology above. 2. The measure life ranges from 1 to 20 years depending on the controls tuned-up. Two years was chosen as conservative, based on a bi-annual tune-up. The measure life used by utilities in the NWEC area is longer as it is part of a comprehensive program with commissioning and sizing of the heat pumps.
Incremental Cost ($)	$ 130, Only 45% of the incremental cost is considered energy benefits. The incremental energy cost is $60 ($130 x 0.45).
Incremental Cost Determination Methodology	see energy savings determination methodology above

FortisBC continues to research and develop new or enhanced measures to compliment or expand current program offers, such as duct sealing and irrigation measures. Since the research is still underway it is not possible to provide the tabular data requested for measures under development.

Program Name **Duct Sealing**	This is a pilot that will be developed during the 2012 year. Savings, measure life and incremental cost in the BC region will be researched in detail. Currently in the States, this is a program for a number of utilities including those under the Bonneville Power Authority.
Irrigation	A number of measures, including low-flow sprinkler heads, efficiency pumps and controls are under consideration. A market research survey will be fielded in the fall of 2011 prior to further development on this program offer.

287.0 Reference: 2012-2013 Capital Plan

Exhibit B-1, Tab 6, p. 117

Demand Side Management

287.1 Please provide a table showing the number of FTEs employed by PowerSense for the years 2000-2011.

<u>Response:</u>

The following table shows the FTE count since 2004. Data prior to 2004 is not readily available. The FTE figures for 2009-11 were budgeted, but due to vacancies weren't continuously filled.

Table BCUC IR1 287.1 PowerSense FTE Count (2004-2011)

2004	2005	2006	2007	2008	2009	2010	2011
8	9	9	8	9	9	8	11

288.0 Reference: 2012-2013 Capital Plan

Exhibit B-1, Tab 6, p. 117; FortisBC 2011 Capital Expenditure Plan Proceeding, Exhibit B-4, BCUC IR 1.103.2

Demand Side Management

The following information request and response was submitted in FortisBC's 2011 Capital Expenditures Plan proceeding:

"Q103.2 For each of the customer classes, please summarize the top 3 categories of achievable energy savings?

A103.2 The following results are based on the 20-year potential:

Residential : Lighting; Building Envelope; and Water Heating

Commercial : Lighting; HVAC; and Refrigeration

Industrial : Fans (cross-industry); Lighting; and Compressed air."

(FortisBC 2011 Capital Expenditures Plan Proceeding, Ex. B-4, BCUC IR 1.103.2)

288.1 Please specify which programs in the 2012-2013 Capital Plan address each of these nine areas of top energy saving potential.

<u>Response:</u>

Please refer to the below table.

Table BCUC IR1 288.1

Cust Class	Top end-uses	2012-13 Capital Plan	2012 Long-Term DSM Plan
Residential	Lighting Building Envelope Water Heating	Lighting Bldg Envelope Water Heating	Lighting Home Improvement Water Heating
Commercial	Lighting HVAC Refrigeration	Lighting Building Improvement Building Improvement	Lighting Building Improvement Building Improvement
Industrial	Fans Lighting Compressed Air	Industrial Efficiency (all end-uses are covered by the custom industrial program)	Industrial Efficiency (all end-uses are covered by the custom industrial program)

288.2 Please specify which programs in the 2012 Long Term DSM Plan address each of these nine areas of top energy saving potential.

Response:

Please refer to the last column of Table BCUC IR1 288.1

289.0 Reference: 2012-2013 Capital Plan

Exhibit B-1, Tab 6, p. 129

Demand Side Management

FortisBC states "PowerSense also co-funds a contract compliance officer, in collaboration with other public utilities, to ensure that market transformation on energy efficiency measures – once regulated - is completed."

289.1 Please provide more details of the work and funding of the compliance officer. For example, what other public utilities fund this position, what are the activities this position undertakes, etc. Please also provide a breakdown of the funding from each utility, or, if this is not known, from FortisBC only.

Response:

Project Description:

The Ministry of Energy and Mines (MEM) manages a compliance enforcement strategy for the BC *Energy Efficient Act* and Energy Efficiency Standards Regulation standards for windows, doors, commercial glazing, thermostats and fluorescent light ballasts, in partnership with public utilities and industry stakeholders. This project will implement these strategies and support compliance with current regulations while gathering research and analysis to develop new standards under the BC Energy Efficiency Act.

This project involves extending the current contract for a MEM Compliance Enhancement Coordinator MEM to perform the following activities:

1. Serve as main contact point for enquiries and questions from industry players and consumers about the Energy Efficiency Standards Regulation standards for windows, doors, commercial glazing and skylights, thermostats, furnaces & water heaters and lighting products as identified by public utilities and the MEM;
2. Educate manufacturers, suppliers and distributors on the EESR requirements for regulated products; and
3. Proactively liaise with key organizations such as AIBC, APEGBC, BSIA and others individuals of influence to support implementation and enhance compliance with regulatory standards under the provincial Energy Efficiency Standards Regulation.
4. As an authorized inspector for the province, attend site inspections and manufacturer inspections as deemed necessary.
5. Estimate and report compliance levels for products covered under the scope of compliance coordinator.
6. Liaise with NRCan's Energy Star coordinator and attend Energy Efficient Fenestration Steering Committee meetings twice per year.

Budget:

Project budget for Compliance Enhancement Coordinator for 2011/12 is CAD $70,000 including all applicable taxes. Contributing partners are:

- FortisBC (gas & electric): $30,000 (43% of total project budget, contribution of each company to be determined)
- BC Hydro: $30,000 (43% of total project budget)
- MEM: $10,000 (14% of total project budget)

Deliverables

1. Bi-monthly reports and teleconferences documenting activities of the Compliance Enhancement Coordinator, including a tracking of questions received and response provided and estimation of compliance rate (in percentages) for each product regulations; and
2. Detailed breakdown of project costs, including Compliance Enhancement Coordinator's fees and expenses

290.0 Reference: 2012-2013 Capital Plan

Exhibit B-1, Tab 6, p. 129

Demand Side Management

Table 7.4 - Planning and Evaluation

1	Programs	2011	2012	2013
		Approved	Plan	
		Cost ($000s)		
2	Salaries (loaded)	420	400	420
3	Office Expenses	60	50	50
4	Consulting Fees	75	80	80
5	M&E Reports	185	200	200
6	DSMAC	10	10	10
7	**Total**	**750**	**740**	**760**

290.1 Please specify exactly what the $185,000 - $200,000 for M&E reports will be spent on.

Response:

Based on the DSM Monitoring & Evaluation Plan 2012-14, filed as Appendix D of the 2012 Long Term DSM Plan, this budget line item will be spent on the following reports:

<u>2012</u>

Comprehensive Studies:

- Commercial Lighting Industrial Efficiency Study – QA review and process Mini Reviews:
- New Homes – mini review

Municipal Program – mini review

<u>2013</u>

Comprehensive Studies:

- Heat Pumps projects to the end of 2011
- Commercial BIP (New) projects to the end of 2011Mini Reviews:
- Residential Lighting – mini review
- Residential behavioural survey and mini-review
- Low Income program mini review

Note that some, if not most of the Mini Reviews listed above will be performed by in-house M&E staff depending on their capability and availability.

290.2 Please specify exactly what the $75,000 - $80,000 in consulting fees will be spent on.

<u>Response:</u>

This budget line item provides for general policy and specific program expertise to the DSM Planning group; as well as allows for collaborative funding of DSM research.

For example, in the past year the HPO (BC Home Protection Office) spearheaded a phase one study of residential high-rise buildings. The study determined the effective R-values of the subject buildings, before and after the building envelope’s rehabilitation, space heating fuel share and relative Building Energy Performance Index (BEPI) based on whole building energy usage. A phase two study is expected to delve into the details of in-suite versus common area energy usage.

No specific expenditures are yet planned for 2012 or 2013.

291.0 Reference: Financial Schedules

Exhibit B-1, Tab 7, pp. 10-15, Table 1-B

Demand Side Management

291.1 Please clarify the tax impact mechanism on the DSM Deferral Account. How is it calculated and why are the gross additions to the account reduced by the amount of tax impact?

Response:

Prior to 2005, FBC recorded all deferred charges (except DSM) on a gross of tax basis. In Decision G-52-05, the Commission directed FBC to begin recording all deferred charges (excluding preliminary and investigative spending transferred to capital projects) on a net-of-tax basis in order to better match the associated income tax either to the customer or the shareholder.

291.2 FortisBC forecasts the balance in the DSM deferral account to increase from $8.433M in 2010 to $20.22M in 2013. Please explain FortisBC's plan for recovery of the balance of this deferral account.

Response:

The Company expects to amortize the DSM expenditures over a ten year period, consistent with the practice of BC Hydro, and as agreed to in the 2006 NSA approved by the BCUC Order G-58-06.

292.0 Reference: Approvals Sought

Exhibit B-1, Tab 8, pp. 1-2; Utilities Commission Act, s. 44.2

2012 Long Term Demand Side Management Plan

FortisBC states "Pursuant to section 44.1(6) of the Act, acceptance that FortisBC's 2012 Integrated System Plan, comprised of three components – 2012 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand Management Plan, is in the public interest." (Tab 8, p. 2)

FortisBC also states "Pursuant to sections 59 to 61 of the Act, approval of the following items:

> …the revenue requirements in the amount of $294.484 million in 2012 and $319.108 million in 2013, as set out in section 4.1 of the Application, resulting in a

> firm rate increase of 4.0 percent, effective January 1, 2012 and a firm rate increase of 6.9 percent effective January 1, 2013.” (Tab 8, p. 1)

Section 44.2 of the UCA states:

> “(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;…
>
> (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.” (UCA)

292.1 Does the approval sought pursuant to section 61 of the Act include recovery of expenditures on demand-side measures?

Response:

The Company is requesting approval for its 2012 and 2013 DSM expenditures as part of the Capital Expenditure Plan, pursuant to section 44.2 of the Act. (See Table 1.1, Table 6 – 2012-13 Capital Plan). The requested revenue requirements for 2012 and 2013, made pursuant to sections 59 to 61, include the amortization and related financing costs of the deferred DSM expenditures from previous years.

292.1.1 If so, please specify by what Commission Order FortisBC received approval pursuant to section 44.2 of the Utilities Commission Act for these demand-side measures. If FortisBC does not have approval pursuant to s. 44.2 then please reconcile the approvals sought with section 44.2 of the Act.

Response:

Amortization and financing costs for DSM Expenditures are included in the 2012 and 2013 Revenue Requirements relate to approved DSM expenditures dating from 2002. DSM was not required to be included in expenditure schedules under the Act until its November 2004 amendment (section 45 (6.1)(c), and subsequently section 44.2).

Up to and including 2006, the Company's capital expenditure schedules were filed as part of its annual revenue requirements applications. The orders approving DSM expenditures beginning in 2002 are as follows.

2002	G-133-01	2002 Revenue Requirements Application
2003	G-10-03	2003 Revenue Requirements Application
2004	G-38-04	2004 Revenue Requirements Application
2005	G-52-05	2005 Revenue Requirements Application
2006	G-58-06	2006 Revenue Requirements Application
2007 – 2008	G-147-06	2007 – 2008 Capital Expenditure Plan
2009 – 2010	G-11-09	2009 – 2010 Capital Expenditure Plan
2011	G-195-10	2011 Capital Expenditure Plan

292.2 Please specify the amount by year for demand-side measures for which approval is sought. Is it $7.73 million in 2012 and $7.88 million in 2013?

Response:

Confirmed.

292.2.1 What expenditure levels are planned for 2014-2016?

Response:

A detailed DSM Plan has not been created for the years 2014-16, thus the expenditure levels are unknown at this time.

292.2.2 What expenditure levels are associated with the years 2014-2016 in the Long Term DSM Plan?

Response:

Please see response to BCUC IR1 Q292.2.1

292.2.2.1 If FortisBC is not seeking approval for expenditures associated with the 2014-2016 Long Term DSM Plan in this proceeding, when does the Company plan to seek approval of these DSM expenditures?

Response:

FortisBC will seek approval of 2014, and possibly future year, DSM expenditures in its next Capital Expenditure Plan filing.

292.2.3 When FortisBC refers to the 2012 DSM Plan timeline, does it mean 2012-2016?

Response:

No, the 2012 Long-Term DSM Plan timeline spans 2012-2031.

293.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 1, p. 4

DSM Regulation

FortisBC states "The DSM Regulation also provides in section 4 that the Commission, in determining the cost-effectiveness of a DSM measure proposed in a long-term resource plan or an expenditure schedule:… (4) must determine the cost-effectiveness of a demand-side measure by determining whether the portfolio is cost-effective as a whole."

293.1 Please confirm that the correct wording of the DSM Regulation is "(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole" and that specified demand-side measure is defined as an education program for students enrolled in schools in the public utility's service area, an education program for students enrolled in post-secondary institutions in the public utility's service area, the funding of energy efficiency training, a community engagement program, or a technology innovation program. Defined by who, source?

Response:

Confirmed.

293.2 Given that only the specified demand-side measures as defined by whom must be assessed on a portfolio basis, is FortisBC requesting approval to have its complete DSM expenditure schedule assessed for cost effectiveness on a portfolio level?

Response:

FortisBC is not making a specific request as to how the Commission assesses cost effectiveness outside of the specified demand-side measures, although the proposed DSM expenditure schedule could be assessed on a complete portfolio level.

293.3 The Commission is aware that the provincial government is exploring amendments to the DSM Regulation. Please provide an estimate of the amount of DSM programming that would be considered cost effective for FortisBC if the proposed changes were put in place.

Response:

The Company has signed a confidentiality agreement with the provincial government in regards to possible amendments to the DSM Regulation, and is concerned that providing the requested information may compromise that agreement. In any case, FortisBC believes that the initial proposal made by government is likely to change, and as such any estimate of potential impacts would be premature.

294.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.1, p. 12

Review of 2011 DSM Plan

FortisBC states “The measure incentives, which were based on 40 percent of TRC for the Medium-option, were modified to either an incentive rate (¢/kWh) or to a unit incentive ($/measure) to make the program offers simpler for customers to understand.”

294.1 Please explain how FortisBC sets the incentive level for demand-side measures. What does the 40 percent of TRC refer to? How exactly are the incentives calculated?

Response:

The TRC (Total Resource Cost) can either be: the full cost to install a demand-side measure, which is often the case in retrofitting a measure to an existing home, office or industrial plant; or the incremental cost, which more often is the case in new construction.

The 2010 CDPR study provided estimates of the cost of each demand-side measure, and as part of the development of the three DSM options a different level of incentive was applied to each scenario. For the medium option, which FortisBC elected to proceed with, a 40% of TRC for mass-market programs was used to develop a preliminary cost estimate of that scenario.

A fundamental step change proposed in the DSM medium option, and subsequently incorporated and approved in the 2011 DSM filing, was to double the nominal incentive rate from the long-standing five cents, up to ten cents per annual kWh saved.

When developing the 2012-13 DSM Plan, 40% of TRC was the starting target point for setting mass-market incentives, but incentives were then adjusted in various ways to provide appropriate market incentives that will ensure program success. Several illustrative examples follow:

- ASHP full cost retrofit measure: the measure cost was listed at $5,340, and 40% equals $2,136 which is seven times the prior incentive of $300 based on 5 cents per kWh saved. The 2012-13 DSM Plan set the incentive at $600 based on the 10 cents per kWh saved “target” incentive rate.
- New home EnerGuide 80 rating: the measure cost incremental cost listed as $3,200, and 40% equals $1,280. The 2012-13 DSM Plan rounds up the offer to $1,500 to make it more substantive and avoid a “lost” opportunity
- EnergyStar fridge: the measure cost incremental was listed as $50, and 40% equals $20 but the 2012-13 incentive is set at $50 to match BC Hydro’s offer.
- Industrial efficiency – no discrete measure or TRC was provided in the CDPR, but the nominal incentive rate was raised from five to ten cents per annual kWh saved, subject to the caps in Schedule 90.

294.1.1 Are incentives ever adjusted after they are initially set? If so, what steps are taken to adjust the incentive?

Response:

Yes, incentives are occasionally adjusted where necessary. For example the EnergyStar clothes washer rebate was set at $50 in the 2011 DSM plan, but subsequently raised to $75 earlier this year to ensure market participation and to match a similar BC Hydro offer.

295.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.1, pp. 12-13

Review of 2011 DSM Plan

FortisBC states "The CDPR report excludes from program achievable savings all known (provincial and federal) Codes and Standards through the appropriate UEC (unit energy consumption) – for products regulated beforehand, or by modification of the ramp rates for affected measures – for products anticipated to be regulated in future years."

295.1 Does this statement mean that FortisBC does not claim any energy savings for demand-side programs for measures that have a code or standard in place? If not, please explain how FortisBC claims savings for measures where a code or standard is in place or is accepted but not yet implemented.

Response:

Please see response to BCUC IR1 Q295.2. FortisBC does not generally claim savings for measures where a code or standard is in place or is accepted but not yet implemented.

295.2 Does FortisBC run any DSM programs for measures for which a code or standard is in place? In other words, does FortisBC incent any programs to increase code or standard compliance? If so, please specify which programs.

Response:

Yes, the residential window retrofit program that is targeted to existing, electrically heated homes with single pane or aluminum framed windows. The CDPR identified a sizeable potential if said building stock was upgraded to EnergyStar qualified windows. The PowerSense incentive is meant to encourage homeowners to accelerate the change-out their inefficient windows.

New home construction is not eligible for this incentive measure, since the provincial EEA regulation prescribes a performance standard equivalent to EnergyStar.

This is the only program known to have a provincial regulation in place.

295.3 Please specify which of FortisBC's DSM programs have no direct energy savings attributable.

Response:

As stated in the section 3.6, line 13 of the Long Term DSM Plan supporting initiatives do not result in direct energy savings. Those initiatives include Public Awareness, Education (schools), Community Energy Planning, Trades Training and Codes and Standards support.

296.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-5, Section 3.2.1, Updated p. 13 and Section 4(1)(3) of the Demand-Side Measures Regulation

Avoided Power Purchase Costs

296.1 Please reconcile FortisBC's calculated blended avoided cost of energy of $104.32/MWh with the direction in the Demand Side Measures Regulation that the commission must consider a bulk electricity purchaser's avoided supply cost to be BC Hydro's long-term marginal cost of acquiring new electricity. Does section 4(1)(3) of the DSM Regulation not apply to FortisBC?

Response:

Section 4(1)(3) of the DSM Regulation, which does apply to FortisBC, reads "In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority."

The embedded clause "…to replace the electricity sold to the bulk electricity purchaser..." means that only electricity purchased from BC Hydro is priced at BC Hydro's long-term marginal cost of acquiring new electricity. For the portion of electricity not purchased from BC Hydro, the levelized mid-C futures price was considered the appropriate marginal price signal based on the 2012 Long Term Resource Plan preferred option.

296.2 Did FortisBC use the blended cost of $104.32/MWh in its TRC calculations for all its DSM programs? If so, please provide a table showing the TRC result for every program using the blended rate and the TRC result using BC Hydro's long-term marginal cost of electricity.

Response:

Yes, the $104.32/MWh blended avoided cost was used in all TRC benefits calculations in the filing. See response to BCOAPO IR1 Q64.1 for the revised $101.34 blended avoided cost, as well as Errata 2.

As would be expected using the higher avoided cost of $143.53/MWh provides approximately a 40% TRC increase across all measures and sectors.

For brevity, an updated table 3.2.2 showing the sector level Benefit/Cost ratios with both the revised $101.34 blended cost, and the higher 2011 BC Hydro avoided cost of $143.53/MWh follows:

Table BCUC IR1 296.2

Sector	Benefit/Cost Ratio Revised $101.34/MWh	Benefit/Cost Ratio BCH marginal $143.53/MWh
Residential	1.6	2.0
Commercial	1.7	2.4
Industrial	3.8	5.4
Sub-total Programs only	1.7	2.2
Total (including Portfolio costs):	1.6	2.1

297.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.3.2, p. 17 and Exhibit B-1-2, Appendix D, p. 4

Monitoring and Evaluation

FortisBC states that "The M&E [Monitoring and Evaluation] Plan recommends that two major program reviews and three mini-reviews be undertaken each calendar year, and that recent behavioural initiatives promoting the use of measures such as clotheslines are also reviewed for effectiveness." (Exhibit B-1-2, Section 3.3.2, p. 17)

FortisBC also states "Given the size of FortisBC and it DSM programs, the resources allocated to accomplish M&E studies is of the order of 5% of the total DSM investment and is sufficient to carry out effective M&E activities. FortisBC plans to conduct two full scale M&E studies annually in addition to three Mini Reviews. A full scale review would normally consist of a process, market and an impact study. The Mini Review consists of a Process study and some measurement and verification activities using a sample of projects." (Exhibit B-1-2, Appendix D, p. 4)

297.1 On what basis was it determined that 5% of total DSM investment is sufficient to carry out effective M&E activities?

Response:

The 5% of total DSM resources allocated to M&E activities is within the range used by the utility industry in North America. The California Evaluation Framework – June 2004 report cites evaluation budgets ranging from 2% to 10%, with allocations averaging 4%. Utilities at the higher-end of the range undertook more complex studies to determine EML (effective measure life) and interactive effects.

The 5% budget figure used by FortisBC is believed to provide sufficient resources for the scope of programs offered and magnitude of DSM plan expenditures. M&E data from other utilities (such as Effective Measure Life, free-rider rates, etc.) will supplement the FortisBC studies.

297.1.1 What dollar figure does 5% of total DSM investment translate to for the years 2012-2016?

Response:

DSM resources planned for the two-year filing period 2012-13 totals $15.6 Million, and 5% of this figure translates into $780,000.

297.2 On what basis was it determined that two full scale M&E studies and three Mini Reviews would be sufficient per year?

Response:

Given the number of programs being operated, the M&E budget and the M&E staff resources available to carry out M&E activities, it was determined as part of M&E Plan that two full scale M&E studies and three Mini Reviews would be sufficient per year.

297.3 What level of resources would be required to allow for Interactive Effects studies? If the current financial resource allocation does not allow for Interactive Effects studies, how are these effects currently estimated?

Response:

Interactive effects studies require a combination of metering and measurement studies and are resource intensive. A change in scope of the FortisBC DSM M&E Plan would be needed to incorporate Interactive Effects studies and necessitate increasing M&E costs from 5% of DSM costs to between 6% and 8%. In dollar terms that would necessitate an increase from $780 thousand, to between approximately $937,000 and $1,249,000 for the 2012-13 test period. Since the proposed budget scope does not allow for Interactive Effects studies, FortisBC will continue to base its Interactive Effects estimates on studies by other utilities, thereby avoiding such additional expenditures.

298.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Appendix D, p. 11; Exhibit B-1, Tab 6, p. 129

Monitoring and Evaluation

FortisBC states that "M&E studies will be conducted when the savings reach 10 GWh/year cumulative since inception or since the last M&E study." (Exhibit B-1-2, Appendix D, p. 11)

Table 7.4 - Planning and Evaluation

1	Programs	2011	2012	2013
		Approved	Plan	
		Cost ($000s)		
2	Salaries (loaded)	420	400	420
3	Office Expenses	60	50	50
4	Consulting Fees	75	80	80
5	M&E Reports	185	200	200
6	DSMAC	10	10	10
7	**Total**	**750**	**740**	**760**

(Exhibit B-1, Tab 6, p. 129)

298.1 Please confirm that the M&E study FortisBC refers to in the preamble is elsewhere referred to as a full scale review including a process, market and impact study and elsewhere again, as a comprehensive study.

Response:

FortisBC confirms that a comprehensive study is referred to as a full scale review including a process, market and impact study.

298.2 On what basis was it decided to conduct a full scale review when the savings accumulate to 10 GWh/year since inception? Doesn't this mean that some programs will never undergo a full scale review or will only undergo one review infrequently?

Response:

When the savings for a DSM program accumulate to 10 GWh/year, FortisBC undertakes a full scale review. In the opinion of the Company, this threshold appropriately balances the cost of the M&E program by reducing the number of full reviews undertaken with the need to ensure that those programs that generate the largest energy savings receive a full review.

In the event that a program has a large potential for savings, a pilot study is undertaken. The pilot would be thoroughly reviewed to ensure that all the relevant program variables could be validated prior to committing resources to a full scale program.

This means that some programs will never undergo a full scale review, or will only undergo one infrequently. However such programs would still be subject to a Mini-Review, which ensures a smaller scale program review is undertaken for smaller programs.

298.2.1 Please specify, given the current energy savings projections, which programs will be eligible for a full scale review within the next 36 months? The next 5 years?

Response:

Based on current energy savings projections the following programs will undergo a full-scale review within the next three years (2012 through 2014): Commercial Lighting, Industrial Efficiency, Heat Pumps, Commercial Building Improvements (New buildings), Commercial Building Improvements (Retrofits), and New Homes. M&E plans for 2015 and 2016 will be finalized by the end of 2013.

298.2.2 Will every program undergo a full review or will a Mini Review be considered adequate?

Response:

All programs that achieve the 10 GWh threshold of energy savings will undergo a full review. Mini Reviews will only be considered adequate for programs that do not exceed the 10 GWh threshold.

298.3 Please specify which of the costs shown in Table 7.4 are for independent M&E professionals and studies and which are for in-house M&E professionals and studies.

Response:

In Table 7.4 the costs listed as M&E reports are all for independent M&E studies, and about 40% of the costs listed for salaries and office expenses are for M&E activities undertaken by in-house staff.

298.4 Who will perform the full scale M&E studies and the Mini Reviews? If it is not an independent party, please justify why it will be done in-house. What is the decision criteria for selecting independent or in-house reviews?

Response:

Full scale M&E studies will continue to be carried out by independent third-party M&E professionals. Mini Reviews will be carried out by internal M&E staff dependent on staff skills, experience and availability or external parties if one of those criteria is lacking. Use of in-house resources can be more cost-effective, and also ensures a strong M&E skill-set is maintained in-house. Independent resources are used for specific expertise and to help ensure objectivity.

For a full comparison of the advantages and disadvantages of each type of resource, please see BCUC IR1 A298.4.1.

298.4.1 Please discuss the pros and cons of independent versus in-house M&E activities.

Response:

Advantages of using internal M&E resources include:

- intimate knowledge of the programs;
- easier access to the program files;
- easier access to customers and other staff members to conduct interviews;
- generally more cost effective than external professionals; and
- improved internal capacity and expertise.

Disadvantages of using in-house M&E staff include:

- the perception of a conflict of interest;
- less specific expertise to undertake studies for a full portfolio of programs;
- restricted resource availability; and
- Internal or external stakeholders may be reluctant to discuss issues or problems related to the program with utility evaluation staff.

Advantages of independent M&E professional consultants include:

- a broader range of expertise;
- ability to tap into consultants experience with other utilities' programs;
- they can perceived as more objective and arms-length;
- the ability to undertake several diverse studies as needed; and
- can conduct several different studies in parallel.

Disadvantages of independent M&E consultants include:

- they may require more time than in-house staff to became familiar with programs;
- they will likely cost more than in-house staff; and
- they may not be readily available when needed.

298.4.2 Please provide an estimate of having all planned M&E activities performed by an independent evaluator. For each of the years 2012-2016 show a cost comparison between 100% in-house evaluation, currently planned evaluation costs, and 100% independent evaluation costs for the planned M&E activities.

Response:

The cost comparison table below is for the fiscal year 2012 only, since 2013 is not materially different and no numbers have yet been developed for 2014-16. The table compares the "as-filed" mix of external and internal M&E resources with 100% independent, or external, resources for both the comprehensive reports and mini-reviews. In the latter case there is still a need for internal staff to provide liaison and project management of the external consultant(s) performing the M&E studies.

The alternative of costing 100% in-house M&E is simply not feasible since it would require several individuals with a diverse skill-set to undertake this work, and there is a dearth of qualified candidates with the appropriate M&E skill-set in the market. For example, it took three consecutive postings over a ten month period for FortisBC to fill the current M&E Analyst position.

Table BCUC IR1 298.4.2

Component	As filed ($000s)	100% External $(000)s
Comprehensive studies	200	200
Mini-reviews	Included	150
Internal M&E staff	160	112
Office expenses	25	20
Total	385	482

299.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.4, p. 18

Best Practices

FortisBC states that "These experts are conducting a DSM best practices literature review and researching best practices developed by other utilities as well as energy efficiency and conservation consortiums and associations. The applicable best practices are being included into new and existing programs as appropriate."

299.1 Please list the specific best practices that have been included into new and existing programs, where the best practices was sourced from, and the specific programming changes that have resulted from the inclusion of the best practice.

<u>Response:</u>

Behavioural change theories and best practices are considered in program design. Some specific community based social marketing strategic and best practices used include:

- Identification of barriers and benefits – and strategies developed to overcome the identified barriers;
- Application of behaviour change theories: reciprocity, building community norms, scarcity, appropriateness, etc;
- Market segmentation and targeting;
- Strategic partnerships to impact perception and reach; and

- Utilization of behaviour-change tactics (prompts, pledges or commitments, contesting, personalized communication, the use of product samples, public relations, feedback, incentives and disincentives and advertising).

In addition, information is regularly sought from other public utilities such as BC Hydro and Manitoba Hydro about their programming and learning. Where it makes sense for FortisBC customers, PowerSense program design is aligned with similar BC Hydro programs to minimize market confusion and increase operational efficiency. E-Source, CEE (Consortium for Energy Efficiency) and Chartwell are also regularly referenced for research papers and examples of other utility programs. PECI (Portland Energy Conservation Inc.) designed programs were also referenced. The following are some of the programs introduced in 2011 that follow other utilities' design and best practices:

- Residential energy efficient lighting rebates;
- Appliance rebate programs;
- Fridge Take-Back program;
- Electronics "spiff" program;
- Building Optimization Program;
- FLIP (Lighting Installation Program); and
- Product Incentive Program (to be launched in late 2011).

300.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.4.1, pp. 18-20

Residential Sector Programs

300.1 Please confirm whether the following residential programs or elements of programs will be new in 2012: Heating and Cooling Program – heat pump maintenance and pilot program for duct sealing; Energy Star Appliances and Electronics – fridge and freezer pick-up; and New Home Program.

Response:

Each of the listed programs was introduced in 2011 and are expected to remain relatively unchanged. However, there are some possible modifications and enhancements starting in 2012 as follows:

- Heat pump program:
    - Considering varying incentive levels based on installer/contractor credentials.
- Energy Star Appliance rebate program:
    - Energy Star Top Tiers may change; if so, qualifying appliances will change to match them.
- Fridge Take-Back:
    - Intend to introduce old freezer pick-up program.
    - Considering pick-up program for old fridges without tie to purchase of new Energy Star fridge.
- Energy Star electronics program:
    - Top Tiers may change; if so, qualifying televisions will change to match them..
    - Considering expansion of program to include additional electronics like video players and stereos.
- New Home Program
    - Will change if qualifying EnerGuide rating tiers are changed.
    - Will include any new insulation technologies.

300.2 Are there any energy savings attributable to the Heat Pump Maintenance program? If so, please quantify and provide back up for the measure savings, including:

i) data source (i.e. DEER, ASHRAE);

ii) any algorithms or engineering analyses;

iii) the range of measure savings considered;

iv) any assumptions made in choosing the energy savings; and

v) what other utilities use as the measure savings.

Response:

Yes, space heating savings of 360 kWh/yr per tune-up are attributable to this measure.

i) Data sources :

North West Energy Council, Bonneville Power Authority and the Energy Trust of Oregon. Savings from a 2005 study by the Energy Trust of Oregon:

Baylon, David, et al. Analysis of Heat Pump Installation Practices and Performance. For the Heat Pump Working Group. Oregon. 2005.

ii) Engineering analyses:

Since tune-ups are recommended bi-annually, a measure life of 2 years was selected.

Lifetime savings = EML (estimate measure life) * Annual Savings = 2 years * 360 kWh = 720 kWh

BCR (benefits cost ratio) = (utility avoided power purchase benefits) / (Total Resource Cost)

= $ 73 / $62 = 1.2

iii) Range of measure savings considered

183-709 kWh/yr as per the above study of 450 participants within a 95% confidence level.

iv) Assumptions:

- An average annual savings from the above mentioned field study is used as an estimate including a 20% free ridership.
- Heat pumps of all ages will have similar savings.
- Heat pumps that are not serviceable to regain performance will be replaced by new heat pumps.

v) Other Utilities with program:

Rocky Mountain Power, Pacific Power, Oregon Energy Trust and many utilities across the states. Some of these programs run for only new installations as commissioning programs.

300.3 Have the energy savings attributable to the Residential Lighting Program changed since the introduction of the BC government's efficient light bulb standards in January 1, 2011? If so, please show the program savings before and after the standard was introduced. If not, why not?

Response:

No, the energy savings attributable to the Residential Lighting Program have not changed. The PowerSense CFL rebate offer was already limited to specialty bulbs (e.g. reflector, 3-way, dimmable) not the ubiquitous "twister" style of CFL that effectively replaced incandescent A-bulbs of 75 and 100 watt ratings.

300.4 Does FortisBC offer incentives for efficient electric water heaters? Please confirm the current electric water heater standard and discuss the feasibility of offering an incentive for increased efficiency electric water heaters.

Response:

The current BC EEA Regulation on electric water heaters is for conventional, resistance element, type of storage tank water heaters. The Company does not plan to offer an incentive due to the low stock turnover (customers only replace tanks when they fail), lack of saleable non-energy benefits (NEB) and modest incremental energy savings.

FortisBC does intend to launch a Heat Pump Water Heater (HPWH) pilot in the fall of 2011. There are early indicators of success based on informal reports from US-based EPRI (Electric Power Research Institute). Assuming the pilot is successful the Company will begin to roll out an efficient electric water heater program based on that technology in 2012-13.

300.4.1 Does BC Hydro offer an incentive for electric water heaters? If so, please provide details of their program offer including incentive amount.

Response:

FortisBC is not aware of BC Hydro offering an incentive for electric water heaters. FortisBC is in discussion with them in regards to collaborating on the HPWH pilot (please see the response to BCUC IR1 Q300.4 above).

300.5 Please provide a breakdown of the costs associated with the In-Home Display incentive program planned. If the Advanced Metering Infrastructure program is not approved, how will this dollar figure be spent?

Response:

The In-Home Display (IHD) is a component of the Behavioural program (line 10 of Table 7.1 on p. 118 of the 2012-13 CEP). An estimated $12,000 (200 units @$50 + 20% administration) is the first year cost, out of the $280,000 plan expenditure; thereafter the market penetration is expected to grow.

If the AMI filing is not approved, other elements of the Behavioural program such as clothesline give-aways, will be scaled up incrementally to compensate for the loss of the IHD measure.

301.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.4.1, pp. 21-23

Commercial Sector Programs

301.1 Please confirm when irrigation DSM programs will be available to irrigation customers.

Response:

PowerSense researched a number of other utility irrigation incentive programs with the intent to introduce a “product option” program in the first half of 2011. However, preliminary market research showed that in the FortisBC service area the irrigation customer class is quite varied and a standardized irrigation program would not necessarily meet customer needs.

FortisBC is now conducting a market survey of all its irrigation customers. The survey results will inform the irrigation program design. It is expected that the irrigation incentive program will commence in early 2012 and are likely to include an audit incentive, efficient pump replacement incentives and a “top up” to the provincial irrigation program.

In the meantime irrigation customers can access PowerSense incentives by applying as custom option projects.

302.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.4.1, pp. 24-25

Other Programs

302.1 Please describe FortisBC's involvement in the Multi-Family Rental Accommodations Program social marketing tactic.

Response:

The social marketing strategy is to incorporate a number of specific tools to engage tenants in volunteer energy conservation activities. Carefully designed marketing tactics would include:

- face-to-face communication (PowerSense staff meeting with tenant groups);
- education (face-to-face information sessions, posters, brochures, newsletters, etc.);
- a friendly challenge between neighbours/floors/buildings. Winners would receive small prizes like a pizza dinner;
- personal conservation pledges; and
- prompts and reminders as follow-up.

303.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.5, pp. 25-26

Collaborative Programs

303.1 For the programs on which FortisBC collaborates with FortisBC Energy Inc., BC Hydro, and LiveSmartBC, please specify how the program savings are attributed among the partners.

Response:

The first determinant is the fuel used for the particular end use. For example, if natural gas is used by the customer for space heating, then the energy savings for an insulation upgrade would be earmarked for FortisBC Energy Utilities (FEU).

The second determinant is the specific service area the customer resides in, i.e. a Victoria customer's gas savings would accrue to FortisBC Energy (Vancouver Island) Inc.

For an electric end-use, the energy savings for the purchase of an EnergyStar refrigerator, would flow to either BC Hydro or FortisBC "electric" depending on the customer's service location.

No electricity savings are attributed to LiveSmartBC by FortisBC.

303.2 For the programs on which FortisBC collaborates with FortisBC Energy Inc. and BC Hydro, please specify how the program costs are shared among the partners. Please show a breakdown of the total costs of the programs on which FortisBC collaborates and how the costs are allocated among the partners.

Response:

The costs are shared using the same methodology by which energy savings are attributed (see the response to BCUC IR1 Q303.1), up to a maximum measure incentive cost agreed to by the respective public utilities collaborating with LiveSmart BC.

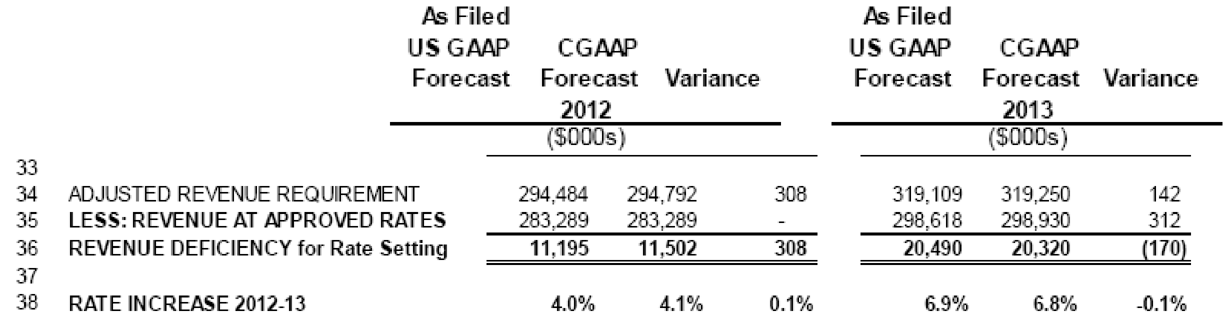
For example, the current LiveSmart BC offer for an Air Source Heat Pump is either $1,000 or $1,500, depending on the characteristics of the heat pump installed. The FortisBC contribution toward this total incentive amount is $600 for the heat pump and an additional $50 if a DC variable speed fan is installed.

As but one partner in the LiveSmart BC collaboration, FortisBC is unable to provide neither the total costs of the program nor the respective contributions of each partner.

US GAAP RECONCILIATION

304.0 Reference: US GAAP Reconciliation

Exhibit B-3, Schedules pp.1, 3



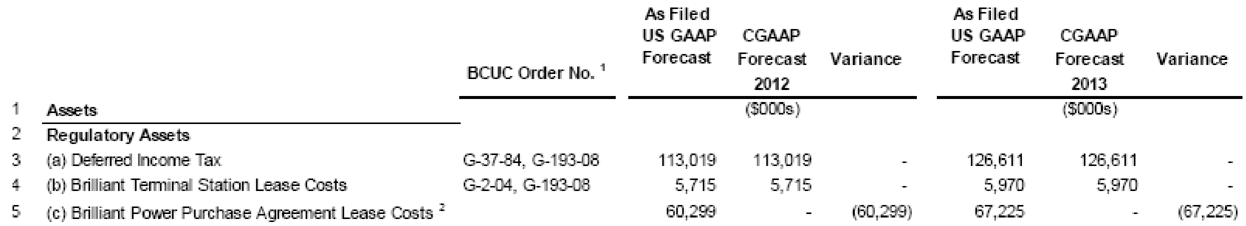
		As Filed US GAAP Forecast	CGAAP Forecast	Variance	As Filed US GAAP Forecast	CGAAP Forecast	Variance
		2012			2013		
		($000s)			($000s)		
33							
34	ADJUSTED REVENUE REQUIREMENT	294,484	294,792	308	319,109	319,250	142
35	**LESS: REVENUE AT APPROVED RATES**	283,289	283,289	-	298,618	298,930	312
36	**REVENUE DEFICIENCY for Rate Setting**	**11,195**	**11,502**	**308**	**20,490**	**20,320**	**(170)**
37							
38	**RATE INCREASE 2012-13**	**4.0%**	**4.1%**	**0.1%**	**6.9%**	**6.8%**	**-0.1%**

(Source: Exhibit B-3, Schedule page 1 "Revenue Requirements Overview")

304.1 Please explain why Line 35 "Revenue at Approved Rates" would have different values under US GAAP and under CGAAP.

Response:

The difference of 0.1% in rates from 2012 between US GAAP and CGAAP will result in a different starting point for the determination of revenue at approved rates for 2013 US GAAP and CGAAP on line 35. In other words, each of the 2013 scenarios is using a different starting point which will result in a variance. The "Revenue At Approved Rates" on line 25 under 2013 column is $298.618 million under US GAAP and $298.930 million under CGAAP for a difference of $0.312 million. There is no such a variance in 2012 under either US GAAP or CGAAP since the starting point, 2011 revenue at approved rates, has been approved and is not subject to change.



		BCUC Order No. [1]	As Filed US GAAP Forecast	CGAAP Forecast 2012	Variance	As Filed US GAAP Forecast	CGAAP Forecast 2013	Variance
1	**Assets**			($000s)			($000s)	
2	**Regulatory Assets**							
3	(a) Deferred Income Tax	G-37-84, G-193-08	113,019	113,019	-	126,611	126,611	-
4	(b) Brilliant Terminal Station Lease Costs	G-2-04, G-193-08	5,715	5,715	-	5,970	5,970	-
5	(c) Brilliant Power Purchase Agreement Lease Costs [2]		60,299	-	(60,299)	67,225	-	(67,225)

(Source: Exhibit B-3, Schedule 1A -page 3 "Non-Rate Base Assets")

304.2 Please confirm that FortisBC has not already previously recovered the Brilliant PPA lease costs through rates.

Response:

FortisBC has previously recognized costs associated with the BPPA through power purchases since 1996, however the $60.3 million in 2012 and $67.2 million in 2013 of regulatory assets are of a different nature. FortisBC can confirm that these regulatory assets have not been previously recovered from customers in rates.

Under US GAAP, the amount previously determined as power purchases under pre-changeover CGAAP will be replaced by depreciation on the finance lease asset and interest and accretion expense on the finance lease obligation. These amounts differ from the amount paid under the BPPA, and as a result approval of a non-rate base deferral account of approximately $60.3 million in 2012 and $67.2 million in 2013 is requested for the timing differences to be recovered from customers through future rates over the life of the BPPA. These regulatory assets are representative of the excess depreciation and interest expense that would otherwise be recognized in cost of service over the BPPA power purchases already recognized in rates. Recognizing the BPPA as a capital lease under US GAAP will affect the timing of amounts recorded as expense, however once the BPPA expires the total amount paid under the agreement as power purchases would equal the total amount expensed related to the capital lease.

2011 LOAD FLOW AND TRANSIENT STABILITY ANALYSIS REPORT

(TO DOCUMENT COMPLIANCE WITH NERC TPL PERFORMANCE STANDARDS)

December 2010

Contents

Appendices

APPENDIX-A	Load Flow Transcripts: Normal System
APPENDIX-B	ACCC (Automatic Contingency Analysis Reports)
APPENDIX-C	Transient Stability Analysis Plots (2012)
APPENDIX-D	Reactive Power Margin Assessment (V-Q Analysis Winter Peak)

1. Introduction

This brief memorandum documents the results of the load flow and transient stability analysis carried out to assess the performance of the FortisBC transmission system in accordance with the NERC system performance standards TPL-001-0, TPL-002-0, TPL-003-0 & TPL-004-0.

The load flow analysis was carried out for years 2012, 2016 and 2020 both for winter and summer peak conditions. In addition, load flow analysis was also carried for the 2012 light load conditions. The transient stability analysis was carried out only for year 2012 winter peak, summer peak and light load conditions.

2. Load Flow Cases

The approved WECC load flow cases 13HW1AP.sav, 16HW1SAP.sav and 19HW1AP.sav representing the winter peak conditions and 12HS2AP.sav, 16HS2AP.sav and 20HS1AP.sav representing the summer peak conditions were used (TPL-001-0 R1.2. & R1.3.1.)

All cases were updated to represent the latest FortisBC system and the correct seasonal equipment ratings (TPL-00-0 R1.3.4.). The future year cases include all the planned system reinforcements identified in the current 2011-2030 twenty year plan (TPL-001-0 R1.3.8. & R1.3.9.).

2.1 Load (TPL-001-0 R1.3.5. & R1.3.6.).

In the load flow cases the FortisBC load modeled is based on the 1-in-20 peak load forecast prepared by Resource Planning. The loads used are given in the table below:

COMPONENT	**WINTER PEAK**			**SUMMER PEAK**		
	2012	**2016**	**2020**	**2012**	**2016**	**2020**
FortisBC	887	951	1001	695	739	778
Teck	220	220	220	220	220	220
Losses	32	37	36	26	27	28
Total	1139	1208	1257	941	986	1026

The FortisBC load includes the Celgar load and the BC Hydro load connected to Duck Lake substation. Celgar has a total load of 40 MW and a generation capacity of approximately 100 MW. Normally the generation at Celgar is around 82 MW. Celgar exports 42 MW after supplying their internal plant load. The excess power is transported over the FortisBC system and supplied to BC Hydro at the Kootenay point of interconnection. The Teck load is assumed constant at 220 MW over the study period.

In the load flow cases the loads are distributed based on the regional forecast "2011-2031 Peak Load Forecast". The loads are scaled down uniformly to match the total winter and summer peaks loads given in the 1-in-20 system load forecast.

In addition, to model off-peak conditions a light load case was created from the 2012 summer peak case. In the light load case the FortisBC load is 266 MW (30% of the winter peak load), the Teck load is 215 MW and the system losses are 24 MW.

2.2 Generation (TPL-001-0 R1.3.5.)

The generation dispatch used in the winter and summer peak cases is given below:

PLANT	**WINTER PEAK (i)**		**SUMMER PEAK (ii)**	
	UNITS	**MW**	**UNITS**	**MW**
LBO	1,2,3	27	1,2,3	27
UBO	5,6	20	5,6	20
SLC	1,2	24	1,2	24
COR	1,2	20	1,2	22
ALH	1,2	60	1,2	166
BRD	1,2,3,4	132	1,2	74
BRX	1	112	1	116
WAN	1,2,3,4	468	1,2,3	333
CEL	2,3	82	2,3	82
Total		945		864

i. The generation dispatch on December 14, 2009 at 18:00 hours the time of system winter peak.

ii. The generation dispatch on July 28, 2010 at 16:00 hours the time of system summer peak.

The generation dispatch used in the 2012 light load case is given below:

PLANT	**LIGHT LOAD**	
	UNITS	**MW**
LBO	1,2,3	42
UBO	1,2,3,4,5,6	52
SLC	1,2,3	46
COR	1,2,3	39
ALH	1,2	170
BRD	1,2,3,4	132
BRX	1	102
WAN	1,2,3,4	417
CEL	2,3	82
Total		1082

2.3 Interchange

The interchange (TPL-001-0 R1.3.5.) with the BCTC system is given in the table below:

YEAR	**INTERCHNAGE (+ EXPORT, - IMPORT)**		
	WINTER PEAK	**SUMMER PEAK**	**LIGHT LOAD**
2012	-194	-78	577
2016	-263	-123	-
2020	-311	-162	-

3. Normal Operation (TPL-001-0 R1.3.7.)

Figures 1 through 18 in Appendix-A are load flow transcripts for years 2012, 2016 and 2020. They show the system voltages and power flows during normal operation for winter peak and summer peak conditions. There are three figures for every year and at each load level; Overall FortisBC transmission system, North Okanagan and South Okanagan & Boundary. Figures 19 through 21 give the system voltages and power flows for the 2012 light load case.

In all cases the PRI Tap is open and the Princeton area load is supplied from the FortisBC system via line 43L from BEN. Also, the 138 kV loop in Kelowna is operated with normal open points.

3.1 Year 2012

System reinforcements included are:

a. The 63 kV facilities at Huth substation have been upgraded so that 63 kV lines 52L & 53L operate in parallel between R. G. Anderson and Huth.
b. The 138 kV tie between Ellison and Sexsmith is in service.

During normal operation the voltages and power flows are within the acceptable limits both during winter and summer peak conditions.

3.2 Year 2016

System reinforcements included are:

a. The necessary communication and protection is provided to operate the 138 kV lines (the outer loop) meshed between LEE and DGB.
b. Lee 3rd 230/138 kV transformer is in service.
c. Lines 52L & 53L between RGA and HUT are re-conductored from 477 kcmil ASC to 1277 kcmil ASC.

During normal operation the voltages and power flows are within the acceptable limits both during winter and summer peak conditions.

3.3 Year 2020

The system reinforcements included are:

a. +150/-50 MVAR SVC connected to the DGB 138 kV bus

During normal operation the voltages and power flows are within the acceptable limits both during winter and summer peak conditions.

4. Contingency Analysis (Loss of a Single BES Element TPL-002-0)

The automatic contingency analysis function (ACCC) in the PSSE program was used to simulate all possible single contingencies in the FortisBC system. The thermal (flows over 90% of the respective winter or summer emergency rating) and voltage violations (±10% of nominal voltage) of the criteria were monitored. For the ACCC simulation the **study area** included all busses above 63 kV in the FortisBC system as well as the following busses of the neighboring BC Hydro and BPA systems:

#50789 AAL 230 KV;#50782 CBK 230 KV;#50784 NLY 230 KV;#50783 SEL 230 KV; #50822 NLYPHS;#40145 BOUNDARY 230 KV;#50788 KCL 230 KV;#50792 SEL 500 KV;#50791 CBK 500 KV;#50693 VNT 230 KV;#50690 ACK 230 KV;#50702 ACK 500 KV;#50703 NIC 500 KV;#51134 VAS 500 KV

The output from the ACCC contingency analysis is given in Appendix-B. The significant results of the ACCC analysis are given below:

4.1 2012 Winter Peak

- The outage of line 40L (VAS-BEN) or BEN T1 results in a voltage collapse in the Oliver and Boundary areas. The voltage collapse can be avoided by transferring line 43L load to BC Hydro by closing the PRI tap and opening the connection between BEN and KER.
- In case of the outage of LEE T3 or T4 the flow on the remaining transformer is 102% of its 227 MVA emergency rating. The loading on the remaining transformer can be lowered by adjusting the normal open points in the Kelowna 138 kV system during the peak period. This results in more optimal distribution of load between LEE and DGB transformers.
- Outage of line 73L (LEE-DGB-RGA) results in voltages close to 0.90 p.u. in Kelowna.
- In case of the outage of line 5L94 (SEL-CBK) the flow on line 2L294 (NLY-AAL-CBK) is 104% of the emergency rating of 537 MVA. Also, the voltage at the ALL 230 kV bus is less than 0.90 p.u. Existing RAS schemes shed generation to reduce the flow after the contingency.

4.2 2012 Summer Peak

- In case of the outage of line 52L or 53L the flow on the remaining line is 92% of its 73.6 MVA emergency rating.
- The outage of line 40L (VAS-BEN) or BEN T1 results in a voltage collapse in the Oliver and Boundary areas. The voltage collapse can be avoided by transferring line 43L load to BC Hydro by closing the PRI tap and opening the connection between BEN and KER.
- In case of the outage of LEE T3 or T4 the flow on the remaining transformer is 92% of its 210 MVA emergency rating. The loading on the remaining transformer can be lowered by adjusting the normal open points in the

Kelowna 138 kV system during the peak period. This results in more optimal distribution of load between LEE and DGB transformers.

4.3 2012 Light Load

- In case of the outage of 2L295 or 2L299 (KCL-SEL) the flow on the remaining circuit is 112% of its emergency rating of 397.2 MVA while the flow on line 82L (BTS-SEL) is 93% of its emergency rating of 527.8 MVA. There are existing RAS schemes that initiate generation shedding which reduces the flow on the remaining circuits.
- In case of the outage of line 82L (BTS-SEL) the flow on lines 2L295 & 2L299 is 111% of their emergency rating of 397.2 MVA. There are existing RAS schemes that initiate generation shedding which reduces the flow on the remaining circuits.
- The outage of line 40L (VAS-BEN) or BEN T1 results in voltages higher than 1.10 p.u. in the Oliver and Boundary areas. After the contingency these voltage can be lowered by adjusting the taps of ASM T1 and T2.

4.3 2016 Winter Peak

- In case of the outage of ASM T1 or T2 the flow on the remaining transformer is 91% of its 108 MVA emergency rating.
- In case of the outage of line 50L (SEX – GLE) the flow on line 51L (DGB-BVN) is 97% of its 213.4 MVA emergency rating. Reconfiguring the Kelowna 138 kV network after the outage and transferring the load onto 55L by closing the HOL-SPR Tap connection and opening 60L between SPR Tap and OKM reduces the loading on line 51L (DGB-OKM) to 32% of the emergency rating.
- In case of the outage of line 50L (LEE-SEX-ELL) the flow on line 51L (DGB-BVN) is 116% of its emergency rating of 213.4 MVA. Also, the flow on line 60L (BVN-OKM) is 104% of its 213.4 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL-SPR Tap connection and opening 60L between SPR Tap and OKM.
- Outage of line 73L (LEE-DGB-RGA) results in voltages less than 0.90 p.u. in Kelowna.

4.4 2016 Summer Peak

- In case of the outage of 2L295 or 2L299 (KCL-SEL) the flow on the remaining circuit is 100% of its emergency rating of 397.2 MVA. There are existing RAS schemes that initiate generation shedding which reduces the flow on the remaining circuit.
- In case of the outage of line 82L (BTS-SEL) the flow on lines 2L295 & 2L299 is 96% of their emergency rating of 397.2 MVA. There are existing RAS schemes that initiate generation shedding which reduces the flow on the remaining circuits.

- In case of the outage of line 50L (LEE-SEX) the flow on line 51L (DGB-BVN) is 94% of its emergency rating of 161.3 MVA. Closing the HOL-SPR Tap connection and opening 60L between SPR Tap and OKM after the outage reduces the flow on 51L (DGB-BVN) to 36% of the emergency rating.
- In case of the outage of line 50L (SEX- GLE) the flow on line 51L (DGB-BVN) is 110% and the flow on line 60L (BVN-OKM) is 97% of the 161.3 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.
- In case of the outage of line 50L (LEE-SEX-ELL) the flow on line 51L (DGB-BVN) is 130% of its emergency rating of 161.3 MVA. Also, the flow on line 60L (BVN-OKM) is 116% of its 161.3 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.

4.5 2020 Winter Peak

- In case of the outage of line 50L (SEX - GLE) the flow on line 51L (DGB-BVN) is 103% and the flow on line 60L (BVN-OKM) is 91% of the 213.4 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.
- In case of the outage of line 50L (LEE-SEX-ELL) the flow on line 51L (DGB-BVN) is 122% of its emergency rating of 213.4 MVA. Also, the flow on line 60L (BVN-OKM) is 109% of its 213.4 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.

4.6 2020 Summer Peak

- In case of the outage of 2L295 or 2L299 (KCL-SEL) the flow on the remaining circuit is 97% of its emergency rating of 397.2 MVA. There are existing RAS schemes that initiate generation shedding which reduces the flow on the remaining circuit.
- In case of the outage of line 82L (BTS-SEL) the flow on lines 2L295 & 2L299 is 93% of their emergency rating of 397.2 MVA. There are existing RAS schemes that initiate generation shedding which reduces the flow on the remaining circuits.
- In case of the outage of line 50L (LEE-SEX) the flow on line 51L (DGB-BVN) is 102% of its emergency rating of 161.3 MVA. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring

some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.

- In case of the outage of line 50L (SEX- GLE) the flow on line 51L (DGB-BVN) is 118% and the flow on line 60L (BVN-OKM) is 103% of the 161.3 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.
- In case of the outage of line 50L (LEE-SEX-ELL) the flow on line 51L (DGB-BVN) is 139% of its emergency rating of 161.3 MVA. Also, the flow on line 60L (BVN-OKM) is 124% of its 161.3 MVA emergency rating. This overloading can be avoided by opening the Kelowna loop during peak periods and transferring some of the load on to line 55L. This can be accomplished by closing the HOL- SPR Tap connection and opening 60L between SPR Tap and OKM.
- In case of the outage of 51L (DGB-BVN) the flow on 50L (LEE-SEX) is 96% of its emergency rating of 244.2 MVA. This flow reduces to 60% of emergency rating if after the outage load is transferred to line 55L by closing the HOL-SPR Tap connection and opening 50L between REC-SAU.

5. Ongoing and Planned System Reinforcements

The system performance violations during contingency conditions indentified above are being addressed by the following projects:

5.1 Ellison to Sexsmith 138 kV Transmission Tie (TPL-002-0 R2.)

The Duck Lake and Ellison are supplied radially from LEE Terminal via line 46L. These substations supply important customers like UBC Okanagan, Kelowna International Airport and the BC Hydro customers in the Winfield area. A fault on the line results in an outage of both substations and with only a single transmission line into the area it is not possible to restore supply until the line is repaired. The Ellison to Sexsmith tie will improve the reliability of supply to the area. This project is included in the 2011-15 Capital Plan with a completion date of December 2012.

5.2 Line 42L Meshed Operation between HUT & OLI (TPL-002-0 R2.)

In 2012 there is a voltage collapse in the Oliver and Boundary areas (refer to sections 4.1 & 4.2) due to the outage of either line 40L or BEN T1. It can be prevented by operating the existing 63 kV transmission line 42L closed between HUT and OLI. The other option available is to close the PRI Tap and open line 43L between BEN and KER during the winter and summer peak periods to transfer the line 43L load to NIC (BC Hydro).

A project to provide the necessary protection and communication infra structure to operate line 42L closed between HUT and OLI is included in the 2011-15 Capital Plan with a completion date of December 2014.

5.3 Kelowna 138 kV Outer Loop (TPL-002-0 R2.)

Presently the Kelowna 138 kV transmission system is operated with normal open points. In case of an outage there is a momentary interruption while the load is restored by switching it to an alternate source/line. This project will provide the necessary communication and protection to operate line 50L and 51L meshed between LEE and DGB. It is included in the 2011-15 Capital Plan with a completion date of December 2014.

5.4 LEE Third 230/138 kV Transformer (TPL-002-0 R2.)

The third 230/138 kV, 168 MVA transformer at LEE will provide additional transformation capacity in Kelowna during single contingency conditions (refer to sections 4.1 & 4.2). This project is included in the 2011-15 Capital Plan with a completion date of December 2015.

The transfer of the BC Hydro Winfield area load to Duck Lake substation in 2011/12 winter will have an impact on the LEE transformer loading. Although in a contingency the loading on the remaining LEE transformer is above its emergency rating in 2012 the transformation capacity addition is not scheduled until 2015. This is to take advantage of the proposed CGT addition in Kelowna in case the Resource Plan is approved. In case it is not approved the risk will be managed by better distribution of load between LEE and DGB by adjusting the normal open points in the Kelowna transmission system.

5.5 Re-conductoring of Lines 52L & 53L (TPL-002-0 R2.)

Re-conductoring of 63 kV transmission lines 52L & 53L to higher ampacity conductor (1272 kcmil ASC) will provide adequate capacity during single contingency outages. (refer to section 4.2). This project is included in the 2011-15 Capital Plan with a completion date of December 2016.

5.6 Additional Reactive Compensation at BEN (TPL-002-0 R2.)

The meshed operation of line 42L between HUT and OLI in 2014 increases the supply capability of line 11L/48L in a contingency (the outage of line 40L or BEN T1) to approximately 150 MW. There is no need to close the PRI Tap and supply line 43L load from the BC Hydro system. However, based on the latest load forecast the combined load of Oliver, Boundary and Similkameen exceeds this limit in 2015/16. Additional reactive compensation is required to prevent a voltage collapse in a contingency. Installation of 2x10 MVAR at BEN 63 kV increases the supply capability to approximately 165 MW. The combined Oliver, Boundary and Smilikameen winter peak load will not exceed this limit until 2030 while the summer peak load remains below the limit over the current forecast horizon. In addition, the flexibility to transfer the line 43L load to NIC (BC Hydro) during peak periods by closing the PRI Tap and opening line 43L between BEN and KER, is also always available.

A project to install reactive compensation (2x10 MVAR) at BEN 63 kV is included in the 2011-15 Capital Plan with a completion date of December 2016.

5.7 SVC (+150/-50 MVAR) at DGB (TPL-002-0 R2.)

During 2016 winter peak in case of the outage of line 73L (LEE-DGB-RGA) the voltages in Kelowna are close to or less than 0.90 p.u. (the minimum acceptable limit in a contingency), refer to section 4.3 . In the future year's further increase in Kelowna load results in a voltage collapse in case of this outage.

A project to install a 230 kV ring at DGB along with a +150/-50 MVAR SVC is included in the 20 year capital plan with a completion date of December 2018.

6. Contingency Analysis (Loss of Two or More BES Elements (TPL-003-0 & TPL-004-0)

As mandated by BCUC the FortisBC transmission system is only planned/reinforced for single contingencies (type B, single element out). Type C (two or more elements out) and type D (extreme contingencies) are studied and RAS schemes (both FortisBC & BCTC) are in place for these contingencies. Depending on the prevailing operating conditions load is armed for shedding and generation armed for tripping to keep the power flows within the equipment ratings. Also, for 500 kV contingencies in the BC Hydro system some low voltage (230 kV & 161 kV) FortisBC transmission lines are opened to restrict flow in the under lying system.

7. Dynamic Analysis (TPL-002-0, TPL-003-0 & TPL-004-0)

Transient stability simulations were carried out only for the 2010 winter peak and summer peak conditions. The following faults were simulated:

1. Three phase fault near the BTS 230 kV bus cleared in 6 cycles by tripping line 82L **(fault type B)**.
2. Three phase fault near the LEE 230 kV bus cleared in 6 cycles by tripping line 73L **(fault type B)**.
3. Single line to ground fault near BTS with backup clearing in 18 cycles by tripping lines 79L and 82L **(fault type C)**. This simulates the tripping of a bus section of BTS 230 kV bus.
4. Single line to ground fault near WAN 63 kV backup clearing in 18 cycles by tripping the bus **(fault type C)**. This simulates the tripping of a WAN 63 kV bus

which results in the tripping WAN units 3 & 4 along with one WAN 230/63 kV transformer.

5. Three phase fault near the BTS 230 kV bus with backup clearing in 18 cycles by tripping the BTS 230 kV bus **(fault type D)**.

For all the faults (listed above) simulated the system was stable during winter peak, summer peak and light load conditions. The plots for relative rotor angle, power flow, voltage and frequency are given in Figures 22 through 36 in Appendix-C.

8. Reactive Power Margin Assessment (VAR-001-1 R2 & R9)

All FortisBC generation resources are located in the Kootenay area while a major portion of the load is in the Okanagan. The Kootenay area usually has surplus generation while the Okanagan region is deficient. To supply the load in the Okanagan the surplus generation from Kootenay is wheeled over the BC Hydro system in addition to the power purchased from BC Hydro. The lack of dynamic reactive resources in Okanagan results in very low voltages especially during contingency conditions.

Figures 37 through 39 in Appendix-D give the V-Q curves for some critical contingencies in the Okanagan for 2012, 2016 and 2020 winter peak. The curves are for the LEE 230 kV bus (#52316) and clearly show the decrease in reactive reserve from 2012 to 2016 and no reactive margin in 2020 for the most critical contingency; outage of line 73L.

Figure 40 gives the V-Q curve for year 2020 winter peak with the 150 MVAR SVC in service at the DGB 138 kV bus. This curve shows that after the installation of the proposed SVC at DGB adequate reactive resources are available in the Okangan to support the voltage during normal and contingency conditions.

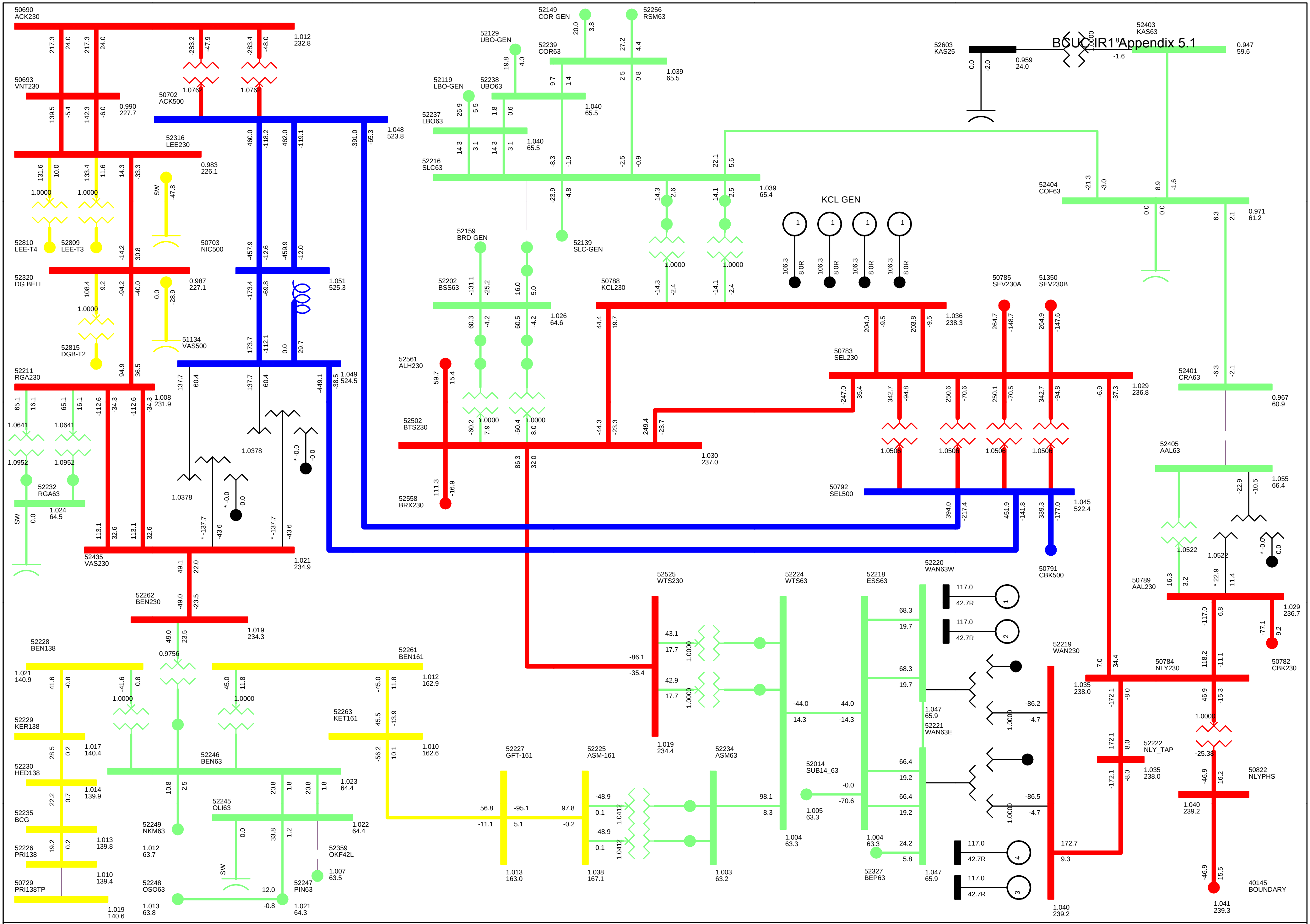
Note: All study files are located on G drive in the following folders:

G:\System Planning\Waseem\LF-work-30\Base Cases 2011
G:\System Planning\Waseem\Stability-ver30\2011 TS Analysis

APPENDIX-A

Load Flow Transcripts: Normal System

(TPL-001-0)

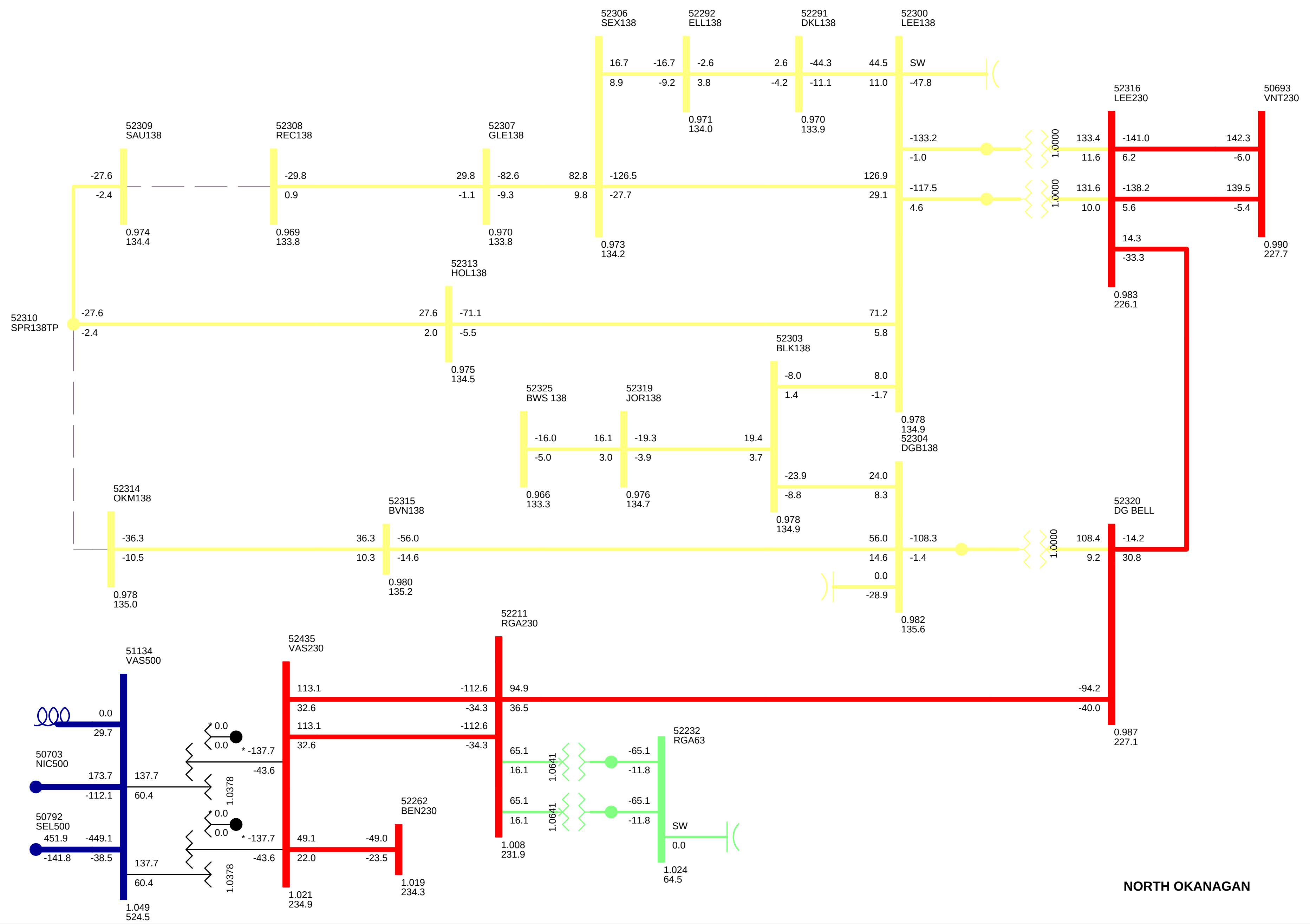


CREATED FROM 13HW1AP.SAV.FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
MON, DEC 06 2010 11:27

2012 WINTER PEAK

FIGURE-1

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



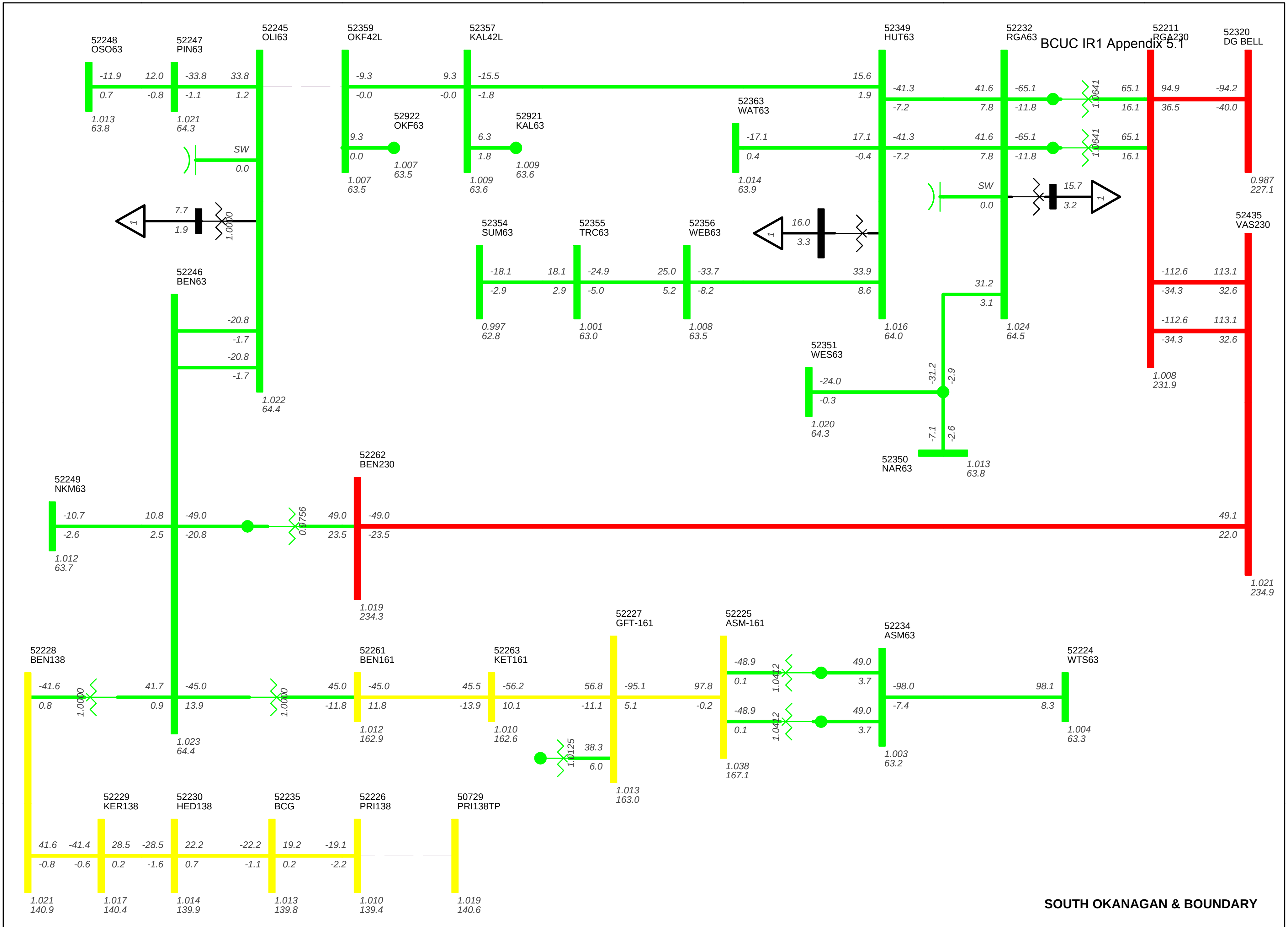
CREATED FROM 13HW1AP.SAV.FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
MON, DEC 06 2010 11:28

2012 WINTER PEAK

KELOWNA 336 MW, BCH DKL 35 MW

FIGURE-2

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



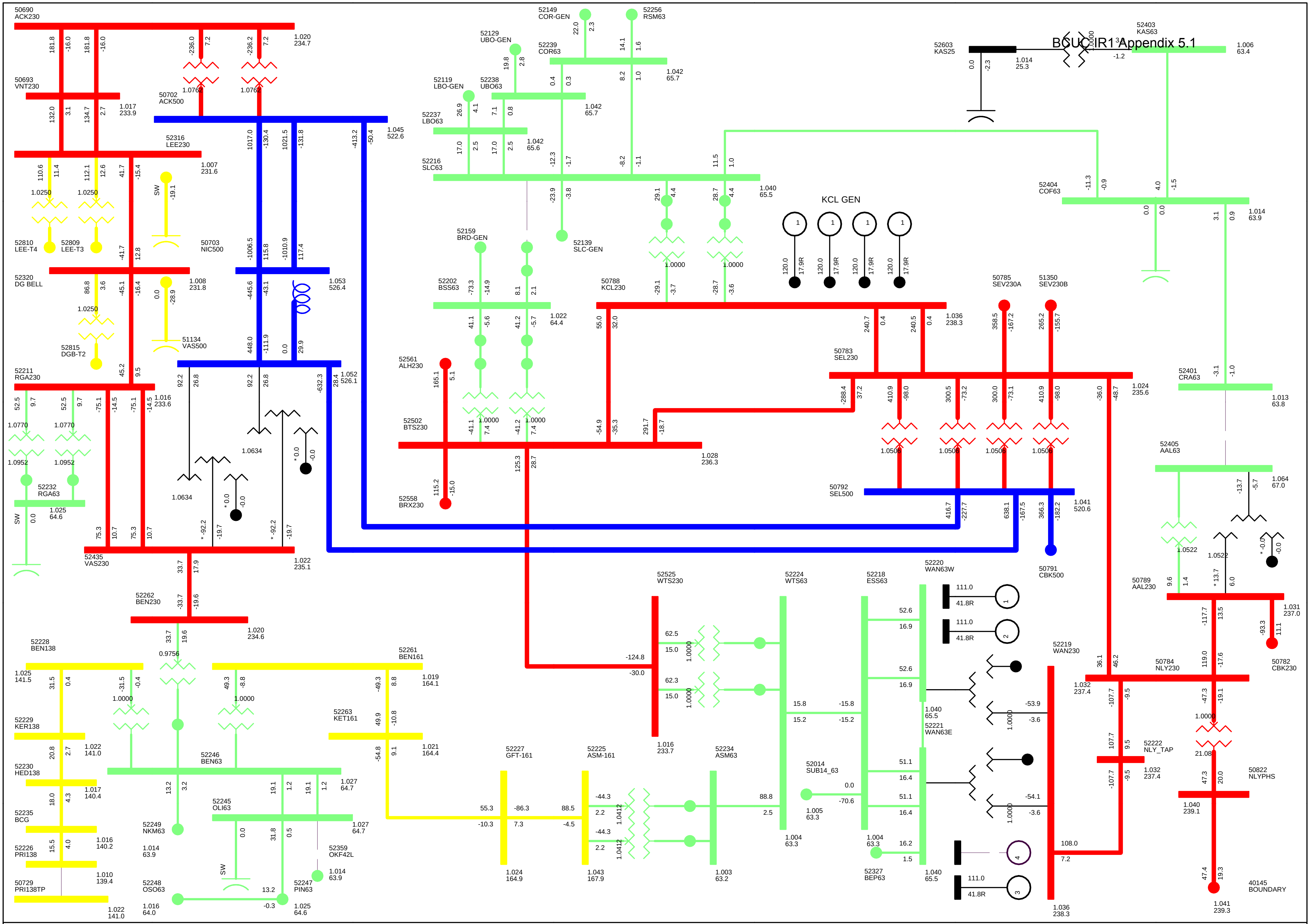
CREATED FROM 13HW1AP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
MON, DEC 06 2010 11:32

2012 WINTER PEAK

LOAD (MW): PENTICTON 129, OLIVER 93, BOU 49

FIGURE-3

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000



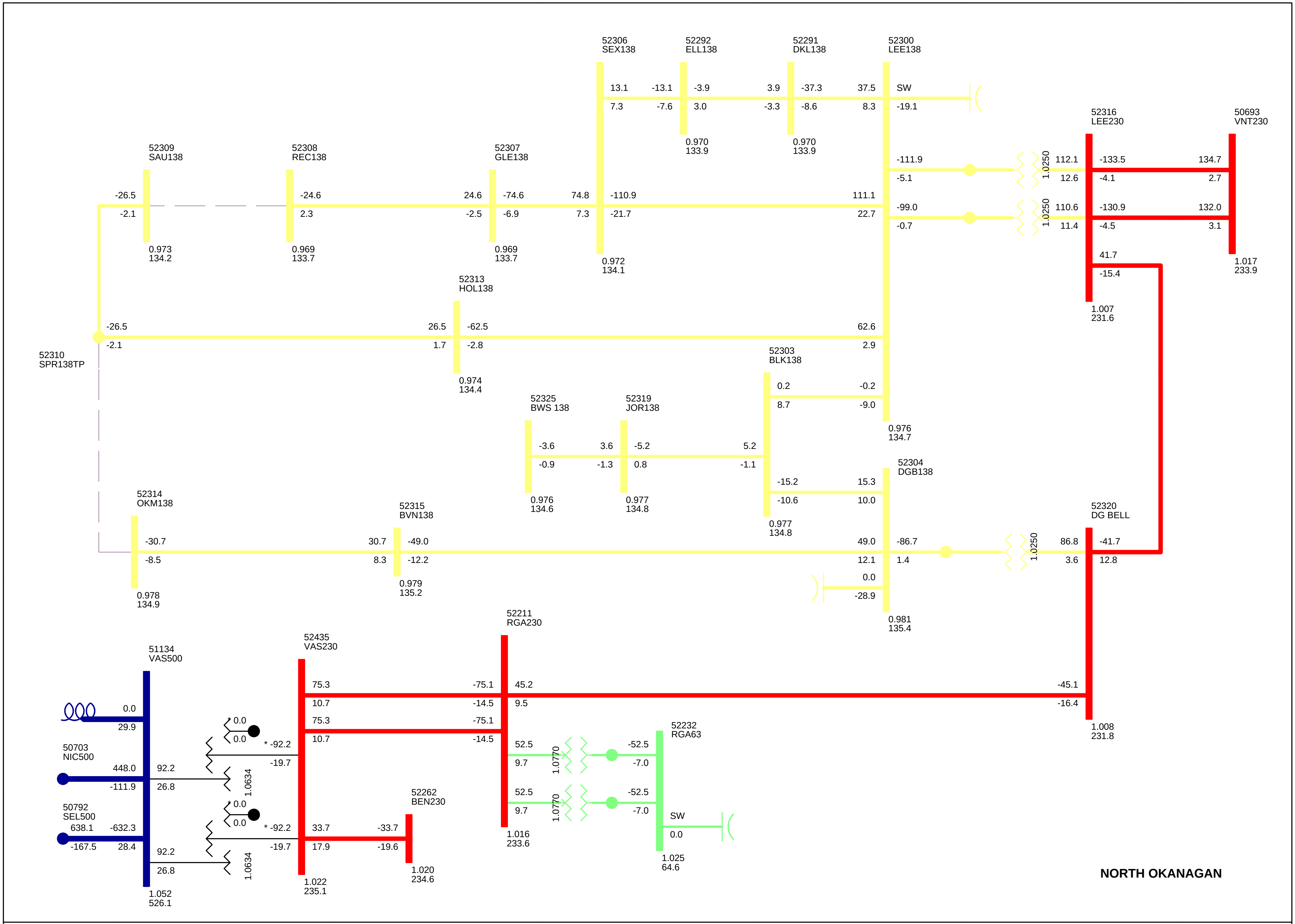
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
MON, DEC 06 2010 11:38

2012 SUMMERPEAK

FIGURE-4

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
MON, DEC 06 2010 11:41

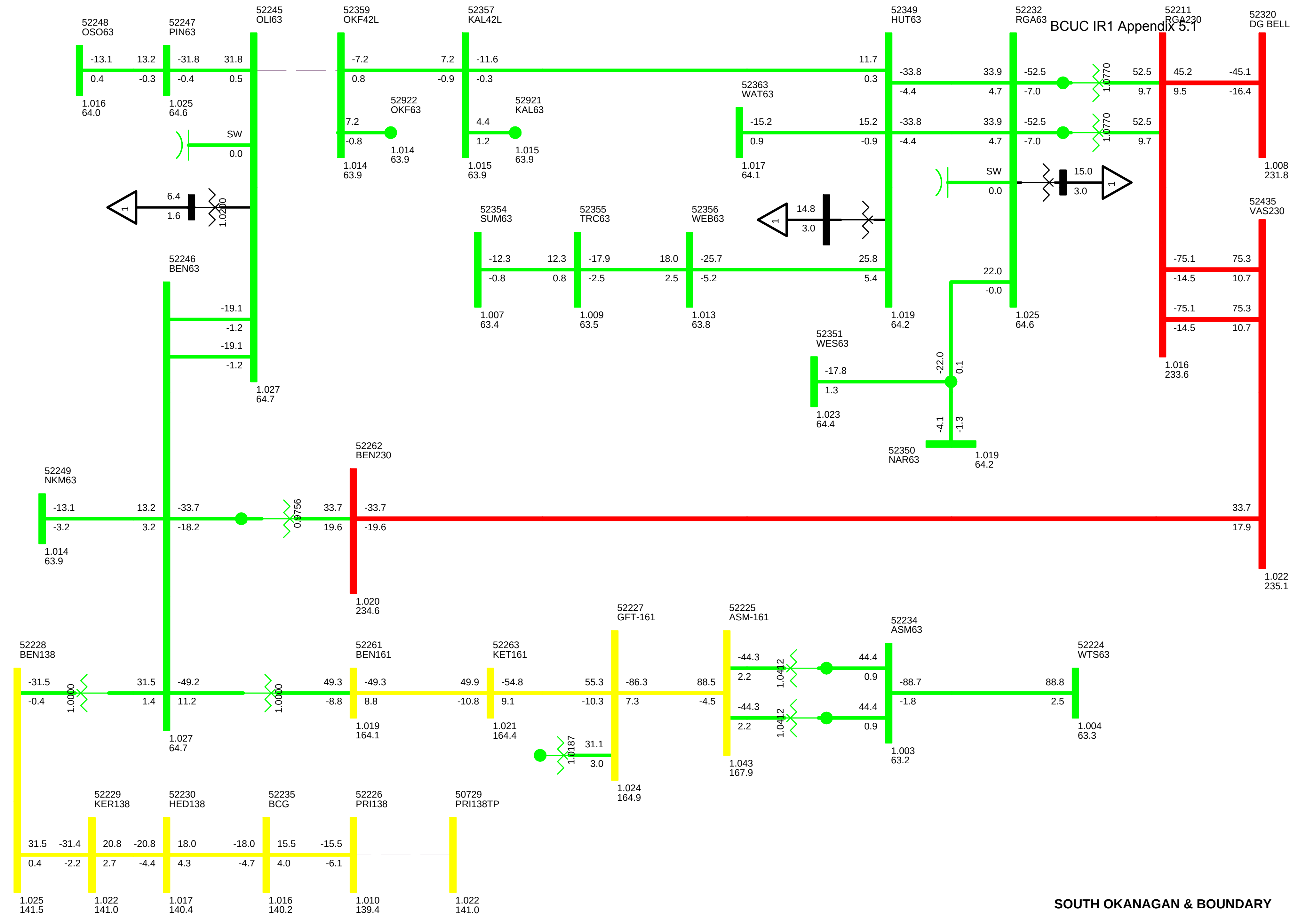
2012 SUMMER PEAK

KELOWNA 279 MW, BCH DKL 28 MW

FIGURE-5

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000

BCUC IR1 Appendix 5.1



SOUTH OKANAGAN & BOUNDARY

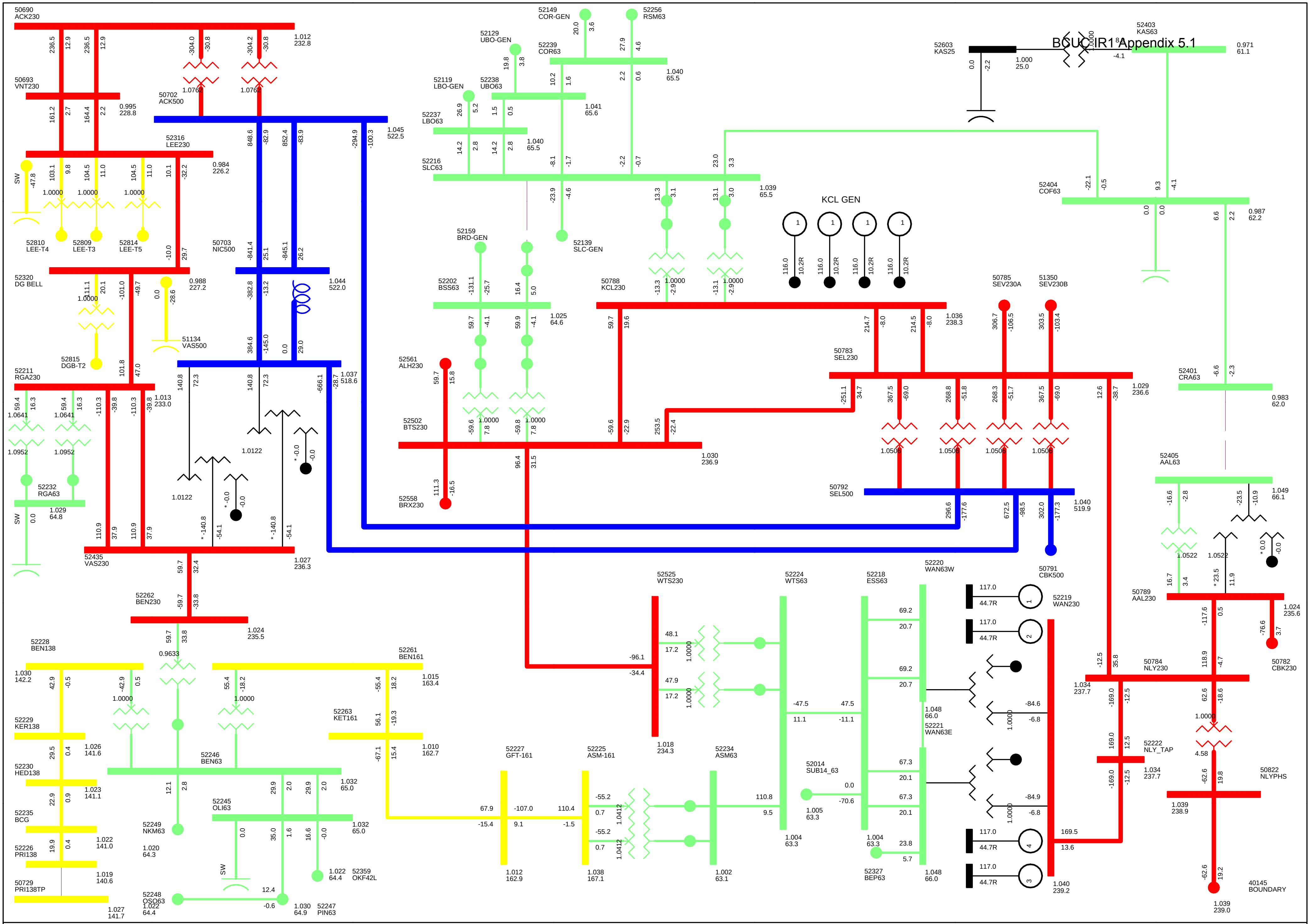
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
MON, DEC 06 2010 11:46

2012 SUMMER PEAK

LOAD (MW): PENTICTON 104, OLIVER 82, BOU 36

FIGURE-6

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000



CREATED FROM 16HW1SAP.SAV.FBC 951MW,TC 220MW
GEN 945MW,LOSSES 37MW,IMPORT 263MW
MON, DEC 06 2010 13:35

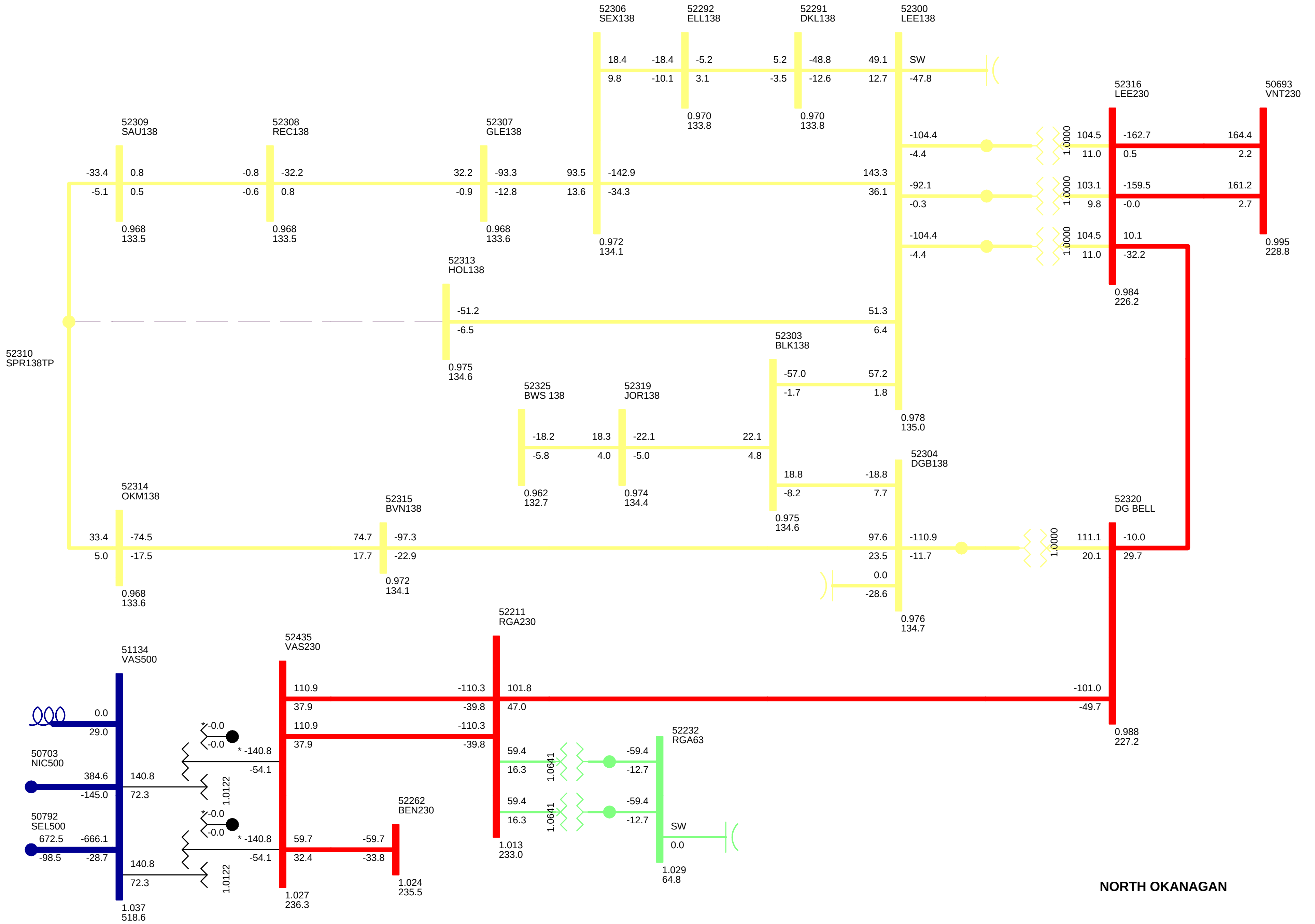
2016 WINTER PEAK

FIGURE-7

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

100.0%RATEA

KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



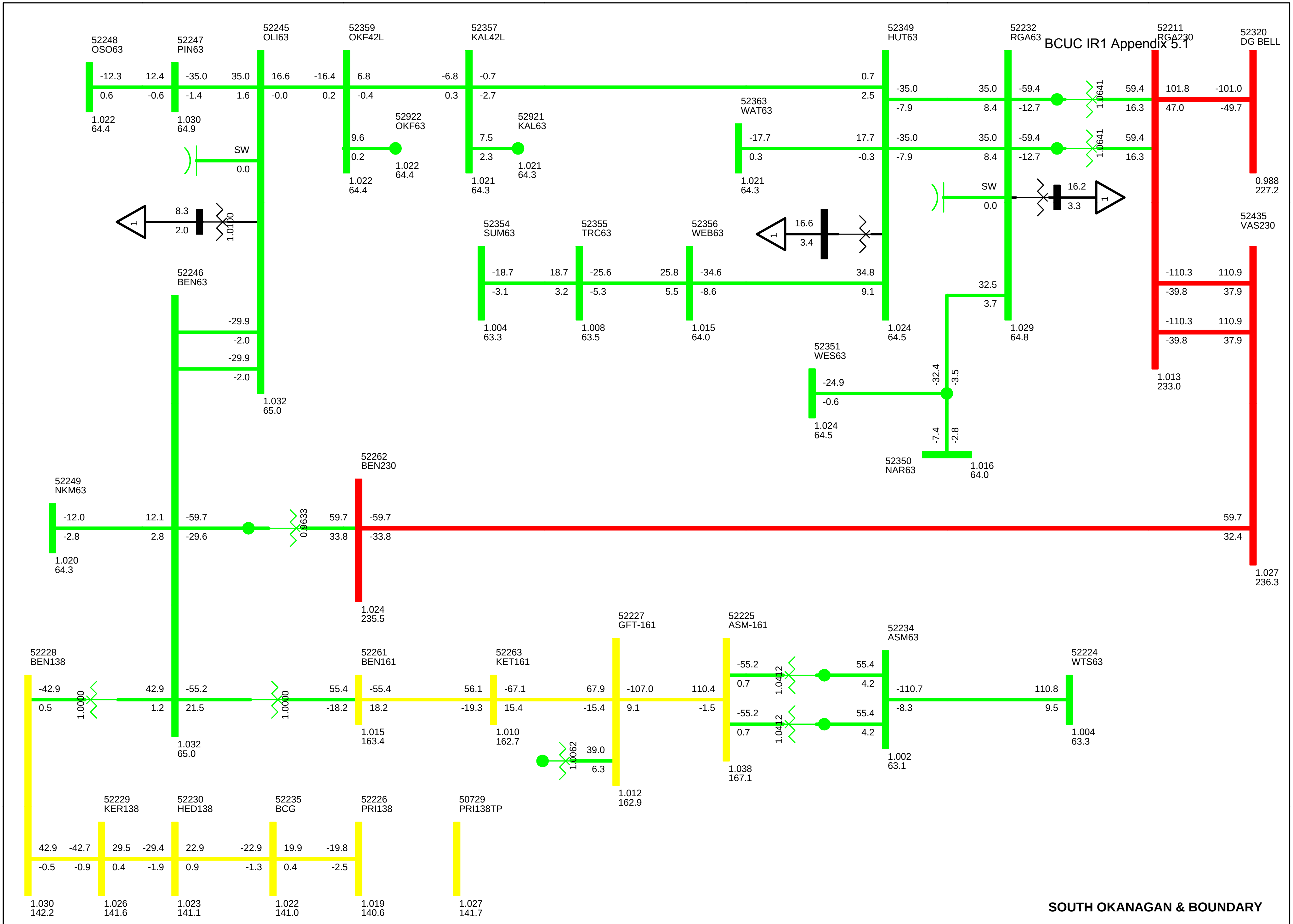
CREATED FROM 16HW1SAP.SAV.FBC 951MW,TC 220MW
GEN 945MW,LOSSES 37MW,IMPORT 263MW
MON, DEC 06 2010 13:37

2016 WINTER PEAK

KELOWNA 384 MW, BCH DKL 36 MW

FIGURE-8

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



CREATED FROM 16HW1SAP.SAV.FBC 951MW,TC 220MW
GEN 945MW,LOSSES 37MW,IMPORT 263MW
MON, DEC 06 2010 13:47

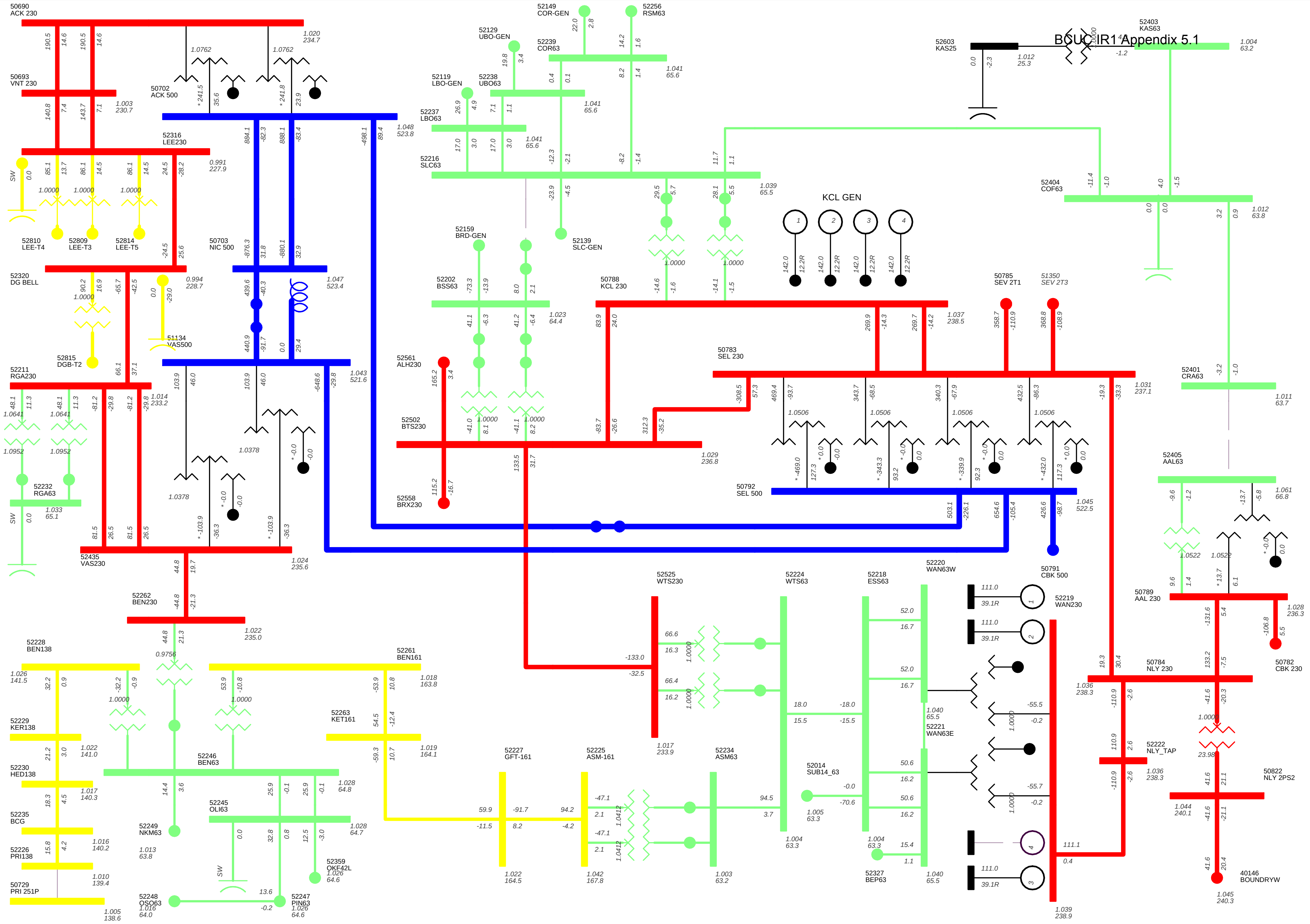
2016 WINTER PEAK

LOAD (MW): PENTICTON 134, OLIVER 98, BOU 50

FIGURE-9

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

100.0%RATEC
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000



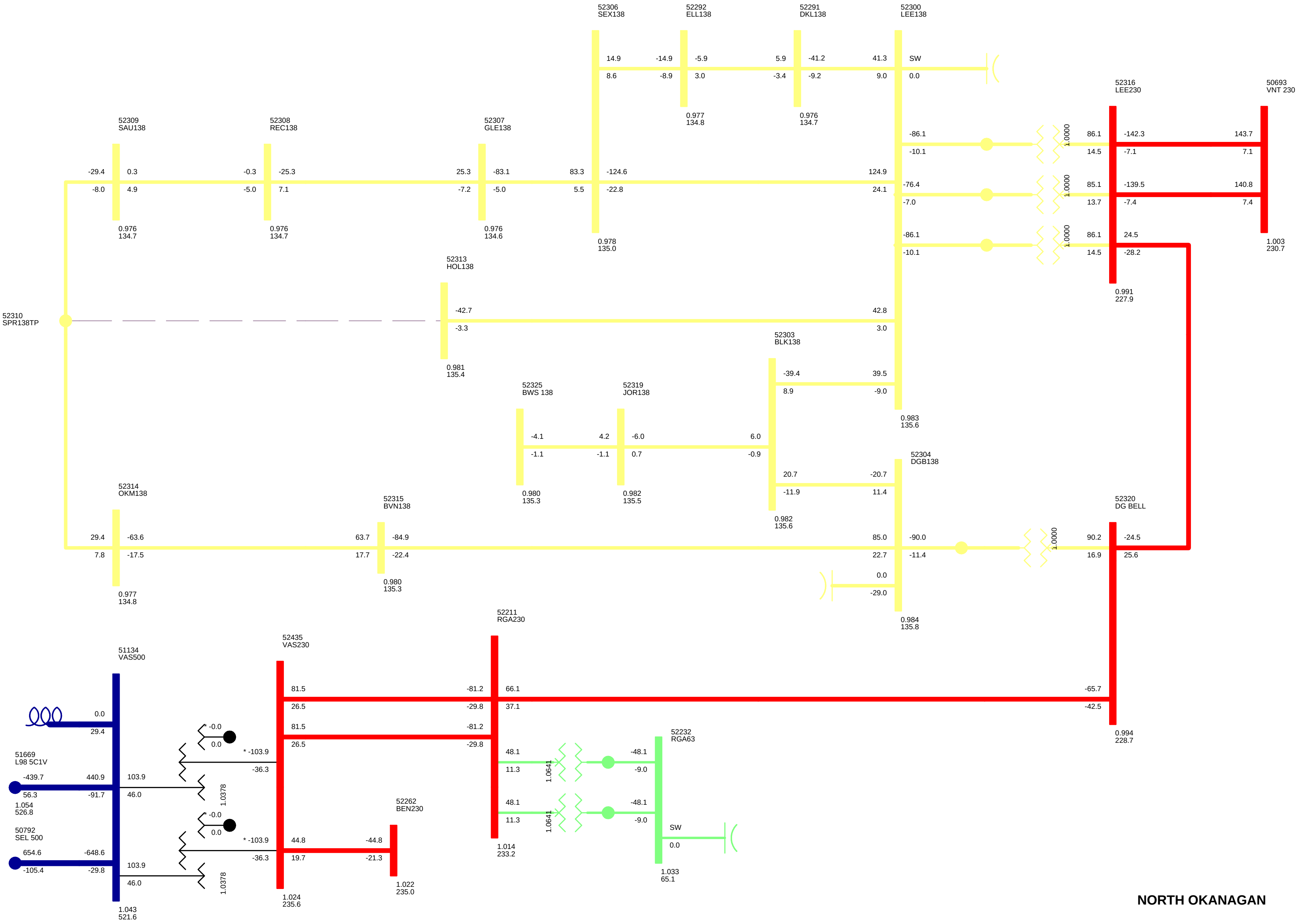
CREATED FROMM 16HS2AP.SAV.FBC740MW,TC 220MW
GEN 864MW,LOSSES 27MW,IMPORT 123MW
MON, DEC 06 2010 13:50

2016 SUMMER PEAK

FIGURE-10

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



NORTH OKANAGAN

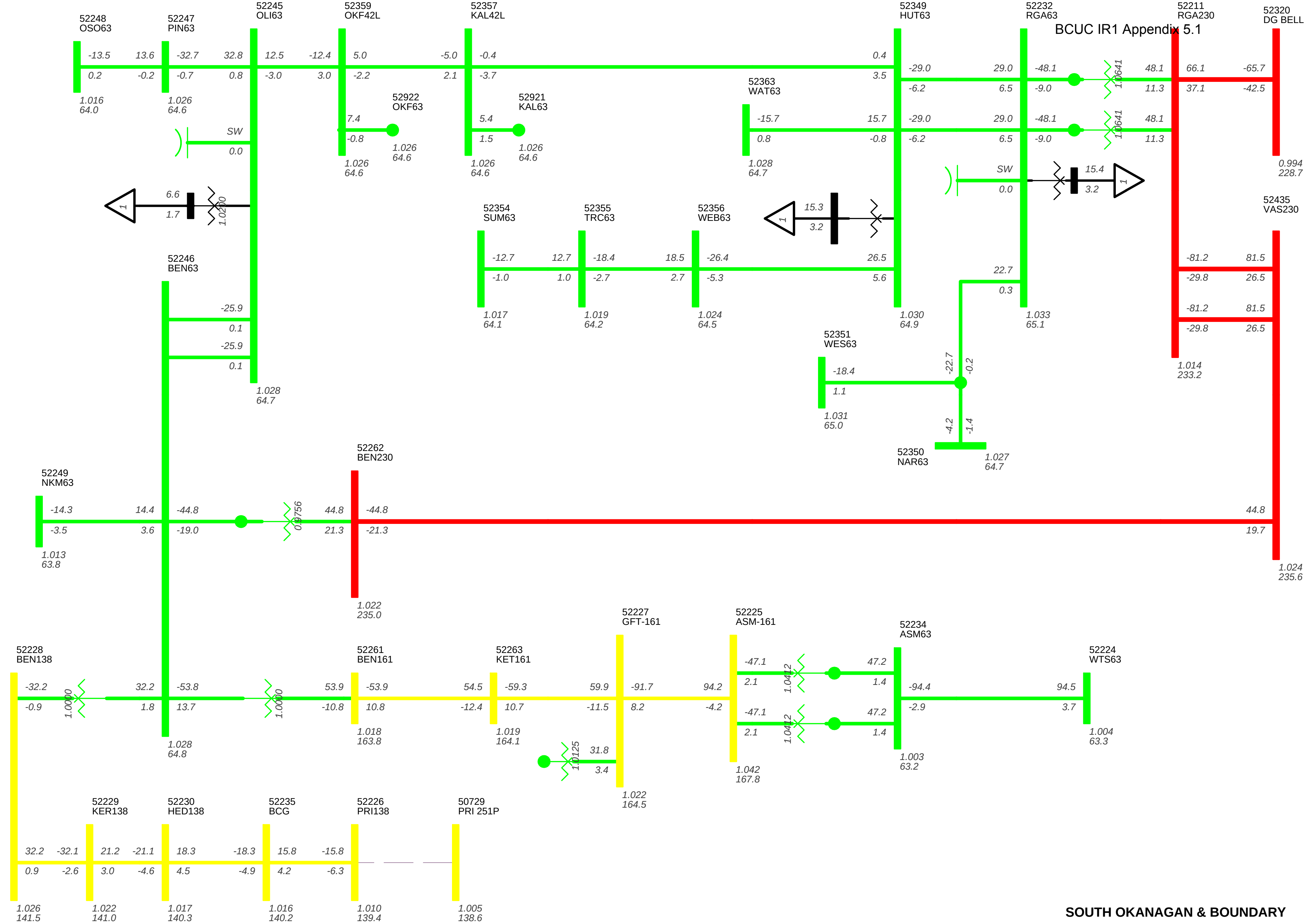
CREATED FROMM 16HS2AP.SAV.FBC740MW,TC 220MW
GEN 864MW,LOSSES 27MW,IMPORT 123MW
MON, DEC 06 2010 13:52

2016 SUMMER PEAK

KELOWNA 316 MW, BCH DKL 36 MW

FIGURE-11

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
90.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



SOUTH OKANAGAN & BOUNDARY

CREATED FROMM 16HS2AP.SAV.FBC740MW,TC 220MW
GEN 864MW,LOSSES 27MW,IMPORT 123MW
MON, DEC 06 2010 13:53

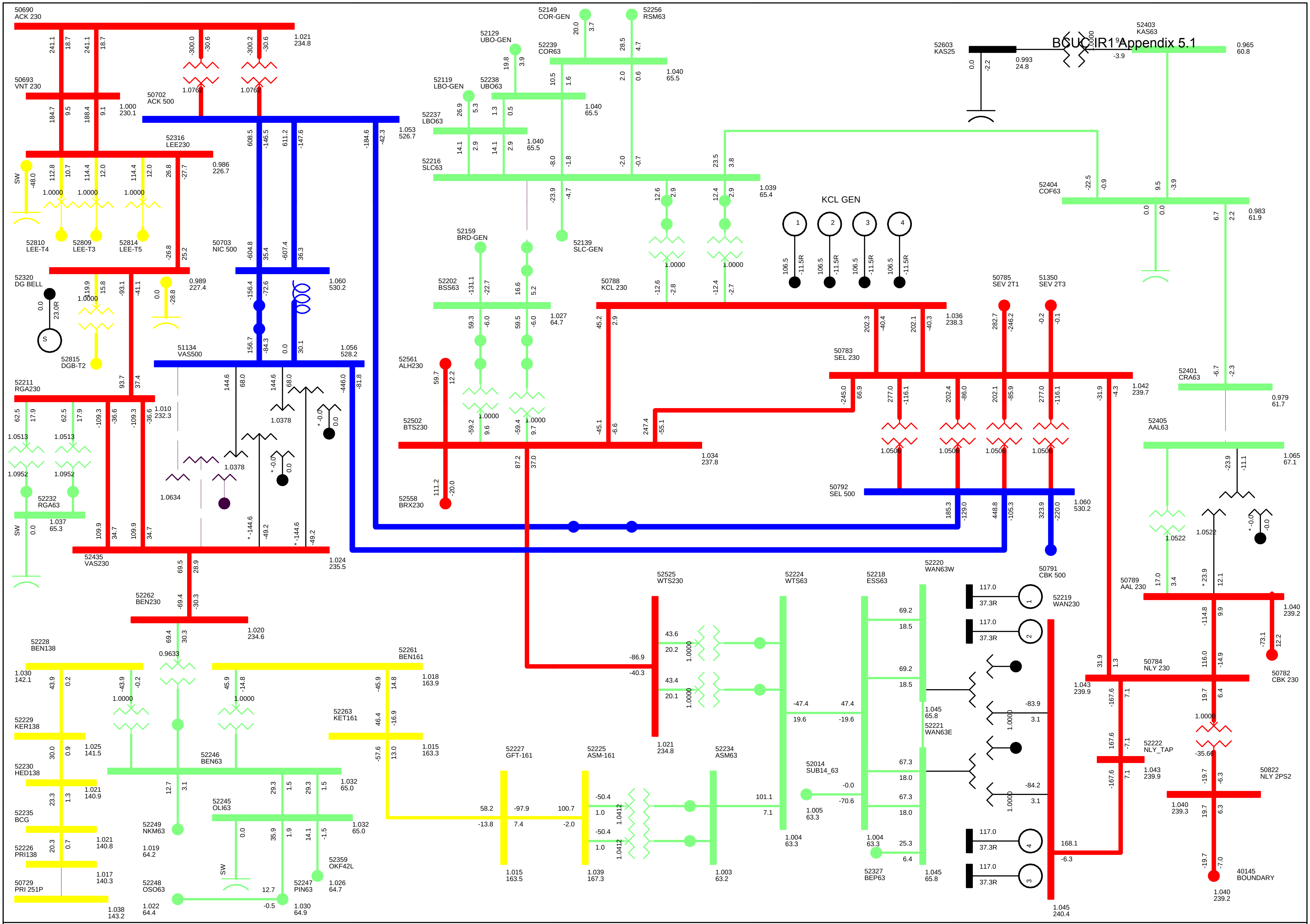
2016 SUMMER PEAK

LOAD (MW): PENTICTON 108, OLIVER 85, BOU 37

FIGURE-12

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000

Page 25



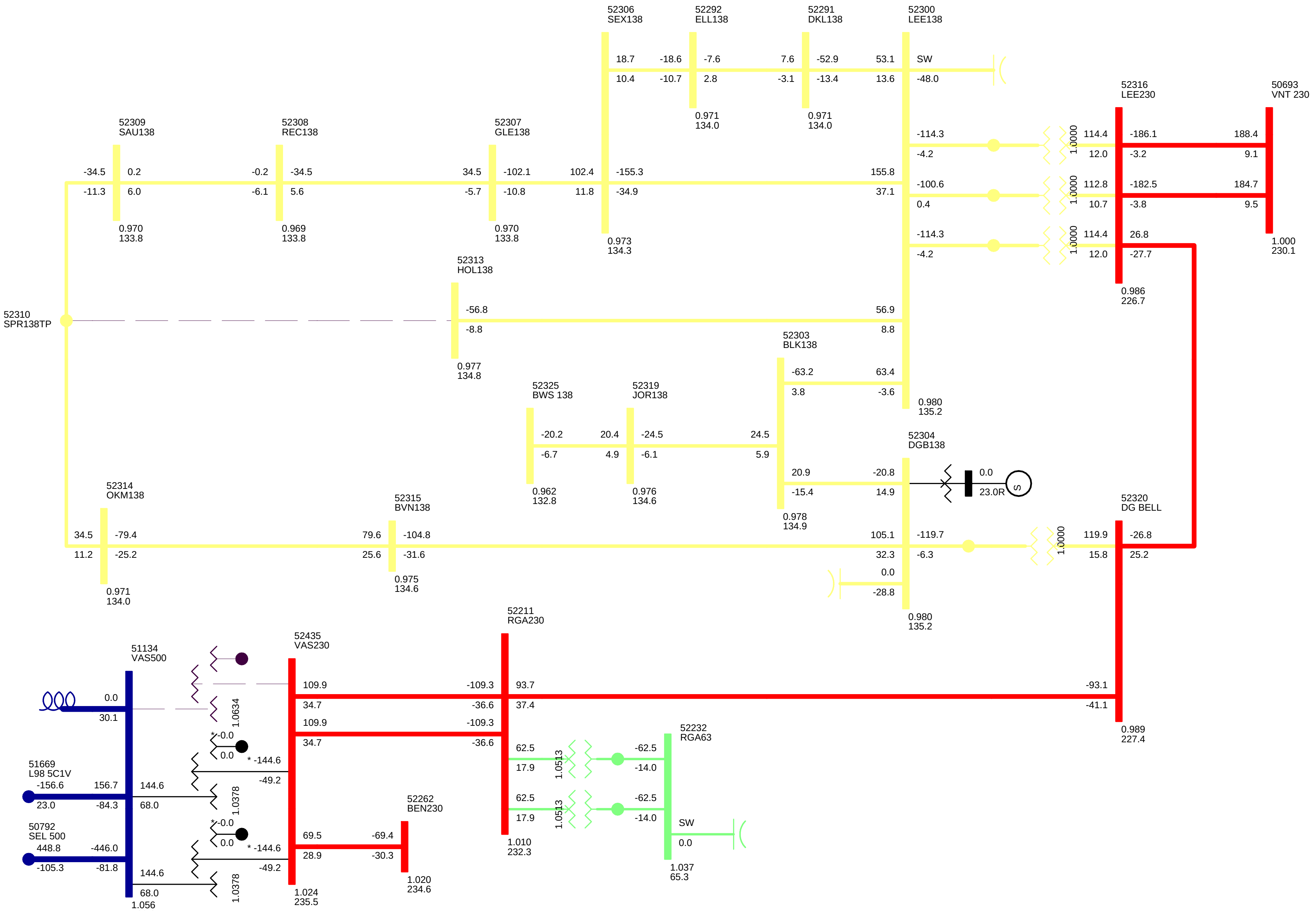
CREATED FROM 19HW1AP.SAV.FBC 1001MW,TC 220MW
GEN 945MW,LOSSES 36MW,IMPORT 311MW
MON, DEC 06 2010 13:57

2020 WINTER PEAK

FIGURE-13

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



NORTH OKANAGAN

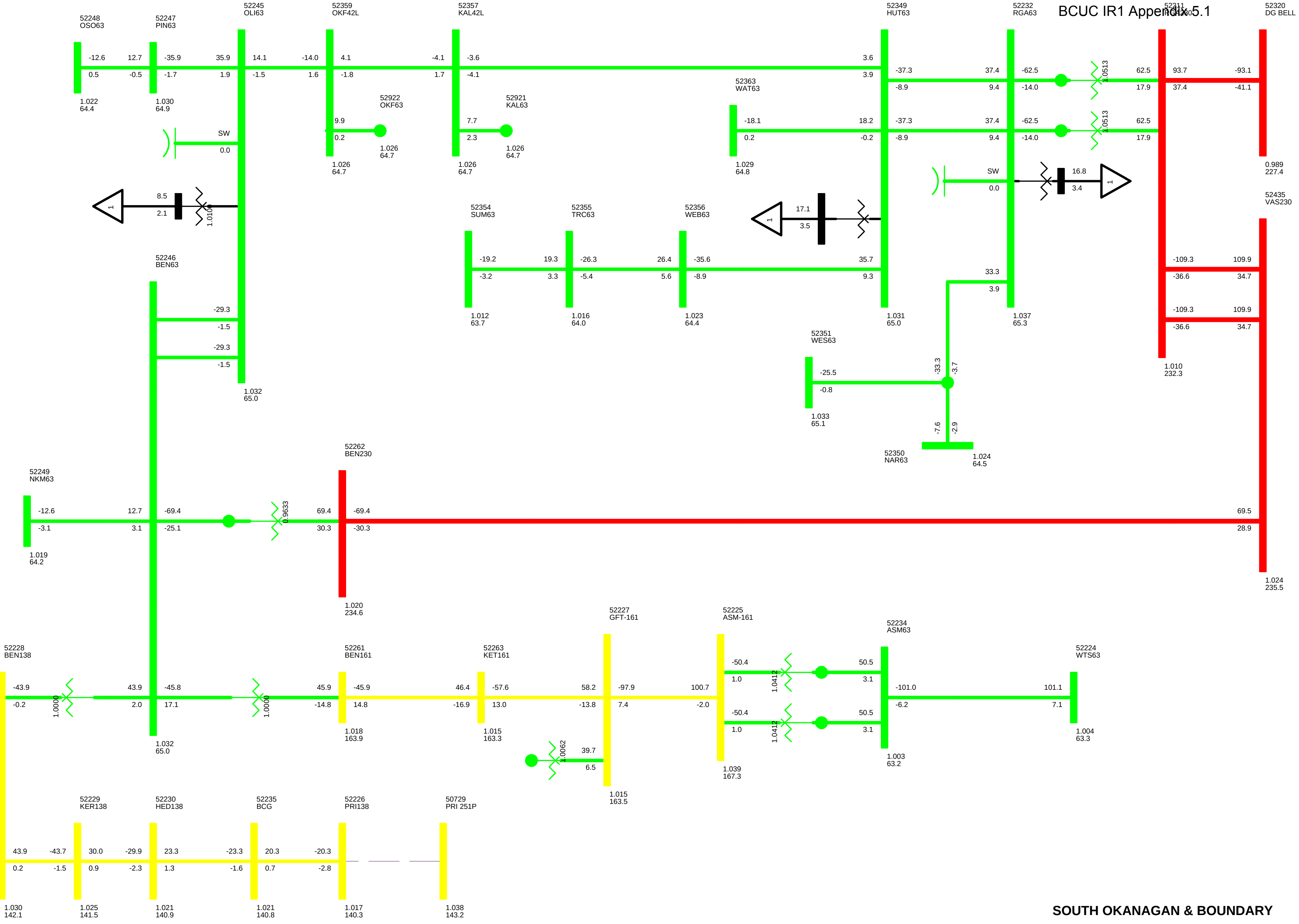
CREATED FROM 19HW1AP.SAV.FBC 1001MW,TC 220MW
GEN 945MW,LOSSES 36MW,IMPORT 311MW
MON, DEC 06 2010 13:59

2020 WINTER PEAK

KELOWNA 421 MW, BCH DKL 37 MW

FIGURE-14

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



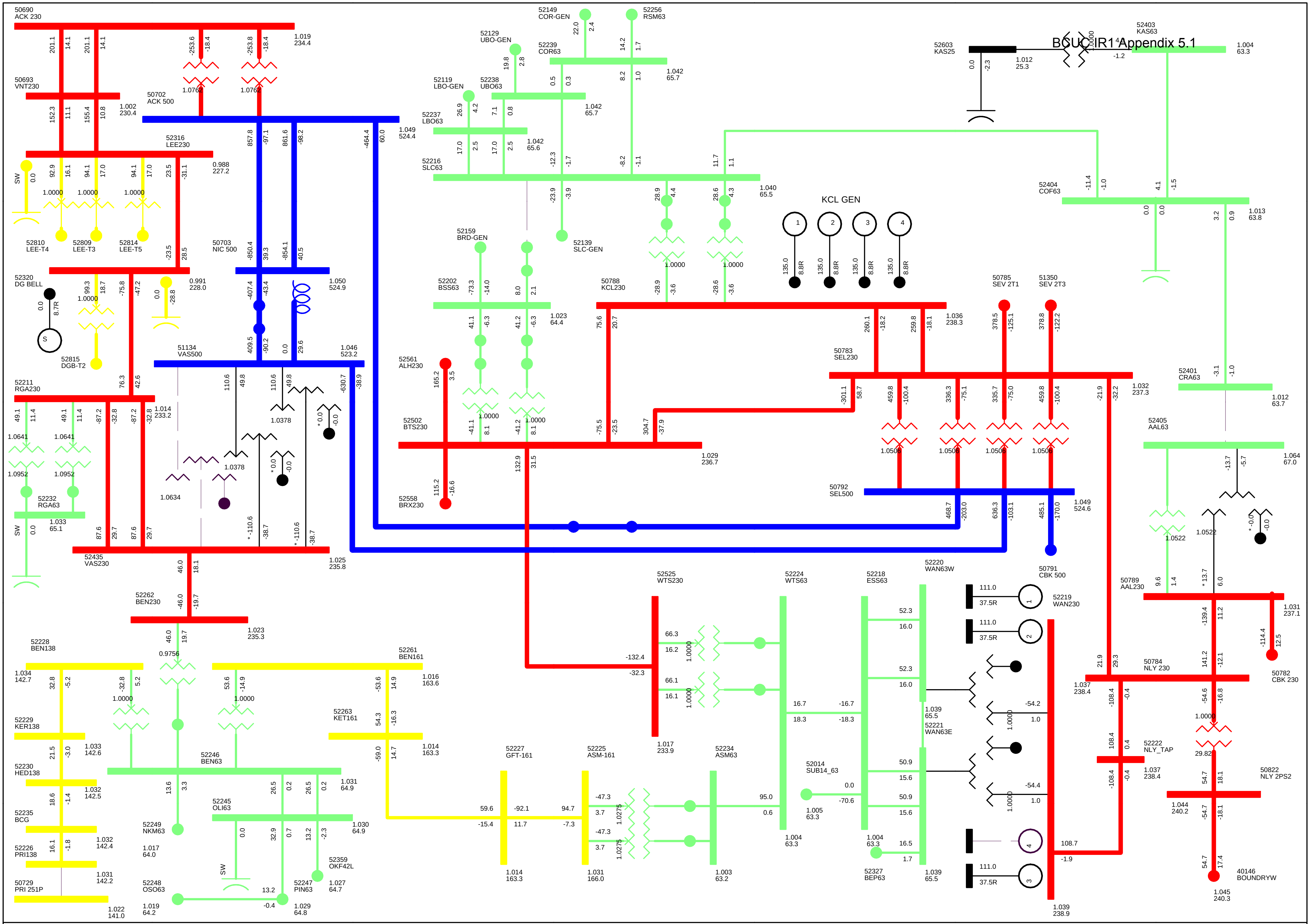
CREATED FROM 19HW1AP.SAV.FBC 1001MW,TC 220MW
GEN 945MW,LOSSES 36MW,IMPORT 311MW
MON, DEC 06 2010 14:01

2020 WINTER PEAK

LOAD (MW): PENTICTON 138, OLIVER 100, BOU 51

FIGURE-15

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000

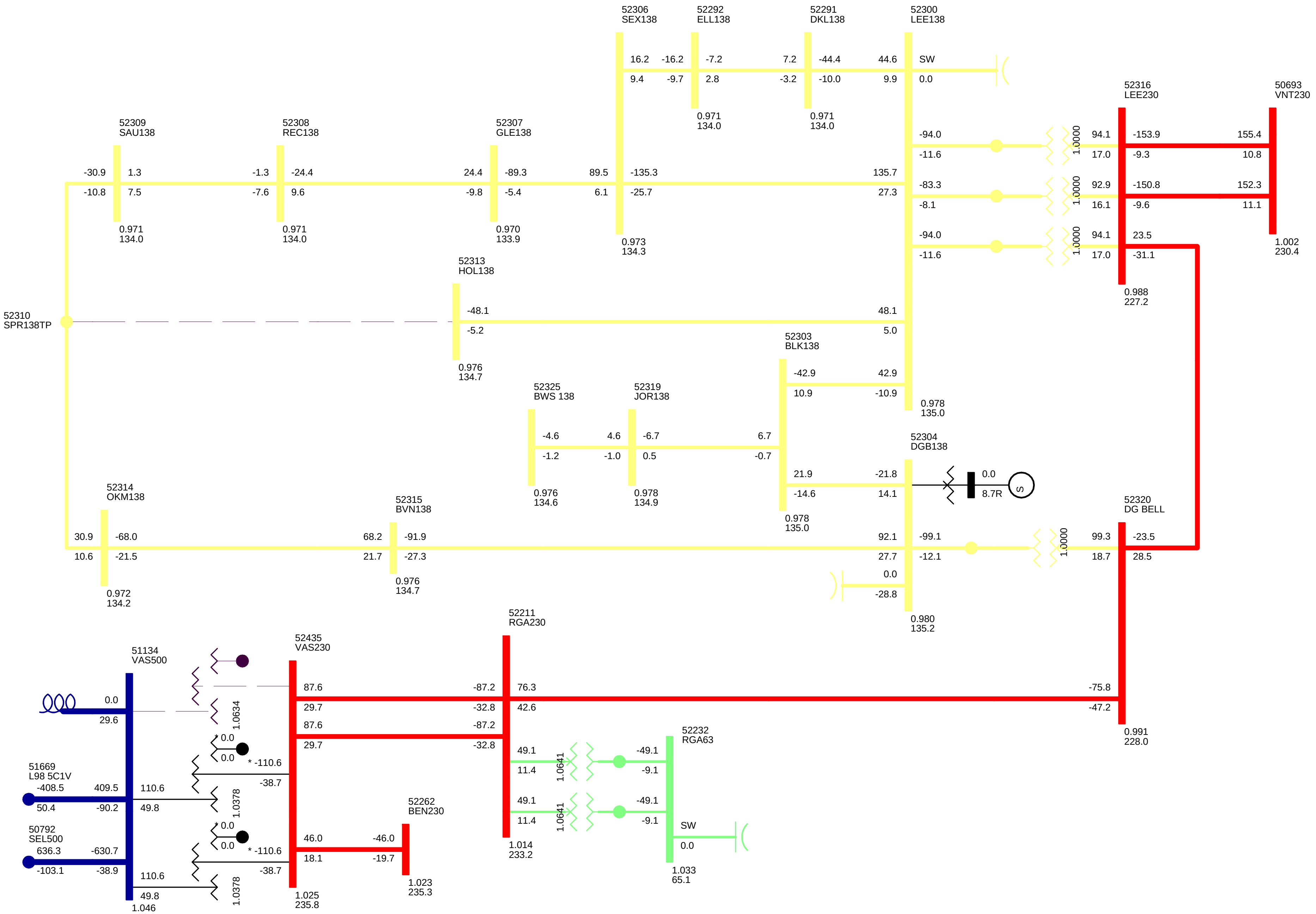


CREATED FROM 20HS1AP.SAV.FBC 778MW,TC 220MW
GEN 864MW,LOSSES 28MW,IMPORT 162MW
MON, DEC 06 2010 14:35

2020 SUMMER PEAK

FIGURE-16

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



NORTH OKANAGAN

CREATED FROM 20HS1AP.SAV.FBC 778MW,TC 220MW
GEN 864MW,LOSSES 28MW,IMPORT 162MW
MON, DEC 06 2010 14:37

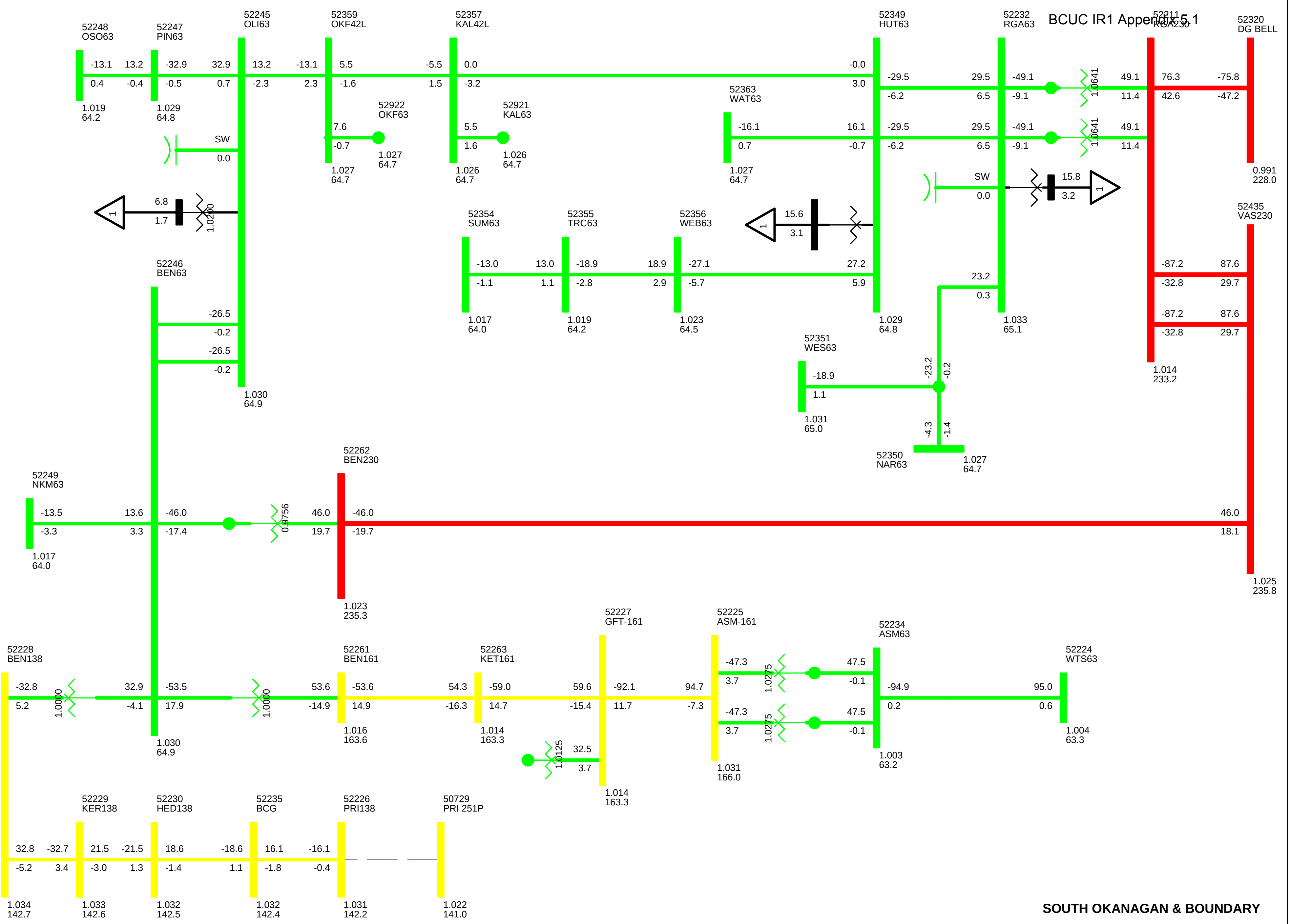
2020 SUMMER PEAK

KELOWNA 347 MW, BCH DKL 31 MW

FIGURE-17

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR

100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



SOUTH OKANAGAN & BOUNDARY

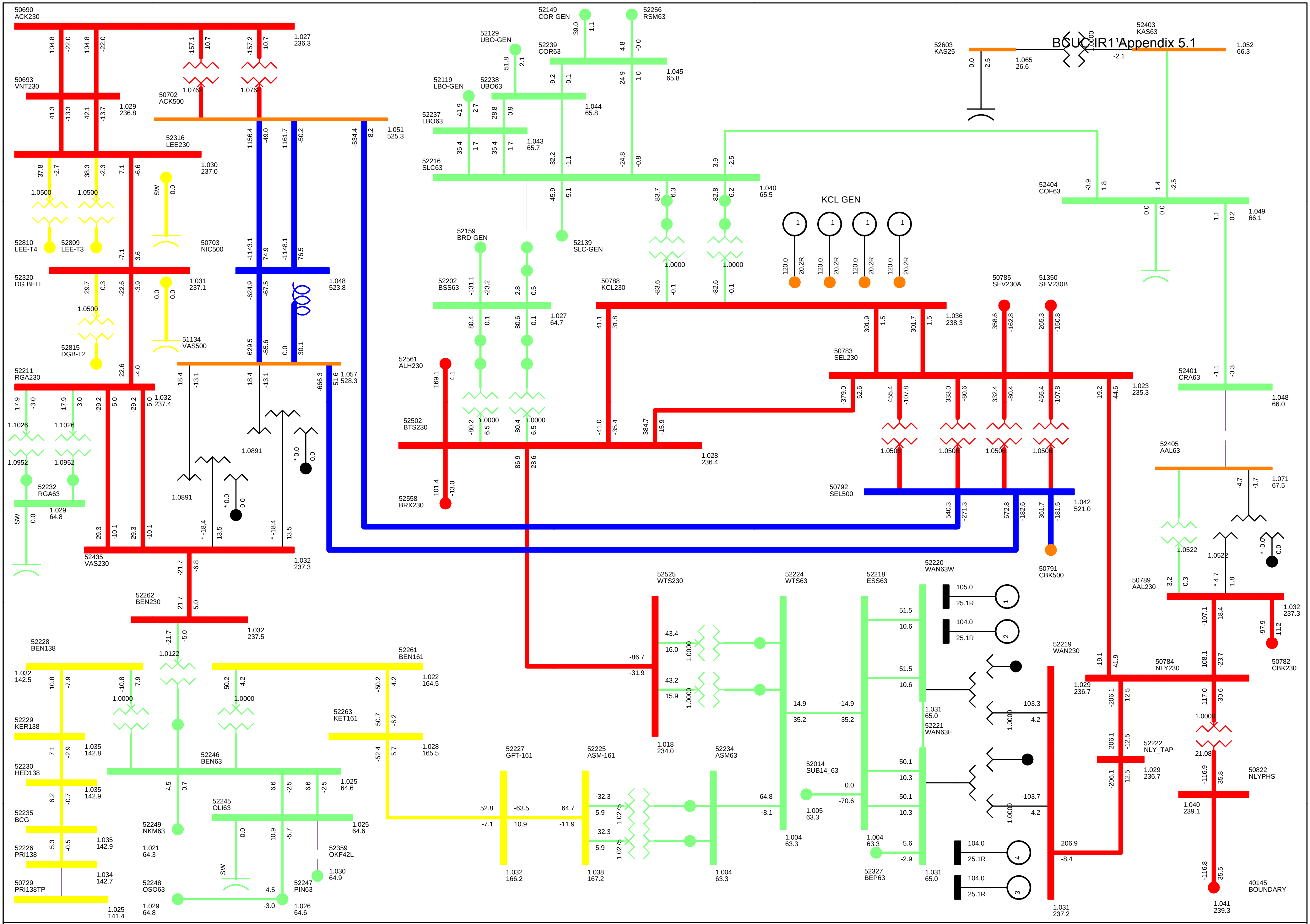
CREATED FROM 20HS1AP.SAV.FBC 778MW,TC 220MW
GEN 864MW,LOSSES 28MW,IMPORT 162MW
MON, DEC 06 2010 14:39

2020 SUMMER PEAK

LOAD (MW): PENTICTON 111, OLIVER 86, BOU 37

FIGURE-18

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000

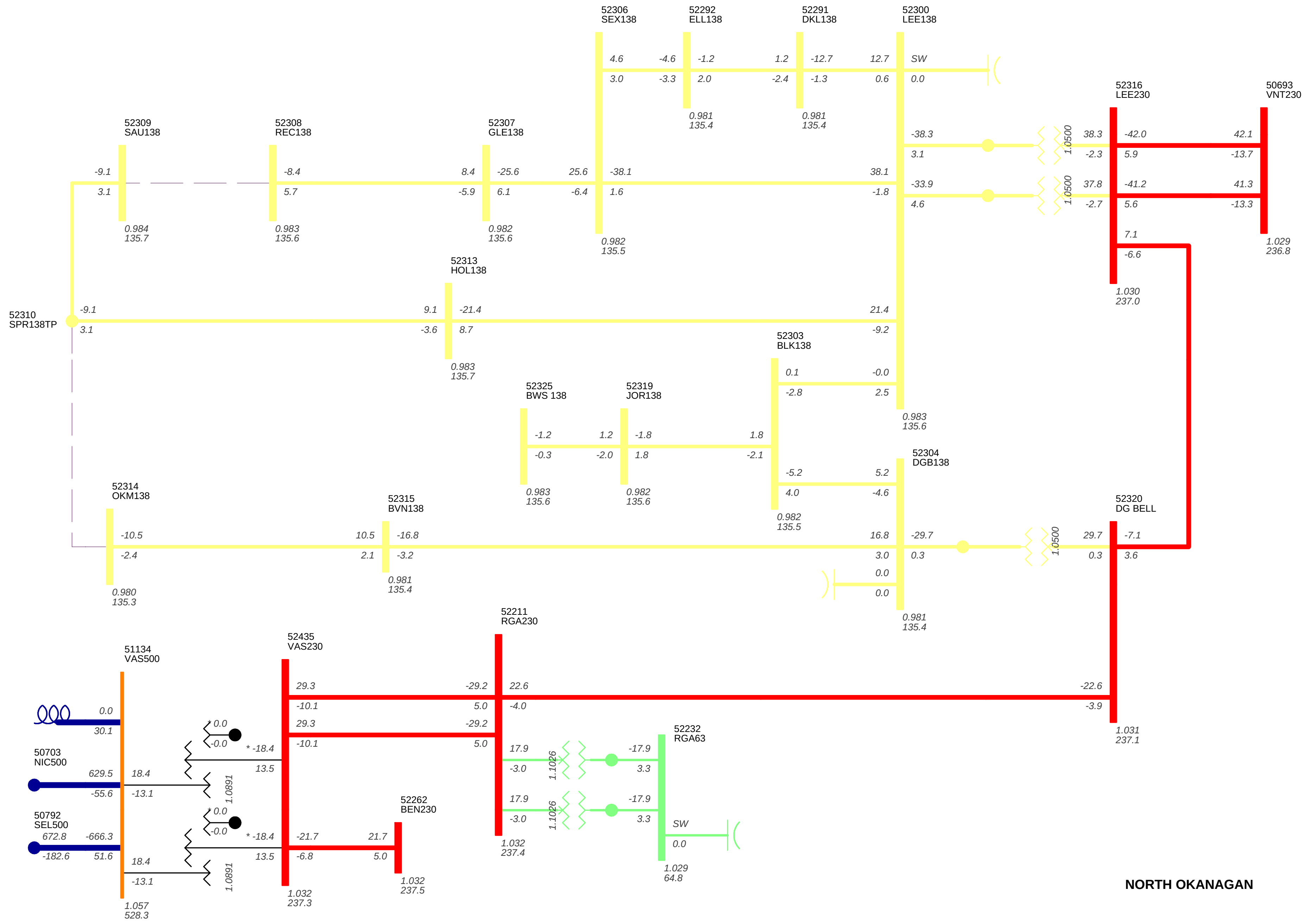


CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
MON, DEC 06 2010 13:23

2012 LIGHT LOAD

FIGURE-19

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
1.050OV0.950UV
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



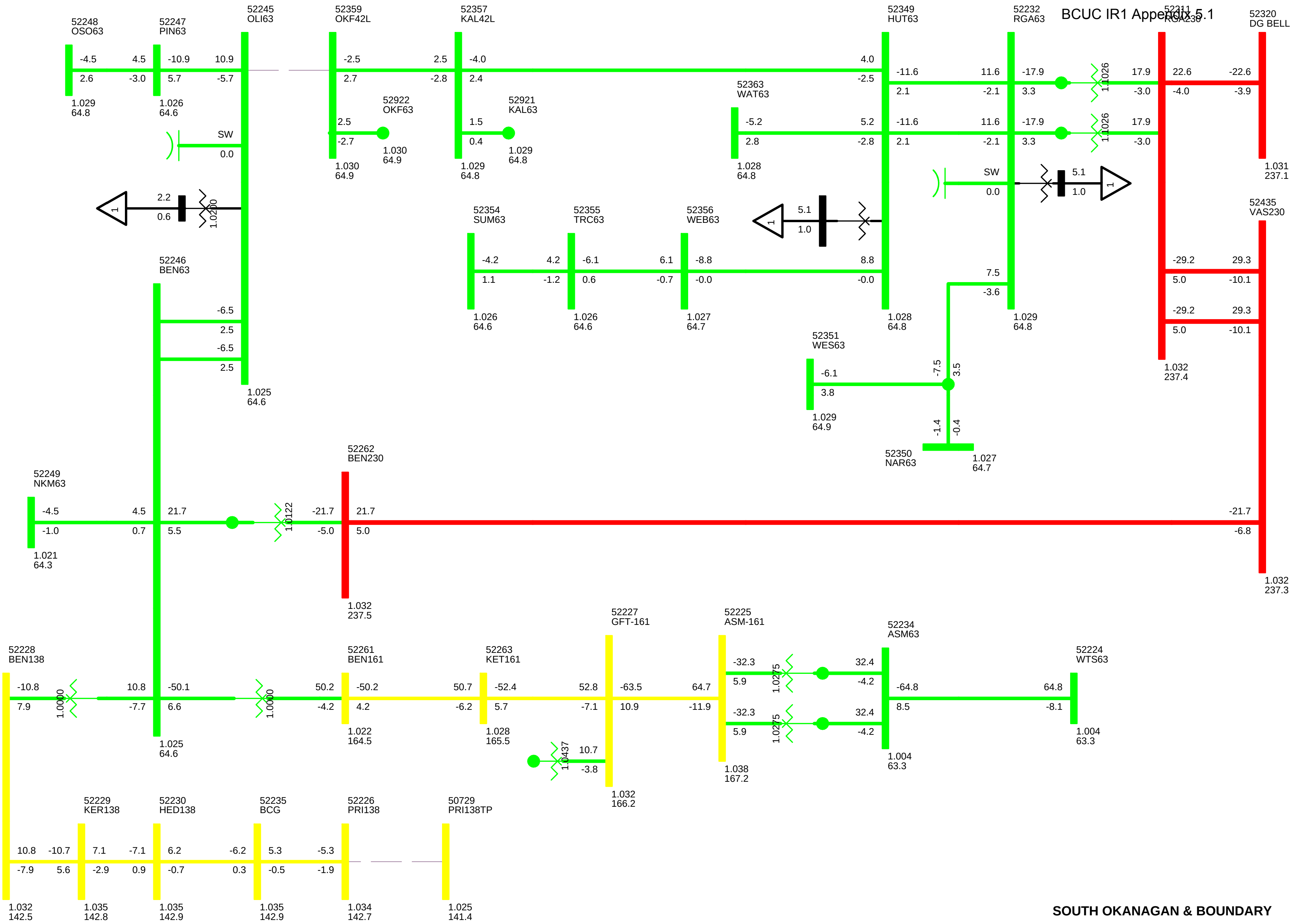
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
MON, DEC 06 2010 13:26

2012 LIGHT LOAD

KELOWNA 96 MW, BCH DKL 10 MW

FIGURE-20

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
1.050OV 0.950UV
KV: <=30.000 <=63.000 <=161.000 <=230.000 <=500.000 >500.000



SOUTH OKANAGAN & BOUNDARY

CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
MON, DEC 06 2010 13:27

2012 LIGHT LOAD

LOAD (MW): PENTICTON 36, OLIVER 28, BOU 12

FIGURE-21

Bus - VOLTAGE (KV/PU)
Branch - MW/MVAR
Equipment - MW/MVAR
100.0%RATEA
1.050OV 0.950UV
KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000

APPENDIX-B

ACCC (Automatic Contingency Analysis) Output Report

(TPL-002-0)

2012 Winter Peak

2012 Summer Peak

2012 Light Load

2016 Winter Peak

2016 Summer Peak

2020 Winter Peak

2020 Summer Peak

2012 WINTER PEAK CONTINGENCY ANALYSIS

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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
CREATED FROM 13HW1AP.SAV.FBC 887MW,TC 220MW                         PAGE 1
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR C (CONTINGENCY CASES)
ACCC VOLTAGE  REPORT

AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\13hw1ap-12WP-F11.ACC
DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\13hw1ap-12WP-F11.DFX
SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys.sub
MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys.mon
CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys-S.con

Solution engine:              Fixed slope decoupled Newton-Raphson (FDNS)
Solution options
  Tap adjustment:             Lock taps
  Area interchange control:   Disable
  Phase shift adjustment:     Disable
  Dc tap adjustment:          Enable
  Switch shunt adjustment:    Enable all
  Non diverge:                Disable
Mismatch tolerance (MW ):     0.5
Dispatch mode:                Disable

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50791 [CBK500      500.00] TO BUS 50792 [SEL500      500.00] CKT 1 -------------------------------------------- CONTINGENCY SINGLE 28
                                                              50782 CBK230      230.00  50789*AAL230      230.00 1      80.7    454.3    537.0     95.5
                                                              50784 NLY230      230.00  50789*AAL230      230.00 1     118.8    493.6    537.0    103.8

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
    'FORTISBC    ' BUSES WITH VOLTAGE LESS THAN 0.9000:  50789 AAL230      230.00 0.88583 1.02921   52408 CRE63       63.000 0.87009 1.02988

  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  50782 CBK230      230.00 0.93844 1.03239   50789 AAL230      230.00 0.88583 1.02921
                                                         50791 CBK500      500.00 0.97384 1.05517   52405 AAL63       63.000 0.90047 1.05461
                                                         52408 CRE63       63.000 0.87009 1.02988

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52224 [WTS63       63.000] TO BUS 52234 [ASM63       63.000] CKT 1 -------------------------------------------- CONTINGENCY SINGLE 77
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52225 ASM-161     161.00 0.98274 1.03813   52234 ASM63       63.000 0.94382 1.00252
                                                         52834 ASM T-1     63.000 0.94382 1.00272   52835 ASM T-2     63.000 0.94382 1.00272

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52246 [BEN63       63.000] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 110
                                                                                               *** NOT CONVERGED ***

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52435 [VAS230      230.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 117
                                                                                               *** NOT CONVERGED ***

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 118
                                                                                               *** NOT CONVERGED ***

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 132
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52292 ELL138      138.00 0.91838 0.97083   52306 SEX138      138.00 0.91030 0.97278
                                                         52307 GLE138      138.00 0.90639 0.96950   52308 REC138      138.00 0.90601 0.96923

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52809 [LEE-T3      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 134
                                                              52300 LEE138      138.00  52810*LEE-T4      138.00 1     117.7    207.3    227.0     95.3
                                                              52316*LEE230      230.00  52810 LEE-T4      138.00 1     132.0    224.8    227.0     99.0

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52810 [LEE-T4      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 135
                                                              52300 LEE138      138.00  52809*LEE-T3      138.00 1     133.3    212.4    227.0     96.9
                                                              52316*LEE230      230.00  52809 LEE-T3      138.00 1     133.9    214.8    227.0     94.6

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52316 [LEE230      230.00] TO BUS 52809 [LEE-T3      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 146
                                                              52300 LEE138      138.00  52810*LEE-T4      138.00 1     117.7    207.3    227.0     95.3
                                                              52316*LEE230      230.00  52810 LEE-T4      138.00 1     132.0    224.8    227.0     99.0

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52316 [LEE230      230.00] TO BUS 52810 [LEE-T4      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 147
                                                              52300 LEE138      138.00  52809*LEE-T3      138.00 1     133.3    221.6    227.0    101.7
                                                              52316*LEE230      230.00  52809 LEE-T3      138.00 1     133.9    224.9    227.0     99.1

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52320 [DG BELL     230.00] TO BUS 52211 [RGA230      230.00] CKT 1 --------------------------------------------- CONTINGENCY 73L-OUT
OPEN LINE FROM BUS 52320 [DG BELL     230.00] TO BUS 52316 [LEE230      230.00] CKT 1
                                                              52300*LEE138      138.00  52809 LEE-T3      138.00 1     133.3    188.5    227.0     90.5

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
    'FORTISBC    ' BUSES WITH VOLTAGE LESS THAN 0.9000:  52314 OKM138      138.00 0.89762 0.97805   52315 BVN138      138.00 0.89977 0.97996
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                                                  52325 BWS 138     138.00 0.89798 0.96602

'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52291 DKL138      138.00 0.90916 0.97030  52292 ELL138      138.00 0.90967 0.97083
                                                  52300 LEE138      138.00 0.91744 0.97779  52303 BLK138      138.00 0.91091 0.97766
                                                  52304 DGB138      138.00 0.90237 0.98227  52306 SEX138      138.00 0.91173 0.97278
                                                  52307 GLE138      138.00 0.90783 0.96950  52308 REC138      138.00 0.90745 0.96923
                                                  52309 SAU138      138.00 0.91244 0.97377  52310 SPR138TP    138.00 0.91260 0.97389
                                                  52313 HOL138      138.00 0.91389 0.97493  52314 OKM138      138.00 0.89762 0.97805
                                                  52315 BVN138      138.00 0.89977 0.97996  52319 JOR138      138.00 0.90925 0.97618
                                                  52320 DG BELL     230.00 0.90237 0.98725  52325 BWS 138     138.00 0.89798 0.96602
                                                  52809 LEE-T3      138.00 0.91661 0.97849  52810 LEE-T4      138.00 0.91648 0.97873
                                                  52815 DGB-T2      138.00 0.90237 0.98220
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2012 SUMMER PEAK CONTINGENCY ANALYSIS

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      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
 CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW                          PAGE 1
 GEN 864MW,LOSSES 26MW,IMPORT 78MW
 ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR B (CONTINGENCY CASES)
 ACCC VOLTAGE  REPORT

 AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\12HS2AP-12SP-F11.acc
 DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\12HS2AP-12SP-F11.dfx
 SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys.sub
 MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys.mon
 CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys-S.con

 Solution engine:              Fixed slope decoupled Newton-Raphson (FDNS)
 Solution options
   Tap adjustment:             Lock taps
   Area interchange control:   Disable
   Phase shift adjustment:     Disable
   Dc tap adjustment:          Enable
   Switch shunt adjustment:    Enable all
   Non diverge:                Disable
 Mismatch tolerance (MW ):     0.5
 Dispatch mode:                Disable

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 50791 [CBK500      500.00] TO BUS 50792 [SEL500      500.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 28
                                                                                               *** NOT CONVERGED ***

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52232 [RGA63       63.000] TO BUS 52349 [HUT63       63.000] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 95
                                                               52232 RGA63       63.000  52349*HUT63       63.000 2      34.0     68.1     73.6     91.5

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52232 [RGA63       63.000] TO BUS 52349 [HUT63       63.000] CKT 2 ------------------------------------------- CONTINGENCY SINGLE 96
                                                               52232 RGA63       63.000  52349*HUT63       63.000 1      34.0     68.1     73.6     91.5

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52246 [BEN63       63.000] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 110
                                                                                               *** NOT CONVERGED ***

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52435 [VAS230      230.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 117
                                                                                               *** NOT CONVERGED ***

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 118
                                                                                               *** NOT CONVERGED ***

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52809 [LEE-T3      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 134
                                                               52316*LEE230      230.00  52810 LEE-T4      138.00 1     111.2    189.1    210.0     90.1

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52316 [LEE230      230.00] TO BUS 52809 [LEE-T3      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 146
                                                               52316*LEE230      230.00  52810 LEE-T4      138.00 1     111.2    189.1    210.0     90.0

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52316 [LEE230      230.00] TO BUS 52810 [LEE-T4      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 147
                                                               52300*LEE138      138.00  52809 LEE-T3      138.00 1     112.1    186.2    210.0     92.2
                                                               52316*LEE230      230.00  52809 LEE-T3      138.00 1     112.8    189.2    210.0     90.1
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2012 LIGHT LOAD CONTINGENCY ANALYSIS

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      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
 CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW                PAGE 1
 GEN 1082MW,LOSSES 24MW,EXPORT 577MW
 ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR B (CONTINGENCY CASES)
 ACCC VOLTAGE  REPORT

 AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\12HS2AP-12LL-F11.acc
 DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\12HS2AP-12LL-F11.dfx
 SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys.sub
 MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys.mon
 CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2012\FortisBC-sys-S.con

 Solution engine:              Full Newton-Raphson (FNSL)
 Solution options
   Tap adjustment:             Lock taps
   Area interchange control:   Disable
   Phase shift adjustment:     Disable
   Dc tap adjustment:          Enable
   Switch shunt adjustment:    Enable all
   Non diverge:                Disable
 Mismatch tolerance (MW ):     0.5
 Dispatch mode:                Disable

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 50783 [SEL230      230.00] TO BUS 50788 [KCL230      230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 14
                                                              50783 SEL230      230.00  50788*KCL230      230.00 2     301.7    460.8    397.2    112.0
                                                              50783 SEL230      230.00  52502*BTS230      230.00 1     385.1    505.0    527.8     93.3

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 50783 [SEL230      230.00] TO BUS 50788 [KCL230      230.00] CKT 2 ------------------------------------------- CONTINGENCY SINGLE 15
                                                              50783 SEL230      230.00  50788*KCL230      230.00 1     302.0    461.1    397.2    112.0
                                                              50783 SEL230      230.00  52502*BTS230      230.00 1     385.1    504.9    527.8     93.3

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 50783 [SEL230      230.00] TO BUS 52502 [BTS230      230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 20
                                                              50783 SEL230      230.00  50788*KCL230      230.00 1     302.0    455.7    397.2    110.7
                                                              50783 SEL230      230.00  50788*KCL230      230.00 2     301.7    455.3    397.2    110.6

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 50791 [CBK500      500.00] TO BUS 50792 [SEL500      500.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 28
                                                                                               *** NOT CONVERGED ***

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52246 [BEN63       63.000] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 110
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE GREATER THAN 1.1000:  52226 PRI138      138.00 1.10914 1.03421  52228 BEN138      138.00 1.10614 1.03239
                                                          52229 KER138      138.00 1.10919 1.03487  52230 HED138      138.00 1.11006 1.03540
                                                          52235 BCG         138.00 1.11006 1.03534  52248 OSO63       63.000 1.10264 1.02870
                                                          52426 MAS138      138.00 1.11007 1.03541

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52435 [VAS230      230.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 117
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE GREATER THAN 1.1000:  52226 PRI138      138.00 1.10914 1.03421  52228 BEN138      138.00 1.10614 1.03239
                                                          52229 KER138      138.00 1.10919 1.03487  52230 HED138      138.00 1.11006 1.03540
                                                          52235 BCG         138.00 1.11006 1.03534  52248 OSO63       63.000 1.10264 1.02870
                                                          52262 BEN230      230.00 1.11130 1.03250  52426 MAS138      138.00 1.11007 1.03541

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 118
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE GREATER THAN 1.1000:  52226 PRI138      138.00 1.10914 1.03421  52228 BEN138      138.00 1.10614 1.03239
                                                          52229 KER138      138.00 1.10919 1.03487  52230 HED138      138.00 1.11006 1.03540
                                                          52235 BCG         138.00 1.11006 1.03534  52248 OSO63       63.000 1.10264 1.02870
                                                          52426 MAS138      138.00 1.11007 1.03541
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2016 WINTER PEAK CONTINGENCY ANALYSIS

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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
CREATED FROM 16HW1SAP.SAV.FBC 951MW,TC 220MW                         PAGE 1
GEN 945MW,LOSSES 37MW,IMPORT 263MW
ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR C (CONTINGENCY CASES)
ACCC VOLTAGE  REPORT

AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\16hw1sap-16WP-F11.ACC
DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\16hw1sap-16WP-F11.DFX
SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\FortisBC-sys.sub
MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\FortisBC-sys.mon
CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\FortisBC-sys-S.con

Solution engine:              Full Newton-Raphson (FNSL)
Solution options
  Tap adjustment:             Lock taps
  Area interchange control:   Disable
  Phase shift adjustment:     Disable
  Dc tap adjustment:          Enable
  Switch shunt adjustment:    Enable all
  Non diverge:                Disable
Mismatch tolerance (MW ):     0.5
Dispatch mode:                Disable

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50791 [CBK500      500.00] TO BUS 50792 [SEL500      500.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 28
                                                                                                   *** NONE ***

                                                       X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  50789 AAL230      230.00 0.93843 1.02418   52405 AAL63       63.000 0.95665 1.04867
                                                         52408 CRE63       63.000 0.92779 1.02304

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52211 [RGA230      230.00] TO BUS 52320 [DG BELL     230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 56
                                                                                                   *** NONE ***

                                                       X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
    'FORTISBC    ' BUSES WITH VOLTAGE LESS THAN 0.9000:  52325 BWS 138     138.00 0.89628 0.96165

  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52291 DKL138      138.00 0.90571 0.96952   52292 ELL138      138.00 0.90584 0.96982
                                                         52300 LEE138      138.00 0.91529 0.97792   52303 BLK138      138.00 0.91144 0.97536
                                                         52304 DGB138      138.00 0.90983 0.97589   52306 SEX138      138.00 0.90801 0.97196
                                                         52307 GLE138      138.00 0.90253 0.96792   52308 REC138      138.00 0.90179 0.96761
                                                         52309 SAU138      138.00 0.90164 0.96764   52310 SPR138TP    138.00 0.90179 0.96783
                                                         52313 HOL138      138.00 0.91235 0.97549   52314 OKM138      138.00 0.90221 0.96836
                                                         52315 BVN138      138.00 0.90583 0.97199   52316 LEE230      230.00 0.92672 0.98355
                                                         52319 JOR138      138.00 0.90948 0.97360   52320 DG BELL     230.00 0.92139 0.98781
                                                         52325 BWS 138     138.00 0.89628 0.96165   52809 LEE-T3      138.00 0.91402 0.97788
                                                         52810 LEE-T4      138.00 0.91401 0.97799   52814 LEE-T5      138.00 0.91402 0.97788
                                                         52815 DGB-T2      138.00 0.90893 0.97497

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52225 [ASM-161     161.00] TO BUS 52834 [ASM T-1     63.000] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 85
                                                              52225 ASM-161     161.00  52835*ASM T-2     63.000 1      55.5     98.1    108.0     90.8
                                                              52234 ASM63       63.000  52835*ASM T-2     63.000 1      55.5     98.1    108.0     90.5

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52225 [ASM-161     161.00] TO BUS 52835 [ASM T-2     63.000] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 86
                                                              52225 ASM-161     161.00  52834*ASM T-1     63.000 1      55.5     98.1    108.0     90.8
                                                              52234 ASM63       63.000  52834*ASM T-1     63.000 1      55.5     98.1    108.0     90.5

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52234 [ASM63       63.000] TO BUS 52834 [ASM T-1     63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 100
                                                              52225 ASM-161     161.00  52835*ASM T-2     63.000 1      55.5     98.1    108.0     90.8
                                                              52234 ASM63       63.000  52835*ASM T-2     63.000 1      55.5     98.1    108.0     90.5

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52234 [ASM63       63.000] TO BUS 52835 [ASM T-2     63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 101
                                                              52225 ASM-161     161.00  52834*ASM T-1     63.000 1      55.5     98.1    108.0     90.8
                                                              52234 ASM63       63.000  52834*ASM T-1     63.000 1      55.5     98.1    108.0     90.5

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52246 [BEN63       63.000] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 111
                                                                                                   *** NONE ***

                                                       X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52226 PRI138      138.00 0.96810 1.01855

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52435 [VAS230      230.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 118
                                                                                                   *** NONE ***

                                                       X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52226 PRI138      138.00 0.96723 1.01855   52230 HED138      138.00 0.97242 1.02266
                                                         52235 BCG         138.00 0.97160 1.02202   52262 BEN230      230.00 0.95060 1.02379
                                                         52426 MAS138      138.00 0.97238 1.02263

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 119
                                                                                                   *** NONE ***

                                                       X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52226 PRI138      138.00 0.96810 1.01855
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<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52306 [SEX138      138.00] TO BUS 52307 [GLE138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 142
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1     100.0    196.3    213.4     96.8

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52320 [DG BELL     230.00] TO BUS 52211 [RGA230      230.00] CKT 1 --------------------------------------------- CONTINGENCY 73L-OUT
OPEN LINE FROM BUS 52320 [DG BELL     230.00] TO BUS 52316 [LEE230      230.00] CKT 1
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
    'FORTISBC    ' BUSES WITH VOLTAGE LESS THAN 0.9000:  52291 DKL138      138.00 0.89574 0.96952   52292 ELL138      138.00 0.89540 0.96982
                                                         52303 BLK138      138.00 0.89900 0.97536   52304 DGB138      138.00 0.89008 0.97589
                                                         52306 SEX138      138.00 0.89722 0.97196   52307 GLE138      138.00 0.88910 0.96792
                                                         52308 REC138      138.00 0.88726 0.96761   52309 SAU138      138.00 0.88644 0.96764
                                                         52310 SPR138TP    138.00 0.88632 0.96783   52314 OKM138      138.00 0.88597 0.96836
                                                         52315 BVN138      138.00 0.88767 0.97199   52319 JOR138      138.00 0.89700 0.97360
                                                         52320 DG BELL     230.00 0.89008 0.98781   52325 BWS 138     138.00 0.88353 0.96165
                                                         52815 DGB-T2      138.00 0.89008 0.97497

  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52291 DKL138      138.00 0.89574 0.96952   52292 ELL138      138.00 0.89540 0.96982
                                                         52300 LEE138      138.00 0.90641 0.97792   52303 BLK138      138.00 0.89900 0.97536
                                                         52304 DGB138      138.00 0.89008 0.97589   52306 SEX138      138.00 0.89722 0.97196
                                                         52307 GLE138      138.00 0.88910 0.96792   52308 REC138      138.00 0.88726 0.96761
                                                         52309 SAU138      138.00 0.88644 0.96764   52310 SPR138TP    138.00 0.88632 0.96783
                                                         52313 HOL138      138.00 0.90338 0.97549   52314 OKM138      138.00 0.88597 0.96836
                                                         52315 BVN138      138.00 0.88767 0.97199   52316 LEE230      230.00 0.92480 0.98355
                                                         52319 JOR138      138.00 0.89700 0.97360   52320 DG BELL     230.00 0.89008 0.98781
                                                         52325 BWS 138     138.00 0.88353 0.96165   52809 LEE-T3      138.00 0.90422 0.97788
                                                         52810 LEE-T4      138.00 0.90396 0.97799   52814 LEE-T5      138.00 0.90422 0.97788
                                                         52815 DGB-T2      138.00 0.89008 0.97497

<----------- C O N T I N G E N C Y   E V E N T S -----------><--------- O V E R L O A D E D   L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 --------------------------------------------- CONTINGENCY ELL-TAP
OPEN LINE FROM BUS 52292 [ELL138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1     100.0    231.0    213.4    115.9
                                                              52314*OKM138      138.00  52315 BVN138      138.00 1      76.6    205.4    213.4    104.2

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52306 SEX138      138.00 0.91172 0.97196   52307 GLE138      138.00 0.91419 0.96792
                                                         52308 REC138      138.00 0.91712 0.96761
```

2016 SUMMER PEAK CONTINGENCY ANALYSIS

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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
CREATED FROMM 16HS2AP.SAV.FBC740MW,TC 220MW                           PAGE 1
GEN 864MW,LOSSES 27MW,IMPORT 123MW
ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR B (CONTINGENCY CASES)
ACCC VOLTAGE  REPORT

AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\16hs2ap-16SP-F11.ACC
DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\16hs2ap-16SP-F11.DFX
SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\FortisBC-sys.sub
MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\FortisBC-sys.mon
CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2016\FortisBC-sys-S.con

Solution engine:              Full Newton-Raphson (FNSL)
Solution options
  Tap adjustment:             Lock taps
  Area interchange control:   Disable
  Phase shift adjustment:     Disable
  Dc tap adjustment:          Enable
  Switch shunt adjustment:    Enable all
  Non diverge:                Disable
Mismatch tolerance (MW ):     0.5
Dispatch mode:                Disable

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50783 [SEL 230     230.00] TO BUS 50788 [KCL 230     230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 10
                                                              50783 SEL 230     230.00  50788*KCL 230     230.00 2     270.0    412.0    397.2    100.0

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50783 [SEL 230     230.00] TO BUS 50788 [KCL 230     230.00] CKT 2 ------------------------------------------- CONTINGENCY SINGLE 11
                                                              50783 SEL 230     230.00  50788*KCL 230     230.00 1     270.3    412.2    397.2    100.1

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50783 [SEL 230     230.00] TO BUS 52502 [BTS230      230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 12
                                                              50783 SEL 230     230.00  50788*KCL 230     230.00 1     270.3    395.1    397.2     95.9
                                                              50783 SEL 230     230.00  50788*KCL 230     230.00 2     270.0    394.8    397.2     95.8

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50791 [CBK 500     500.00] TO BUS 50792 [SEL 500     500.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 20
                                                                                               *** NOT CONVERGED ***

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52435 [VAS230      230.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 112
                                                                                                    *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52262 BEN230      230.00 0.97076 1.02186

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 127
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1      87.8    146.4    161.3     94.0

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52306 [SEX138      138.00] TO BUS 52307 [GLE138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 136
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1      87.8    171.8    161.3    110.3
                                                              52314*OKM138      138.00  52315 BVN138      138.00 1      66.0    149.2    161.3     96.5

<----------- C O N T I N G E N C Y  E V E N T S -----------><--------- O V E R L O A D E D  L I N E S ----------> <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 --------------------------------------------- CONTINGENCY ELL-TAP
OPEN LINE FROM BUS 52292 [ELL138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1      87.8    200.6    161.3    130.3
                                                              52314*OKM138      138.00  52315 BVN138      138.00 1      66.0    177.4    161.3    116.2
```

2020 WINTER PEAK CONTINGENCY ANALYSIS

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      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
 CREATED FROM 19HW1AP.SAV.FBC 1001MW,TC 220MW                          PAGE 1
 GEN 945MW,LOSSES 36MW,IMPORT 311MW
 ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR C (CONTINGENCY CASES)
 ACCC VOLTAGE  REPORT

 AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\19hw1ap-20WP-F11.ACC
 DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\19hw1ap-20WP-F11.DFX
 SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\FortisBC-sys.sub
 MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\FortisBC-sys.mon
 CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\FortisBC-sys-S.con

 Solution engine:              Full Newton-Raphson (FNSL)
 Solution options
   Tap adjustment:             Lock taps
   Area interchange control:   Disable
   Phase shift adjustment:     Disable
   Dc tap adjustment:          Enable
   Switch shunt adjustment:    Enable all
   Non diverge:                Disable
 Mismatch tolerance (MW ):     0.5
 Dispatch mode:                Disable

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 50791 [CBK 500     500.00] TO BUS 50792 [SEL 500     500.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 28
                                                                                                      *** NOT CONVERGED ***

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52225 [ASM-161     161.00] TO BUS 52227 [GFT-161     161.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 88
                                                                                                           *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
   'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52277 CHR-9L      63.000 0.94732 0.99923  52278 CHR-10L     63.000 0.94521 0.99670
                                                          52279 RUC-9L      63.000 0.94959 1.00076  52280 RUC-10L     63.000 0.94497 0.99644
                                                          52281 GFK-9L      63.000 0.94995 1.00098  52282 GFK-10L     63.000 0.94995 1.00098
                                                          52597 ROX63       63.000 0.94497 0.99644  52827 GFK T-1     63.000 0.94857 0.99994

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52246 [BEN63       63.000] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 115
                                                                                                           *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
   'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52226 PRI138      138.00 0.94946 1.01679  52228 BEN138      138.00 0.96725 1.02985
                                                          52229 KER138      138.00 0.96075 1.02520  52230 HED138      138.00 0.95539 1.02124
                                                          52235 BCG         138.00 0.95445 1.02055  52245 OLI63       63.000 0.97400 1.03190
                                                          52246 BEN63       63.000 0.97306 1.03231  52247 PIN63       63.000 0.97172 1.02994
                                                          52248 OSO63       63.000 0.96144 1.02152  52249 NKM63       63.000 0.95912 1.01937
                                                          52261 BEN161      161.00 0.95684 1.01826  52263 KET161      161.00 0.96075 1.01456
                                                          52426 MAS138      138.00 0.95535 1.02121

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52435 [VAS230      230.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 122
                                                                                                           *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
   'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52226 PRI138      138.00 0.96123 1.01679  52228 BEN138      138.00 0.97814 1.02985
                                                          52229 KER138      138.00 0.97199 1.02520  52230 HED138      138.00 0.96688 1.02124
                                                          52235 BCG         138.00 0.96599 1.02055  52261 BEN161      161.00 0.96541 1.01826
                                                          52262 BEN230      230.00 0.94727 1.02019  52426 MAS138      138.00 0.96685 1.02121

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52262 [BEN230      230.00] TO BUS 52802 [BEN-T1      63.000] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 123
                                                                                                           *** NONE ***

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
   'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  52226 PRI138      138.00 0.94946 1.01679  52228 BEN138      138.00 0.96725 1.02985
                                                          52229 KER138      138.00 0.96075 1.02520  52230 HED138      138.00 0.95539 1.02124
                                                          52235 BCG         138.00 0.95445 1.02055  52245 OLI63       63.000 0.97400 1.03190
                                                          52246 BEN63       63.000 0.97306 1.03231  52247 PIN63       63.000 0.97172 1.02994
                                                          52248 OSO63       63.000 0.96144 1.02152  52249 NKM63       63.000 0.95912 1.01937
                                                          52261 BEN161      161.00 0.95684 1.01826  52263 KET161      161.00 0.96075 1.01456
                                                          52426 MAS138      138.00 0.95535 1.02121  52802 BEN-T1      63.000 0.97306 1.02964

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52306 [SEX138      138.00] TO BUS 52307 [GLE138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 146
                                                               52304 DGB138      138.00  52315*BVN138      138.00 1     109.5    213.5    213.4    103.0
                                                               52314*OKM138      138.00  52315 BVN138      138.00 1      83.3    186.0    213.4     90.5

 <----------- C O N T I N G E N C Y   E V E N T S ----------><--------- O V E R L O A D E D   L I N E S ---------->  <- MVA(MW)FLOW ->
      <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
 OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 --------------------------------------------- CONTINGENCY ELL-TAP
 OPEN LINE FROM BUS 52292 [ELL138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1
                                                               52304 DGB138      138.00  52315*BVN138      138.00 1     109.5    251.6    213.4    121.6
                                                               52314*OKM138      138.00  52315 BVN138      138.00 1      83.3    223.2    213.4    109.1
```

2020 SUMMER PEAK CONTINGENCY ANALYSIS

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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   TUE, DEC 07 2010   8:45
CREATED FROM 20HS1AP.SAV.FBC 778MW,TC 220MW                        PAGE 1
GEN 864MW,LOSSES 28MW,IMPORT 162MW
ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE  90.0 % OF RATING SET A (BASE CASE) OR B (CONTINGENCY CASES)
ACCC VOLTAGE  REPORT

AC CONTINGENCY RESULTS FILE:  G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\20hs1ap-20SP-F11.ACC
DISTRIBUTION FACTOR FILE:     G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\20hs1ap-20SP-F11.DFX
SUBSYSTEM DESCRIPTION FILE:   G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\FortisBC-sys.sub
MONITORED ELEMENT FILE:       G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\FortisBC-sys.mon
CONTINGENCY DESCRIPTION FILE: G:\System Planning\Waseem\Lf-Work30\Base Cases 2011\2020\FortisBC-sys-S.con

Solution engine:              Full Newton-Raphson (FNSL)
Solution options
  Tap adjustment:             Lock taps
  Area interchange control:   Disable
  Phase shift adjustment:     Disable
  Dc tap adjustment:          Enable
  Switch shunt adjustment:    Enable all
  Non diverge:                Disable
Mismatch tolerance (MW ):     0.5
Dispatch mode:                Disable

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50783 [SEL230      230.00] TO BUS 50788 [KCL230      230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 13
                                                              50783 SEL230      230.00  50788*KCL230      230.00 2     260.5    397.2    397.2     96.5

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50783 [SEL230      230.00] TO BUS 50788 [KCL230      230.00] CKT 2 ------------------------------------------- CONTINGENCY SINGLE 14
                                                              50783 SEL230      230.00  50788*KCL230      230.00 1     260.7    397.4    397.2     96.6

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50783 [SEL230      230.00] TO BUS 52502 [BTS230      230.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 19
                                                              50783 SEL230      230.00  50788*KCL230      230.00 1     260.7    382.5    397.2     92.9
                                                              50783 SEL230      230.00  50788*KCL230      230.00 2     260.5    382.1    397.2     92.9

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 50791 [CBK 500     500.00] TO BUS 50792 [SEL500      500.00] CKT 1 ------------------------------------------- CONTINGENCY SINGLE 27
                                                              50782 CBK 230     230.00  50789*AAL230      230.00 1     117.6    513.5    419.1    134.9
                                                              50784 NLY 230     230.00  50789*AAL230      230.00 1     141.7    536.1    419.1    140.8

                                                        X-------- B U S --------X  V-CONT  V-INIT  X-------- B U S --------X  V-CONT  V-INIT
  'FORTISBC    ' BUSES WITH VOLTAGE DROP BEYOND 0.0500:  50789 AAL230      230.00 0.90862 1.03068   52405 AAL63       63.000 0.93515 1.06394
                                                         52408 CRE63       63.000 0.91826 1.04941

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 136
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1      95.9    160.6    161.3    102.3

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52304 [DGB138      138.00] TO BUS 52315 [BVN138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 143
                                                              52300 LEE138      138.00  52306*SEX138      138.00 1     137.8    222.9    244.2     95.7

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52306 [SEX138      138.00] TO BUS 52307 [GLE138      138.00] CKT 1 ------------------------------------------ CONTINGENCY SINGLE 145
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1      95.9    185.8    161.3    118.4
                                                              52314*OKM138      138.00  52315 BVN138      138.00 1      71.3    160.3    161.3    102.9

<----------- C O N T I N G E N C Y  E V E N T S ----------->< --------- O V E R L O A D E D  L I N E S ---------->  <- MVA(MW)FLOW ->
     <----------- MULTI-SECTION LINE GROUPINGS ----------->  <------- F R O M -------> <--------- T O --------->CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 52300 [LEE138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1 --------------------------------------------- CONTINGENCY ELL-TAP
OPEN LINE FROM BUS 52292 [ELL138      138.00] TO BUS 52306 [SEX138      138.00] CKT 1
                                                              52304 DGB138      138.00  52315*BVN138      138.00 1      95.9    218.1    161.3    139.2
                                                              52314*OKM138      138.00  52315 BVN138      138.00 1      71.3    192.0    161.3    123.7
```

APPENDIX-C

Transient Stability Analysis Plots

Figure-35: Light Load – Single-Line-to-Ground Fault at WAN 63 kV Bus, Delayed Clearing in 18 Cycles, Trip 63 kV Bus Section (WAN units 3 & 4 and WAN 230/63 kV Trans. T2) (TPL-003-0)

Figure-36: Light Load – Three-Phase Fault at BTS 230 kV Bus, Delayed Clearing in 18 Cycles, BTS 230 kV Bus Tripped (TPL-004-0)

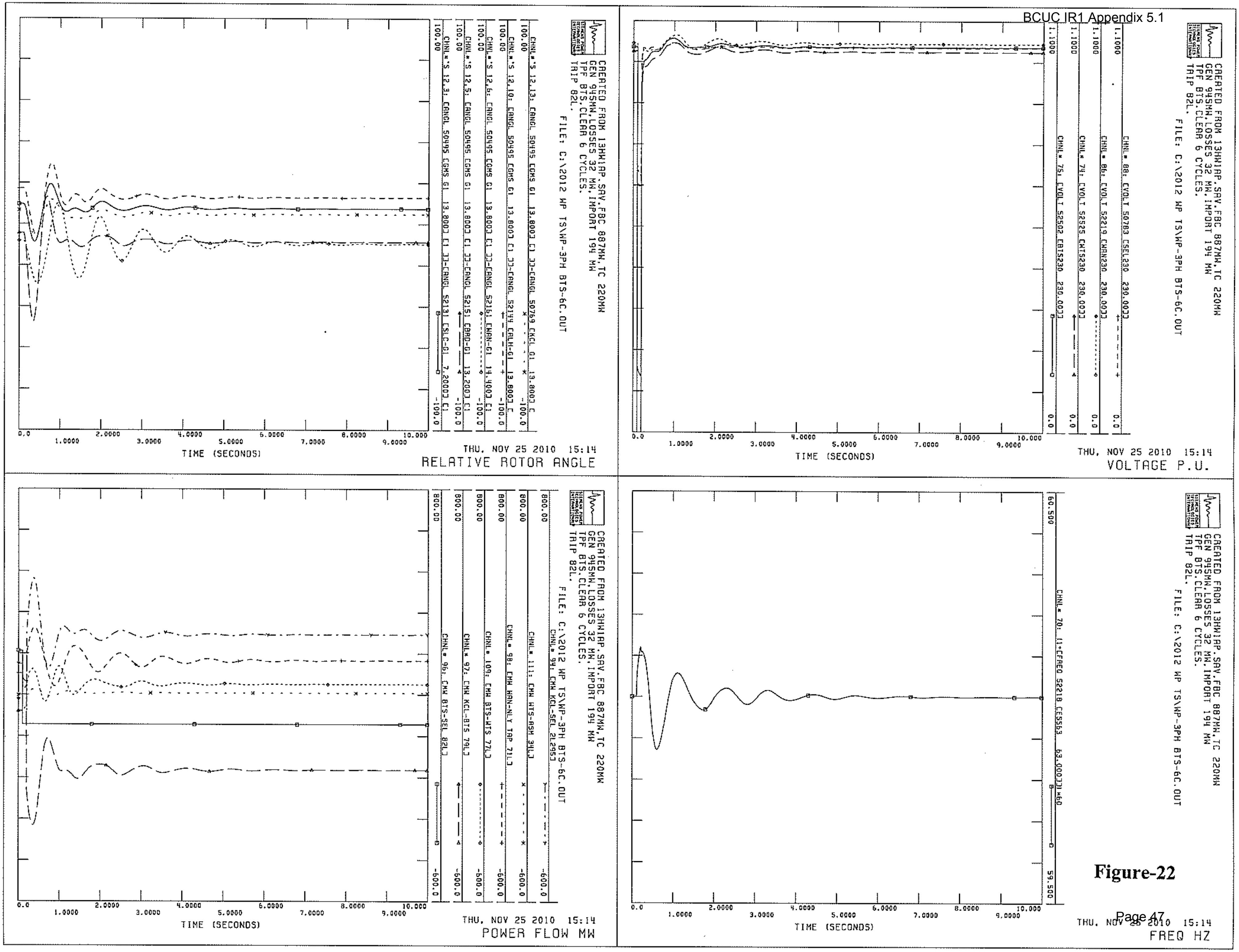

CREATED FROM 13HW1AP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
TPF BTS,CLEAR 6 CYCLES.
TRIP 82L.
FILE: C:\2012 WP TS\WP-3PH BTS-6C.OUT
CHNL#'S 12,13: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 50769 CKCL G1 13.800] C
CHNL#'S 12,10: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52144 CALH-G1 13.800] C
CHNL#'S 12,6: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52161 CWAN-G1 14.400] C1
CHNL#'S 12,5: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52151 CBRD-G1 13.200] C1
CHNL#'S 12,3: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52131 CSLC-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, NOV 25 2010 15:14
RELATIVE ROTOR ANGLE
CHNL# 88: CVOLT 50783 CSEL230 230.00]
CHNL# 86: CVOLT 52219 CWAN230 230.00]
CHNL# 74: CVOLT 52525 CWTS230 230.00]
CHNL# 75: CVOLT 52502 CBTS230 230.00]
1.1000
0.0
VOLTAGE P.U.
CHNL# 94: CMW KCL-SEL 2L295]
CHNL# 111: CMW WTS-ASM 34L]
CHNL# 98: CMW WAN-NLY TAP 71L]
CHNL# 109: CMW BTS-WTS 77L]
CHNL# 97: CMW KCL-BTS 79L]
CHNL# 96: CMW BTS-SEL 82L]
800.00
-600.0
POWER FLOW MW
CHNL# 70: (1+CFREQ 52218 CSS563 63.000])*60
60.500
59.500
FREQ HZ

Figure-22

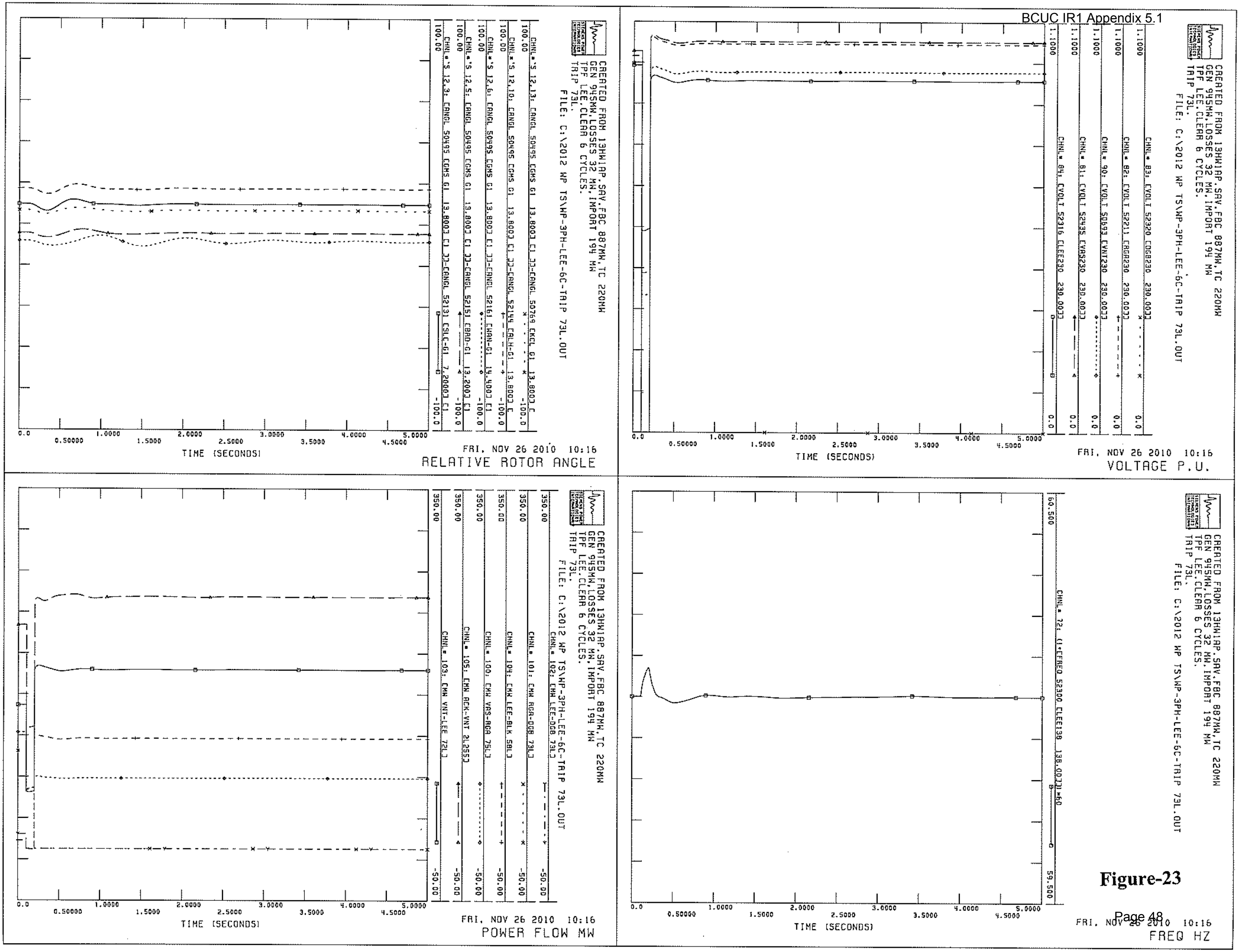

CREATED FROM 13HW1AP.SAV.FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 WP TS\WP-3PH-LEE-6C-TRIP 73L.OUT
CHNL#'S 12,13: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 50769 CKCL G1 13.800] C 100.00 -100.0
CHNL#'S 12,10: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52144 CALH-G1 13.800] C 100.00 -100.0
CHNL#'S 12,6: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52161 CWAN-G1 14.400] C1 100.00 -100.0
CHNL#'S 12,5: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52151 CBRD-G1 13.200] C1 100.00 -100.0
CHNL#'S 12,3: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52131 CSLC-G1 7.2000] C1 100.00 -100.0
0.0 0.50000 1.0000 1.5000 2.0000 2.5000 3.0000 3.5000 4.0000 4.5000 5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:16
RELATIVE ROTOR ANGLE
CHNL# 83: CVOLT 52320 CDGB230 230.00] 1.1000 0.0
CHNL# 82: CVOLT 52211 CRGA230 230.00] 1.1000 0.0
CHNL# 90: CVOLT 50693 CVNT230 230.00] 1.1000 0.0
CHNL# 81: CVOLT 52435 CVAS230 230.00] 1.1000 0.0
CHNL# 84: CVOLT 52316 CLEE230 230.00] 1.1000 0.0
VOLTAGE P.U.
CHNL# 102: CMW LEE-DGB 73L] 350.00 -50.00
CHNL# 101: CMW RGA-DGB 73L] 350.00 -50.00
CHNL# 104: CMW LEE-BLK 58L] 350.00 -50.00
CHNL# 100: CMW VAS-RGA 75L] 350.00 -50.00
CHNL# 105: CMW ACK-VNT 2L255] 350.00 -50.00
CHNL# 103: CMW VNT-LEE 72L] 350.00 -50.00
POWER FLOW MW
CHNL# 72: (1+CFREQ 52300 CLEE138 138.00])*60 60.500 59.500
FREQ HZ

Figure-23

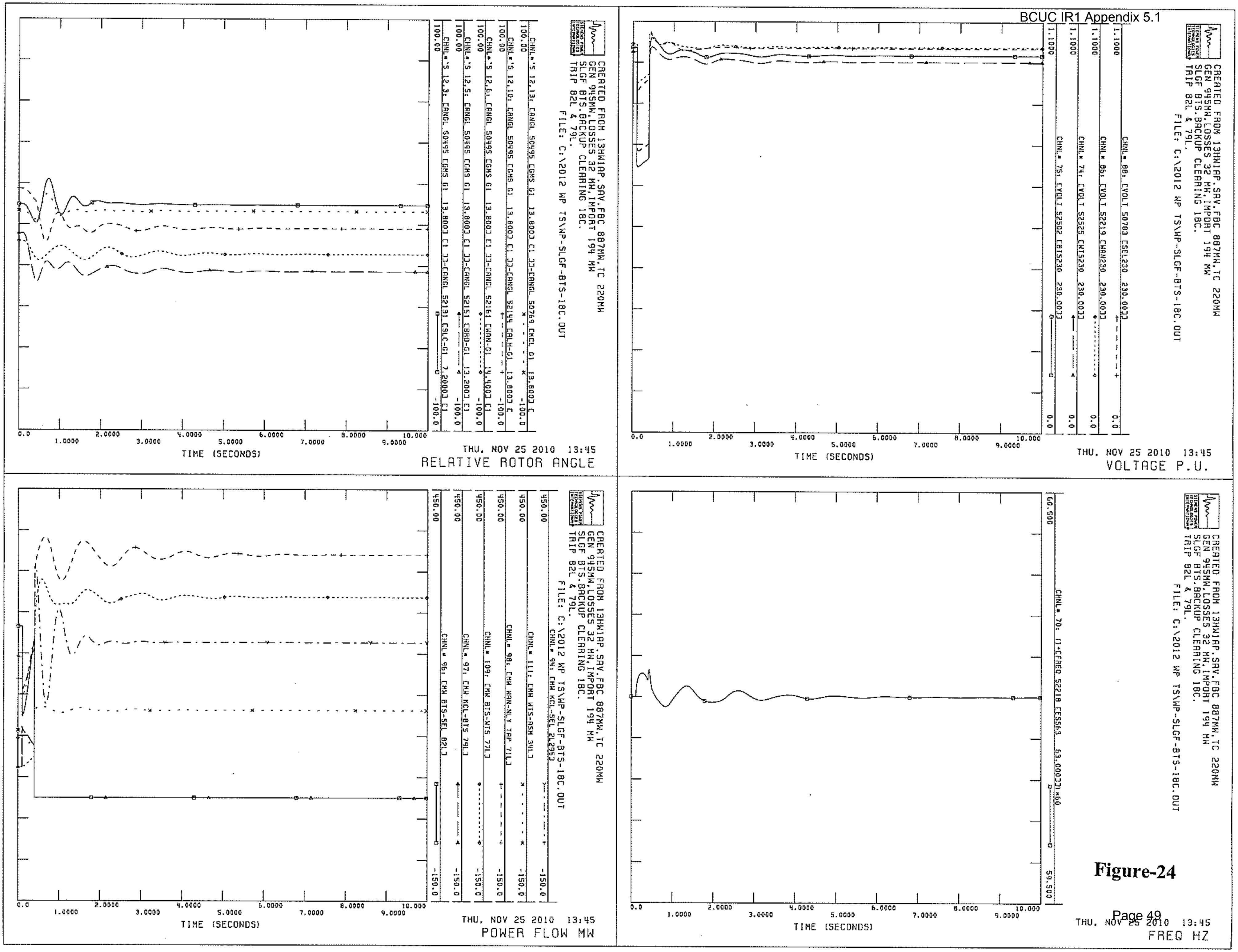

CREATED FROM 13HWIAP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 WP TS\WP-SLGF-BTS-18C.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800]1]-[ANGL 50769 [KCL G1 13.800]1
CHNL#'S 12,10: [ANGL 50495 [GMS G1 13.800]1]-[ANGL 52144 [ALH-G1 13.800]1
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800]1]-[ANGL 52161 [WAN-G1 14.400]1
CHNL#'S 12,5: [ANGL 50495 [GMS G1 13.800]1]-[ANGL 52151 [BRD-G1 13.200]1
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800]1]-[ANGL 52131 [SLC-G1 7.2000]1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, NOV 25 2010 13:45
RELATIVE ROTOR ANGLE
CREATED FROM 13HWIAP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 WP TS\WP-SLGF-BTS-18C.OUT
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 74: [VOLT 52525 [MIS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
1.1000
0.0
TIME (SECONDS)
THU, NOV 25 2010 13:45
VOLTAGE P.U.
CREATED FROM 13HWIAP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 WP TS\WP-SLGF-BTS-18C.OUT
CHNL# 94: [MW KCL-SEL 2L295]
CHNL# 111: [MW WTS-ASM 34L]
CHNL# 98: [MW WAN-NLY TAP 71L]
CHNL# 109: [MW BTS-WTS 77L]
CHNL# 97: [MW KCL-BTS 79L]
CHNL# 96: [MW BTS-SEL 82L]
450.00
-150.0
TIME (SECONDS)
THU, NOV 25 2010 13:45
POWER FLOW MW
CREATED FROM 13HWIAP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 WP TS\WP-SLGF-BTS-18C.OUT
CHNL# 70: [1+[FREQ 52218 [ESS63 63.000]]*60
60.500
59.500
TIME (SECONDS)
THU, NOV 25 2010 13:45
FREQ HZ

Figure-24

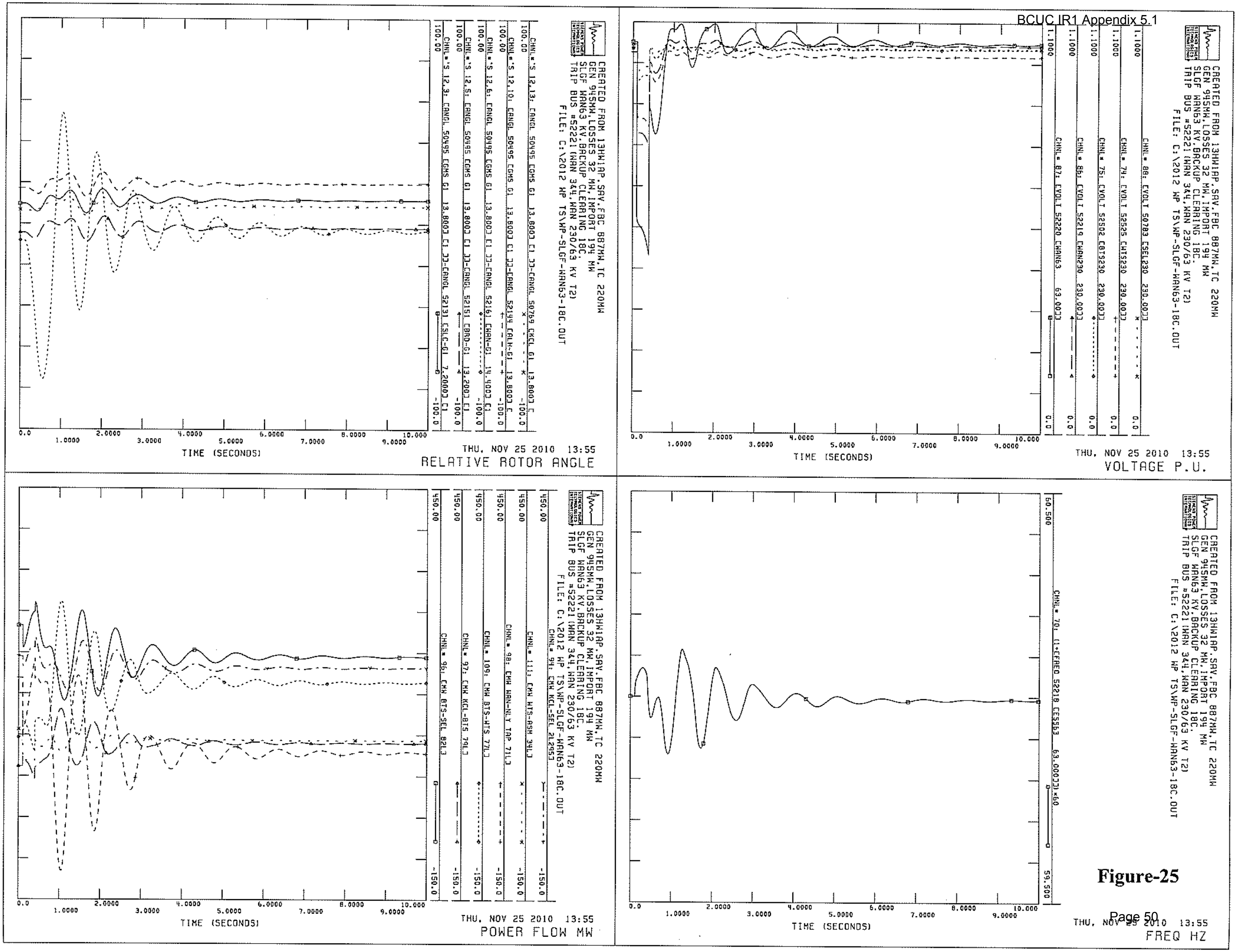

CREATED FROM 13HW1AP.SAV.FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 3&4,WAN 230/63 KV T2)
FILE: C:\2012 WP TS\WP-SLGF-WAN63-18C.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800] [1]]-[ANGL 50769 [KCL G1 13.800] [
CHNL#'S 12,10: [ANGL 50495 [GMS G1 13.800] [1]]-[ANGL 52144 [ALH-G1 13.800] [
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800] [1]]-[ANGL 52161 [WAN-G1 14.400] [1
CHNL#'S 12,5: [ANGL 50495 [GMS G1 13.800] [1]]-[ANGL 52151 [BRD-G1 13.200] [1
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800] [1]]-[ANGL 52131 [SLC-G1 7.2000] [1
100.00
-100.0
TIME (SECONDS)
THU, NOV 25 2010 13:55
RELATIVE ROTOR ANGLE
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 74: [VOLT 52525 [WTS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 87: [VOLT 52220 [WAN63 63.000]]
1.1000
0.0
THU, NOV 25 2010 13:55
VOLTAGE P.U.
CHNL# 94: [MW KCL-SEL 2L295]
CHNL# 111: [MW WTS-ASM 34L]
CHNL# 98: [MW WAN-NLY TAP 71L]
CHNL# 109: [MW BTS-WTS 77L]
CHNL# 97: [MW KCL-BTS 79L]
CHNL# 96: [MW BTS-SEL 82L]
450.00
-150.0
THU, NOV 25 2010 13:55
POWER FLOW MW
CHNL# 70: (1+[FREQ 52218 [ES563 63.000]])*60
60.500
59.500
THU, NOV 25 2010 13:55
FREQ HZ
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

Figure-25

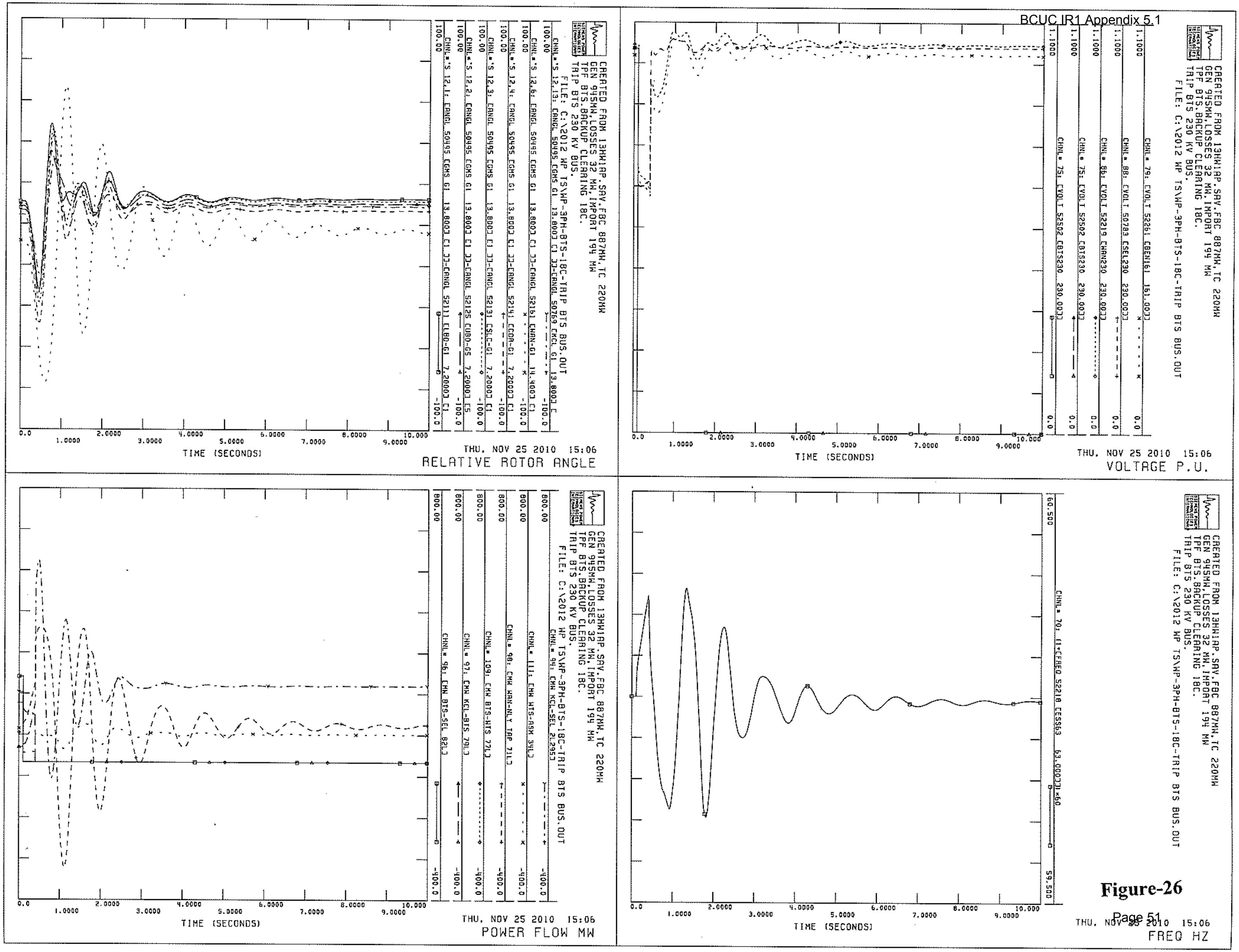

CREATED FROM 13HW1AP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
TPF BTS,BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 WP TS\WP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800] C1]-[ANGL 50769 [KCL G1 13.800] C
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800] C1]-[ANGL 52161 [WAN-G1 14.400] C1
CHNL#'S 12,4: [ANGL 50495 [GMS G1 13.800] C1]-[ANGL 52141 [COR-G1 7.2000] C1
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800] C1]-[ANGL 52131 [SLC-G1 7.2000] C1
CHNL#'S 12,2: [ANGL 50495 [GMS G1 13.800] C1]-[ANGL 52125 [UBO-G5 7.2000] C5
CHNL#'S 12,1: [ANGL 50495 [GMS G1 13.800] C1]-[ANGL 52111 [LBO-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, NOV 25 2010 15:06
RELATIVE ROTOR ANGLE
CREATED FROM 13HW1AP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
TPF BTS,BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 WP TS\WP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 79: [VOLT 52261 [BEN161 161.00]]
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
1.1000
0.0
TIME (SECONDS)
THU, NOV 25 2010 15:06
VOLTAGE P.U.
CREATED FROM 13HW1AP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
TPF BTS,BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 WP TS\WP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 94: [MW KCL-SEL 2L295]
CHNL# 111: [MW WTS-ASH 34L]
CHNL# 98: [MW WAN-NLY TAP 71L]
CHNL# 109: [MW BTS-WTS 72L]
CHNL# 97: [MW KCL-BTS 79L]
CHNL# 96: [MW BTS-SEL 82L]
800.00
-400.0
TIME (SECONDS)
THU, NOV 25 2010 15:06
POWER FLOW MW
CREATED FROM 13HW1AP.SAV,FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
TPF BTS,BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 WP TS\WP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 70: [1+[FREQ 52218 [ESS63 63.000]]*60
60.500
59.500
TIME (SECONDS)
THU, NOV 25 2010 15:06
FREQ HZ

Figure-26

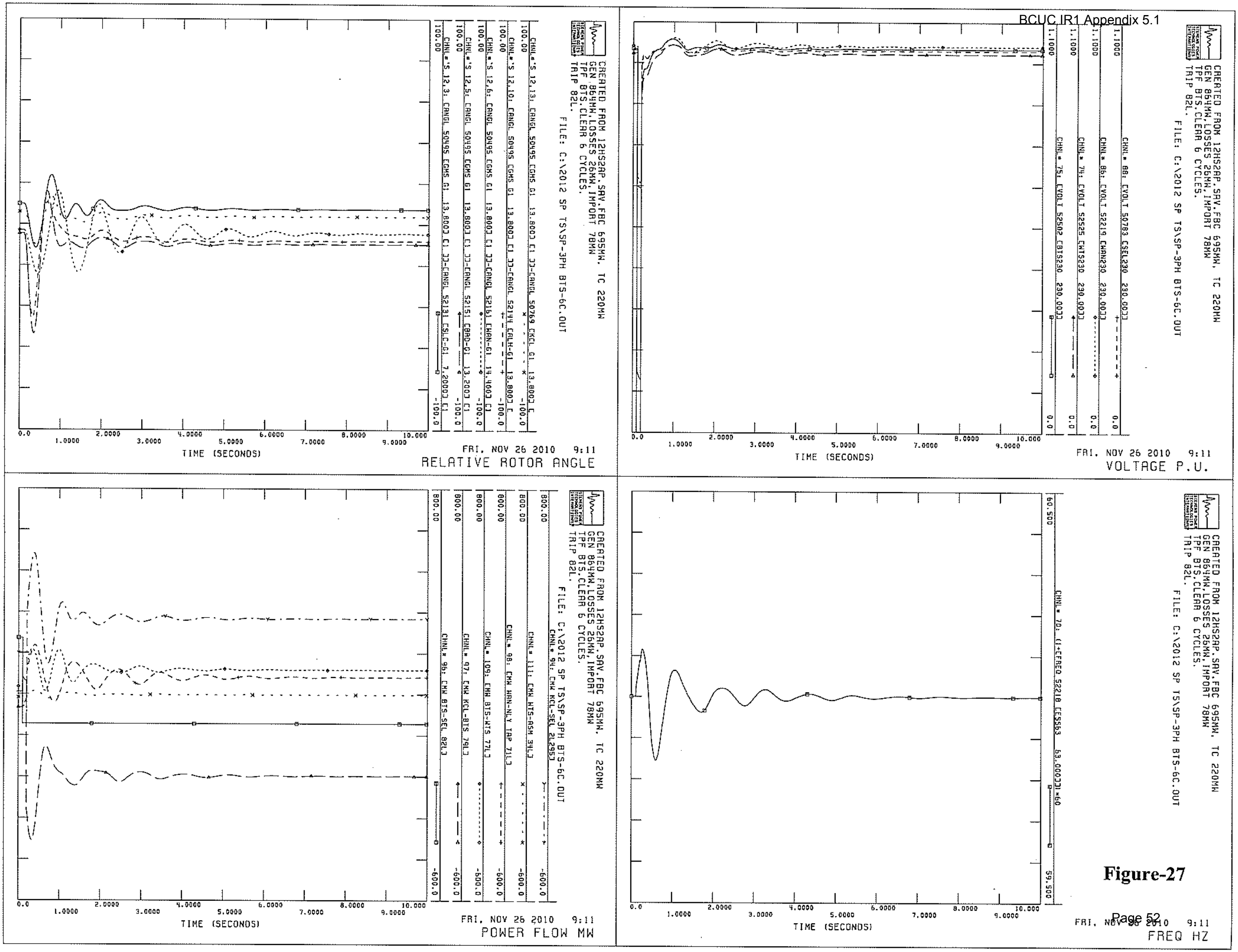

CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
TPF BTS.CLEAR 6 CYCLES.
TRIP 82L.
FILE: C:\2012 SP TS\SP-3PH BTS-6C.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 50769 [KCL G1 13.800] C
CHNL#'S 12,10: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52144 [ALH-G1 13.800] C
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52161 [WAN-G1 14.400] C1
CHNL#'S 12,5: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52151 [BRD-G1 13.200] C1
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52131 [SLC-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
TPF BTS.CLEAR 6 CYCLES.
TRIP 82L.
FILE: C:\2012 SP TS\SP-3PH BTS-6C.OUT
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 74: [VOLT 52525 [WTS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
1.1000
0.0
TIME (SECONDS)
FRI, NOV 26 2010 9:11
VOLTAGE P.U.
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
TPF BTS.CLEAR 6 CYCLES.
TRIP 82L.
FILE: C:\2012 SP TS\SP-3PH BTS-6C.OUT
CHNL# 94: CMW KCL-SEL 2L295]
CHNL# 111: CMW WTS-ASW 34L]
CHNL# 98: CMW WAN-NLY TAP 71L]
CHNL# 109: CMW BTS-WTS 77L]
CHNL# 97: CMW KCL-BTS 79L]
CHNL# 96: CMW BTS-SEL 82L]
800.00
-600.0
TIME (SECONDS)
FRI, NOV 26 2010 9:11
POWER FLOW MW
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
TPF BTS.CLEAR 6 CYCLES.
TRIP 82L.
FILE: C:\2012 SP TS\SP-3PH BTS-6C.OUT
CHNL# 70: (1+[FREQ 52210 [ESS63 63.000]])*60
60.500
59.500
TIME (SECONDS)
FRI, NOV 26 2010 9:11
FREQ HZ

Figure-27

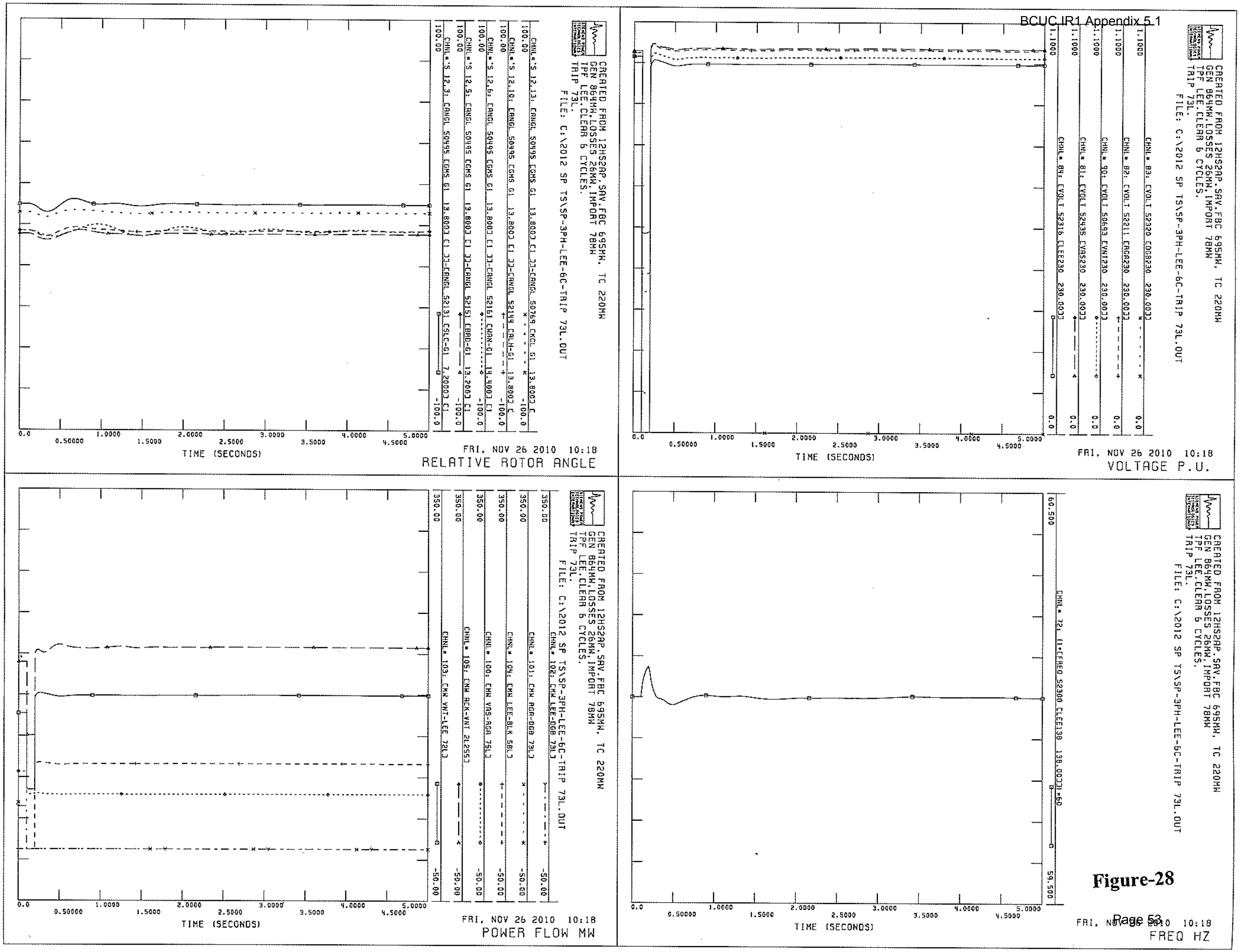


Figure-28

CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 SP TS\SP-3PH-LEE-6C-TRIP 73L.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 50769 [KCL G1 13.800] C
CHNL#'S 12,10: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52149 [ALH-G1 13.800] C
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52161 [WAN-G1 14.400] C1
CHNL#'S 12,5: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52151 [BRD-G1 13.200] C1
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52131 [SLC-G1 7.2000] C1
100.00
-100.0
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:18
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 SP TS\SP-3PH-LEE-6C-TRIP 73L.OUT
CHNL# 83: [VOLT 52320 [DGB230 230.00]]
CHNL# 82: [VOLT 52211 [AGA230 230.00]]
CHNL# 90: [VOLT 50693 [VNT230 230.00]]
CHNL# 81: [VOLT 52435 [VAS230 230.00]]
CHNL# 84: [VOLT 52316 [LEE230 230.00]]
1.1000
0.0
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:18
VOLTAGE P.U.
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 SP TS\SP-3PH-LEE-6C-TRIP 73L.OUT
CHNL# 102: [MW LEE-DGB 73L]
CHNL# 101: [MW AGA-DGB 73L]
CHNL# 104: [MW LEE-BLK 58L]
CHNL# 100: [MW VAS-AGA 75L]
CHNL# 105: [MW ACK-VNT 2L255]
CHNL# 103: [MW VNT-LEE 72L]
350.00
-50.00
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:18
POWER FLOW MW
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 SP TS\SP-3PH-LEE-6C-TRIP 73L.OUT
CHNL# 72: [(1+FREQ 52300 [LEE138 138.00])*60
60.500
59.500
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:18
FREQ HZ

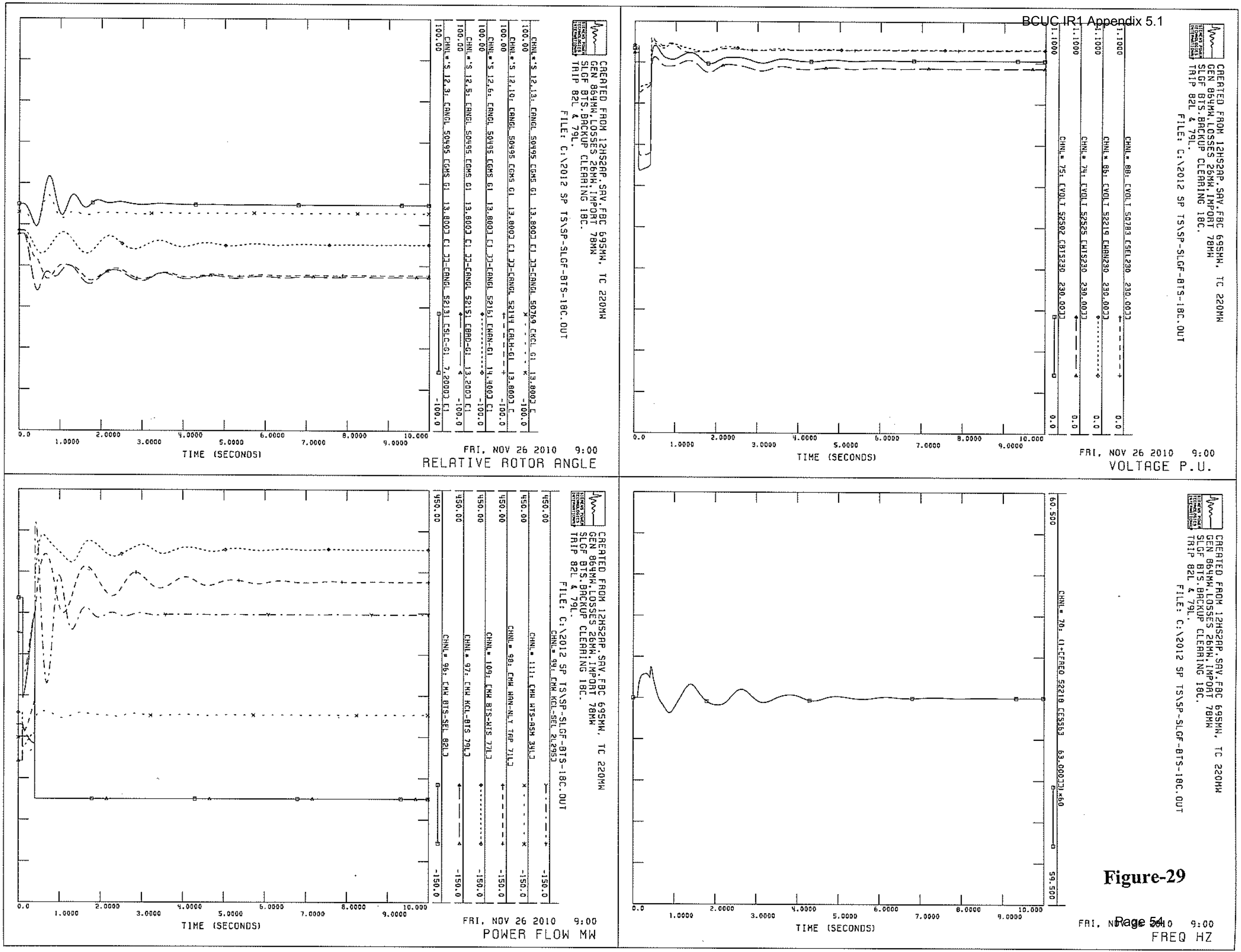
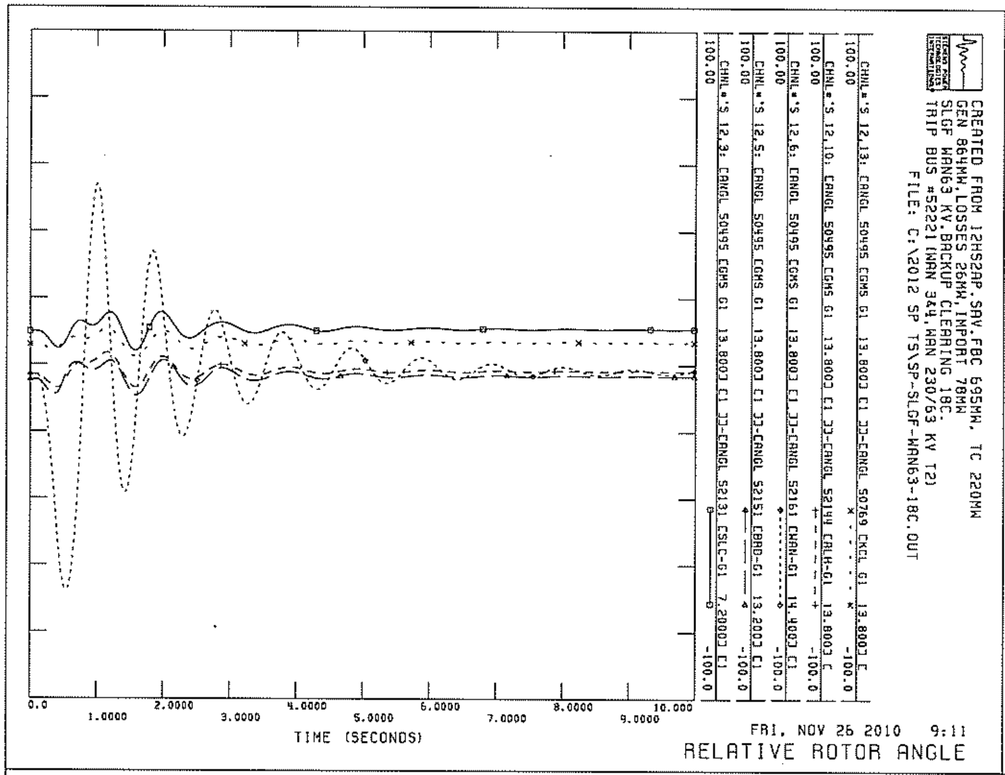
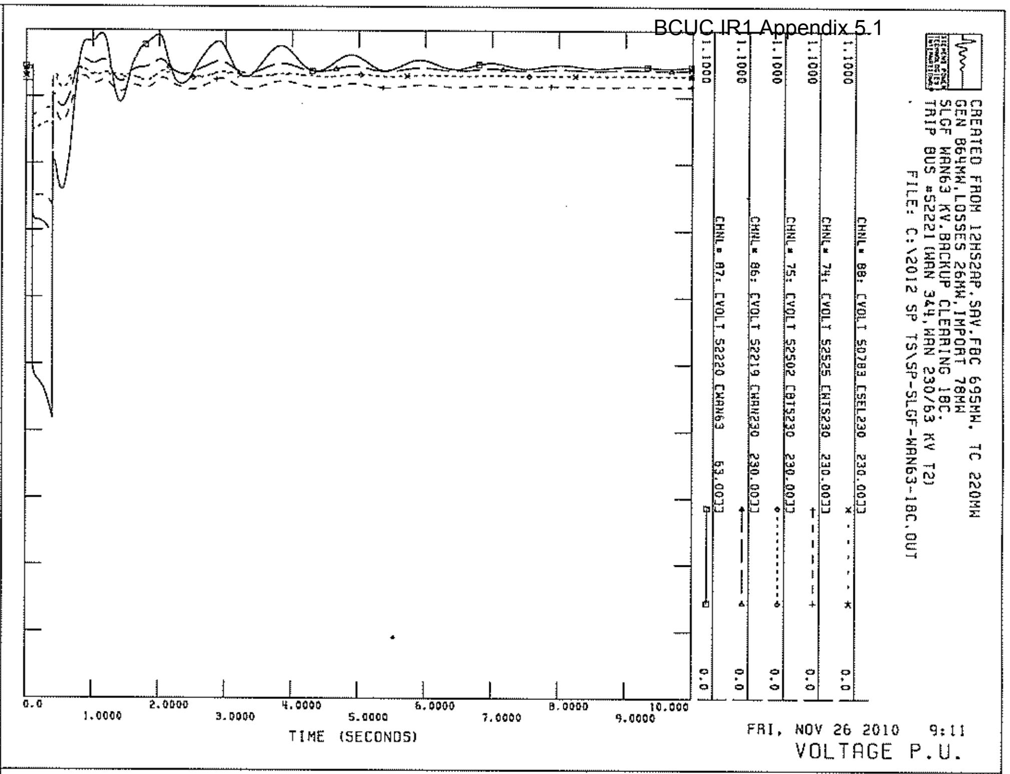
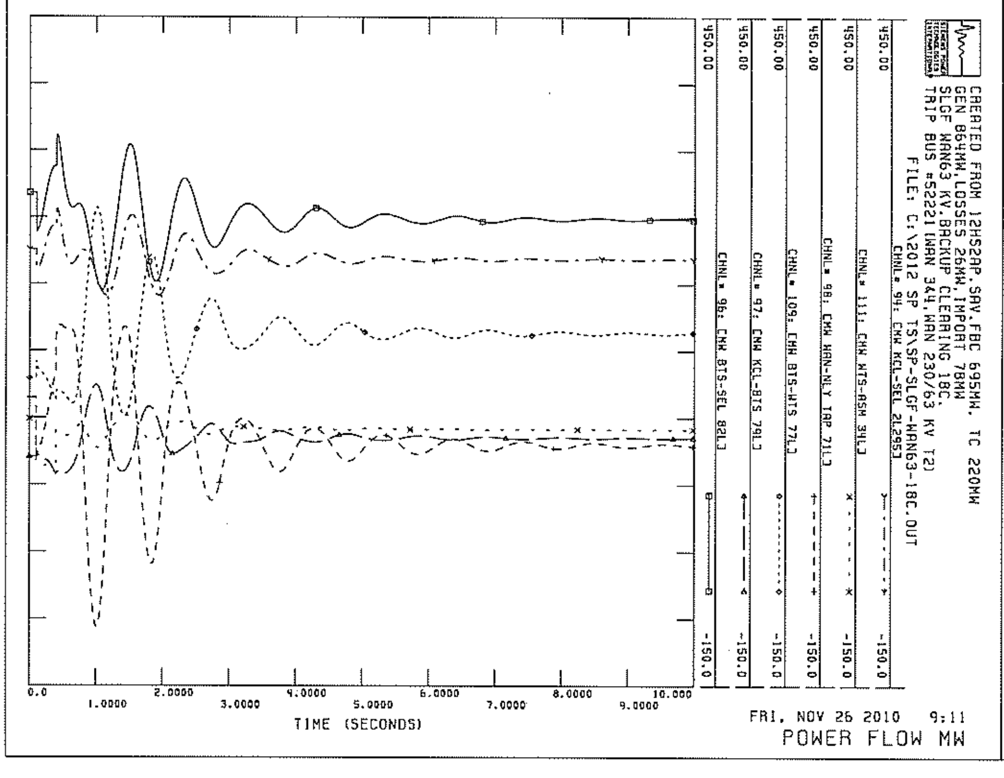

CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 SP TS\SP-SLGF-BTS-18C.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800] []]]-[ANGL 50769 [KCL G1 13.800] [
CHNL#'S 12,10: [ANGL 50495 [GMS G1 13.800] []]]-[ANGL 52144 [ALH-G1 13.800] [
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800] []]]-[ANGL 52161 [WAN-G1 14.400] []
CHNL#'S 12,5: [ANGL 50495 [GMS G1 13.800] []]]-[ANGL 52151 [BAD-G1 13.200] []
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800] []]]-[ANGL 52131 [SLC-G1 7.2000] []
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:00
RELATIVE ROTOR ANGLE
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 74: [VOLT 52525 [MIS230 230.00]]
CHNL# 75: [VOLT 52502 [BIS230 230.00]]
1.1000
0.0
TIME (SECONDS)
FRI, NOV 26 2010 9:00
VOLTAGE P.U.
CHNL# 94: CMW KCL-SEL 2L295]
CHNL# 111: CMW WTS-ASM 34L]
CHNL# 98: CMW WAN-NLY TAP 71L]
CHNL# 109: CMW BTS-WTS 77L]
CHNL# 97: CMW KCL-BTS 79L]
CHNL# 96: CMW BTS-SEL 82L]
450.00
-150.0
TIME (SECONDS)
FRI, NOV 26 2010 9:00
POWER FLOW MW
CHNL# 70: (1+[FREQ 52218 [ES563 63.000]])*60
60.500
59.500
TIME (SECONDS)
FRI, NOV 26 2010 9:00
FREQ HZ

Figure-29


CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 344,WAN 230/63 KV T2)
FILE: C:\2012 SP TS\SP-SLGF-WAN63-18C.OUT
CHNL#'S 12,13: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 50769 [KCL G1 13.800] C
CHNL#'S 12,10: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52194 [ALH-G1 13.800] C
CHNL#'S 12,6: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52161 [WAN-G1 14.400] C1
CHNL#'S 12,5: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52151 [BRD-G1 13.200] C1
CHNL#'S 12,3: [ANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52131 [SLC-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
RELATIVE ROTOR ANGLE


CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 344,WAN 230/63 KV T2)
FILE: C:\2012 SP TS\SP-SLGF-WAN63-18C.OUT
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 74: [VOLT 52525 [WTS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 87: [VOLT 52220 [WAN63 63.000]]
1.1000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
VOLTAGE P.U.


CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 344,WAN 230/63 KV T2)
FILE: C:\2012 SP TS\SP-SLGF-WAN63-18C.OUT
CHNL# 94: [MW KCL-SEL 2L295]
CHNL# 111: [MW WTS-ASH 3L4]
CHNL# 98: [MW WAN-NLY TAP 71L]
CHNL# 109: [MW BTS-WTS 77L]
CHNL# 97: [MW KCL-BTS 79L]
CHNL# 96: [MW BTS-SEL 82L]
450.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
POWER FLOW MW

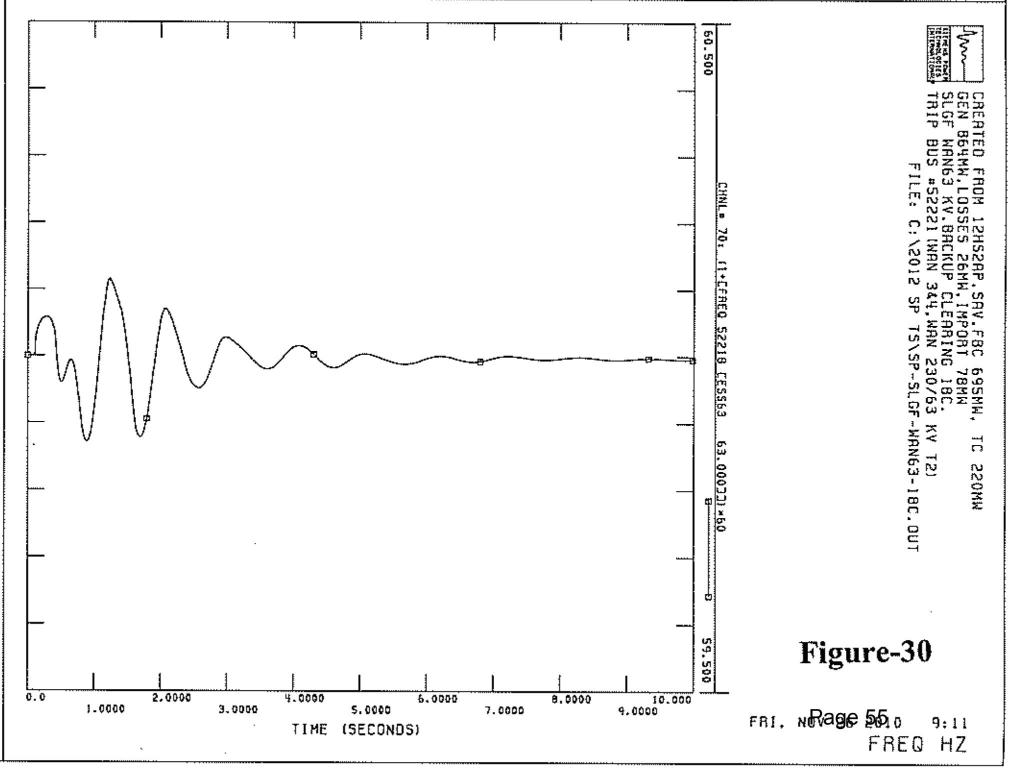

CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW.LOSSES 26MW.IMPORT 78MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 344,WAN 230/63 KV T2)
FILE: C:\2012 SP TS\SP-SLGF-WAN63-18C.OUT
CHNL# 70: (1+[FREQ 52218 [ES563 63.000])*60
60.500
59.500
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
FREQ HZ

Figure-30

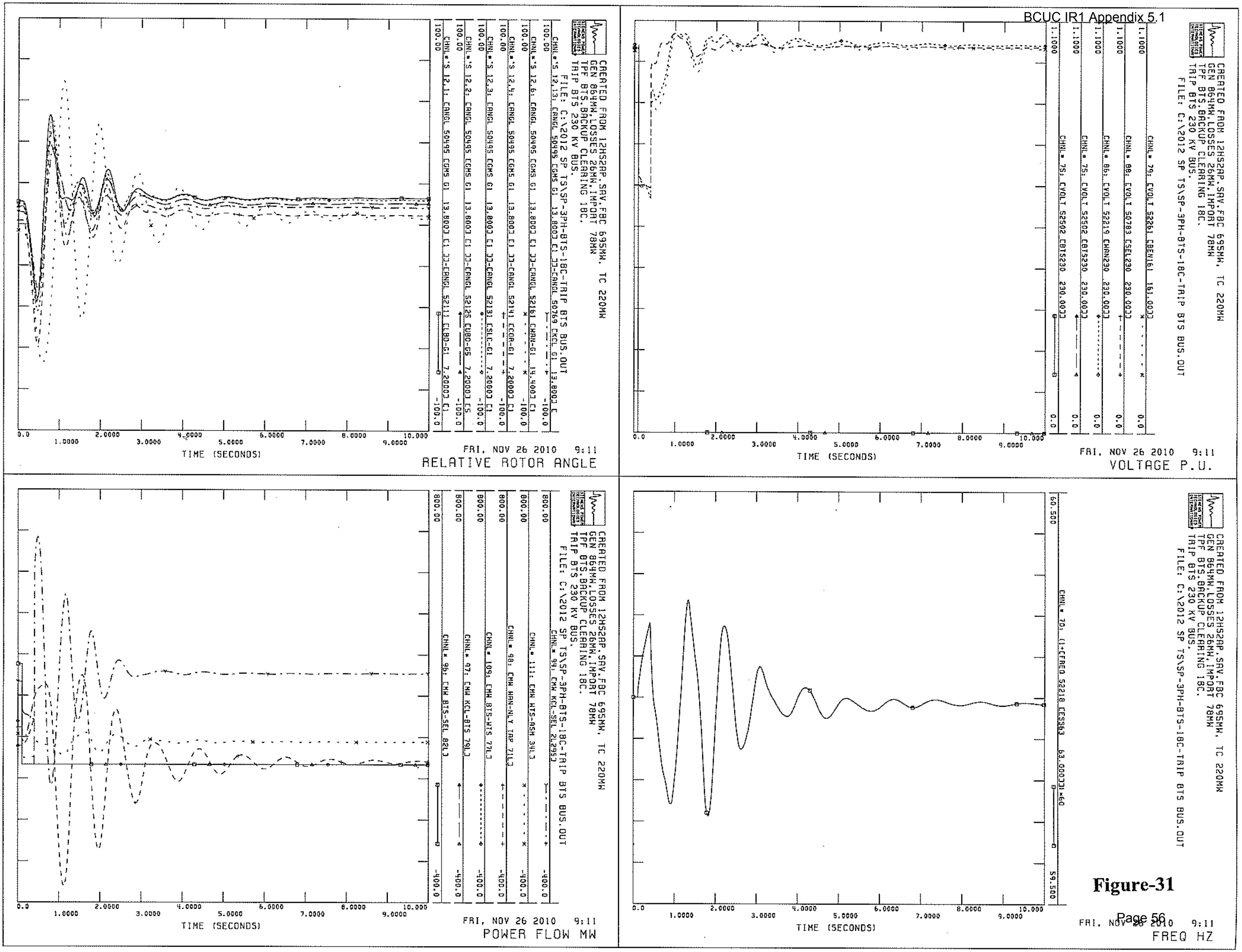
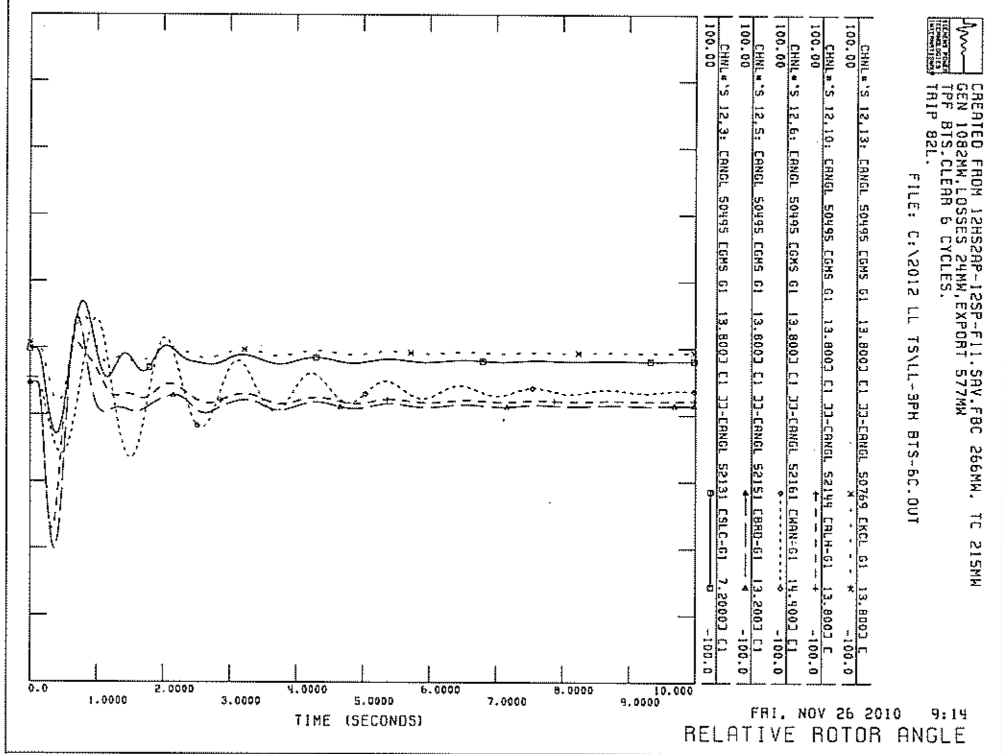
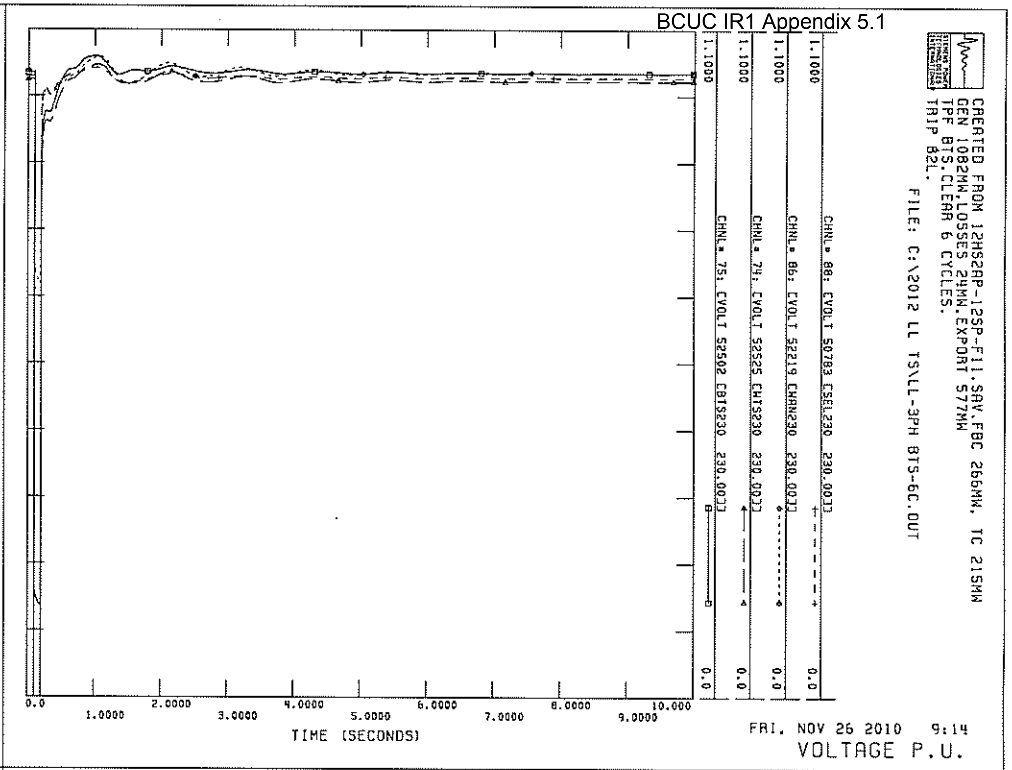

CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 SP TS\SP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL#'S 12,13: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 50769 CKCL G1 13.800] C 100.00 -100.0
CHNL#'S 12,6: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52161 CWAN-G1 14.400] C1 100.00 -100.0
CHNL#'S 12,4: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52141 CCOR-G1 7.2000] C1 100.00 -100.0
CHNL#'S 12,3: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52131 CSLC-G1 7.2000] C1 100.00 -100.0
CHNL#'S 12,2: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52125 CUBO-G5 7.2000] C5 100.00 -100.0
CHNL#'S 12,1: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52111 CLBO-G1 7.2000] C1 100.00 -100.0
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 SP TS\SP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 79: CVOLT 52261 CBENU161 161.00] 1.1000 0.0
CHNL# 88: CVOLT 50783 CSEL230 230.00] 1.1000 0.0
CHNL# 86: CVOLT 52219 CWAN230 230.00] 1.1000 0.0
CHNL# 75: CVOLT 52502 CBTS230 230.00] 1.1000 0.0
CHNL# 75: CVOLT 52502 CBTS230 230.00] 1.1000 0.0
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
VOLTAGE P.U.
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 SP TS\SP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 94: CMW KCL-SEL 2L295] 800.00 -400.0
CHNL# 111: CMW WTS-RSM 34L] 800.00 -400.0
CHNL# 98: CMW HRN-NLY TAP 71L] 800.00 -400.0
CHNL# 109: CMW BTS-WTS 77L] 800.00 -400.0
CHNL# 97: CMW KCL-BTS 79L] 800.00 -400.0
CHNL# 96: CMW BTS-SEL 82L] 800.00 -400.0
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
POWER FLOW MW
CREATED FROM 12HS2AP.SAV.FBC 695MW, TC 220MW
GEN 864MW,LOSSES 26MW,IMPORT 78MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 SP TS\SP-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 70: (1+CFREQ 52218 CESS63 63.000])*60 60.500 59.500
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:11
FREQ HZ

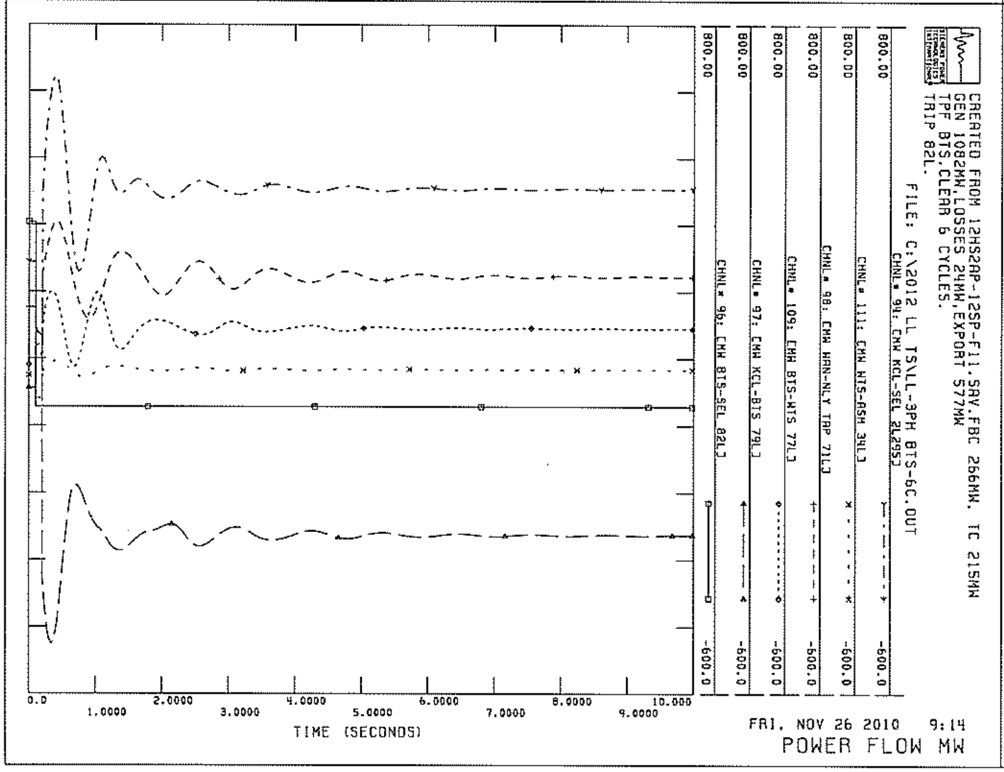
Figure-31



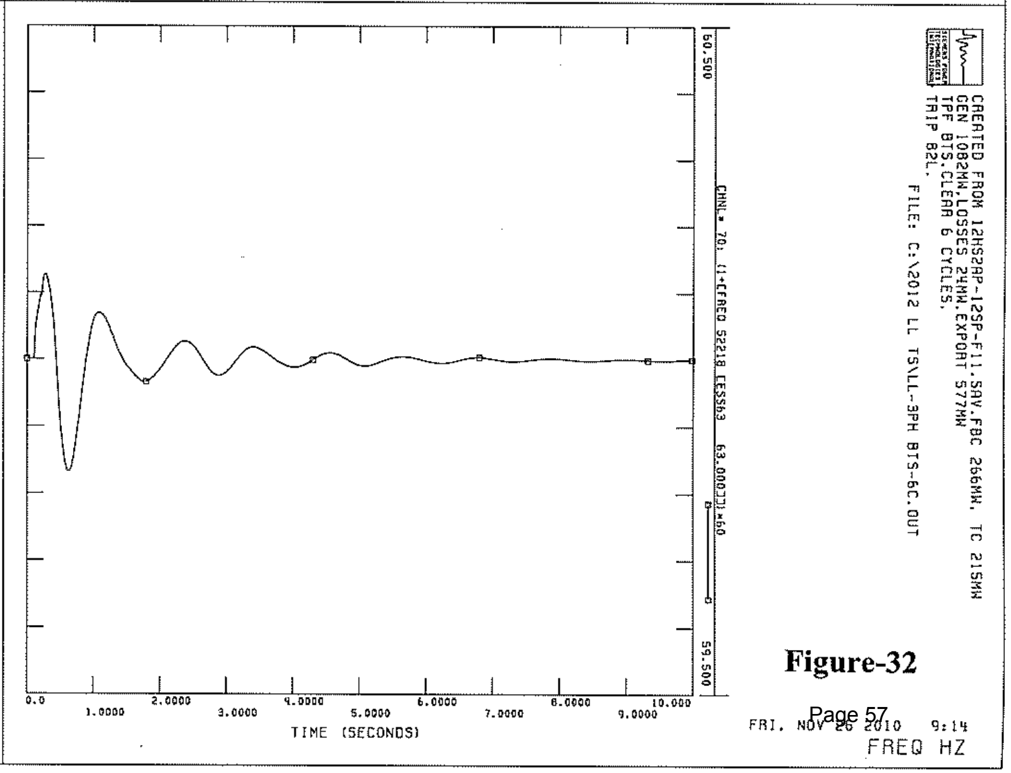
RELATIVE ROTOR ANGLE



VOLTAGE P.U.



POWER FLOW MW



FREQ HZ

Figure-32

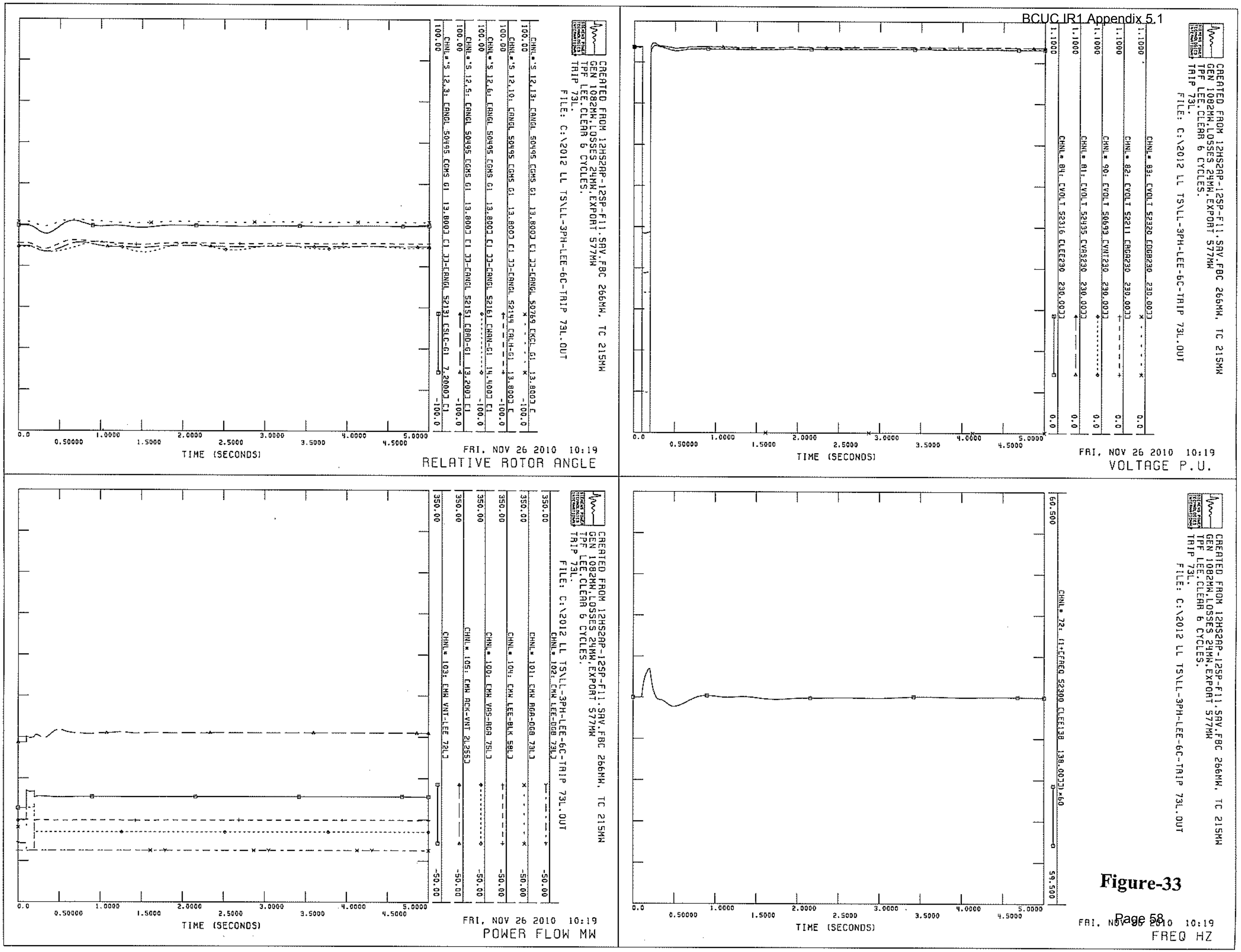

CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 LL TS\LL-3PH-LEE-6C-TRIP 73L.OUT
CHNL#'S 12,13: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 50769 CKCL G1 13.800] C
CHNL#'S 12,10: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52144 CALH-G1 13.800] C
CHNL#'S 12,6: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52161 CWAN-G1 14.400] C1
CHNL#'S 12,5: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52151 CBAO-G1 13.200] C1
CHNL#'S 12,3: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52131 CSLC-G1 7.2000] C1
100.00
-100.0
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:19
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 LL TS\LL-3PH-LEE-6C-TRIP 73L.OUT
CHNL# 83: CVOLT 52320 CDGB230 230.00]
CHNL# 82: CVOLT 52211 CRGR230 230.00]
CHNL# 90: CVOLT 50693 CVNT230 230.00]
CHNL# 81: CVOLT 52435 CVAS230 230.00]
CHNL# 84: CVOLT 52316 CLEE230 230.00]
1.1000
0.0
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:19
VOLTAGE P.U.
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 LL TS\LL-3PH-LEE-6C-TRIP 73L.OUT
CHNL# 102: CMW LEE-DGB 73L]
CHNL# 101: CMW AGA-DGB 73L]
CHNL# 104: CMW LEE-BLK 58L]
CHNL# 100: CMW VAS-AGA 75L]
CHNL# 105: CMW ACK-VNT 2L255]
CHNL# 103: CMW VNT-LEE 72L]
350.00
-50.00
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:19
POWER FLOW MW
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW,LOSSES 24MW,EXPORT 577MW
TPF LEE.CLEAR 6 CYCLES.
TRIP 73L.
FILE: C:\2012 LL TS\LL-3PH-LEE-6C-TRIP 73L.OUT
CHNL# 72: (1+CFREQ 52300 CLEE138 138.00])*60
60.500
59.500
0.0
0.50000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
TIME (SECONDS)
FRI, NOV 26 2010 10:19
FREQ HZ

Figure-33

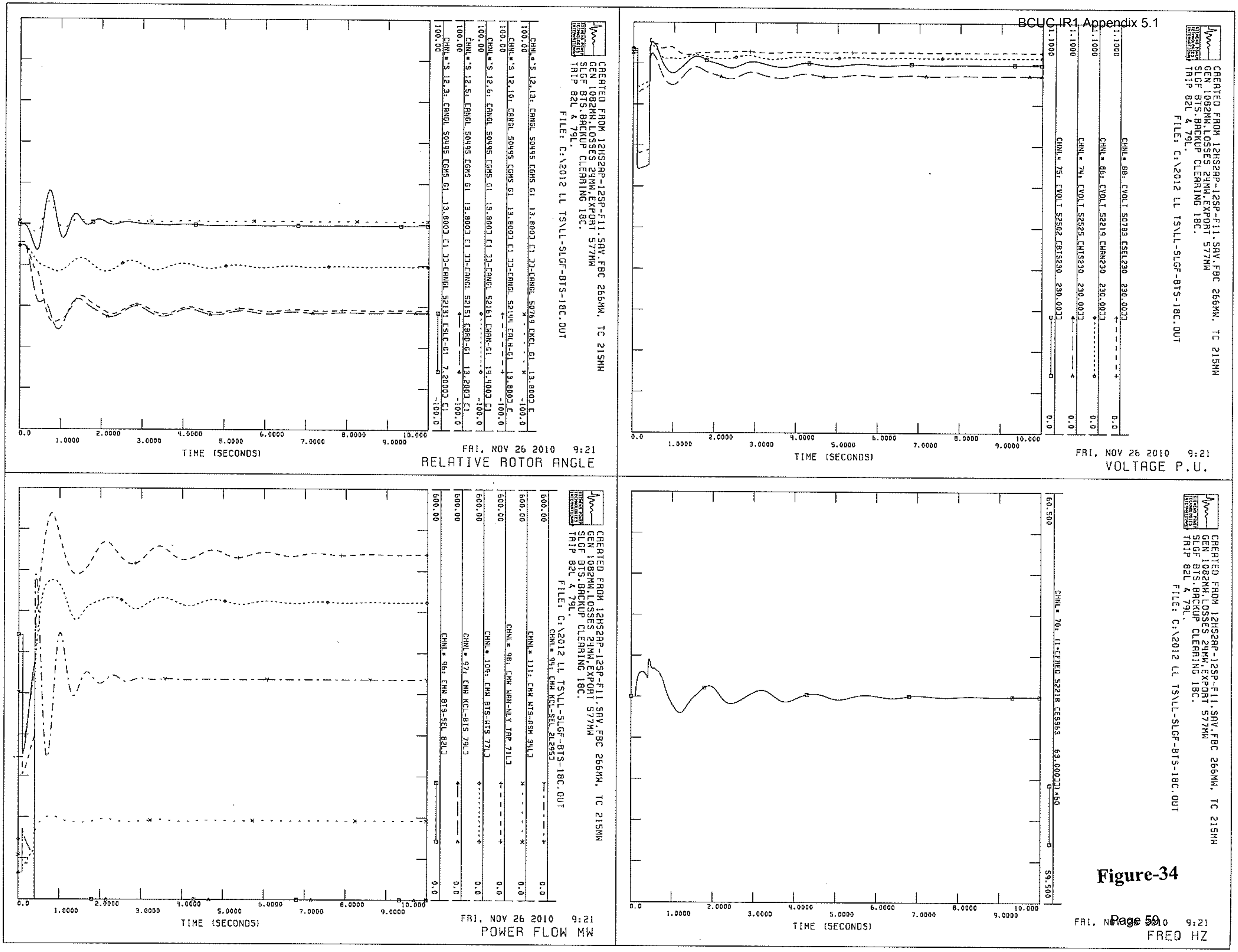

CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 LL TS\LL-SLGF-BTS-18C.OUT
CHNL#'S 12,13: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 50769 CKCL G1 13.800] C
CHNL#'S 12,10: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52144 CALH-G1 13.800] C
CHNL#'S 12,6: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52161 CWAN-G1 14.400] C1
CHNL#'S 12,5: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52151 CBRD-G1 13.200] C1
CHNL#'S 12,3: CANGL 50495 CGMS G1 13.800] C1]]-CANGL 52131 CSLC-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:21
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 LL TS\LL-SLGF-BTS-18C.OUT
CHNL# 88: CVOLT 50783 CSEL230 230.00]]
CHNL# 86: CVOLT 52219 CWAN230 230.00]]
CHNL# 74: CVOLT 52525 CWTS230 230.00]]
CHNL# 75: CVOLT 52502 CBTS230 230.00]]
1.1000
0.0
TIME (SECONDS)
FRI, NOV 26 2010 9:21
VOLTAGE P.U.
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 LL TS\LL-SLGF-BTS-18C.OUT
CHNL# 94: CMW KCL-SEL 2L295]
CHNL# 111: CMW WTS-ASM 34L]
CHNL# 98: CMW WAN-NLY TAP 71L]
CHNL# 109: CMW BTS-WTS 77L]
CHNL# 97: CMW KCL-BTS 79L]
CHNL# 96: CMW BTS-SEL 82L]
600.00
0.0
TIME (SECONDS)
FRI, NOV 26 2010 9:21
POWER FLOW MW
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF BTS.BACKUP CLEARING 18C.
TRIP 82L & 79L.
FILE: C:\2012 LL TS\LL-SLGF-BTS-18C.OUT
CHNL# 70: (1+CFREQ 52218 CES563 63.000]])*60
60.500
59.500
TIME (SECONDS)
FRI, NOV 26 2010 9:21
FREQ HZ

Figure-34

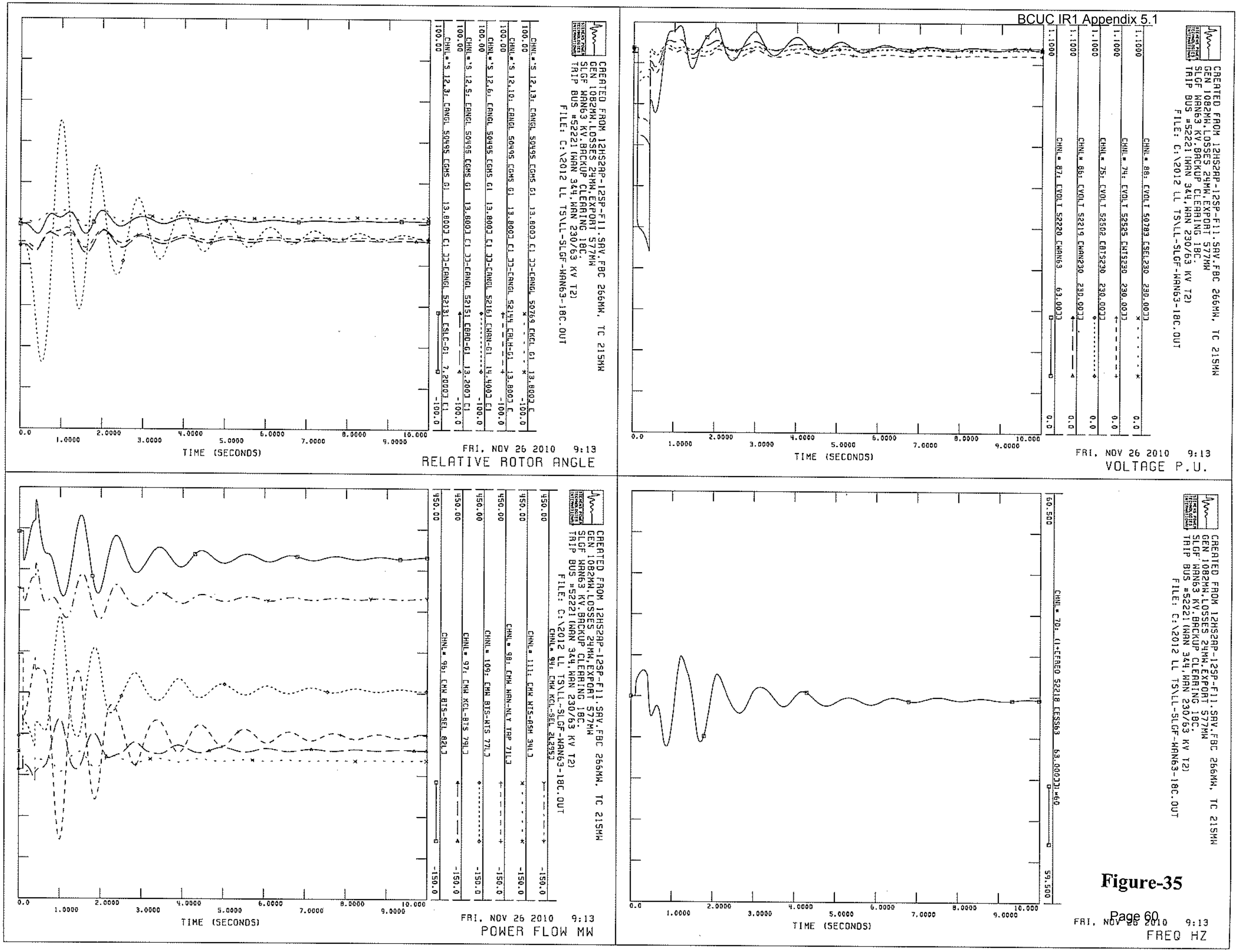

CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 3&4,WAN 230/63 KV T2)
FILE: C:\2012 LL TS\LL-SLGF-WAN63-18C.OUT
CHNL#'S 12,13: CANGL 50495 [GMS G1 13.800] C1]]-[ANGL 50769 [KCL G1 13.800] C
CHNL#'S 12,10: CANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52144 [ALH-G1 13.800] C
CHNL#'S 12,6: CANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52161 [WAN-G1 14.400] C1
CHNL#'S 12,5: CANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52151 [BAD-G1 13.200] C1
CHNL#'S 12,3: CANGL 50495 [GMS G1 13.800] C1]]-[ANGL 52131 [SLC-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:13
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 3&4,WAN 230/63 KV T2)
FILE: C:\2012 LL TS\LL-SLGF-WAN63-18C.OUT
CHNL# 88: [VOLT 50283 [SEL230 230.00]]
CHNL# 74: [VOLT 52525 [WTS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 87: [VOLT 52220 [WAN63 63.000]]
1.1000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:13
VOLTAGE P.U.
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 3&4,WAN 230/63 KV T2)
FILE: C:\2012 LL TS\LL-SLGF-WAN63-18C.OUT
CHNL# 94: [MW KCL-SEL 2L295]
CHNL# 111: [MW WTS-RSM 3L]
CHNL# 98: [MW WAN-NLY TAP 71L]
CHNL# 109: [MW BTS-WTS 77L]
CHNL# 97: [MW KCL-BTS 79L]
CHNL# 96: [MW BTS-SEL 82L]
450.00
-150.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:13
POWER FLOW MW
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
SLGF WAN63 KV.BACKUP CLEARING 18C.
TRIP BUS #52221(WAN 3&4,WAN 230/63 KV T2)
FILE: C:\2012 LL TS\LL-SLGF-WAN63-18C.OUT
CHNL# 70: (1+[FREQ 52218 [ESS63 63.000]])*60
60.500
59.500
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:13
FREQ HZ

Figure-35

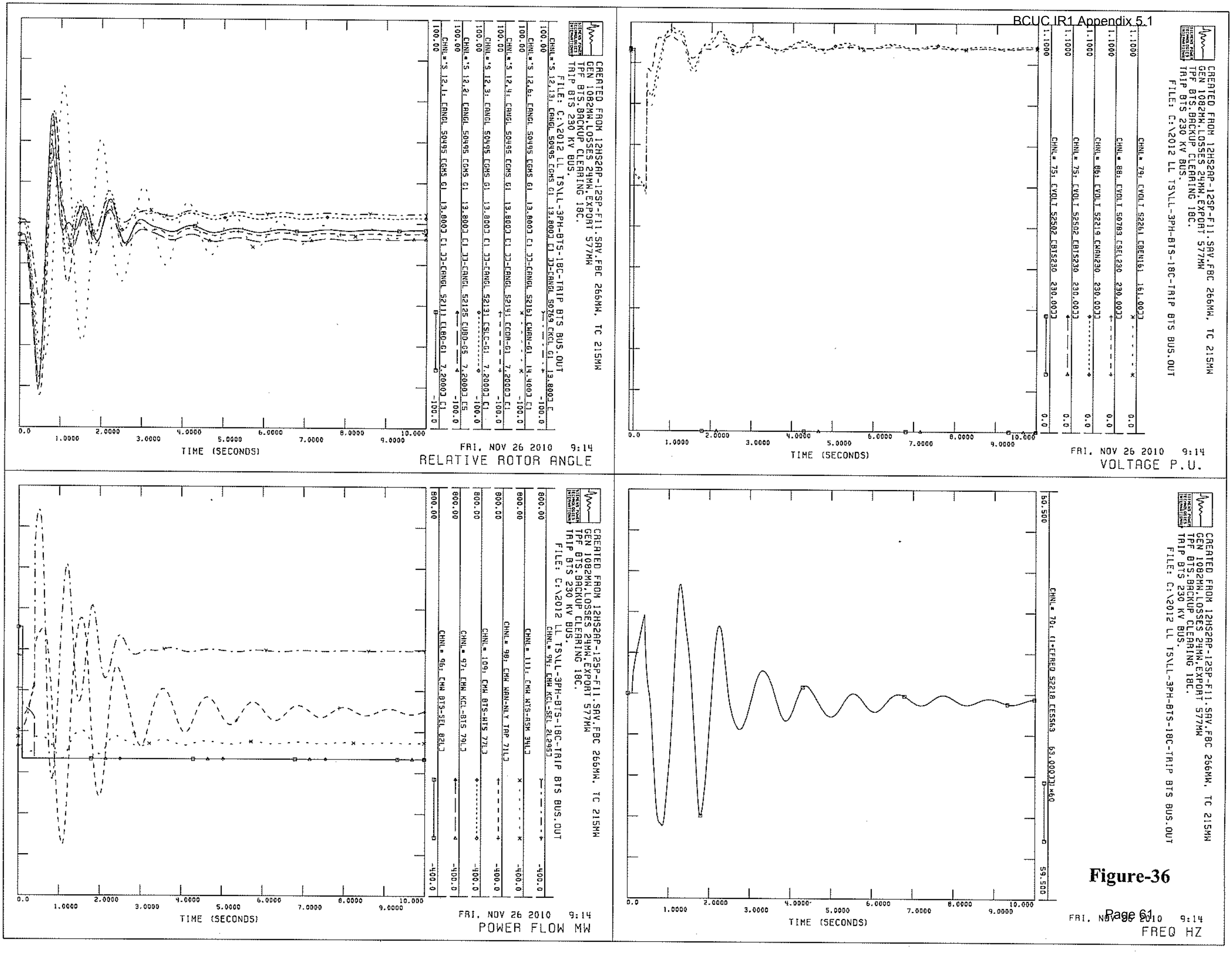

CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 LL TS\LL-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL#'S 12.13: CANGL 50495 [GMS G1 13.800] C1]]-CANGL 50769 [KCL G1 13.800] C
CHNL#'S 12.6: CANGL 50495 [GMS G1 13.800] C1]]-CANGL 52161 [WAN-G1 14.400] C1
CHNL#'S 12.4: CANGL 50495 [GMS G1 13.800] C1]]-CANGL 52141 [CDR-G1 7.2000] C1
CHNL#'S 12.3: CANGL 50495 [GMS G1 13.800] C1]]-CANGL 52131 [SLC-G1 7.2000] C1
CHNL#'S 12.2: CANGL 50495 [GMS G1 13.800] C1]]-CANGL 52125 [UBO-G5 7.2000] C5
CHNL#'S 12.1: CANGL 50495 [GMS G1 13.800] C1]]-CANGL 52111 [LBO-G1 7.2000] C1
100.00
-100.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, NOV 26 2010 9:14
RELATIVE ROTOR ANGLE
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 LL TS\LL-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 79: [VOLT 52261 [BEN161 161.00]]
CHNL# 88: [VOLT 50783 [SEL230 230.00]]
CHNL# 86: [VOLT 52219 [WAN230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
CHNL# 75: [VOLT 52502 [BTS230 230.00]]
1.1000
0.0
TIME (SECONDS)
FRI, NOV 26 2010 9:14
VOLTAGE P.U.
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 LL TS\LL-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 94: [MW KCL-SEL 2L295]
CHNL# 111: [MW WTS-ASM 34L]
CHNL# 98: [MW WAN-NLY TAP 71L]
CHNL# 109: [MW BTS-WTS 77L]
CHNL# 97: [MW KCL-BTS 79L]
CHNL# 96: [MW BTS-SEL 82L]
800.00
-400.0
TIME (SECONDS)
FRI, NOV 26 2010 9:14
POWER FLOW MW
CREATED FROM 12HS2AP-12SP-F11.SAV.FBC 266MW, TC 215MW
GEN 1082MW.LOSSES 24MW.EXPORT 577MW
TPF BTS.BACKUP CLEARING 18C.
TRIP BTS 230 KV BUS.
FILE: C:\2012 LL TS\LL-3PH-BTS-18C-TRIP BTS BUS.OUT
CHNL# 70: [1+FREQ 52218 [ESS63 63.000]]*60
60.500
59.500
TIME (SECONDS)
FRI, NOV 26 2010 9:14
FREQ HZ

Figure-36

APPENDIX-D

Reactive Power Margin Assessment (V-Q Analysis Winter Peak)

(VAR-001-1, R2 & R9)

Figure-37: 2012 - V-Q Curves for BUS 52316 LEE 230 kV

1. **Base case (Normal Operation)**
2. **One ACK-VNT 230 kV line out (2L255 or 2L256)**
3. **One VNT-LEE 230 kV line out (72L or 74L)**
4. **One VAS-RGA 230 kV line out (75L or 76L)**
5. **LEE-DGB-RGA 230 kV line out (73L)**

Figure-38: 2016 - V-Q Curves for BUS 52316 LEE 230 kV

1. **Base case (Normal Operation)**
2. **One ACK-VNT 230 kV line out (2L255 or 2L256)**
3. **One VNT-LEE 230 kV line out (72L or 74L)**
4. **One VAS-RGA 230 kV line out (75L or 76L)**
5. **LEE-DGB-RGA 230 kV line out (73L)**

Figure-39: 2020 (NO SVC) - V-Q Curves for BUS 52316 LEE 230 kV

1. **Base case (Normal Operation)**
2. **One ACK-VNT 230 kV line out (2L255 or 2L256)**
3. **One VNT-LEE 230 kV line out (72L or 74L)**
4. **One VAS-RGA 230 kV line out (75L or 76L)**
5. **LEE-DGB-RGA 230 kV line out (73L)**

Figure-40: 2020 (SVC AT DGB) - V-Q Curves for BUS 52316 LEE 230 kV

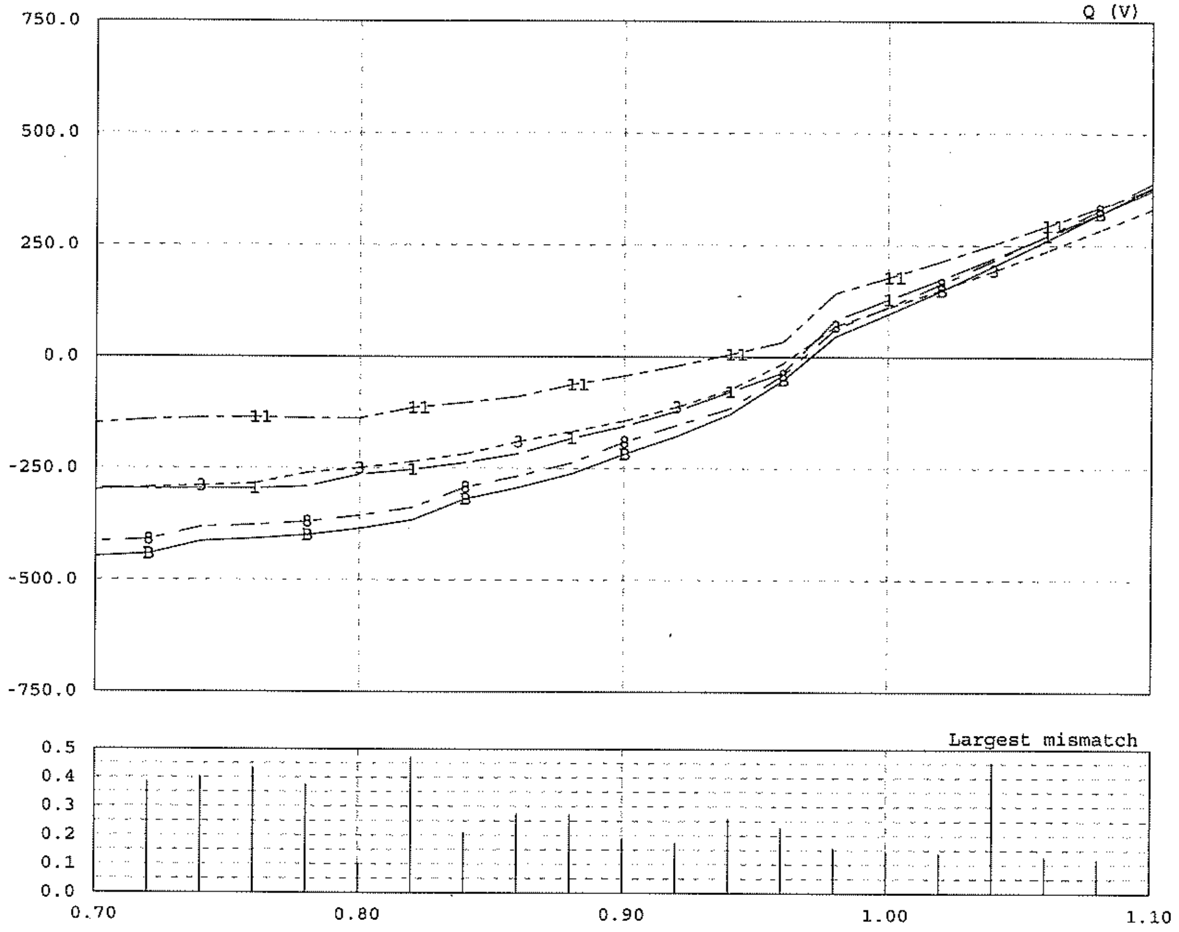
1. **Base case (Normal Operation)**
2. **One ACK-VNT 230 kV line out (2L255 or 2L256)**
3. **One VNT-LEE 230 kV line out (72L or 74L)**

iv. One VAS-RGA 230 kV line out (75L or 76L)

v. LEE-DGB-RGA 230 kV line out (73L)

CREATED FROM 13HW1AP.SAV.FBC 887MW,TC 220MW
GEN 945MW,LOSSES 32 MW,IMPORT 194 MW
MON, DEC 06 2010 8:28

Study bus: 52316

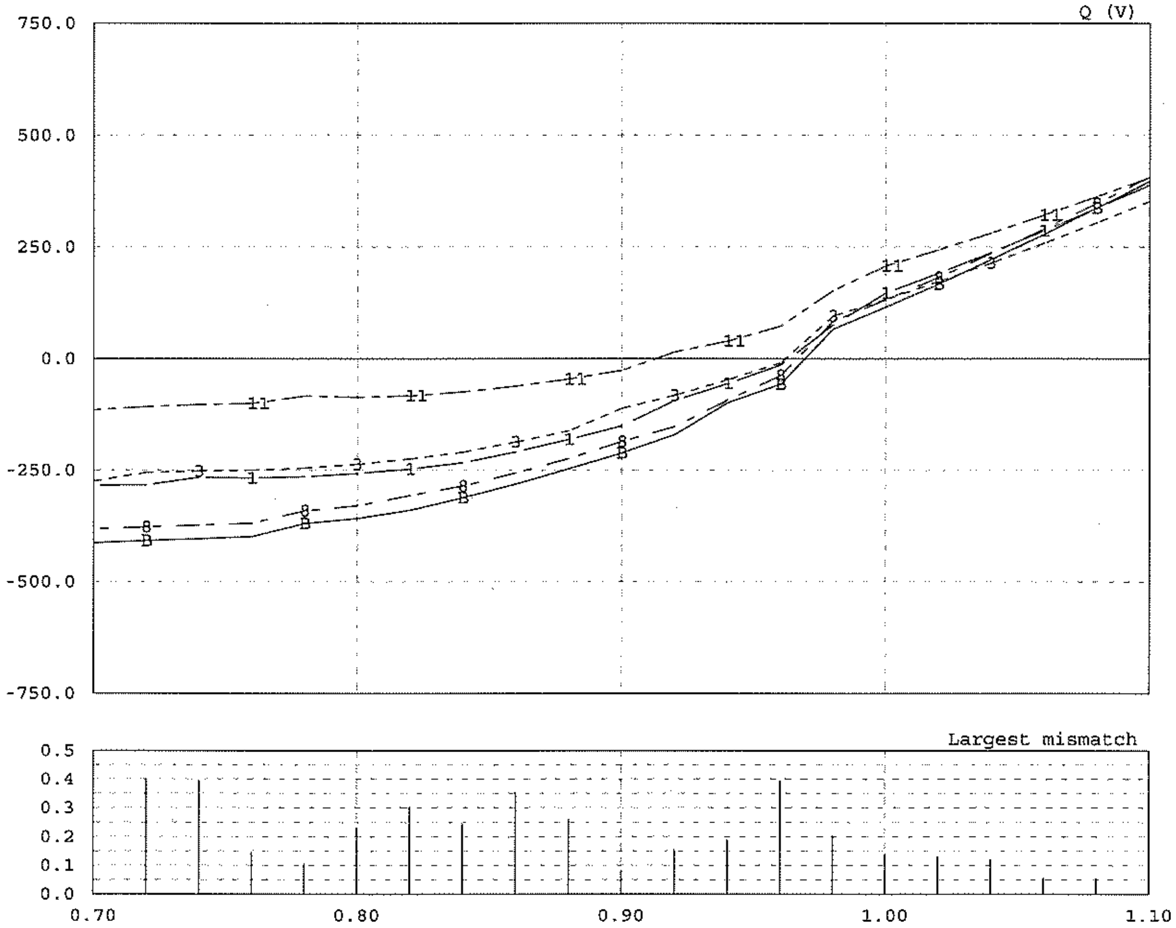


	Mark	Description	Q min
———	B	BASE CASE	-448.263
—— –	1	OPEN LINE FROM BUS 50690 [ACK230 230.00] TO BUS 50693 [VNT230 230.00] CKT 1	-296.706
- - - - -	3	OPEN LINE FROM BUS 50693 [VNT230 230.00] TO BUS 52316 [LEE230 230.00] CKT 1	-298.687
— - -	8	OPEN LINE FROM BUS 52211 [RGA230 230.00] TO BUS 52435 [VAS230 230.00] CKT 1	-414.507
—- - -	11	OPEN LINE FROM BUS 52320 [DG BELL 230.00] TO BUS 52211 [RGA230 230.00] CKT 1...	-149.381

Figure-37

CREATED FROM 16HW1SAP.SAV.FBC 951MW,TC 220MW
GEN 945MW,LOSSES 37MW,IMPORT 263MW
FRI, DEC 03 2010 14:38

Study bus: 52316

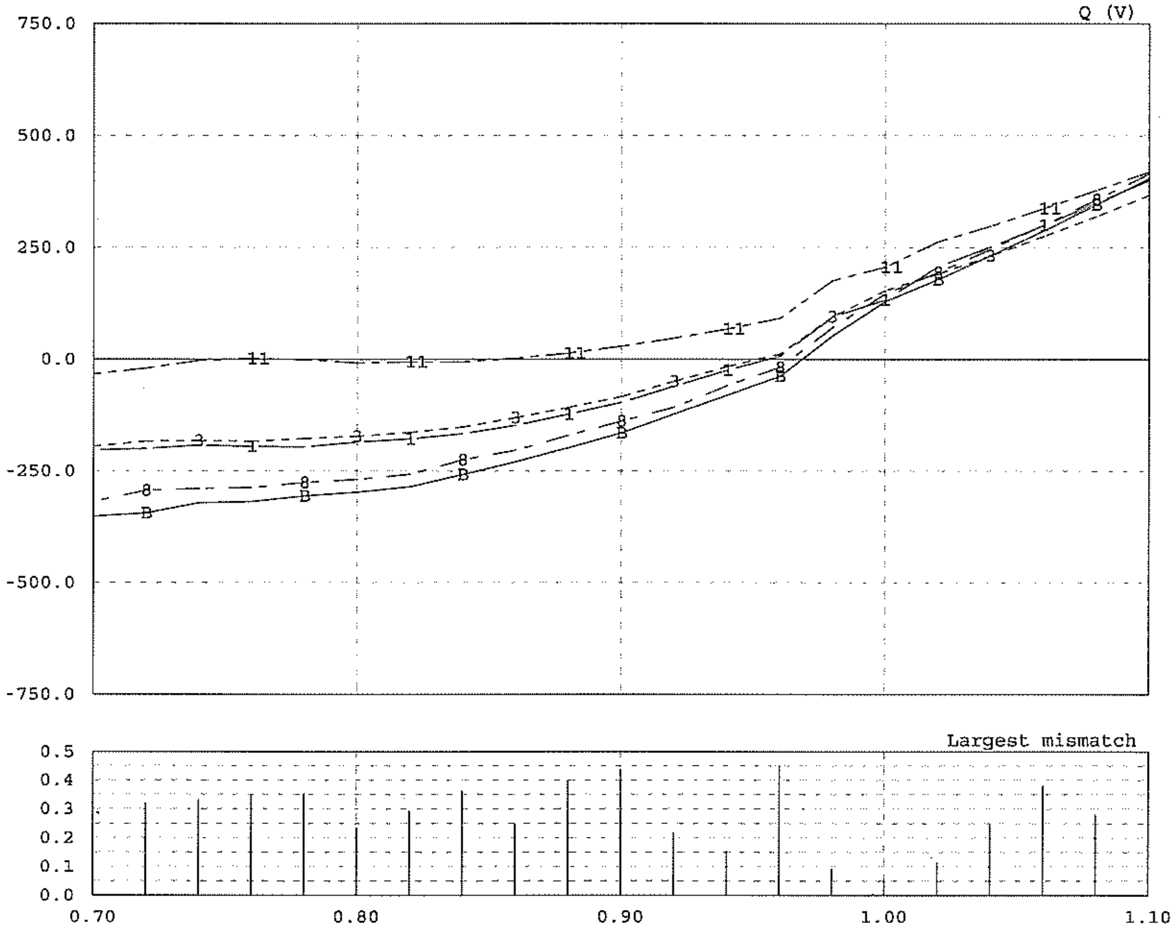


	Mark	Description	Q min
——	B	BASE CASE	-413.253
—— –	1	OPEN LINE FROM BUS 50690 [ACK230 230.00] TO BUS 50693 [VNT230 230.00] CKT 1	-284.195
- - - - -	3	OPEN LINE FROM BUS 50693 [VNT230 230.00] TO BUS 52316 [LEE230 230.00] CKT 1	-274.567
— - -	8	OPEN LINE FROM BUS 52211 [RGA230 230.00] TO BUS 52435 [VAS230 230.00] CKT 1	-381.979
—- - - -	11	OPEN LINE FROM BUS 52320 [DG BELL 230.00] TO BUS 52211 [RGA230 230.00] CKT 1...	-115.533

Figure-38

CREATED FROM 19HW1AP.SAV.FBC 1001MW,TC 220MW
GEN 945MW,LOSSES 36MW,IMPORT 311MW
FRI, DEC 03 2010 14:57

Study bus: 52316

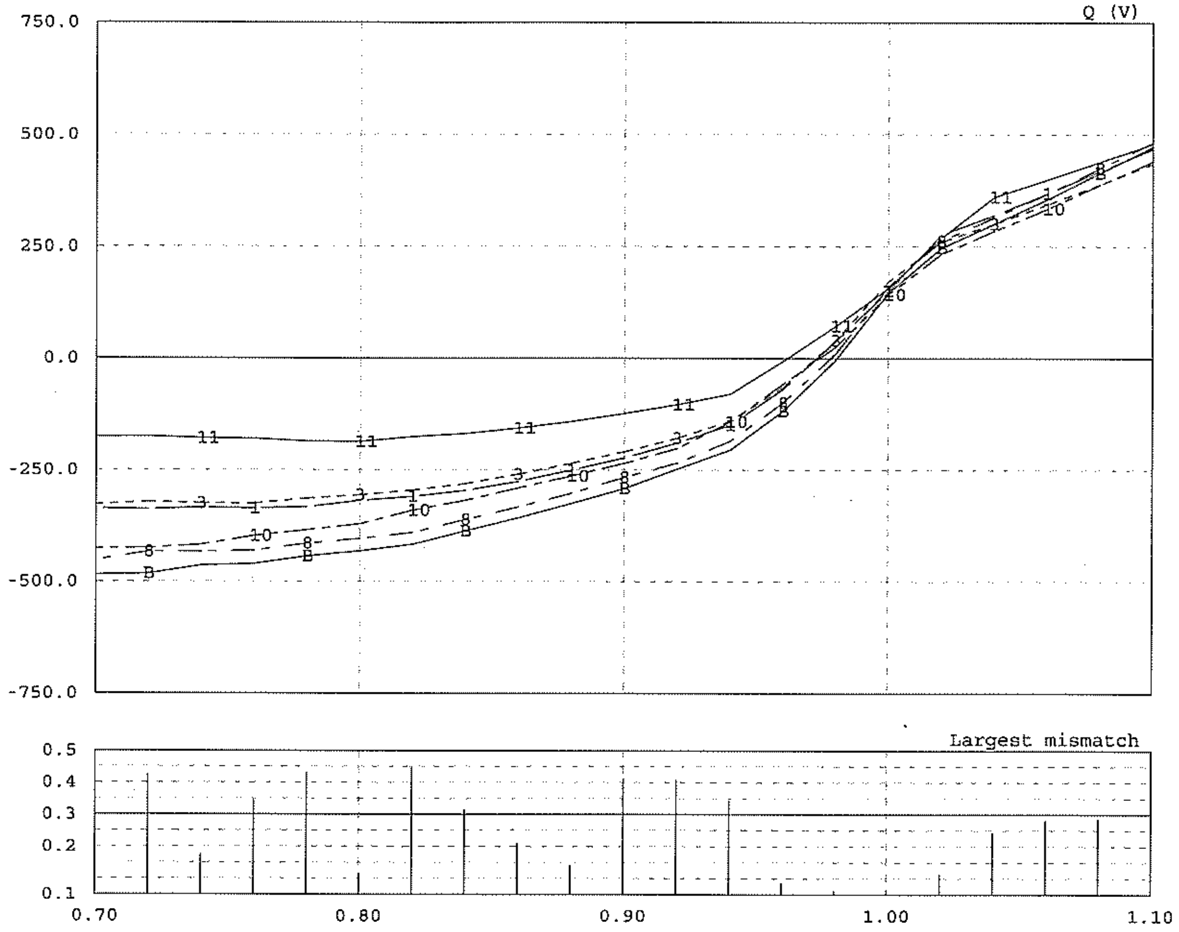


	Mark	Description	Q min
———	B	BASE CASE	-351.700
—— –	1	OPEN LINE FROM BUS 50690 [ACK 230 230.00] TO BUS 50693 [VNT 230 230.00] CKT 1	-204.087
- - - - -	3	OPEN LINE FROM BUS 50693 [VNT 230 230.00] TO BUS 52316 [LEE230 230.00] CKT 1	-195.396
— - -	8	OPEN LINE FROM BUS 52211 [RGA230 230.00] TO BUS 52435 [VAS230 230.00] CKT 1	-318.654
—– – –	11	OPEN LINE FROM BUS 52320 [DG BELL 230.00] TO BUS 52211 [RGA230 230.00] CKT 1...	-33.067

Figure-39

CREATED FROM 19HW1AP.SAV.FBC 1001MW,TC 220MW
GEN 945MW,LOSSES 36MW,IMPORT 311MW
TUE, DEC 07 2010 14:39

Study bus: 52316



	Mark	Description	Q min
———	B	BASE CASE	-484.869
—— -	1	OPEN LINE FROM BUS 50690 [ACK 230 230.00] TO BUS 50693 [VNT 230 230.00] CKT 1	-338.066
- - - - -	3	OPEN LINE FROM BUS 50693 [VNT 230 230.00] TO BUS 52316 [LEE230 230.00] CKT 1	-327.758
— - -	8	OPEN LINE FROM BUS 52211 [RGA230 230.00] TO BUS 52435 [VAS230 230.00] CKT 1	-452.619
—- - -	10	OPEN LINE FROM BUS 52316 [LEE230 230.00] TO BUS 52320 [DG BELL 230.00] CKT 1	-426.223
———	11	OPEN LINE FROM BUS 52320 [DG BELL 230.00] TO BUS 52211 [RGA230 230.00] CKT 1...	-186.525

Figure-40

Attachment A – Commercial Industrial Comparator Group

(N = 295)

A&W Food Services of Canada Inc.
ACA Co-operative Limited
AV Nackawic Inc.
Abbott Laboratories, Limited
Abbott Products Inc.
Agfa Healthcare Canada
Agfa Inc.
Agnico-Eagle Mines Limited
Ainsworth Engineered Canada L. P.
Air New Zealand
Air Products Canada Ltd.
Aker Chemetics
Akzo Nobel Canada Inc.
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Allergan Canada Inc.
ALS Laboratory Group
AltaSteel Ltd.
Aluminerie Alouette Inc.
Amcor Limited
Amgen Canada Inc.
Amway Canada Corporation
Andrew Peller Limited
Anglo American Exploration (Canada) Ltd.
Apotex Inc.
ArcelorMittal Canada
ArcelorMittal Canada Contrecoeur-Ouest Inc.
ArcelorMittal Canada Hamilton
ArcelorMittal Canada Lachine
ArcelorMittal Canada Saint-Patrick
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal P&T
ArcelorMittal Tubular Products - Automotive Division
Arkema Canada Inc.
Arrow Transportation Systems Inc.
Ashland Distribution
Ashland Global Chemicals
Ashland Performance Materials
Ashland Water Technologies
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
Atlantic Packaging Products Ltd.
Atotech Canada Ltd.
Axcan Pharma Inc.
BASF Canada Inc.
BHP Billiton - Ekati Diamond Mines
BIC Graphic Canada
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barrick Gold Corporation
Baxter Corporation
The Bay
Bayer Inc.
The Beer Store
Beiersdorf Canada Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
bioMérieux Canada Inc.
Biovail Corporation
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Bronswerk Group
Bruce Power
CHEP Canada
CKF Inc.
CNH America, LLC.
Cabot Canada Ltd.
Cadbury North America
Campbell Company of Canada
Canada Safeway Limited
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Limited
Canfor Pulp Limited Partnership
Canpotex Limited
Cargill Limited
Caterpillar of Canada Corporation
Centerra Gold Inc.
Chubb Edwards
The Churchill Corporation
Co-op Atlantic
Coca-Cola Bottling Company

Cognis Canada Corporation
Compass Group Canada
Cooper B-Line
Cooper Bussmann
Cooper Crouse Hinds
Cooper Hand Tools
Cooper Industries (Canada) Inc.
Cooper Lighting
Cooper Power Systems
Cooper Power Tools
Cooper Wiring Devices
Corby Distilleries Limited
Country Ribbon Inc.
Covance (Canada) Inc.
Cytec Canada Inc.
DENSO Manufacturing Canada, Inc.
DSM Nutritional Products Canada Inc.
Daishowa-Marubeni International Ltd.
Danfoss Inc.
Danone Canada Inc.
Davis + Henderson
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
Dow Chemical Canada Inc.
Dow Corning Canada Inc.
Dr Pepper Snapple Group
Dundee Precious Metals
EFW Radiology
E.I. du Pont Canada Company
EWOS Canada Ltd.
Eaton Corporation
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
Enbridge Gas Distribution Inc.
Essar Steel Algoma Inc.
Evonik Degussa Canada Inc.
FANUC CNC AMERICA Corporation
FMC of Canada, Ltd.
Ferrero Canada Limited Commercial Division
Ferrero Canada Limited Industrial Division
Finning (Canada)
Finning International Inc.
Fisher & Paykel Healthcare Inc.
FundSERV Inc.
G4S Cash Services (Canada) Ltd.
GDF SUEZ Energy North America, Inc.
Galderma Canada Inc.
Gates Canada Inc.
General Kinetics Engineering Corporation
GlaxoSmithKline Inc.
Goldcorp Inc.
Graceway Pharmaceuticals
Grand & Toy
Griffith Laboratories Limited
Group SEB Canada Inc.
Gulf Chemical Canada
HDS Retail North America
H. H. Angus & Associates Limited
H.J. Heinz Company of Canada Ltd.
Hecla Mining Company
Henkel Canada Corporation
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Hudson's Bay Company
HumanWare
Huntsman Polyurethane
IAMGOLD Corporation
INEOS Canada Partnership
INVISTA (Canada) Company
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Interquisa Canada
J. Ennis Fabrics Ltd.
J. H. Ryder Machinery Limited
JTI-Macdonald Corp.
JYSK CANADA
John Deere Limited Canada
Johnson Matthey Ltd.
Katz Group Canada Ltd.
Kellogg Canada Inc.
Kennametal Ltd.
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
LANXESS Inc.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
Lehigh Hanson
Levi Strauss & Co. (Canada) Inc.
Lilydale Inc.

MDA
MDS Nordion
MMG Resources Inc.
Mainstream Canada Ltd.
McCormick Canada Co.
McElhanney Consulting Services Ltd.
The McElhanney Group Ltd.
McElhanney Land Surveys Ltd.
Meridian Lightweight Technologies Inc.
Methanex Corporation
Michelin North America (Canada) Inc.
Mitsubishi Canada Limited
Montship Inc.
The Mosaic Company
Mother Parkers Tea & Coffee Inc.
Mustang Survival Corp.
Mylan Pharmaceuticals ULC
NOVA Chemicals Corporation
Neopost Canada
Nestlé Canada Inc.
New Horizon System Solutions LP
Newmont Mining Corporation of Canada Limited
Northern Pulp Nova Scotia Corp.
Nova Scotia Power Inc.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Nycomed Canada Inc.
Oakrun Farm Bakery Ltd.
Octapharma Canada Inc.
Olin Chlor-Alkali Products
L'Oréal Canada Inc.
Osler, Hoskin & Harcourt, LLP
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Pan American Silver Corporation
Patheon Inc.
Penske Truck Leasing
PepsiCo Canada
PERI Formwork Systems, Inc. Canada
Pfizer Canada Inc.
Phantom Mfg. (Int'l) Ltd.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Poly-Drill Drilling Systems Ltd.
Potash Corporation of Saskatchewan Inc.
Praxair Canada Inc.
Puratos Canada Inc.
QIT-Fer et Titane Inc.
Randstad Canada
Reflex Instrument North America
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rogers Communications Inc.
Rothmans, Benson & Hedges Inc.
Royal Group, Inc.
Russel Metals Inc.
SMS Equipment Inc.
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
sanofi-aventis
Sapphire Technologies
Saskatchewan Roughrider Football Club
Schlumberger Oilfield Services
Schneider Electric
The Shaw Group Limited
Sherritt Coal
Sherritt International Corporation
Shore Gold Inc.
Sidel Canada Inc.
Siemens Canada Limited
Sonoco Canada Corporation
Sultran Ltd.
Suncor Energy Inc.
Takeda Pharmaceuticals North America, Inc.
Taro Pharmaceuticals Inc.
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
Tembec Inc.
Teranet Inc.
Thales Rail Signalling Solutions
Thompson Creek Metals Company
Thrifty Foods Inc.
TimberWest Forest Corp.
Timminco Limited
Tolko Industries Ltd.
TomTom International
Toromont CAT, A Division of Toromont Industries Ltd.
Total E&P Canada

Twin Rivers Paper Company
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Vale Inco Limited
Valeant Canada Limited
Valvoline
Vanguard Plastics Ltd.
Vicwest Income Fund
Viterra Inc.
Votorantim Cement North America
Wal-Mart Canada Corp.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Xstrata Nickel Canada
Xstrata Zinc Canada
Zellers
Zellstoff Celgar Partnership Limited

Kristen G. Ellis no later than 5 p.m. on Thursday, June 16, 2011, at *kristen.ellis@em.doe.gov.* An early confirmation of attendance will help facilitate access to the building more quickly. Please provide your name, organization, citizenship and contact information. Space is limited. Entry to the DOE Forrestal building will be restricted to those who have confirmed their attendance in advance. Anyone attending the meeting will be required to present government issued photo identification, such as a passport, driver's license, or government identification. EMAB welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Kristen G. Ellis at least seven days in advance of the meeting at the phone number or e-mail address listed above. Written statements may be filed with the Board either before or after the meeting. Individuals who wish to make oral statements pertaining to the agenda should contact Kristen G. Ellis at the address or telephone number listed above. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Time allotted for individuals wishing to make public comments will depend on the number of individuals who wish to speak, but will not exceed five minutes.

Minutes: Minutes will be available by writing or calling Kristen G. Ellis at the address or phone number listed above. Minutes will also be available at the following Web site: *http://www.em.doe.gov/stakepages/emabmeetings.aspx.*

Issued at Washington, DC, on May 25, 2011.

LaTanya R. Butler,

Acting Deputy Committee Management Officer.

[FR Doc. 2011–13511 Filed 5–27–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC11–725B–001]

Commission Information Collection Activities (FERC–725B); Comment Request; Submitted for OMB Review

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice.

SUMMARY: In compliance with the requirements of section 3507 of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507, the Federal Energy Regulatory Commission (Commission or FERC) has submitted the information collection described below to the Office of Management and Budget (OMB) for review of the information collection requirements. Any interested person may file comments directly with OMB and should address a copy of those comments to the Commission as explained below. The Commission published a Notice in the **Federal Register** (75 FR 65618, 10/26/2010) requesting public comments. In addition, FERC published a notice in the **Federal Register** (76 FR 19333, 4/7/2011) indicating submission to OMB of the information collection described below and that it had not received any comments regarding the collection of information thus far. Subsequently, FERC staff became aware of a comment from the Transmission Agency of Northern California (TANC) that had been submitted in a timely manner but internally was indexed incorrectly. On May 3, 2011 the Commission issued a notice extending the comment period[1] (on the notice published April 7, 2011) to June 23, 2011. The Commission is revising its submission to OMB to reflect receipt of the comment.

DATES: Comments on the collection of information are due by June 30, 2011.

ADDRESSES: Address comments on the collection of information to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention: Federal Energy Regulatory Commission Desk Officer. Comments to OMB should be filed electronically, c/o *oira_submission@omb.eop.gov* and include OMB Control Number 1902–0248 for reference. The Desk Officer may be reached by telephone at 202–395–4638.

A copy of the comments should also be sent to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426. Comments may be filed either on paper or on CD/DVD, and should refer to Docket No. IC11–725B–001. Documents must be prepared in an acceptable filing format and in compliance with Commission submission guidelines at *http://www.ferc.gov/help/submission-guide.asp.* eFiling and eSubscription are not available for Docket No. IC11–725B–001, due to a system issue.

All comments may be viewed, printed or downloaded remotely via the Internet through FERC's homepage using the "eLibrary" link. For user assistance, contact *ferconlinesupport@ferc.gov* or toll-free at (866) 208–3676, or for TTY, contact (202) 502–8659.

FOR FURTHER INFORMATION CONTACT: Ellen Brown may be reached by e-mail at *DataClearance@FERC.gov,* by telephone at (202) 502–8663, and by fax at (202) 273–0873.

SUPPLEMENTARY INFORMATION: The information collected by the FERC–725B, Reliability Standards for Critical Infrastructure Protection (OMB Control No. 1902–0248), is required to implement the statutory provisions of section 215 of the Federal Power Act (FPA) (16 U.S.C. 824o). On January 18, 2008, the Commission issued Order No. 706, approving eight Critical Infrastructure Protection Reliability Standards (CIP Standards) submitted by the North American Electric Reliability Corporation (NERC) for Commission approval.[2]

The CIP Standards require certain users, owners, and operators of the Bulk-Power System to comply with specific requirements to safeguard critical cyber assets.[3] These standards help protect the nation's Bulk-Power System against potential disruptions from cyber attacks.[4] The CIP Standards include one actual reporting requirement and several recordkeeping requirements. Specifically, CIP–008–1 requires responsible entities to report cyber security incidents to the Electricity Sector-Information Sharing and Analysis Center (ES–ISAC). In addition, the eight CIP Standards

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[1] The previous comment period ending on June 23rd will be extended to the date 30 days after publication of this revised notice in the **Federal Register** as stated in the **DATES** section of this notice.

[2] CIP–002–1, CIP–003–1, CIP–004–1, CIP–005–1, CIP–006–1, CIP–007–1, CIP–008–1, and CIP–009–1.

[3] In addition, in accordance with section 215(d)(5) of the FPA, the Commission proposed to direct NERC to develop modifications to the CIP Reliability Standards to address specific concerns identified by the Commission.

[4] For a description of the CIP Standards, see the Critical Infrastructure Protection Section on NERC's Web site at *http://www.nerc.com/page.php?cid=2\20.*

require responsible entities to develop various policies, plans, programs, and procedures.[5]

The CIP Standards do not require a responsible entity to report to the Commission, ERO or Regional Entities, the various policies, plans, programs and procedures. However, a showing of the documented policies, plans, programs and procedures is required to demonstrate compliance with the CIP Standards.

Public Comment and FERC Response: TANC stated that they believed that the Commission did not adequately address or articulate the burden that falls on companies in complying with the CIP Standards and in particular, the hourly and cost burdens to comply with the documentation required by the CIP Standards. In looking at the commenter's submittal, FERC has decided to examine more carefully the burden calculations. Relying on OMB guidance in interpreting the requirements of the Paperwork Reduction Act of 1995, FERC has determined that its initial estimate of cost burden was indeed lower than is reasonable for the average respondent.

FERC maintains that the universe of respondents breaks down into three main categories: (1) Entities that have identified Critical Cyber Assets and have undergone a previous audit; (2) Entities that have not identified Critical Cyber Assets but must show compliance with CIP–003 R1 and CIP–002 R1 through R3; and (3) New entities that have come into compliance with the CIP Standards and undergoing their first compliance audit. FERC's revised burden analysis is based on the average amount of time expended annually to obtain or maintain the information necessary in the event of a compliance audit. The fact that the average company may experience a spike in the burden hours immediately proceeding and during a compliance audit is accounted for in the revised estimate.

The differences between the first and third categories of respondents is that, as an entity goes through multiple compliance audits, their processes become streamlined and more automated, which then becomes reflected in a lessening of their burden. Other areas that cause the burden numbers to fluctuate deal with the size of the company, the number of overall electric assets they have, the number of critical assets and critical cyber assets that they identify, etc. Therefore, the total numbers currently used by FERC to calculate cost burden are considered the case for an average-sized company with an average number of Critical Assets and Critical Cyber Assets. It is expected that the actual burden experienced by respondents may be higher or lower than the Commission estimate, based on factors listed above.

Based on observations over several audit cycles, FERC now thinks that the preparation of the audit paperwork for an entity undergoing their first compliance audit (respondent category 3) is approximately 3,840 hours. This represents 20 technical personnel working 50% of their time over 8 weeks gathering and compiling all of the required paperwork to show compliance. In addition, a secondary period that is 20% of the primary effort is estimated to be needed to respond and gather information generated from questions arising from the initial submission.

Based on observations over several audit cycles, FERC now thinks that the burden associated with ongoing compliance and preparation for future audits (respondent category 1) is less than entities coming into compliance for the first time (respondent category 3) as they are familiar with the audit compliance process and presumably will have streamlined their processes to handle the data collection effort. FERC estimates this should result in a reduction of 50% of their effort. This would result in a burden of approximately 1,920 hours.

Finally, for those entities that have not identified Critical Cyber Assets but must still show compliance with CIP–003 R1 and CIP–002 R1 through R3 (respondent category 2), FERC agrees with TANC and now estimates that these entities must expend approximately 120 hours or the equivalent of 3 employees working 50% of their time for 2 weeks. FERC believes this is a reasonable estimate as the majority of these entities are small and therefore have fewer electrical assets to examine in order to determine if they have any Critical Assets, which is the first stage of the CIP–002 process.

FERC has also reconsidered dividing the burden hours by three to reflect the NERC audit schedule of 3–5 years and is instead not dividing the burden hours at all. This is due to the fact that a company will have to be obtaining and maintaining the information necessary for an audit on a consistent basis, and not only during an audit that occurs every 3–5 years. Therefore, the revised burden hours presented here represent the average annual burden hours per respondent, including the spikes that may result during an audit.

Action: The Commission is requesting a three-year extension of the existing collection with no changes to the requirements.

Burden Statement: The revised estimated annual burden is shown below in accordance with the discussion above. The Commission has developed estimates using data from NERC's compliance registry as well as a 2009 survey that was conducted by NERC to assess the number of entities reporting Critical Cyber Assets.

Data collection	Number of respondents[6] (1)	Average number of responses per respondent (2)	Average number of burden hours per response[7] (3)	Total annual hours (1) × (2) × (3)
FERC–725B:				
Category 1—Estimate of U.S. Entities that have identified Critical Cyber Assets.	345	1	1,920	662,400
Category 2—Estimate of U.S. Entities that have not identified Critical Cyber Assets.	1,156	1	120	138,720
Category 3—New U.S. Entities that have to come into compliance with the CIP Standards[8].	6	1	3,840	23,040

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[5] The October notice issued in this docket contains more information on the reporting requirements and can be found at *http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13857625.* The full text of the standards can be found on NERC's Web site at *http://www.nerc.com/page.php?cid=2\20.*

Data collection	Number of respondents [6] (1)	Average number of responses per respondent (2)	Average number of burden hours per response [7] (3)	Total annual hours (1) × (2) × (3)
Entities no longer required to comply with CIP Standards (Two category 1 respondents and four category 2 respondents).	Category 1: −2	1	Category 1 (2 respondents): 1,920.	−3,840
	Category 2: −4	....	Category 2 (4 respondents): 120.	−480
Totals	1,501	....	....	819,840

The total estimated annual cost burden to respondents is:

- Category 1, Entities that have identified Critical Assets = 658,560 (662,400 − 3,840) hours @ $96 = $63,221,760
- Category 2, Entities that have not identified Critical Assets = 138,240 (138,720 − 480) hours @ $96 = $13,271,040
- Category 3, New U.S. Entities that have to comply with CIP Standards = 23,040 hours @ $96 = $2,211,840
- Storage Costs for Entities that have identified Critical Assets [9] = 345 Entities @ $15.25 = $5,261
- Total Cost for the FERC–725B = $78,709,901

The hourly rate of $96 is the average cost of legal services ($230 per hour), technical employees ($40 per hour) and administrative support ($18 per hour), based on hourly rates from the Bureau of Labor Statistics (BLS) and the 2009 Billing Rates and Practices Survey Report.[10] The $15.25 rate for storage costs for each entity is an estimate based on the average costs to service and store 1 GB of data to demonstrate compliance with the CIP Standards.[11]

The reporting burden includes the total time, effort, or financial resources expended to generate, maintain, retain, disclose, or provide the information including: (1) Reviewing instructions; (2) developing, acquiring, installing, and utilizing technology and systems for the purposes of collecting, validating, verifying, processing, maintaining, disclosing and providing information; (3) adjusting the existing ways to comply with any previously applicable instructions and requirements; (4) training personnel to respond to a collection of information; (5) searching data sources; (6) completing and reviewing the collection of information; and (7) transmitting, or otherwise disclosing the information.

Comments are invited on: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have practical utility; (2) the accuracy of the agency's estimates of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility and clarity of the information to be collected; and (4) ways to minimize the burden of the collections of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.* permitting electronic submission of responses.

Dated: May 25, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–13475 Filed 5–27–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2277–023]

Union Electric Company (dba Ameren Missouri); Notice of Scoping Meetings and Environmental Site Review and Soliciting Scoping Comments

Take notice that the following hydroelectric application has been filed with Commission and is available for public inspection:

a. *Type of Application:* New Major License.

b. *Project No.:* 2277–023.

c. *Date filed:* June 24, 2008.

d. *Applicant:* Union Electric Company (dba Ameren Missouri).

e. *Name of Project:* Taum Sauk Pumped Storage Project.

f. *Location:* On the East Fork of the Black River, in Reynolds County, Missouri. The project occupies no Federal lands.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)–825(r).

h. *Applicant Contact:* Michael O. Lobbig, P.E., Managing Supervisor, Hydro Licensing, Ameren Missouri, 3700 S. Lindbergh Blvd., St. Louis, MO 63127; telephone 314–957–3427; e-mail at *mlobbig@ameren.com.*

i. *FERC Contact:* Janet Hutzel, telephone (202) 502–8675, or by e-mail at *janet.hutzel@ferc.gov.*

j. *Deadline for filing scoping comments:* July 23, 2011.

All documents may be filed electronically via the Internet. See 18

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[6] The NERC Compliance Registry as of 9/28/2010 indicated that 2079 entities were registered for NERC's compliance program. Of these, 2057 were identified as being U.S. entities. Staff concluded that of the 2057 U.S. entities, only 1501 were registered for at least one CIP-related function. According to an April 7, 2009, memo to industry, NERC's VP and Chief Security Officer noted that only 31% of entities responded to an earlier survey and reported that they had at least one Critical Asset, and only 23% reported having a Critical Cyber Asset. Staff applied the 23% reporting to the 1501 figure to obtain an estimate. The 6 new entities listed here are assumed to match a similar set of 6 entities that would drop out in an existing year. Thus, the net estimate of respondents remains at 1501 per year.

[7] Calculations:

Respondent category 3:

20 employees × (working 50%) × (40 hrs/week) × (8 weeks) = 3200 hours

20 employees × (working 20%) × (3200 hrs) = 640 hours

Total = 3840

Respondent category 2:

3 employees × (working 50%) × (40 hrs/week) × (2 weeks) = 120 hours

Respondent category 1:

50% of 3840 hours = 1920

[8] These respondents and those in the subsequent column of the table (with the corresponding burden and cost figures) were not included in the 60-day public notice due to an oversight by Commission staff.

[9] This cost category was not included in the 60-day public notice due to an oversight by Commission staff.

[10] Bureau of Labor Statistics figures were obtained from *http://www.bls.gov/oes/current/naics2_22.htm*, and 2009 Billing Rates figures were obtained from *http://www.marylandlawyerblog.com/2009/07/average_hourly_rate_for_lawyer.html.* Legal services were based on the national average billing rate (contracting out) from the above report and BLS hourly earnings (in-house personnel). It is assumed that 25% of respondents have in-house legal personnel.

[11] Based on the aggregate cost of an IBM advanced data protection server.

FINANCIAL INDICATOR OUTLOOK

end-of-period level

	Spot Rate	2010				2011				2012			
	16/03/2011	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADIAN FIXED INCOME													
Overnight Target Rate (%)	1.00	0.25	0.50	1.00	1.00	1.00	1.00	1.50	2.00	2.25	2.50	2.75	3.00
3-mth T-Bill Rate (%)	1.14	0.29	0.51	0.88	1.04	1.00	1.05	1.50	2.00	2.25	2.50	2.80	3.05
2-yr Govt. Bond Yield (%)	1.62	1.74	1.39	1.38	1.68	1.85	2.15	2.45	2.60	2.75	3.10	3.50	3.45
5-yr Govt. Bond Yield (%)	2.53	2.90	2.36	2.03	2.42	2.70	3.00	3.30	3.50	3.55	3.65	3.85	3.80
10-yr Govt. Bond Yield (%)	3.17	3.57	3.08	2.76	3.12	3.40	3.75	4.00	4.05	4.20	4.35	4.40	4.40
30-yr Govt. Bond Yield (%)	3.71	4.12	3.65	3.36	3.52	3.80	3.95	4.15	4.30	4.55	4.45	4.40	4.40
10-yr-2-yr Govt. Spread (%)	1.56	1.83	1.69	1.38	1.44	1.55	1.60	1.55	1.45	1.45	1.25	0.90	0.95
GLOBAL CURRENCIES													
USD per CAD	1.02	0.99	0.94	0.97	1.00	1.03	1.03	1.04	1.04	1.05	1.00	0.98	0.94
USD per EUR	1.40	1.35	1.22	1.36	1.34	1.38	1.35	1.30	1.25	1.25	1.23	1.21	1.20
JPY per USD	80.6	93.4	88.4	83.5	81.1	85.0	90.0	92.0	95.0	98.0	98.0	100.0	100.0

Source: Bank of Canada, Bloomberg, Statistics Canada/Haver Analytics, Forecast by TD

May 3, 2011

Global Forecast Update

Financial Markets	10Q4	11Q1	11Q2f	11Q3f	11Q4f	12Q1f	12Q2f	12Q3f	12Q4f
				(%, end of period)					
Canada									
BoC Overnight Target Rate	1.00	1.00	1.00	1.00	1.50	2.00	2.25	2.25	2.25
3-month T-bill	1.05	0.96	1.10	1.30	1.70	2.20	2.30	2.30	2.30
2-year Canada	1.68	1.83	1.75	1.80	2.00	2.30	2.50	2.50	2.50
5-year Canada	2.42	2.78	2.65	2.70	2.85	3.00	3.10	3.25	3.35
10-year Canada	3.12	3.35	3.25	3.40	3.50	3.70	3.75	3.90	4.05
30-year Canada	3.53	3.76	3.70	3.80	3.90	4.15	4.20	4.30	4.50
Real GDP (q/q, ann. % change)	3.3	4.0	2.0	3.0	3.0	2.5	2.6	2.6	2.6
Real GDP (y/y, % change)	3.2	2.8	2.8	3.1	3.0	2.6	2.8	2.6	2.6
Consumer Prices (y/y, % change)	2.3	2.6	2.9	2.9	2.9	2.5	2.1	2.2	2.2
Core CPI (y/y % change)	1.6	1.3	1.5	1.8	1.7	1.9	1.6	1.9	2.1
United States									
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.75	1.25	1.75	2.00
3-month T-bill	0.12	0.09	0.15	0.20	0.40	0.90	1.40	1.90	2.20
2-year Treasury	0.59	0.82	0.70	0.85	1.00	1.40	1.75	2.00	2.20
5-year Treasury	2.00	2.28	2.10	2.20	2.25	2.60	2.85	3.05	3.40
10-year Treasury	3.29	3.47	3.40	3.65	3.75	4.00	4.10	4.30	4.65
30-year Treasury	4.33	4.51	4.50	4.65	4.75	4.95	5.05	5.20	5.35
Real GDP (q/q, ann. % change)	3.1	1.7	2.9	3.5	3.0	2.7	2.7	2.5	2.5
Real GDP (y/y, % change)	2.8	2.3	2.6	2.8	2.8	3.0	3.0	2.7	2.6
Consumer Prices (y/y, % change)	1.3	2.2	3.1	3.2	3.0	2.1	2.0	1.9	1.9
Core CPI (y/y % change)	0.6	1.1	1.1	1.2	1.4	1.3	1.4	1.4	1.5
Spreads									
Target Rate	0.75	0.75	0.75	0.75	1.25	1.25	1.00	0.50	0.25
3-month T-bill	0.93	0.87	0.95	1.10	1.30	1.30	0.90	0.40	0.10
2-year	1.09	1.01	1.05	0.95	1.00	0.90	0.75	0.50	0.30
5-year	0.42	0.50	0.55	0.50	0.60	0.40	0.25	0.20	-0.05
10-year	-0.17	-0.12	-0.15	-0.25	-0.25	-0.30	-0.35	-0.40	-0.60
30-year	-0.80	-0.75	-0.80	-0.85	-0.85	-0.80	-0.85	-0.90	-0.85
Central Bank Rates									
European Central Bank	1.00	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.50
Bank of England	0.50	0.50	0.50	0.75	1.00	1.25	1.50	1.75	2.00
Swiss National Bank	0.25	0.25	0.25	0.25	0.50	0.50	0.75	0.75	1.00
Bank of Japan	0.10	0.10	0.10	0.10	0.10	0.10	0.25	0.25	0.50
Reserve Bank of Australia	4.75	4.75	5.00	5.25	5.50	5.75	6.00	6.25	6.50
Exchange Rates									
Canadian Dollar (USDCAD)	1.00	0.97	0.95	0.94	0.93	0.94	0.94	0.93	0.92
Canadian Dollar (CADUSD)	1.00	1.03	1.05	1.06	1.08	1.06	1.06	1.08	1.09
Euro (EURUSD)	1.34	1.42	1.47	1.49	1.50	1.48	1.48	1.50	1.50
Euro (EURGBP)	0.86	0.88	0.90	0.91	0.91	0.90	0.89	0.89	0.88
Sterling (GBPUSD)	1.56	1.60	1.64	1.64	1.65	1.65	1.67	1.69	1.70
Yen (USDJPY)	81	83	79	82	84	86	87	89	90
Australian Dollar (AUDUSD)	1.02	1.03	1.07	1.08	1.09	1.09	1.10	1.10	1.11
Chinese Yuan (USDCNY)	6.6	6.5	6.4	6.2	6.1	6.0	5.9	5.8	5.8
Mexican Peso (USDMXN)	12.3	11.9	11.6	11.8	12.0	12.1	12.0	12.1	12.3
Brazilian Real (USDBRL)	1.66	1.63	1.59	1.59	1.60	1.62	1.65	1.67	1.70

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MARKET CALL

- Earlier this month, we stepped out of the way of considerable momentum trading by leaving more room for US$ depreciation against the euro in the near term. Even if oil settles down, we see only a modest pull-back for the Canadian dollar. We still see greenback selling as overdone, and look for troubles in Europe to be one of the triggers for a turning point around mid-year.
- Treasury yields have hewed close to our expectations, but we see a bit of temporary pressure pushing yields higher as Wall Street frets about how the market will clear once quantitative easing is over. Relatively modest US growth, contained core inflation and a Fed on hold should keep US yields steady in the second half.
- A surprise jump in core inflation didn't alter our expectations for the timing of the first Bank of Canada hike, with the appreciation in the C$ likely enough to keep Carney on hold until July. We're staying with our call for four quarter point hikes through the end of the year, with a chance of seeing only 75 bps if the loonie stays materially stronger than our current forecast trajectory.

INTEREST & FOREIGN EXCHANGE RATES

		2011				2012			
END OF PERIOD:		**27-Apr**	**Jun**	**Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
CDA	Overnight target rate	1.00	1.00	1.50	2.00	2.00	2.00	2.00	2.25
	98-Day Treasury Bills	0.99	1.00	1.55	1.90	1.85	1.85	1.85	1.90
	2-Year Gov't Bond	1.78	2.00	2.15	2.50	2.40	2.75	2.85	3.00
	10-Year Gov't Bond	3.27	3.50	3.55	3.50	3.60	3.85	3.95	4.00
	30-Year Gov't Bond	3.74	3.80	3.90	3.85	4.00	4.10	4.25	4.25
U.S.	Federal Funds Rate	0.08	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	91-Day Treasury Bills	0.05	0.15	0.15	0.15	0.15	0.15	0.15	0.20
	2-Year Gov't Note	0.64	0.75	0.65	0.65	0.85	0.90	0.90	1.00
	10-Year Gov't Note	3.36	3.55	3.50	3.40	3.50	3.80	3.85	3.95
	30-Year Gov't Bond	4.45	4.60	4.55	4.40	4.65	4.75	4.80	4.80
Canada - US T-Bill Spread		0.94	0.85	1.40	1.75	1.70	1.70	1.70	1.70
Canada - US 10-Year Bond Spread		-0.09	-0.05	0.05	0.10	0.10	0.05	0.10	0.05
Canada Yield Curve (30-Year — 2-Year)		1.96	1.80	1.75	1.35	1.60	1.35	1.40	1.25
US Yield Curve (30-Year — 2-Year)		3.81	3.85	3.90	3.75	3.80	3.85	3.90	3.80
EXCHANGE RATES	CADUSD	1.05	1.00	1.02	1.03	1.01	1.02	1.02	1.03
	USDCAD	0.95	1.00	0.98	0.97	0.99	0.98	0.98	0.97
	USDJPY	82	86	87	89	88	90	92	94
	EURUSD	1.48	1.49	1.36	1.34	1.30	1.35	1.34	1.32
	GBPUSD	1.66	1.66	1.60	1.62	1.62	1.67	1.65	1.65
	AUDUSD	1.09	1.02	0.98	0.97	0.98	1.03	1.01	1.00
	USDCHF	0.87	0.89	0.95	0.96	0.97	0.95	0.97	1.01
	USDBRL	1.57	1.54	1.62	1.65	1.62	1.60	1.58	1.56
	USDMXN	11.52	11.55	11.80	12.00	12.00	11.85	11.75	11.50

ECONOMICS | **RESEARCH**

FINANCIAL MARKET FORECASTS

May 2011

Interest rates (%, end of quarter)

				Forecast									Forecast	
	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009	2010	2011	2012
Canada														
Overnight rate	1.00	1.00	1.00	1.00	1.50	2.00	2.25	2.50	2.75	3.00	0.25	1.00	2.00	3.00
Three-month T-bills	0.88	0.97	1.10	1.35	1.70	2.15	2.40	2.65	2.90	3.15	0.19	0.97	2.15	3.15
Two-year GoC bonds	1.40	1.71	1.85	2.10	2.15	2.40	2.80	3.00	3.35	3.75	1.47	1.71	2.40	3.75
Five-year GoC bonds	2.04	2.46	2.77	2.80	3.00	3.30	3.50	3.65	3.85	4.05	2.77	2.46	3.30	4.05
10-year GoC bonds	2.75	3.16	3.25	3.30	3.50	3.80	3.95	4.05	4.15	4.15	3.61	3.16	3.80	4.15
30-year GoC bonds	3.34	3.55	3.85	3.90	4.10	4.40	4.45	4.50	4.50	4.55	4.07	3.55	4.40	4.55
Yield curve (10s-2s)	135	145	140	120	135	140	115	105	80	40	214	145	140	40
United States														
Fed funds rate	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0.75	1.50	2.00	0 to 0.25	0 to 0.25	0 to 0.25	2.00
Three-month T-bills	0.16	0.12	0.15	0.20	0.25	0.30	0.35	0.90	1.65	2.10	0.06	0.12	0.30	2.10
Two-year bonds	0.44	0.61	0.80	1.00	0.90	1.10	1.50	1.75	2.25	2.80	1.14	0.61	1.10	2.80
Five-year bonds	1.27	2.01	2.10	2.30	2.40	2.70	3.05	3.25	3.50	3.75	2.69	2.01	2.70	3.75
10-year bonds	2.48	3.30	3.47	3.50	3.65	4.00	4.15	4.25	4.45	4.50	3.85	3.30	4.00	4.50
30-year bonds	3.67	4.34	4.50	4.55	4.60	4.85	4.90	4.95	5.00	5.05	4.63	4.34	4.85	5.05
Yield curve (10s-2s)	204	269	267	250	275	290	265	250	220	170	271	269	290	170
Yield spreads														
Three-month T-bills	0.72	0.85	0.95	1.15	1.45	1.85	2.05	1.75	1.25	1.05	0.13	0.85	1.85	1.05
Two-year	0.96	1.10	1.05	1.10	1.25	1.30	1.30	1.25	1.10	0.95	0.33	1.10	1.30	0.95
Five-year	0.77	0.45	0.67	0.50	0.60	0.60	0.45	0.40	0.35	0.30	0.08	0.45	0.60	0.30
10-year	0.27	-0.14	-0.22	-0.20	-0.15	-0.20	-0.20	-0.20	-0.30	-0.35	-0.24	-0.14	-0.20	-0.35
30-year	-0.33	-0.79	-0.65	-0.65	-0.50	-0.45	-0.45	-0.45	-0.50	-0.50	-0.56	-0.79	-0.45	-0.50

Exchange rates (%, end of quarter)

				Forecast									Forecast	
	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009	2010	2011	2012
Australian dollar	0.97	1.02	1.02	0.99	1.05	1.00	0.98	0.96	0.94	0.94	0.90	1.02	1.00	0.94
Brazilian real	1.70	1.66	1.73	1.75	1.68	1.70	1.72	1.73	1.74	1.75	1.74	1.66	1.70	1.75
Canadian dollar	1.03	1.00	0.97	0.95	0.94	0.95	0.97	1.00	1.02	1.02	1.05	1.00	0.95	1.02
Renmibi	6.69	6.59	6.55	6.40	6.30	6.20	6.10	6.00	5.90	5.80	6.83	6.59	6.20	5.80
Euro	1.36	1.34	1.42	1.36	1.42	1.35	1.30	1.30	1.29	1.29	1.43	1.34	1.35	1.29
Yen	84	81	83	81	84	87	90	95	100	105	93	81	87	105
Mexican peso	12.59	12.36	11.90	11.75	12.00	12.00	12.00	12.50	12.25	12.00	13.10	12.36	12.00	12.00
New Zealand dollar	0.73	0.78	0.76	0.72	0.76	0.72	0.70	0.70	0.69	0.69	0.73	0.78	0.72	0.69
Swiss franc	0.98	0.93	0.92	0.86	0.89	0.93	0.97	0.97	0.98	0.98	1.04	0.93	0.93	0.98
U.K. pound sterling	1.57	1.56	1.60	1.66	1.67	1.63	1.59	1.63	1.63	1.65	1.62	1.56	1.63	1.65

Note: Rates are expressed in currency units per US$ except the Euro, UK pound, A$ and New Zealand dollar, which are expressed in US$ per currency unit.

Source: Bank of Canada, Federal Reserve Board, Reuters, RBC Economics Research forecasts

FORTISBC

26-Aug-11

CONCRETE AND STRUCTURAL REHABILITATION - CONCRETE AND STRUCTURAL PROJECTS

PLANT	DESCRIPTION	START YEAR	FINISH YEAR	SERVICE PRIORITY	INJURY PRIORITY	TOTAL PRIORITY	2012	2013
	PROJECTS FOR YEARS 2012 TO 2013							
P1 - LBO	ROCK TRAP CLEANOUT REFURBISH LEAKING PIPE	2012	2012	3	1	5	■	
P2 - UBO	REPLACE DAMAGED BRACING ON HEAD GATE TOWERS	2012	2012	3	1	5	■	
P3 - SLC	RESURFACE STAIR NOSINGS	2012	2012	5	2	9	■	
P4 - COR	INSTALL KICK PLATE ON WALKWAY	2012	2012	5	1	7	■	
P4 - COR	REFURBISH DAMAGED STAIRS	2012	2012	5	2	9	■	
P4 - COR	REPLACE DAMAGED BRACING ON HEAD GATE TOWERS	2012	2012	3	1	5	■	
P1 - LBO	SERVICE TUNNEL CRACK - MONITOR AT THIS TIME	2012	2012	1	0	1	■	
P1 - LBO	UPGRADE HOIST FRAME TO TOWER CONNECTIONS	2012	2012	4	1	6	■	
P3 - SLC	STAIRWAY TO HEAD GATES - REPLACE ROTTEN ROOF	2012	2012	2	2	6	■	
P4 - COR	RESURFACE TAILRACE WALL	2012	2012	4	0	4	■	
P4 - COR	REGROUT HEAD GATE SUPERSTRUCTURE BASE PLATES	2012	2012	5	3	11	■	
P2 - UBO	UPGRADE HOIST FRAME TO TOWER CONNECTIONS	2012	2012	5	1	7	■	
P1 - LBO	REFURBISH TAILRACE GANTRY LOWER SILLS	2012	2012	4	1	6	■	
P4 - COR	UPGRADE SPILLWAY GANTRY LIFELINES TO CURRENT STANDARDS	2012	2012	4	1	6	■	
P2 - UBO	REFURBISH CRACK IN POWER HOUSE WALL	2012	2012	4	0	4	■	
P4 - COR	UPGRADE HOIST FRAME TO TOWER CONNECTIONS	2013	2013	4	1	6		■
P3 - SLC	UPGRADE HOIST FRAME TO TOWER CONNECTIONS	2013	2013	4	1	6		■
P4 - COR	WORK PLATFORMS ON CRANE BRIDGE	2013	2013	3	1	5		■
P4 - COR	UPGRADE GATE ACCESS LIFELINES TO CURRENT STANDARDS	2013	2013	4	1	6		■
P1 - LBO	REFURBISH CORE HOLES IN FOREBAY WALKWAY	2013	2013	2	1	4		■
P1 - LBO	RESURFACE FOREBAY WALL AND NORTH PIERS	2013	2013	4	0	4		■
P1 - LBO	RESURFACE FOREBAY DECK AREA	2013	2013	2	1	4		■
							$ 570,000	$ 617,000

DBS ENERGY SERVICES INC.

Report

To: Curtis Goriuk, Brian Edall, Alison Meredith; FortisBC

From: Jonathan Turner, Dennis Schlender; DBS Energy

CC: Mike LeClair, Aram Khalil-Pour; FortisBC

Date: 2010-08-05

Re: 30L (SLC-COF) 2010 CONDITION ASSESSMENT ENGINEERING REVIEW

INTRODUCTION

This 30L engineering review, from South Slocan Substation (SLC) to the Coffee Creek Substation (COF), is based on the data collected from the condition assessment patrols completed by DBS Energy personnel in April-May 2010. This report provides an engineering design review, summary of deficiencies with an anticipated scope of work, as well as construction estimates for the on-going operational improvements for 30L stemming from the condition assessment and pole test & treat data. The recommendations of this report outline the risks and reliability issues of the 30L circuit, for which FortisBC can position the needed improvements into the Capital Plan budgets.

OVERVIEW OF THE LINE

The section of 30L that is included in this condition assessment review is from the South Slocan Substation to the Coffee Creek Substation, which is approximately 57.5km in length (roughly 240 structures). The line is a 161kV circuit, but is to be converted to 63kV in the near future. The 30L circuit was originally constructed in the 1950's to carry load from the Generation at South Slocan to the Crawford Bay area and east to the Cominco Mine in Kimberly.

The line is constructed with an H-Frame wood pole design to allow for the longer span lengths needed for this segment of 30L. This section of 30L has had many structure change-outs as required over the years, but there are still several 1950's original vintage poles and/or structures that may need attention. Recently in 2005, there was a major rehab of the line, where approximately 34 structures were replaced. Other recent rehab work to note is the Kootenay River crossing near Nelson that was replaced in 1988, as well as the rebuild of the first 12 structures on 30L coming out of South Slocan that was rebuilt in the 1970's. Most of the structure work done on 30L to date has been completed on the regular maintenance cycle, as needed. Refer to Appendix I for a histogram of the structure vintages on 30L (SLC to COF) that are currently in service.

The inspected 30L circuit is strung primarily with single 477 ACSR Hawk conductors for the majority of the line. The conductor used on the Kootenay Lake crossing (Grohman Narrows area – near Nelson at structures 30L61-62) is 466kcmil ACSR with 38/19 stranding. The conductors are deemed to be in good condition and no issues were observed from the assessment patrols that may impact the integrity of the circuits.

SUMMARY OF FINDINGS

Records from the original design of 30L are sparse, but a dated structure list was used for reference. There are several structures that have been replaced throughout the years and few mark-ups in terms of as-built data and/or recent works have been added to the line records. The condition assessment records completed by DBS Energy produced detailed information in terms of the poles, hardware, framing, conductors, insulation, anchoring, and site information, which is to be added to the permanent 30L line records (structure list and plan & profile).

The latest pole test and treat data was completed by Gilnockie Inspections in 2009 for the section of 30L from the South Slocan Substation to the Coffee Creek Substation. There was a significant amount of discrepancies found between the T&T records and the field inspected data in regards to pole information (height/class/vintage) and structure numbering for action items. These inconsistencies in data were reconciled as best as possible, with the field data considered as being accurate when unable to be resolved. Follow-up detailed engineering and confirmation of data can be completed during the engineering design stage of the project. There are a total of 30 structures requiring minor rehab repairs, 25 H-Frame tangent structure recommended for replacement, and 51 structure locations requiring brushing and/or removal of danger trees. A detailed summary of the recommended rehabilitation work for 30L (SLC-COF) can be found in Appendix II. A list of various generic issues on 30L as determined from the condition assessment patrols are listed below.

- Brushing required at several locations for trees growing close to conductors and for removal of danger trees.
- Anchors with missing guy guards that need to be added.
- Large wood pecker holes needing to be filled.
- Broken pole ground wire needing to be repaired.
- Future reference for older structures that are possible replacements for subsequent condition assessment cycle(s). These structures should be reviewed in close detail in the following assessment cycle(s), and replaced completely as major work becomes required.
- 25 H-Frame tangent structures (original vintage poles) recommended to be replaced. These structures are to be replaced due to one or both poles being red tagged, low clearance issues not meeting CSA code requirements, and/or the structure in overall very poor condition and adjacent to a priority structure replacement.
- Follow-up engineering and survey review for possible low clearance issues, possible insulator damage, and poles that appear to be over capacity.

The 30L section from SLC to COF has significant access concerns along the right of way, which includes access roads to the R/W through private property, poor road quality along the right of way, and right of way access roads that are gated without a FortisBC lock. In many sections of the line, current access conditions are only achievable by foot or via helicopter for major structure work. Despite a relatively recent access assessment done by FortisBC several years ago, access conditions seem to have changes quite significantly, in particular around the Nelson area. Access and structure locations have been noted during the assessment patrols and entered into a Google Earth kmz file for use as a future reference. A detailed list of the structure access concerns are as follows.

- The access road to structures 30L13-15 is gated and locked with no FortisBC lock.
- Structures 30L62-68 are accessible by a private road to the R/W, however there seems to be no legal access to the R/W. There is private access road to the R/W through a locked gate off Marsden Rd, which is owned by a landowner (with dogs) reluctant to let anyone on his land.
- Structures 30L69-77 are foot access only along the R/W (approx 1.68 km), with the only nearby access to the R/W at structure 30L78. There is a road that parallels below the R/W at approx 50m-80m, which may provide possible access to structures 30L62-68 with substantial road work and access rights being required.
- Structure 30L79 is accessible by foot only along the R\W. The area is on a steep side hill and rock slide.

- Structures 30L80-91 are accessible from #965 off Hwy3A. Randy Tice is the property owner and the land is presently for sale. If there is currently no legal access to this section of the R/W, now might be a good time to address it. There is an existing road on the R/W between structures 30L80 and 30L82, but is not drivable without some work. There is also access to the 30L83 site, but not to the actual structure location. This area is on a side hill and rock slide, and therefore these structures would require a heli set, when needing to be replaced.
- Structures 30L84-91 are foot access only (approx 2.23km). Structures are on a steep side hill, and therefore these structures would be a heli set when replaced.
- Access road near structure 30L189 is gated with no FortisBC lock. Need to call 250-229-4425 to have gate unlocked for access.

ESTIMATE OF WORK

This 30L (SLC-COF) Condition Assessment Review Summary (Appendix II) shows the work required on each structure and the +/-30% estimated construction costs. There is a total of 30 structures requiring minor rehab repairs (missing guy guards, ground wire repair, wood pecker repair, etc.), 25 H-Frame tangent structure replacements (red tagged, low clearances, poor condition), and 51 structure locations requiring brushing and/or removal of danger trees. The urgent work refers to rehabs that need to be done immediately, and the recommended work refers to the rehabs that could be postponed for one to two years (if needed), but should still be done in the near future. The table below shows the estimate summary and details the costs broken down into the various aspects for the total rehab work. The total estimate for the 30L SLC-COF rehabilitation works is $876k including a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that all work will be completed with 30L de-energized.

	Repair	**Str Replace**	**Brushing**
# of Structures	30	25	51
Urgent Work	$ 0.0k	$ 332.0k	$ 1.0k
Recommended Work	$ 13.1k	$ 305.0k	$ 58.5k
+/-30% Estimate	**$ 13.1k**	**$ 637.0k**	**$ 59.5k**

Excludes contingency or FortisBC overheads.

Labor	$ 305.1k	43%	Approx 1900 man-hours with 30L de-energized.
Brushing	$ 59.5k	8%	Brushing for the required areas. Brushing crew for approx 3 weeks.
Material	$ 177.4k	25%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 63.9k	9%	Includes review of outstanding issues and survey follow-up.
PM	$ 42.6k	6%	Project management.
Misc	$ 61.1k	9%	For preliminary work, flagging, EVT, etc.
SUBTOTAL =	$ 709.6k		Does not include any FortisBC Capitalized Overheads.
Land & Access	$ 20.0k		Placeholder to deal with land and R/W access issues.
20% Contingency	$ 145.9k		Allows for 20% contingency.
TOTAL =	**$ 875.5k**		Does not include any FortisBC Capitalized Overheads.

CONCLUSIONS AND RECOMMENDATIONS

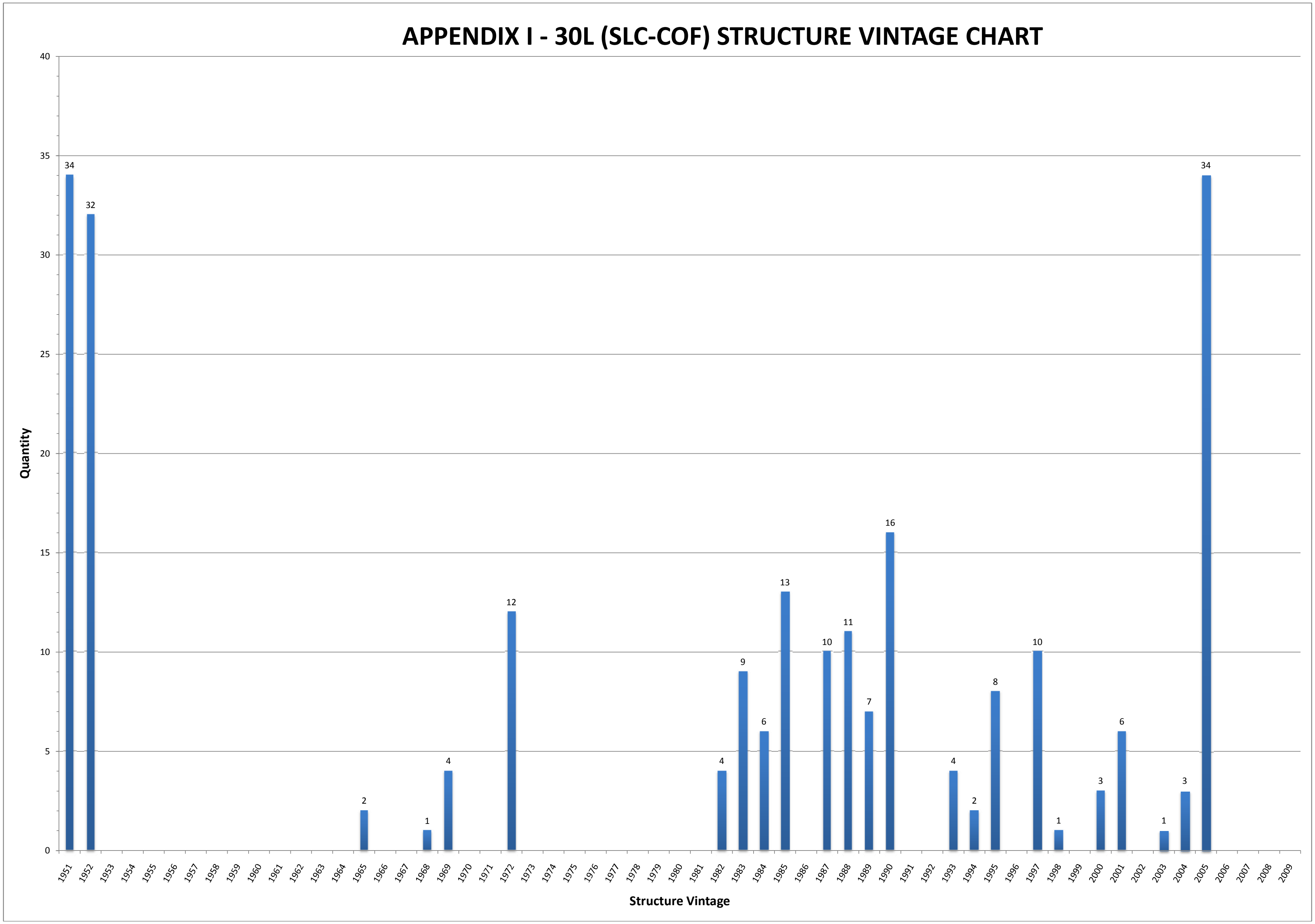
All the assumptions to date for the engineering review of 30L have been based on the data collected from the DBS condition assessment patrols in conjunction with the Gilnockie pole test and treat data. It should be noted that 30L is to be converted from 161kV to 63kV in the near future, and therefore the line will be substantially over insulated, which will reduce the need for re-insulating structures.

A detailed summary of the recommended rehabilitation work for the section of 30L from the South Slocan Substation to the Coffee Creek Substation can be found in Appendix II. There is work on this section of 30L that is considered to be urgent and should be completed in 2010/2011. A total of 13 tangent H-Frame structures are recommended for urgent replacement as a result of red tagged poles or low clearances not meeting CSA requirements. There is one span (30L21-22) with urgent brushing required where a tree had contacted the conductor and is still within the limits of approach – Removal of this tree will most likely require an outage. The remaining recommended work as listed in Appendix II should be completed before the next assessment cycle (ideally in the near future), and would be advantageous to complete these rehabs at the same time as the urgent work in order to capitalize on reduced overheads and mobilization costs. The total cost estimate for the 30L SLC-COF rehabilitation works is $876k, which includes a 20% contingency allowance and excludes any FortisBC capitalized overheads. It is expected that all work will be completed with 30L de-energized.

There are also several outstanding issues that require follow-up engineering review, which are suggested to be done during the design stage of the project. These structure issues are shown in the 30L (SLC-COF) Condition Assessment Review Summary (Appendix II). Review and survey of these issues are included in the estimate (incorporated into the engineering costs), and any additional repairs that may be required as a result would be covered by the contingency allowance.

It is recommended that the existing 30L (SLC-COF) structure list and line records (plan & profile) be updated with the condition assessment records for any missing data. This updated 30L structure list will form part of the permanent FortisBC Engineering line records. The 30L structure list or plan & profile documents do not appear to have been updated at all through recent years and should be revised with structure numbering and format, as well as include any recent works completed on the line.

Details relating to the right of way access and issues with the access roads that were noted during the condition assessment patrols have been added into Google Earth as a kmz file. It is recommended that this access information be incorporated into the ArcFM system for future reference and use. It is also recommended that any access issues through private property or access roads with locked gates and no FortisBC lock need to be resolved. A $20.0k allowance has been added into the overall estimate as a placeholder to encompass any legal and/or land access that may be required for this section of 30L. Refer to the Summary of Findings section of the report and/or the Google Earth access kmz file for the location of these issues. Mike Bancroft has been notified to these access issues through private property and is currently following-up to determine if any agreements are currently in place.


APPENDIX I - 30L (SLC-COF) STRUCTURE VINTAGE CHART
Quantity
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Structure Vintage

APPENDIX II - 30L (SLC-COF) CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed
1	✓	Repair	0.5	Add 10 guy guards
	✓	Brushing	1.0	Brushing rquired in aftspan and forespan at 40m
1A	✓	Repair	2.5	Replace jumper spar arm - Heavy WP damage
1B	-	-	-	Future Reference - Add crossbracing for long span
2	-	-	-	Engr Review - Corona damage on jumper insulators
				Note: Insulators should be OK with conversion from 161kV to 63kV on 30L
2B	✓	Repair	0.3	Add 4 guy guards
	-	-	-	Replace jumper string insulators (Corona Damage) on all phases
				Note: Insulators should be OK with conversion from 161kV to 63kV on 30L
5	✓	Repair	0.5	Repair WP holes near spar arm
6	-	-	-	Engr Review - Check ground clr issues on forespan at +64.8m
9	✓	Brushing	1.0	Brushing required on forespan
	-	-	-	Future Reference - Left phase is noisy
10	✓	Repair	1.0	Bucket inspection for lightning damage on LØ insulator - Replace if needed
11	✓	Repair	0.3	Add 2 guy guards (side anchors)
	-	-	-	Future Reference - All phases are noisy (possible corona damage)
14	✓	Repair	0.5	Repair ground wire
17	-	-	-	Future Reference - Possible structure replace next assessment cycle
18	-	-	-	Future Reference - Possible structure replace next assessment cycle
19	-	-	-	Future Reference - Possible structure replace next assessment cycle
20	✓	Brushing	1.5	Brushing required on both spans
21	URGENT	Brushing	1.0	Brushing required on forespan at +158m (tree contact)
22	✓	Str Replace	25.0	Replace H-Frame tangent str - Poles in very poor condition
	✓	Brushing	1.0	Possible danger tree on aftspan at -47m
24	URGENT	Str Replace	25.0	Replace H-Frame tangent str - LP pole top in very poor condition
25	✓	Str Replace	25.0	Replace H-Frame tangent str - Pole tops in very poor condition
26	✓	Repair	0.3	Repair WP holes on RP
	✓	Brushing	1.5	Brushing required on forespan for branches on edge of R/W
27	✓	Brushing	1.0	Possible danger tree in aftspan (right side)
28	✓	Brushing	1.0	Possible danger tree in aftspan at -24m
33	-	-	-	Future Reference - Possible structure replace next assessment cycle
34	-	-	-	Future Reference - Possible structure replace next assessment cycle
35	-	-	-	Future Reference - Possible structure replace next assessment cycle
38	✓	Brushing	1.0	Possible danger tree (dead birch) on forespan
39	-	-	-	RØ is approx 1m from pole - OK to leave (30L to be converted to 63kV)
40	✓	Brushing	1.0	Brushing required on forespan for branches on edge of R/W
	-	-	-	Future Reference - Possible structure replace next assessment cycle
41	-	-	-	Minor chip on RØ bottom bell insulator - OK to leave
42	-	-	-	Future Reference - Possible structure replace next assessment cycle
43	-	-	-	Future Reference - Possible structure replace next assessment cycle
44	-	-	-	Future Reference - Possible structure replace next assessment cycle
46	✓	Brushing	1.0	Possible danger tree (deade birch) on forespan at +124m
48	✓	Brushing	1.5	Possible danger tree (dead birch) on forespan at +60m and +120m
50	-	-	-	Future Reference - Possible structure replace next assessment cycle
51	-	-	-	Future Reference - Possible structure replace next assessment cycle
60	-	-	-	Engr Review - Dx crossing clearance concerns on aftspan at -69.8m
	-	-	-	Future Reference - Possible structure replace next assessment cycle
61	✓	Repair	0.3	Add 2 guy guards
	✓	Brushing	1.0	Danger tree (dead pine) on aftspan at -47m
	-	-	-	Future Reference - Lots of vibration at str (old torsion dampers)
	-	-	-	Note: Maker ball str to be replaced with MoT widening (red tagged)
62	✓	Repair	0.5	Add 7 guy guards
	✓	Brushing	1.5	Brushing required on forespan
63	✓	Repair	0.2	Add 2 guy guards (Access thru private property - Landowner issues)
	-	-	-	Future Reference - Possible structure replace next assessment cycle
64	✓	Brushing	1.0	Possible danger tree (dead birch) on aftspan at -40m
69A	✓	Brushing	1.5	Brushing required on aftspan
72	-	-	-	Engr Review - Check bottom phase insulator for lightning damage
77	✓	Brushing	1.0	Possible danger tree on forespan at +25m
78	URGENT	Str Replace	25.0	Replace H-Frame tangent str with taller poles - Low clearance issues

APPENDIX II - 30L (SLC-COF) CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed
79	✓	Str Replace	30.0	Replace H-Frame tangent str (heli set) - Replace with str 30L78
	✓	Brushing	1.5	Brushing required on forespan and aftspan
80	✓	Brushing	1.0	Danger trees on aftspan at -45m and on forespan at +90m
82	✓	Brushing	1.0	Danger tree (dead pine) on forespan at +104m
84	URGENT	Str Replace	30.0	Replace H-Frame tangent str (heli set) - LP red tagged
86	✓	Repair	0.5	Add 6 guy guards
88	✓	Repair	0.3	Add 2 guy guards
91	✓	Brushing	1.5	Brushing required on forespan and aftspan
93	✓	Brushing	1.0	Possible danger trees on forespan for leaning firs with exposed roots
95	-	-	-	Future Reference - Possible structure replace next assessment cycle
96	✓	Brushing	1.5	Brushing required on forespan and aftspan
98	-	-	-	Future Reference - Possible structure replace next assessment cycle
99	✓	Brushing	1.0	Possible danger tree on aftspan at -39m for fir with exposed roots
103	✓	Brushing	1.0	Brushing required on forespan (left side)
105	-	-	-	Future Reference - Possible structure replace next assessment cycle
106	-	-	-	Future Reference - Possible structure replace next assessment cycle
109	✓	Repair	0.3	Add crimp connector for bonding ground rod to downlead
115	✓	Repair	0.3	Add guy guards
	-	-	-	Future Reference - Possible structure replace next assessment cycle
117	-	-	-	Future Reference - Possible structure replace next assessment cycle
120	✓	Repair	0.2	Add guy guard
121	✓	Brushing	1.0	Possible danger tree on forespan at +213m
122	URGENT	Str Replace	27.0	Replace H-Frame tangent str - LP blue taged and RP red tagged
				Note: access road needs work
123	✓	Brushing	1.0	Possible danger tree (dead larch) on forespan at +25m (left side)
124	-	-	-	Future Reference - Possible structure replace next assessment cycle
125	✓	Brushing	1.0	Brushing required on aftspan (left side)
126	✓	Str Replace	25.0	Replace H-Frame tangent str with taller poles - Low clearance issues
	✓	Brushing	1.5	Danger trees on aftspan at -73m and on forespan at +30m and +50m
127	✓	Str Replace	25.0	Replace H-Frame tangent str with taller poles - Low clearance issues
	✓	Brushing	1.0	Brushing required on aftspan
129	✓	Str Replace	25.0	Replace H-Frame tangent - Crossarm in poor condition
	✓	Brushing	1.0	Brushing required on forespan
132	-	-	-	Future Reference - Possible structure replace next assessment cycle
133	✓	Brushing	1.5	Brushing required on forespan and aftspan
135	✓	Brushing	1.0	Brushing required on aftspan
137	✓	Brushing	1.0	Brushing required on aftspan
138	✓	Brushing	1.0	Brushing required on forespan
145	✓	Brushing	1.5	Danger trees on forespan at +16m (right side) and +72m (left side)
146	✓	Brushing	1.0	Danger tree (dead larch) on forespan at +37m (left side)
151	URGENT	Str Replace	25.0	Replace H-Frame tangent str - LP Red tagged
152	✓	Str Replace	25.0	Replace H-Frame tangent str (old str) - Replace with other strs in area
153	✓	Str Replace	25.0	Replace H-Frame tangent str (old str) - Replace with other strs in area
155	URGENT	Str Replace	25.0	Replace H-Frame tangent str - Red tagged (from T&T data)
156	URGENT	Str Replace	25.0	Replace H-Frame tangent str - Red tagged (from T&T data)
157	✓	Str Replace	25.0	Replace H-Frame tangent str (old str) - Replace with other strs in area
158	✓	Str Replace	25.0	Replace H-Frame tangent str (old str) - Replace with other strs in area
159	✓	Brushing	1.5	Brushing required on forespan and aftspan
160	✓	Str Replace	25.0	Replace H-Frame tangent str (old str) - Replace with other strs in area
163	✓	Brushing	1.0	Danger tree (dead birch) on aftspan at -142m
168	✓	Repair	0.3	Add guy guard
166	✓	Brushing	1.0	Brushing required on aftspan (left side)
167	✓	Brushing	1.5	Brushing required in forespan and aftspan.
168	✓	Repair	0.3	Add guy guard
169	URGENT	Str Replace	25.0	Replace H-Frame tangent str - LP red tagged in the field
	✓	Brushing	1.5	Possible danger trees (leaning birch) on aftspan and forespan
170	✓	Repair	0.3	Add 2 guy guards
	✓	Brushing	1.0	Possible danger trees (leaning birch) on forespan (left side)
	-	-	-	Engr Review - Check capacity of poles for weight span and angle
171	URGENT	Str Replace	25.0	Replace H-Frame tangent str - RP red tagged in the field

APPENDIX II - 30L (SLC-COF) CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed
	✓	Brushing	1.5	Several danger trees (leaning birch) on forespan, dying cedar at -30m
172	✓	Str Replace	25.0	Replace H-Frame tangent str (old str) - Replace with str 30L171
	✓	Brushing	1.0	Danger tree (dead pine) on aftspan at -30m
	-	-	-	Note: Add double arms for large weight span
177	✓	Brushing	1.5	Brushing required on forespan, dead birch at +98m, dying pine left of str
179	-	-	-	Engr Review - Check possible low clr issues over access road at +112m
180	✓	Repair	0.5	Repair WP holes on LP
181	✓	Repair	0.5	Repair WP holes on LP
182	✓	Brushing	1.0	Brushing required on forespan
183	-	-	-	Engr Review - Check possible low clr issues at -138m
188	✓	Brushing	1.0	Brushing required on forespan at +235m
190	✓	Repair	0.3	Add 2 guy guards
192	-	-	-	Engr Review - Check possible low clr issues over access road at +69m
194	-	-	-	Future Reference - Possible structure replace next assessment cycle
197	✓	Repair	0.3	Add staples to downlead (near pole top)
198	URGENT	Str Replace	25.0	Replace H-Frame tangent str - LP blue/red tagged by PPSI in 2001
202	✓	Repair	0.3	Add 2 guy guards
207	✓	Repair	0.3	Add 3 guy guards
208	✓	Repair	0.3	Add 3 guy guards
210	URGENT	Str Replace	25.0	Replace H-Frame tangent str - Both poles red tagged
212	URGENT	Str Replace	25.0	Replace H-Frame tangent str - LP red tagged
213	✓	Brushing	1.0	Danger tree (dead aspen) on aftspan at -52m
214	✓	Brushing	1.5	Brushing required on forespan (right side) at +85m to +100m
217	-	-	-	Future Reference - Possible structure replace next assessment cycle
219	✓	Repair	0.3	Add 4 guy guards
222	✓	Repair	0.3	Add 4 guy guards
225	-	-	-	Engr Review - Check possible low clr at +72m
226	URGENT	Str Replace	25.0	Replace H-Frame tangent str - LP red tagged (from T&T data)
230	-	-	-	Future Reference - Possible structure replace next assessment cycle
231	✓	Brushing	1.0	Danger tree (dead Fir) on forespan at +172m (left side)
232	✓	Repair	0.3	Add 5 guy guards
233A	✓	Repair	0.3	Add 3 guy guards

ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	Str Replace	Brushing
# of Structures	30	25	51
Urgent Work	$ 0.0k	$ 332.0k	$ 1.0k
Recommended Work	$ 13.1k	$ 305.0k	$ 58.5k
+/-30% Estimate	**$ 13.1k**	**$ 637.0k**	**$ 59.5k**

Excludes contingency or FortisBC overheads.

Labor	$ 305.1k	43%	Approx 1900 man-hours with 30L de-energized.
Brushing	$ 59.5k	8%	Brushing for the required areas. Brushing crew for approx 3 weeks.
Material	$ 177.4k	25%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 63.9k	9%	Includes review of outstanding issues & survey follow-up.
PM	$ 42.6k	6%	Project management.
Misc	$ 61.1k	9%	For preliminary work, flagging, EVT, etc.
SUBTOTAL =	$ 709.6k		Does not include any FortisBC Capitalized Overheads.
Land and Access	$ 20.0k		Placeholder to deal with land and R/W access issues.
20% Contingency	$ 145.9k		Allows for 20% contingency.
TOTAL =	**$ 875.5k**		Does not include any FortisBC Capitalized Overheads.

DBS ENERGY SERVICES INC.

Report

To: Curtis Goriuk, Brian Edall, Alison Meredith; FortisBC

From: Jonathan Turner, Dennis Schlender; DBS Energy

CC: Aram Khalil-Pour; FortisBC

Date: 2010-09-27

Re: 42L 2010 CONDITION ASSESSMENT ENGINEERING REVIEW

INTRODUCTION

This 42L engineering review, from the Oliver Substation to the Huth Substation, is based on the data collected from the condition assessment patrols completed by DBS Energy personnel in June/July 2010 and the test & treat inspections completed by Gilnockie in 2006. This report provides an engineering design review, summary of deficiencies with an anticipated scope of work, as well as construction estimates for the on-going operational improvements for 42L and related distribution facilities. The recommendations of this report outline the risks and reliability issues of the 42L circuit, for which FortisBC can place the needed improvements into the Capital Plan budgets.

OVERVIEW OF THE LINE

The 42L 63kV circuit is approximately 35.5km in length (roughly 297 structures) and is parallel with 41L from the Oliver Substation to the Huth Substation, while providing supply to the OK Falls and Kaleden Substations. The 42L circuit is primarily a single wood pole design with portions of distribution underbuild (for approximately 8km of the total 42L line length). H-frame construction is used in some areas to accommodate larger span lengths. The line seems to have been constructed in the 1950's and completely rebuilt in 1978, for which the majority of the structures remain as 1978/1980 pole vintage. The majority of these 1978 vintage structures are still in service, but a few that have been changed-out through recent years. Refer to Appendix I for a histogram of the structure vintages on 42L that are currently in service.

The 42L circuit is strung with single 477 AAC Cosmos for the entirety of the line length. The distribution underbuild is strung with a variety of conductor types that include #6 Copper, #2 ACSR, 477 AAC, for single phase and three phase circuits. The #6 copper on the distribution underbuild, as well as the #6 and #8 copper conductor on the several distribution taps have been labelled as a brittle conductor type by FortisBC, and extra care should be taken during work on these conductors.

The 42L circuit also shares a right of way with 41L for the entire route and both of these lines are used to supply OK Falls and Kaleden Substations. The 41L/42L circuits can also feed 47L from switching structures WAT41ML or WAT42ML located near the Huth Substation. Due to the redundancy configuration of these two lines, either 41L or 42L can be periodically de-energized with the supply load transferred to the other circuit. It should be noted that there is discussion at the planning level that 41L transmission circuit may be salvaged in the near future with the distribution underbuild consolidated to the existing 41L facilities, and the transmission load transferred completely to 42L. It should also be noted that there is construction work at the Huth Substation and the Oliver Substation that may impact the actual configuration of these lines at the time of construction. There is also the possibility of 2-3km of line (located immediately outside of Oliver) that may be requested to be relocated and rebuilt (funded by Developer) for both 41L and 42L through the Oliver Golf Course area.

SUMMARY OF FINDINGS

There are only a few structures on 42L that have been replaced throughout the recent years (since the 1978 major rebuild), but few mark-ups in terms of as-built data and/or recent works have been added to the line records. The condition assessment records completed by DBS Energy produced detailed information in terms of the poles, hardware, framing, conductors, insulation, anchoring, and site information, which is being added to the permanent 42L line records.

The latest pole test and treat data for 42L was completed by Gilnockie Inspections in 2006. The data from the T&T records was used as a reference during the field assessment patrols of the 42L structures, and a few discrepancies were found for inconsistencies of pole information in terms of pole height/class/vintage. There are a total of 50 structures recommended for minor repairs, and two tangent structures recommended for replacement due to severe woodpecker damage. There is also one location requiring urgent brushing and was submitted to the district office for immediate correction. Replacement of structure tag numbers on approximately 100 structures is also recommended where the numbering is missing or badly faded. A detailed summary of the recommended rehabilitation work for 42L can be found in Appendix II. A general list of the issues seen on 41L as determined from the condition assessment patrols are listed below.

- Urgent brushing required at a one location for tree growth underneath the distribution conductors – District office has been notified and should be completed. To be confirmed as completed.
- Repair of major wood pecker holes and removal of bird nests (if applicable).
- Tighten loose Tx/Dx hardware and add lock nuts and lock washers. Some hardware the nut has completely backed off and is listed as an urgent repair.
- Anchors with missing guy guards that need to be added.
- Minor repairs on the distribution underbuild facilities - Missing stirrups, broken ground wire, etc.
- Repair of cotter keys that are missing or partly out.
- Replacement of damaged Tx/Dx arms and insulation.
- Replace structure number tags that are missing or badly faded.
- Structures recommended to be replaced. These structures are to be replaced due to severe woodpecker damage.
- Clean-up of right of way and salvage of old pole butts.
- Follow-up engineering review for anchor support requirements, review of Tx insulation for tracking and confirm recommended repair details.
- Minor fire damage at the base of the pole – OK to leave.
- Minor chip in Tx skypin in insulators – OK to leave.

ESTIMATE OF WORK

This 42L Condition Assessment Review Summary (Appendix II) shows the work required on each structure and the +/- 30% estimated construction costs. There are a total of 50 structures requiring minor rehabilitation repairs, and two tangent structures recommended for replacement. The table below shows the estimate summary and details of the proposed rehabilitation costs broken down into the various aspects for the total projected work. The urgent work refers to rehabs that need to be done immediately, and the recommended work refers to the rehabs that could be postponed for one to two years (if needed), but should still be done before the next assessment cycle. The total estimate for the 42L rehabilitation works is $97k, which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the rehabilitation work will be completed with 42L de-energized (backed-up via 41L) with some distribution outages expected.

	Repair	Str Replace	Brushing
# of Structures	50	2	0
Urgent Work	$ 16.0k	$ 0.0k	$ 0.0k
Recommended Work	$ 23.6k	$ 32.0k	$ 0.0k
+/-30% Estimate	**$ 39.6k**	**$ 32.0k**	**$ 0.0k**

Excludes contingency or FortisBC overheads.

Str Tag # Replacement	$ 11.0k		Approx 100 str locations have missing or faded str tag # that need replacing. $7.3k added to labor and $3.7k added to materials.
Labor	$ 37.3k	42%	Approx 200 man-hours with 42L de-energized.
Salvage	$ 7.2k	10%	Salvage labor. Approx 50 man-hours.
Brushing	$ 0.0k	0%	No brushing required. Assumed completed.
Material	$ 20.2k	23%	Includes poles & hardware; Transportation and overheads.
Engineering	$ 6.4k	9%	Includes review of outstanding issues & survey follow-up.
PM	$ 4.3k	6%	Project management.
Misc	$ 7.2k	10%	For preliminary work, flagging, EVT, etc.
SUBTOTAL =	$ 82.6k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 14.3k	20%	Allows for 20% contingency.
TOTAL =	**$ 96.9k**		Does not include any FortisBC Capitalized Overheads.

CONCLUSIONS AND RECOMMENDATIONS

All the assumptions to date for the engineering review of 42L have been based on the data collected from the DBS condition assessment patrols in conjunction with the Gilnockie pole test and treat data.

A detailed summary of the recommended rehabilitation work for 42L, from the Oliver Substation to the Huth Substation, can be found in Appendix II. There is work on 42L that is considered to be urgent and should be completed in 2010/2011. A total of 8 structures are recommended with urgent repairs, as listed below.

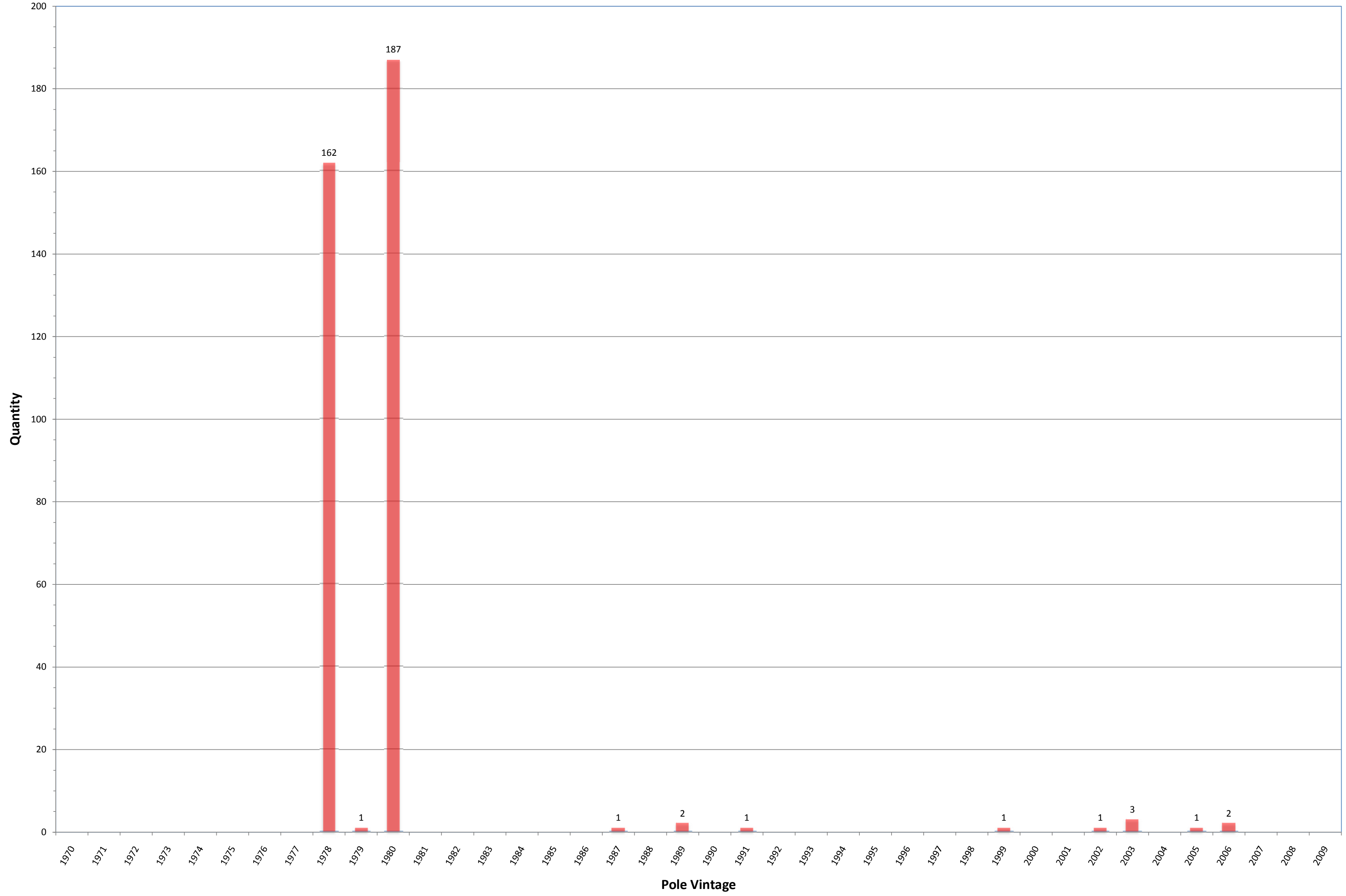
- 42L14 – Urgent repair for tightening Tx v-brace hardware and adding lock washers and lock nuts. Hardware is almost completely backed off of bolt.
- 42L48 – Urgent repair for replacement of Tx tangent crossarm and insulation. Crossarm has significant fire damage at v-brace bolt.
- 42L106 – Urgent repair for tightening Tx insulator hardware and adding lock washers and lock nuts. Hardware is backing off of bolts and one insulator is completely missing a nut.
- 42L118 – Urgent repair for tightening Tx insulator hardware and adding lock washers and lock nuts. Hardware is backing off of bolts and one insulator is completely missing a nut.
- 42L152 – Urgent repair for replacement of Tx DDE arms and insulation. Crossarm is badly splitting.
- 42L206 – Urgent repair for tightening Tx v-brace hardware and adding lock washers and lock nuts. Hardware is backing off of bolts and one bolt is completely missing a nut.
- 42L207 – Urgent repair for tightening Tx v-brace hardware and adding lock washers and lock nuts. Hardware is almost completely backed off of bolt.
- 42L292 – Urgent repair for tightening Tx v-brace hardware and adding lock washers and lock nuts. Hardware is almost completely backed off of bolt.

The remaining recommended work as listed in Appendix II should be completed before the next assessment cycle (ideally in the near future), and would be advantageous to complete these rehabs at the same time as the urgent work in order to capitalize on reduced overheads and mobilization costs. The total cost estimate for the 42L rehabilitation works is $97k, which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the work will be completed with 42L de-energized and load transferred to 41L, with some distribution outages.

There are also several outstanding issues that require follow-up engineering review, which are suggested to be done during the design stage of the project. These structure issues are shown in the 42L Condition Assessment Review Summary (Appendix II). A more detailed design review of these outstanding issues are included in the estimate (incorporated into the engineering costs), and any additional repairs that may be required as a result would be covered by the contingency allowance.

Currently the 42L structure list and line records have been updated with the condition assessment records for any missing data. This updated 42L structure list will form part of the permanent FortisBC Engineering line records. The 42L line records have not been updated at all through recent years and need to be revised with any new work and planned future work on the line.

APPENDIX I - 42L POLE VINTAGE CHART



APPENDIX II - 42L CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed
14	URGENT	Repair	0.5	Tighten Tx v-brace bolt; Add lock nut and lock washer
18	-	-	-	Minor chip on Tx skypin insulator - OK to leave
19	✓	Repair	0.5	Repair WP holes at pole top
22	✓	Repair	0.5	Add stirrups for Dx tap
23	✓	Repair	0.3	Remove bird nest on Dx tap arm
26	✓	Str Replace	15.0	Replace tang str with Dx u/b - Severe WP damage at pole top
	-	-	-	Note: Possibly cutdown top 5ft of pole and re-frame str - Check clearances
27	✓	Str Replace	17.0	Replace tang str with Dx u/b and openers - Severe WP damage mid pole
30	✓	Repair	0.5	Repair WP holes
32	✓	Repair	0.3	Clean-up right of way (old pole)
35	✓	Repair	0.5	Repair WP holes
43	✓	Repair	0.5	Repair WP holes
47	✓	Repair	0.3	Clean-up right of way (old steel banding)
48	URGENT	Repair	4.0	Replace Tx tangent dbl arm and insulation (fire damage); Add bonding
	✓	Repair	0.5	Add stirrups for Dx tap
59	✓	Repair	0.2	Add guy guard
72	✓	Repair	0.5	Add stirrups for Dx tap (caution #6 Cu)
85	✓	Repair	0.2	Add guy guard
86	✓	Repair	0.2	Add guy guard
87	✓	Repair	0.2	Add guy guard
99	✓	Repair	0.2	Add guy guards
100	✓	Repair	0.2	Add guy guard
106	URGENT	Repair	0.5	Tx post hardware missing nut; Tighten hardware; Add lock nuts & washers
110	✓	Repair	0.5	Repair WP holes
111	✓	Repair	0.2	Add guy guards
114	✓	Repair	0.3	Replace missing cotter key falling out on Tx saddle
	✓	Repair	0.2	Add missing guy guard
	✓	Repair	0.5	Repair WP holes; Remove bird nest
	-	-	-	Note - Minor fire damage at base of pole - OK to leave
118	URGENT	Repair	0.5	Tx post hardware missing nut; Tighten hardware; Add lock nuts & washers
122	✓	Repair	0.3	Salvage old anchor
133	✓	Repair	0.5	Repair WP holes; Remove bird nest
139	✓	Repair	0.5	Repair WP holes; Remove bird nest
144	✓	Repair	0.2	Cotter key falling out on Tx CØ deadend shoe
152	URGENT	Repair	9.0	Replace Tx DDE arms and install synthetic insulation (arm badly splitting)
153	✓	Repair	0.2	Add guy guard
155	✓	Repair	0.5	Add stirrups for Dx tap
157	✓	Repair	0.3	Repair ground wire at pole base
	-	-	-	Urgent brushing required for trees burning in Dx - District office notified - Confirm completed
170	✓	Repair	0.5	Repair WP holes; Remove possible bird nest
194	✓	Repair	2.5	Replace Tx tangent insulation; Add Tx hardware bonding
	-	-	-	Engr Review - Confirm insulation tracking and structure repair details
198	✓	Repair	0.2	Add guy guard
202	✓	Repair	0.2	Add guy guard
204	✓	Repair	0.5	Repair WP holes on RP; Remove bird nest
206	URGENT	Repair	0.5	Tx v-brace bolts missing nut; Tighten hardware; Add lock nuts & washer
207	URGENT	Repair	0.5	Tighten Tx v-brace bolt; Add lock nut and lock washer
208	✓	Repair	0.5	Repair WP holes; Remove possible bird nest
209	✓	Repair	0.5	Replace guy wire and attachment for side guy
	✓	Repair	0.2	Cotter key falling out on Tx CØ aft deadend shoe
	✓	Repair	0.2	Add guy guards
229	✓	Repair	6.0	Replace Tx H-Frame arm and install sythetic insulation
	✓	Repair	0.3	Clean-up right of way (old pole)
234	✓	Repair	0.2	Add guy guard
239	✓	Repair	0.2	Add guy guard
240	✓	Repair	0.2	Add guy guard
241	✓	Repair	0.2	Add guy guard

APPENDIX II - 42L CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed
	✓	Repair	0.3	Clean-up right of way (old pole)
244	✓	Repair	0.2	Add guy guard
246	✓	Repair	0.2	Add guy guards
244	✓	Repair	0.2	Add guy guards
261	✓	Repair	0.2	Add guy guards
262	-	-	-	Minor chip on Tx skypin insulator - OK to leave
266	-	-	-	Minor chip on Tx skypin insulator - OK to leave
268	✓	Repair	0.3	Clean-up right of way (old pole)
290	-	-	-	3rd party fiber cable with 7° delf'n and not anchored
	-	-	-	Engr Review - Check if anchoring support for fiber defl'n is required
292	URGENT	Repair	0.5	Tighten Tx v-brace bolt; Add lock nut and lock washer

ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	Str Replace	Brushing
# of Structures	50	2	0
Urgent Work	$ 16.0k	$ 0.0k	$ 0.0k
Recommended Work	$ 23.6k	$ 32.0k	$ 0.0k
+/-30% Estimate	**$ 39.6k**	**$ 32.0k**	**$ 0.0k**

OF URGENT STR REPLACEMENTS = 0

OF URGENT REPAIRS = 8

Excludes contingency or FortisBC overheads.

Str Tag # Replacement	$ 11.0k		Approx 100 str locations have missing or faded str tag # that need replacing. $7.3k added to labor and $3.7k added to materials.
Labor	$ 37.3k	42%	Approx 200 man-hours with 42L de-energized.
Salvage	$ 7.2k	10%	Salvage labor. Approx 50 man-hours.
Brushing	$ 0.0k	0%	No brushing required. Assumed completed.
Material	$ 20.2k	23%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 6.4k	9%	Includes review of outstanding issues & survey follow-up.
PM	$ 4.3k	6%	Project management.
Misc	$ 7.2k	10%	For preliminary work, flagging, EVT, etc.
SUBTOTAL =	$ 82.6k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 14.3k	20%	Allows for 20% contingency.
TOTAL =	**$ 96.9k**		Does not include any FortisBC Capitalized Overheads.

DBS ENERGY SERVICES INC.

Report

To: Curtis Goriuk, Brian Edall, Alison Meredith; FortisBC

From: Jonathan Turner, Dennis Schlender; DBS Energy

CC: Mike LeClair, Aram Khalil-Pour; FortisBC

Date: 2010-08-17

Re: 45L 2010 CONDITION ASSESSMENT ENGINEERING REVIEW

INTRODUCTION

This 45L engineering review, from the R.G. Anderson Substation (RGA) to the Arawana Substation, is based on the data collected from the condition assessment patrols completed by DBS Energy personnel in April-June 2010 and the test & treat inspections completed by Gilnockie in 2009. This report provides an engineering design review, summary of deficiencies with an anticipated scope of work, as well as construction estimates for the on-going operational improvements for 45L stemming from the condition assessment and pole test & treat data. The distribution underbuild from RGA to structure 45L131 is owned and operated by the City of Penticton (CoP), for which a separate construction estimate was provided for the recommended work on those CoP facilities. The recommendations of this report outline the risks and reliability issues of the 45L circuit, for which FortisBC can place the needed improvements into the Capital Plan budgets.

OVERVIEW OF THE LINE

The 45L 63kV circuit is approximately 13.4km in length (roughly 190 structures) and is a radial feed from the R.G. Anderson Substation to the new Arawana Substation, while providing supply to the Westminster Substation via the 45AL circuit that taps off at structure 45L25. The 45L circuit is a single wood pole design with distribution underbuild and was originally constructed in 1950's. Most of the original vintage structures have been changed-out through recent years, but there are a number of these original vintage poles still in service, which may require attention in the near future. Refer to Appendix I for a histogram of the structure vintages on 45L that are currently in service.

The 45L circuit is strung with single 927 AAC "BC Hydro Special" conductor from RGA to structure 45L24, with single 477 ACSR "Hawk" conductor from structure 45L24 to 45L54, and 90kcmil copper conductor for the remaining portion of the line from structure 45L54 to the Arawana Substation. The distribution underbuild is strung with a variety of conductor types that include #6 Copper, #2 ACSR, and 2/0 ACSR, for single phase and three phase underbuild circuits. The 90kcmil copper conductor on the 45L transmission line and the #6 copper on the distribution underbuild, as well as #6 and #8 copper conductor on several distribution taps have been tagged as a brittle conductor type by FortisBC, and extra care should be taken during work on these conductors.

SUMMARY OF FINDINGS

There are several structures on 45L that have been replaced throughout the years and few mark-ups in terms of as-built data and/or recent works have been added to the line records. The condition assessment records completed by DBS Energy produced detailed information in terms of the poles, hardware, framing, conductors, insulation, anchoring, and site information, which is being added to the permanent 45L line records.

The latest pole test and treat data for 45L was completed by Gilnockie Inspections in November of 2009. The data from the T&T records was used as a reference during the field assessment patrols of the 45L structures, and only a few discrepancies were found for inconsistencies of pole information (height/class/vintage). There are a total of 100 structures requiring minor repairs, of which 57 are solely related to the City of Penticton distribution underbuild facilities. There are a total of 7 structures recommended for replacement (one H-Frame double deadend, three tangents, two angles, and one distribution mutt structure). The H-Frame DDE has CoP distribution underbuild with switch, and the distribution mutt is a CoP underbuild structure. There are also 3 structure locations requiring brushing and/or removal of vines growing close to the distribution level of the structure. A detailed summary of the recommended rehabilitation work for 45L can be found in Appendix II. A list of various generic issues on 45L as determined from the condition assessment patrols are listed below.

- Brushing required at a few locations for trees growing close to conductors and for removal of vines that are growing close to the distribution conductors up the guy wire or pole.
- Tighten loose hardware and add lock nuts and lock washers.
- Anchors with missing guy guards that need to be added.
- Minor repairs on the distribution underbuild facilities - Missing stirrups, broken neutral tie, broken secondary spool attachment, missing PIC#'s, etc.
- Replacement of damaged single Tx arm and insulation with double arms and insulation for medium angle structures.
- Replace structure number tags that are falling off the pole – These structure tags were poorly installed using only one short nail to attach two number tags together on the pole.
- Tx v-brace bolt missing nut and backing almost completely out of the hole – Dispatched for repair during the condition assessment patrols and should be completed.
- Future reference for older structures that are possible replacements for subsequent condition assessment cycle(s). These structures should be reviewed in close detail in the following assessment cycle(s) and replaced completely as major work becomes required.
- Future reference for copper conductors that should be addressed under the brittle copper replacement program.
- Structures recommended to be replaced. These structures are to be replaced due to the pole being red tagged, clearance issues, or the structure blue tagged but with only 1" of shell thickness as noted from the 2009 Gilnockie T&T inspections.
- Poles requiring steel stub – Determined from the 2009 Gilnockie T&T data.
- Adding new anchor for angle structures with insufficient anchoring support.
- Follow-up engineering review for possible insufficient anchoring capacity, Tx-Dx circuit spacing issues, and foundation strength.

There are several 45L structures that still have older arms installed (on Tx and Dx) that are using flat braces, where dry rot tends to occur around the flat brace bolts on these arms. These flat braces generally have smaller thru bolts, less structural strength, provide higher wood fibre stresses on the arms, are installed generally on much older vintage arms, and therefore are reaching end of life. There have also been several arm fires as experienced in the past that are aggravated by dry rot of the arms and the fact that the braces are not bonded. When these transmission arms fail, the 63kV line falls into the distribution underbuild and can severely damage customer equipment. This has occurred numerous times over the years on all of the older 63kV transmission lines in the South Okanagan. Recently on 45L, a large number of these older arms and flat braces have been changed-out with new 10ft arms and bonding. The remaining structures with these older arms and flat braces are not scheduled to be replaced with this recommended assessment work, but any major future work at these structure locations should include replacement of the arms and braces. The general replacement and condition of all flat braced arms can be re-evaluated during the next condition assessment cycle.

The 90kcmil copper conductor on the 45L transmission line has at some structure locations been eaten away to only a few strands as seen during past work, which to a point the ties would be helping to carry the load. This is likely due to aeolian vibration on the circuit and any future work should consider the use of dampering activities. Any major Tx structure work along the section on 45L with 90kcmil copper should be done with great care, and a close inspection of the copper conductor must be conducted for any damaged conductor needing repairs or planned future work.

ESTIMATE OF WORK

This 45L Condition Assessment Review Summary (Appendix II) shows the work required on each structure and the +/-30% estimated construction costs. There are a total of 100 structures requiring minor rehabilitation repairs, 43 of which are related to FortisBC facilities and 57 related to City of Penticton distribution underbuild facilities. There are 7 structure replacements (one H-Frame DDE, three tangents, two angles, and one Dx mutt), with two of these structure replacements having City of Penticton Dx underbuild facilities (one H-Frame DDE Dx underbuild with switch, and one Dx tangent mutt structure). There are also 3 structure locations requiring brushing for tree growth getting close to the conductor or vines growing up the structure and getting close the distribution level. The urgent work refers to rehabs that need to be done immediately, and the recommended work refers to the rehabs that could be postponed for one to two years (if needed), but should still be done before the next assessment cycle. The table below shows the estimate summary and details the costs broken down into the various aspects for the total rehabilitation work. The total estimate for the 45L rehabilitation works is $192.5k (FortisBC portion) and $59.6k (City of Penticton portion) for the recommended rehabilitation work. The project cost for the entire rehabilitation work is $252k, which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the rehabilitation work will be completed with 45L energized and construction techniques using the robotic arm. It is anticipated that the H-Frame DDE structure replacement will require a temporary 45L bypass, which was included in the overall estimate.

FortisBC	**Repair**	**Str Replace**	**Brushing**
# of Structures	43	6	3
Urgent Work	$ 0.6k	$ 88.0k	$ 1.0k
Recommended Work	$ 33.8k	$ 35.0k	$ 2.0k
+/-30% Estimate	**$ 34.4k**	**$ 123.0k**	**$ 3.0k**

Excludes contingency or FortisBC overheads.

City of Penticton	**CoP u/b Repair**	**CoP u/b Replace**	**CoP u/b Brushing**
# of Structures	57	2	0
Urgent Work	$ 0.3k	$ 10.0k	$ 0.0k
Recommended Work	$ 32.4k	$ 7.0k	$ 0.0k
+/-30% Estimate	**$ 32.7k**	**$ 17.0k**	**$ 0.0k**

Excludes contingency or FortisBC overheads.

	FortisBC	**CoP**		
Labor	$ 83.4k	$ 25.8k	52%	Approx 650 man-hours with mostly hot work. Includes salvage labor.
Brushing	$ 3.0k	$ 0.0k	2%	Brushing for the required areas.
Material	$ 36.9k	$ 11.4k	23%	Includes poles and hardware; transportation and overheads.
Engineering	$ 16.0k	$ 5.0k	10%	Includes engr review of outstanding issues; updates to line record details.
PM	$ 9.6k	$ 3.0k	6%	Project management.
Misc	$ 11.4k	$ 4.5k	8%	For preliminary work, flagging, etc.
SUBTOTAL =	$ 160.4k	$ 49.7k		Does not include any FortisBC Capitalized Overheads.
20% Contingency	$ 32.1k	$ 9.9k		Allows for 20% contingency.
TOTAL =	**$ 192.5k**	**$ 59.6k**		Does not include any FortisBC Capitalized Overheads.

CONCLUSIONS AND RECOMMENDATIONS

All the assumptions to date for the engineering review of 45L have been based on the data collected from the DBS condition assessment patrols in conjunction with the Gilnockie pole test and treat data.

A detailed summary of the recommended rehabilitation work for 45L from the R.G. Anderson Substation to the Arawana Substation can be found in Appendix II. There is work on 45L that is considered to be urgent and should be completed in 2010/2011. A total of 4 structures are recommended for urgent replacement, two structures with urgent repairs, and one structure location with urgent brushing, as listed below.

- 45L1 – Urgent structure replacement for H-Frame DDE with CoP Dx underbuild and Dx switch. Replacement required due to left pole being red tagged.
- 45L56 – Urgent brushing required at structure location for vine growing up the guy wire close to distribution conductor level and is within the limits of approach – Removal of this vine may require an outage of the distribution underbuild circuit.
- 45L88 – Urgent repair for CoP secondary attachment near failure and needs to be replaced.
- 45L139 – Urgent structure replacement for tangent structure with FortisBC Dx underbuild. Replacement required due to pole being blue tagged with only 1” shell thickness.
- 45L148 – Urgent structure replacement for tangent structure with FortisBC Dx underbuild. Replacement required due to pole being blue tagged with only 1” shell thickness.
- 45L160 – Urgent structure replacement for light angle structure with FortisBC Dx underbuild. Replacement required due to pole being red tagged.
- 45L161 – Urgent repair for steel stub to be added due to pole being blue tagged.

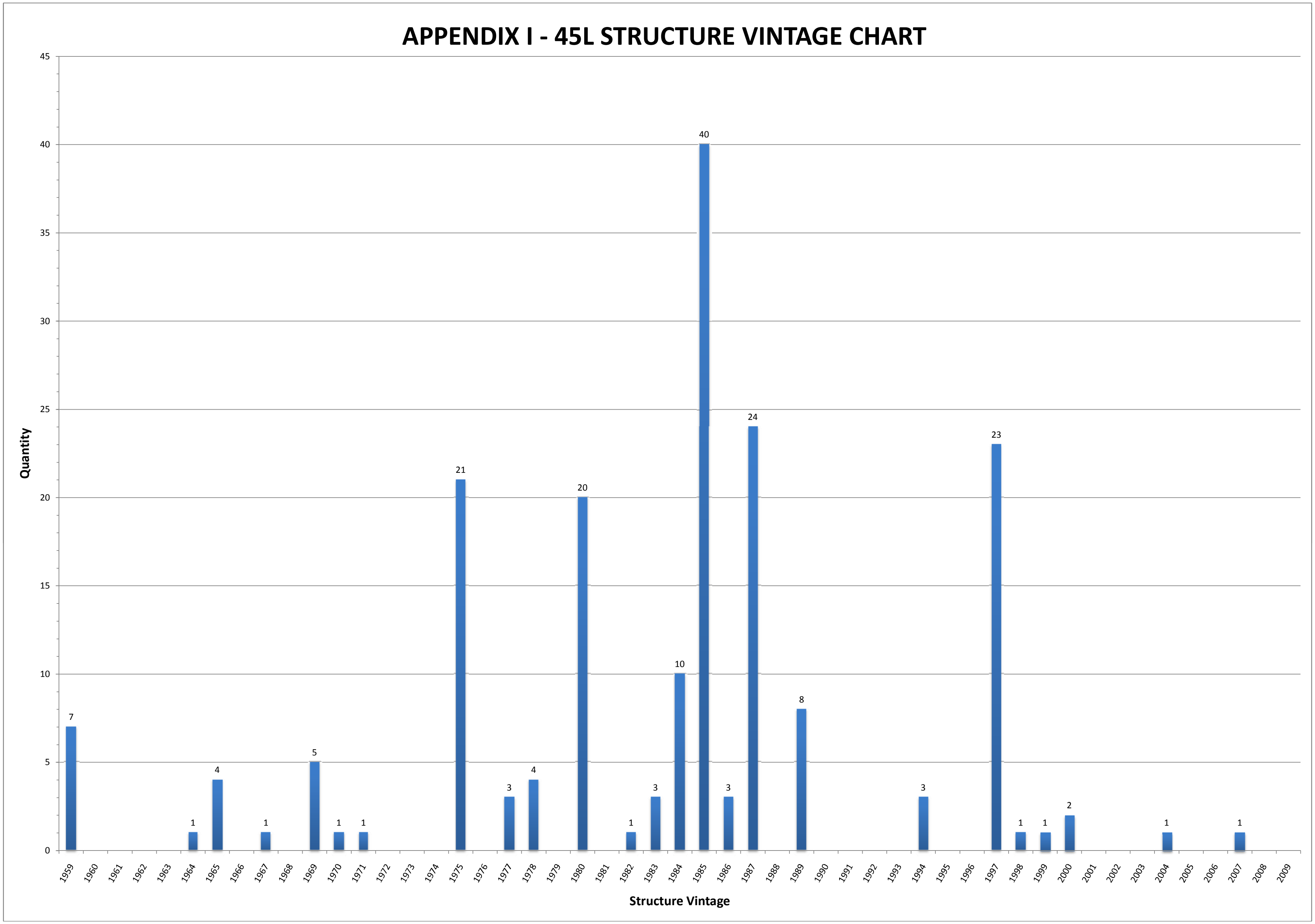
The remaining recommended work as listed in Appendix II should be completed before the next assessment cycle (ideally in the near future), and would be advantageous to complete these rehabs at the same time as the urgent work in order to capitalize on reduced overheads and mobilization costs. The total cost estimate for the 45L rehabilitation works is $252k (FortisBC-$192.5k and CoP-$59.6k), which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the work will be completed hot with 45L energized with the use of the robotic arm, as the 45L circuit is a radial feed to the Naramata area feeding the Arawana Substation.

All structure replacements and transmission arm replacements are recommended to include a rigorous inspection of the 90kcmil copper conductor under the ties at the structure locations. If any damage is noticed, the conductor must be repaired with patch rod or spliced out depending on the extent of the damage. It is suggested that any major structure work should also include a detailed dampering review.

The structures with older arms and flat braces still in service should be monitored closely during future condition assessment cycle(s) for dry rot or arm damage. These arms should be replaced and possibly replacement of the entire structure, if any significant work at these structure locations is needed.

There are also several outstanding issues that require follow-up engineering review, which are suggested to be done during the design stage of the project. These structure issues are shown in the 45L Condition Assessment Review Summary (Appendix II). Review of these outstanding issues are included in the estimate (incorporated into the engineering costs), and any additional repairs that may be required as a result would be covered by the contingency allowance.

Currently the 45L structure list and line records are being updated with the condition assessment records for any missing data. This updated 45L structure list will form part of the permanent FortisBC Engineering line records. The 45L line records have not been updated at all through recent years and need to be revised with any new work and planned future work on the line.


APPENDIX I - 45L STRUCTURE VINTAGE CHART
Quantity
0
5
10
15
20
25
30
35
40
45
Structure Vintage
1959
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
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1978
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5
1
1
21
3
4
20
1
3
10
40
3
24
8
3
23
1
1
2
1
1

APPENDIX II - 45L CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed	Ownership
1	URGENT	Str Replace	40.0	Replace H-Frame DDE Str with Dx u/b (Dx switch) - LP red tagged	FortisBC/CoP
	-	-	-	Note: Estimate inlcudes temporary Tx by-pass and new Dx switch	
3 Dx Mutt	✓	Str Replace	7.0	Replace Dx mutt str and engr review for cct-cct clearance issues	CoP
4	✓	Repair	0.2	Add guy guards	FortisBC
	✓	Repair	0.3	Tighten Neutral deadend hardware for 2 loose shoe bolts	CoP
	-	-	-	Engr Review - Dx LØ for jumper attached on main line - Move to tail	
5	✓	Repair	0.2	Add guy guards	FortisBC
	-	-	-	Engr Review - Check Dx hardware capacity and anchoring capacity	
5 Dx Mutt	✓	Repair	0.5	Add stirrups for xfmr bank	CoP
	-	-	-	Engr Review - Check str for xfmr pole grounding	CoP
7	✓	Repair	0.2	Add guy guard	FortisBC
	✓	Repair	0.5	Tighten hardware on bottom phase Tx post insulator - Add lock washer	FortisBC
8	✓	Repair	0.5	Add stirrups for Dx tap and xfmr	CoP
	✓	Repair	0.2	Add PIC#	CoP
9	✓	Repair	0.2	Add PIC#	CoP
10	✓	Repair	0.5	Add stirrups for Dx tap	CoP
11	✓	Repair	0.5	Add stirrup for xfmr	CoP
13	✓	Repair	0.5	Add stirrup for xfmr	CoP
14	✓	Repair	0.5	Add stirrups for Dx URD dip	CoP
	✓	Repair	0.2	Add PIC#	CoP
15	✓	Repair	0.3	Add guy guards	FortisBC
16	✓	Repair	0.3	Add guy guards	FortisBC
17	✓	Repair	0.3	Add guy guards	FortisBC
	-	-	-	Note: Anchoring (1/2" x 6' rods) is insufficient for full DDE - OK to leave	
	-	-	-	Str list to reflect str as NOT having full DDE capacity (full DDE at 45L16)	
20	✓	Repair	0.2	Add guy guards	FortisBC
21	✓	Repair	0.2	Add guy guards	FortisBC
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx u/b	CoP
22	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx u/b	CoP
23	-	-	-	NO STRUCTURE	
24	-	-	-	Future Reference - Dx 1Ø cct to be consolidated to Tx pole	CoP
25	-	-	-	Future Reference - Dx 1Ø cct to be consolidated to Tx pole	CoP
28	✓	Repair	0.3	Replace str tag# 45L28 and remove obsolete numbering at pole top	FortisBC
30	✓	Repair	0.3	Replace str tag# 45L30 and remove obsolete numbering at pole top	FortisBC
31	✓	Repair	0.3	Add backfill to pole base	FortisBC
	✓	Repair	1.0	Remove old CoP 1Ø Dx tap - Confirm	CoP
32	✓	Repair	0.3	Replace broken neutral tie	CoP
40	✓	Repair	0.3	Replace str tag# 45L40 and remove obsolete numbering at pole top	FortisBC
48	✓	Repair	0.5	Add stirrup for xfmr	CoP
49	✓	Repair	0.5	Add stirrups for Dx tap	CoP
56	URGENT	Brushing	1.0	Brushing required on guy wire for vine growing close to pole top	FortisBC
57	✓	Repair	0.3	Replace str tag# 45L57	FortisBC
	✓	Repair	0.2	Add guy guard	FortisBC
58	✓	Repair	0.2	Add guy guard	FortisBC
65	✓	Repair	0.5	Add stirrups for xfmr bank	CoP
	-	-	-	Future Reference - Dx mutt str on forespan could be salvaged out	CoP
67	✓	Repair	0.5	Add stirrup for xfmr	CoP
68	✓	Repair	0.5	Add stirrup for xfmr	CoP
70	✓	Repair	0.5	Add stirrup for xfmr	CoP
71	✓	Repair	0.5	Add stirrups for Dx tap and xfmr	CoP
	✓	Repair	0.2	Add PIC#	CoP
72	✓	Repair	0.5	Add stirrup for xfmr	CoP
73	-	-	-	Tx v-brace bolt almost completely out - Dispatched for repair - Confirm	FortisBC
74	✓	Repair	0.5	Add stirrup for xfmr	CoP
	-	-	-	Tx v-brace bolt almost completely out - Dispatched for repair - Confirm	FortisBC
75	✓	Repair	0.5	Add stirrup for xfmr	CoP
76	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
77	✓	Repair	0.5	Add stirrup for xfmr	CoP
	✓	Repair	0.2	Add guy guard	FortisBC
78	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
80	✓	Repair	0.5	Add stirrups for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
82	-	-	-	Note: Minor chip on RØ Tx insulator - OK to leave	
84	✓	Repair	0.5	Add stirrup for xfmr	CoP
	✓	Repair	1.0	OHG pole - Replace hardware with combo guy tees, add split bolt	FortisBC
	✓	Repair	0.2	Add guy guard	FortisBC
85	✓	Repair	0.5	Add stirrups for Dx taps	CoP
	✓	Repair	0.2	Add PIC#	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
86	✓	Repair	0.5	Add stirrup for xfmr	CoP
87	✓	Repair	0.5	Add stirrups for xfmr bank	CoP
88	URGENT	Repair	0.3	Replace secondary service attachment	CoP

APPENDIX II - 45L CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed	Ownership
89	✓	Repair	0.5	Add stirrup for xfmr	CoP
	-	-	-	Engr Review - Check pole foundation (possibly add side guy to Telus)	FortisBC
91	✓	Repair	0.5	Add stirrups for Dx	CoP
	✓	Repair	0.2	Add PIC#	CoP
92	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
	✓	Repair	0.3	Replace secondary service attachment	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
93	✓	Repair	0.5	Add stirrup for xfmr	CoP
	✓	Repair	0.3	Replace secondary service attachment	CoP
94	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
	✓	Repair	0.2	Add guy guard	FortisBC
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
95	✓	Repair	0.5	Add stirrup for xfmr	CoP
	✓	Repair	1.0	OHG pole - Replace hardware with combo guy tees, add split bolt	FortisBC
97	✓	Repair	0.5	Add stirrup for xfmr	CoP
98	✓	Repair	0.5	Add stirrup for xfmr	CoP
99	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
100	✓	Repair	0.5	Add stirrup for Dx tap	CoP
101	✓	Repair	0.5	Add stirrup for Dx tap	CoP
102	✓	Repair	0.5	Add stirrup for xfmr	CoP
103	✓	Repair	0.5	Add stirrup for xfmr	CoP
104	✓	Repair	0.5	Add stirrup for xfmr	CoP
106	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
107	-	-	-	Note: Pole base missing chunk (from vehicle contact) - OK to leave	
108	✓	Repair	0.5	Add stirrup for xfmr	CoP
109	✓	Repair	4.0	Replace Tx arm and insulators with double arms and insulation	FortisBC
110	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
112	✓	Repair	0.5	Add stirrup for xfmr	CoP
113	✓	Repair	4.0	Replace Tx arm and insulators with double arms and insulation	FortisBC
114	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
118	✓	Repair	0.5	Add stirrup for xfmr	CoP
119	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
120	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
122	✓	Repair	0.3	Add guy guard	FortisBC
123	✓	Repair	0.5	Add stirrup for xfmr	CoP
125	✓	Repair	4.0	Replace Tx arm and insulators with double arms and insulation	FortisBC
	✓	Repair	0.8	Add stirrup for xfmr and replace cutout	CoP
	✓	Repair	0.3	Replace secondary service attachment	CoP
127	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
128	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	CoP
129	✓	Repair	0.5	Add stirrup for xfmr	CoP
	✓	Repair	0.2	Add guy guard	CoP
130	✓	Repair	0.5	Add stirrup for xfmr	CoP
131	-	-	-	Engr Review - Check anchoring capacity	FortisBC
	-	-	-	Note: End of CoP u/b and start of FortisBC u/b	
132	✓	Str Replace	20.0	Replace vertical angle str - Old pole with low clearances	FortisBC
133	✓	Str Replace	15.0	Replace tang str - Old pole with low clearances	FortisBC
	✓	Brushing	1.5	Brushing required on forespan	FortisBC
134	✓	Repair	0.3	Add guy guard	FortisBC
	-	-	-	Note: Minor chip on CØ Tx insulator - OK to leave	
	-	-	-	Future Reference - Possible structure replace next assessment cycle	FortisBC
135	-	-	-	Future Reference - Possible structure replace next assessment cycle	FortisBC
136	-	-	-	Engr Review - Check anchoring condition and capacity	FortisBC
138	✓	Repair	0.5	Tighten CØ Tx hardware with lock nut & lock washer, add split bolt	FortisBC
139	URGENT	Str Replace	18.0	Replace tang str with 2x 1Ø Dx taps - Blue tagged (1" shell thickness)	FortisBC
148	URGENT	Str Replace	18.0	Replace tang str with xfmr & 1Ø Dx tap - Blue tagged (1" shell thickness)	FortisBC
150	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	FortisBC
153	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	FortisBC
154	✓	Repair	1.5	Add new anchor for Tx and Dx angle - Easement required	FortisBC
157	-	-	-	Future Reference - Replace #8 Cu on 1Ø Dx tap	FortisBC

APPENDIX II - 45L CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed	Ownership
158	✓	Repair	0.5	Add stirrup for Dx tap, remove unused stirrup on RØ	FortisBC
159	✓	Repair	0.5	Add stirrup for xfmr	FortisBC
160	URGENT	Str Replace	22.0	Replace light angle str with xfmr and 2x 1Ø Dx taps - Red tagged	FortisBC
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	FortisBC
161	URGENT	Repair	0.6	Add steel stub to pole - Blue tagged	FortisBC
162	✓	Repair	0.2	Repair str# tag	FortisBC
	-	-	-	Future Reference - Possible structure replace next assessment cycle	FortisBC
163	✓	Repair	0.5	Add stirrup for Dx tap	FortisBC
	✓	Repair	0.3	Tighten Dx v-brace hardware and add lock nut	FortisBC
167	-	-	-	Future Reference - Replace #8 Cu on 1Ø Dx tap	FortisBC
168	✓	Repair	0.5	Add stirrup for Dx tap	FortisBC
170	✓	Repair	0.5	Add stirrup for xfmr	FortisBC
	✓	Brushing	0.5	Brushing required at str for vine growing up pole	FortisBC
	-	-	-	Engr Review - Check condition of OHG pole and anchor capacity	FortisBC
171	✓	Repair	0.5	Add stirrups for cap bank	FortisBC
172	✓	Repair	0.5	Add stirrup for Dx and xfmr	FortisBC
173	✓	Repair	0.5	Add stirrup for Dx tap	FortisBC
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	FortisBC
174	✓	Repair	0.5	Add stirrups for Dx tap	FortisBC
	✓	Repair	1.5	Add new OHG anchor for Dx 3Ø tap - Easement required	FortisBC
175	✓	Repair	0.5	Add stirrups for Dx tap and xfmr	FortisBC
177	✓	Repair	0.5	Add stirrup for xfmr	FortisBC
179	✓	Repair	0.5	Add stirrup for xfmr	FortisBC
181	✓	Repair	0.5	Add stirrup for Dx tap	FortisBC
	-	-	-	Future Reference - Replace #8 Cu on 1Ø Dx tap with poor splice	FortisBC
182	✓	Repair	0.5	Add stirrups for Dx tap	FortisBC
	-	-	-	Future Reference - Replace #6 Cu on 1Ø Dx tap	FortisBC
187	✓	Repair	2.0	Replace 3Ø Dx tap arm to double arm, add stirrups, add PIC#	FortisBC
	✓	Repair	0.3	Repair WP damage at pole top	FortisBC
188	✓	Repair	0.5	Add stirrup for Dx tap	FortisBC
189	✓	Repair	0.5	Add stirrup for xfmr	FortisBC

ESTIMATE OF URGENT AND RECOMMENDED WORK

FortisBC	**Repair**	**Str Replace**	**Brushing**
# of Structures	43	6	3
Urgent Work	$ 0.6k	$ 88.0k	$ 1.0k
Recommended Work	$ 33.8k	$ 35.0k	$ 2.0k
+/-30% Estimate	$ 34.4k	$ 123.0k	$ 3.0k

City of Penticton	**CoP u/b Repair**	**CoP u/b Replace**	**CoP u/b Brushing**
# of Structures	57	2	0
Urgent Work	$ 0.3k	$ 10.0k	$ 0.0k
Recommended Work	$ 32.4k	$ 7.0k	$ 0.0k
+/-30% Estimate	$ 32.7k	$ 17.0k	$ 0.0k

	FortisBC	**City of Penticton**		
Labor	$ 83.4k	$ 25.8k	52%	Approx 650 man-hours with mostly hot work. Includes salvage labor.
Brushing	$ 3.0k	$ 0.0k	1%	Brushing for the required areas.
Material	$ 36.9k	$ 11.4k	23%	Includes poles and hardware; transportation and overheads.
Engineering	$ 16.0k	$ 5.0k	10%	Includes engr review of outstanding issues; updates to line records.
PM	$ 9.6k	$ 3.0k	6%	Project management.
Misc	$ 11.4k	$ 4.5k	8%	For preliminary work, flagging, etc.
SUBTOTAL =	$ 160.4k	$ 49.7k		Does not include any FortisBC Capitalized Overheads.
20% Contingency	$ 32.1k	$ 9.9k		Allows for 20% contingency.
TOTAL =	**$ 192.5k**	**$ 59.6k**		Does not include any FortisBC Capitalized Overheads.

DBS ENERGY SERVICES INC.

Report

To: Curtis Goriuk, Brian Edall, Alison Meredith; FortisBC

From: Jonathan Turner, Dennis Schlender; DBS Energy

CC: Aram Khalil-Pour; FortisBC

Date: 2010-09-13

Re: 45AL 2010 CONDITION ASSESSMENT ENGINEERING REVIEW

INTRODUCTION

This 45AL engineering review includes all 45AL structure from the 63kV 45L tap at structure 45L25 to the Westminster Substation located in Penticton. The report is based on data collected from the condition assessment patrols completed by DBS Energy personnel in July 2010 and the test & treat inspections completed by Gilnockie in November of 2009. This report provides a preliminary engineering design review, summary of deficiencies with an anticipated scope of work, as well as construction estimates for the on-going operational improvements for 45AL. The distribution underbuild on 45AL structures is owned and operated by the City of Penticton (CoP), for which a separate construction estimate is broken out for the rehabilitation work. The recommendations of this report outline the risks and reliability issues of the 45AL circuit, for which FortisBC can use as needed for the Capital Plan budgets.

OVERVIEW OF THE LINE

The 45AL 63kV circuit is approximately 2.15km in length (32 structures) and is a radial feed to the Westminster Substation. The 45AL circuit taps off of 45L at structure 45L25 and continues west into Penticton. The 45AL circuit is a single wood/steel pole design with CoP distribution underbuild and was originally constructed in 1977. Some of the original vintage structures have been changed-out through recent years, but the majority of the structures are in overall good condition. Refer to Appendix I for a histogram of the pole vintages on 45L that are currently in service.

The 45AL circuit is strung with single 477 AAC “Cosmos” conductor for the entirety of the line into the Westminster Substation. The distribution underbuild is strung with a variety of conductor types that include #2 ACSR, 2/0 ACSR, and 477 AAC for the single phase and three phase distribution underbuild circuits.

SUMMARY OF FINDINGS

There are several structures on 45AL that have been replaced throughout the years and few mark-ups in terms of as-built data and/or recent works have been added to the line records. The condition assessment records completed by DBS Energy produced detailed information in terms of the poles, hardware, framing, conductors, insulation, anchoring, and site information, which is being added to the permanent 45AL line records.

The latest pole test and treat data for 45AL was completed by Gilnockie Inspections in November of 2009. The data from the T&T records was used as a reference during the field assessment patrols of the 45AL structures, and there were several discrepancies found for inconsistencies of pole information (height/class/vintage). There are a total of 35 structures requiring repairs (mostly minor in nature), of which 12 are solely related to the City of Penticton distribution underbuild facilities. There are a total of 2 structures recommended for replacement (one vertical double deadend, and one heavy angle structure). The DDE structure replacement has CoP distribution underbuild facilities (1Ø DDE on arm). A detailed summary of the recommended rehabilitation work for 45AL can be found in Appendix II. A list of various generic issues on 45L as determined from the condition assessment patrols are listed below.

- Tighten loose hardware and general addition of lock nuts and lock washers.
- Anchors with missing guy guards that need to be added.
- Minor repairs on the distribution underbuild facilities - Missing stirrups, missing PIC#'s, etc.
- Replacement of rotten Tx arm and related insulation.
- Adding structure number tags for all steel structures.
- Structures recommended to be replaced. These structures are to be replaced due to the pole being red tagged or the structure blue tagged but with only 1" of shell thickness as noted from the 2009 Gilnockie T&T inspections.
- Follow-up engineering review for possible Tx-Dx circuit spacing issues.

There are a select few 45AL structures that still have older arms installed on the Dx underbuild that are using flat braces, where dry rot tends to occur around the flat brace bolts on these arms. These flat braces generally have smaller thru bolts, less structural strength, provide higher wood fibre stresses on the arms, are installed generally on much older vintage arms, and therefore are reaching end of life. There have also been several arm fires as experienced in the past that are aggravated by dry rot of the arms and the fact that the braces are not bonded. The remaining structures with these older arms and flat braces are not scheduled to be replaced with this recommended assessment work, but any major future work at these structure locations should include replacement of the arms and braces. The general replacement and condition of all flat braced arms can be re-evaluated during the next condition assessment cycle.

ESTIMATE OF WORK

This 45AL Condition Assessment Review Summary (Appendix II) shows the work required on each structure and the +/-30% estimated construction costs. There are a total of 35 structures requiring rehabilitation repairs, 23 of which are related to FortisBC facilities and 12 are related exclusively to the City of Penticton distribution underbuild facilities. There are also 2 structure replacements (one vertical double deadend, and one heavy angle structure), with the heavy angle structure having City of Penticton Dx underbuild facilities (1Ø DDE on arm). These two structure replacements will require additional anchoring and new land easements are expected to be required. There is a $2.0k allowance in the estimate as a placeholder to capture these land costs.

The urgent work refers to rehabs that need to be done immediately, and the recommended work refers to the rehabs that could be postponed for one to two years (if needed), but should still be done before the next assessment cycle. The table below shows the estimate summary and details the costs broken down into each section of the total rehabilitation cost. The total estimate for the recommended 45AL rehabilitation works is $88.9k (FortisBC portion) and $14.2k (City of Penticton portion). The project cost for the entire rehabilitation work is $103k, which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the rehabilitation work will be completed with 45AL energized and construction techniques using the robotic arm. City of Penticton costs should be reviewed and compared to actual third party billing rates FortisBC may have for CoP.

FortisBC	**Repair**	**Str Replace**	**Brushing**
# of Structures	23	2	0
Urgent Work	$ 6.0k	$ 48.6k	$ 0.0k
Recommended Work	$ 19.5k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 25.5k	$ 48.6k	$ 0.0k

City of Penticton	**CoP u/b Repair**	**CoP u/b Replace**	**CoP u/b Brushing**
# of Structures	12	1	0
Urgent Work	$ 0.3k	$ 4.4k	$ 0.0k
Recommended Work	$ 7.1k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 7.4k	$ 4.4k	$ 0.0k

	FortisBC	**CoP**		
Labor	$ 31.1k	$ 5.0k	42%	Approx 200 man-hours with mostly hot work.
Salvage	$ 7.4k	$ 1.2k	10%	Salvage Labor. Approx 50 man-hours.
Brushing	$ 0.0k	$ 0.0k	0%	Brushing for the required areas. None required.
Material	$ 16.3k	$ 2.6k	22%	Includes poles and hardware; transportation and overheads.
Land	$ 2.0k	$ 0.0k	2%	Land for new anchor easements. Approx $0.5 per sq ft.
Engineering	$ 7.4k	$ 1.2k	10%	Includes engr review of outstanding issues; updates to line records.
PM	$ 4.4k	$ 0.7k	6%	Project management.
Misc	$ 5.4k	$ 1.2k	8%	For preliminary work, flagging, etc.
SUBTOTAL =	$ 74.1k	$ 11.8k		Does not include any FortisBC Capitalized Overheads.
20% Contingency	$ 14.8k	$ 2.4k		Allows for 20% contingency.
TOTAL =	**$ 88.9k**	**$ 14.2k**		Does not include any FortisBC Capitalized Overheads.

CONCLUSIONS AND RECOMMENDATIONS

All the assumptions to date for the engineering review of 45AL have been based on the data collected from the DBS condition assessment patrols in conjunction with the Gilnockie pole test and treat data.

A detailed summary of the recommended rehabilitation work for 45AL (from the 63kV tap at structure 45L25 to the Westminster Substation) can be found in Appendix II. There is work on 45AL that is considered to be urgent and should be completed in 2010/2011. There are 2 structures that are recommended for urgent replacement, and 2 structures with urgent repairs, as listed below.

- 45AL7 – Urgent repair for replacement of overhead guy pole. Replacement required due to pole being blue tagged with only 1" shell thickness.
- 45AL13 – Urgent repair for tightening distribution hardware on the pin insulators and adding lock washers and lock nuts. Hardware is backing off of bolt and one insulator has nut completely missing.
- 45LA22 – Urgent structure replacement for heavy angle structure with CoP Dx underbuild. Replacement required due to pole being blue tagged with only 1" shell thickness. Also recommending change-out for overhead guy pole and new anchoring on the half angle. Anchor will most likely require land easement.
- 45AL23 – Urgent structure replacement for vertical DDE structure. Replacement required due to pole being red tagged. Structure is currently framed as a running corner, but the angle is too

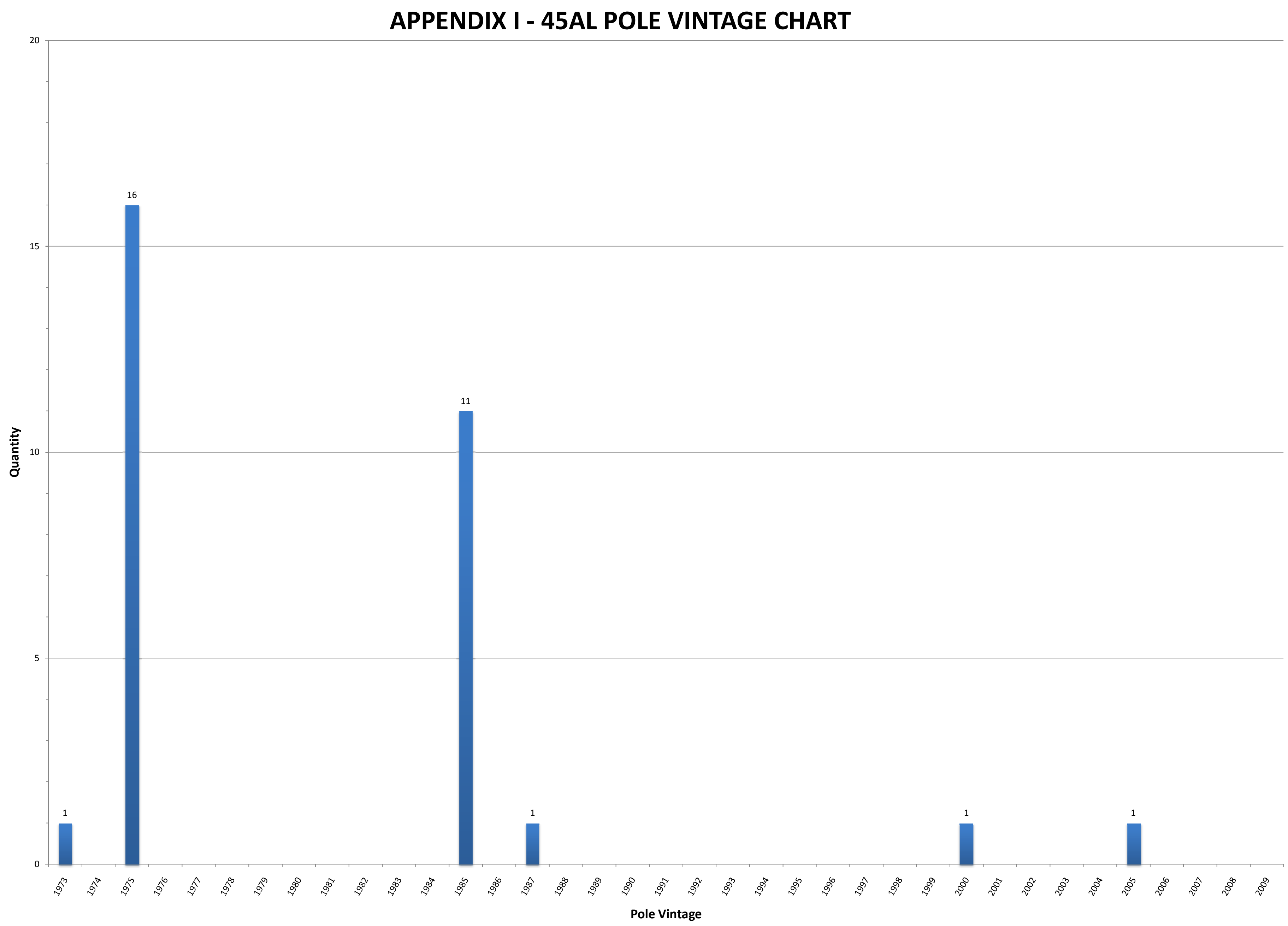
heavy for an angle structure type. Recommend changing out to a vertical DDE with new anchoring, which will require an anchor easement.

The remaining recommended work as listed in Appendix II should be completed before the next assessment cycle (ideally should be in the near future), and would be advantageous to complete these rehabs at the same time as the urgent work in order to capitalize on reduced overheads and mobilization costs. The total cost estimate for the 45AL rehabilitation works is $103k (FortisBC-$88.9k and CoP-$14.2k), which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the work will be completed hot with 45AL energized (with the use of the robotic arm), as the 45AL circuit is a radial feed to the downtown Penticton area feeding the Westminster Substation. The distribution underbuild will also likely be required to be done hot and must be coordinated with the CoP.

The structures having distribution underbuild with older arms and flat braces still in service should be monitored closely during future condition assessment cycle(s) for dry rot or arm damage. These arms should be replaced and possibly replacement of the entire structure, if any significant work at these structure locations is needed.

There are also outstanding clearance issues that require follow-up engineering review, which are suggested to be done during the detailed design stage of this project. These structure issues are shown in the 45AL Condition Assessment Review Summary (Appendix II). Review of these outstanding issues are included in the estimate (incorporated into the engineering costs), and any additional repairs that may be required as a result would need to be covered by the contingency allowance, or funded as an extra cost.

Currently the 45AL structure list and line records are being updated with the condition assessment records for any missing data. This updated 45AL structure list will form part of the permanent FortisBC Engineering line records. The 45AL line records have not been updated at all through recent years and need to be revised with any new work and planned future work on the line.



APPENDIX I - 45AL POLE VINTAGE CHART

APPENDIX II - 45AL CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed	Ownership
2	✓	Repair	0.8	Add stirrup for xfmr and replace cutout	CoP
4	✓	Repair	0.6	Remove old pole and transfer Telus	FortisBC
	✓	Repair	0.2	Repair RØ key (falling out) on socket adapter	FortisBC
5	✓	Repair	0.5	Add stirrup for Dx tap and xfmr	CoP
	✓	Repair	0.2	Add PIC#	CoP
7	URGENT	Repair	6.0	Replace OHG pole - Blue tagged (1" shell thickness)	FortisBC
	✓	Repair	0.2	Add str tag #	FortisBC
	✓	Repair	0.5	Add stirrup for xfmr	CoP
8	✓	Repair	0.2	Add str tag #	FortisBC
	✓	Repair	0.2	Add guy guard	FortisBC
9	✓	Repair	0.2	Add str tag #	FortisBC
10	✓	Repair	0.2	Add str tag #	FortisBC
11	✓	Repair	0.2	Add str tag #	FortisBC
12	✓	Repair	0.2	Add str tag #	FortisBC
13	✓	Repair	0.2	Add str tag #	FortisBC
	✓	Repair	0.5	Add stirrup for xfmr	CoP
	URGENT	Repair	0.3	Tighten Dx insul hardware; Add lockwasher and locknut	CoP
14	✓	Repair	0.2	Add str tag #	FortisBC
15	✓	Repair	0.2	Add str tag #	FortisBC
	✓	Repair	0.2	Add guy guards	FortisBC
	✓	Repair	0.5	Add stirrup for xfmr	CoP
16	✓	Repair	0.2	Add str tag #	FortisBC
17	✓	Repair	0.2	Add str tag #	FortisBC
	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	-	-	-	Future Reference - Tx RØ jumper attached on main line	FortisBC
				(Should be moved to conductor tail)	
18	✓	Repair	0.2	Add str tag #	FortisBC
19	✓	Repair	0.2	Repair str tag #	FortisBC
	✓	Repair	0.5	Add stirrup for xfmr	CoP
20	✓	Repair	3.5	Replace Tx tangent arm and insulation	FortisBC
	✓	Repair	0.5	Add stirrup for Dx URD tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
20 Dx mutt	-	-	-	Engr Review - Check cct-cct clearances issues at str	FortisBC
21	✓	Repair	0.5	Add stirrup for xfmr	CoP
21 Dx mutt	-	-	-	Engr Review - Check cct-cct clearances issues at str	FortisBC
22	URGENT	Str Replace	22.0	Replace heavy ang str - Blue tagged (1" shell thickness)	FortisBC/CoP
	✓	Repair	7.0	Replace OHG pole and anchor (need easement)	FortisBC
				Note: estimate includes $1k for anchor easement	
23	URGENT	Str Replace	31.0	Replace heavy ang str with DDE str - Red tagged	FortisBC
				(need to redo fore anchoring - easement required)	
				Note: estimate includes $1k for anchor easement	
24	✓	Repair	0.2	Add str tag #	FortisBC
25	✓	Repair	0.2	Add str tag #	FortisBC
26	✓	Repair	0.2	Add str tag #	FortisBC
27	✓	Repair	0.2	Add str tag #	FortisBC
	✓	Repair	0.5	Add stirrup for Dx tap	CoP
28	✓	Repair	0.2	Add str tag #	FortisBC
29	✓	Repair	0.2	Add str tag #	FortisBC
30	✓	Repair	4.0	Replace Tx dbl arms and insulation	FortisBC
	✓	Repair	0.5	Add stirrup for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
32	✓	Repair	0.5	Add stirrup for Dx	CoP
	✓	Repair	0.2	Add PIC#	CoP

APPENDIX II - 45AL CONDITION ASSESSMENT REVIEW SUMMARY

ESTIMATE OF URGENT AND RECOMMENDED WORK

FortisBC	**Repair**	**Str Replace**	**Brushing**
# of Structures	23	2	0
Urgent Work	$ 6.0k	$ 48.6k	$ 0.0k
Recommended Work	$ 19.5k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 25.5k	$ 48.6k	$ 0.0k

City of Penticton	**CoP u/b Repair**	**CoP u/b Replace**	**CoP u/b Brushing**
# of Structures	12	1	0
Urgent Work	$ 0.3k	$ 4.4k	$ 0.0k
Recommended Work	$ 7.1k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 7.4k	$ 4.4k	$ 0.0k

	FortisBC	**City of Penticton**		
Labor	$ 31.1k	$ 5.0k	42%	Approx 200 man-hours with mostly hot work.
Salvage	$ 7.4k	$ 1.2k	10%	Salvage Labor. Approx 50 man-hours.
Brushing	$ 0.0k	$ 0.0k	0%	Brushing for the required areas. None required
Material	$ 16.3k	$ 2.6k	22%	Includes poles and hardware; transportation and overheads.
Land	$ 2.0k	$ 0.0k	2%	Land for new anchor easements; Approx $0.5 per sq foot.
Engineering	$ 7.4k	$ 1.2k	10%	Includes engr review of outstanding issues; updates to line records.
PM	$ 4.4k	$ 0.7k	6%	Project management.
Misc	$ 5.4k	$ 1.2k	8%	For preliminary work, flagging, etc.
SUBTOTAL =	$ 74.1k	$ 11.8k		Does not include any FortisBC Capitalized Overheads.
20% Contingency	$ 14.8k	$ 2.4k		Allows for 20% contingency.
TOTAL =	**$ 88.9k**	**$ 14.2k**		Does not include any FortisBC Capitalized Overheads.

DBS ENERGY SERVICES INC.

Report

To: Curtis Goriuk, Brian Edall, Alison Meredith; FortisBC

From: Jonathan Turner, Dennis Schlender; DBS Energy

CC: Aram Khalil-Pour

Date: 2010-09-14

Re: 47L 2010 CONDITION ASSESSMENT ENGINEERING REVIEW

INTRODUCTION

We have completed the engineering review of the 47L facilities from the 41L/42L tap points (outside the HUTH Substation) to the Waterford Substation (WAT). This review is based on the data collected from the condition assessment patrols completed by DBS Energy personnel in June 2010 and the test & treat inspections completed by Gilnockie in 2006. This report provides an engineering design review, summary of deficiencies with an anticipated scope of work, as well as construction estimates for the on-going operational improvements for 47L. The distribution underbuild from structure 47L1 to 47L26 is FortisBC owned. However, the distribution underbuild from 47L32 to 47L34 is owned and operated by the City of Penticton (CoP), for which a separate construction estimate was provided for the recommended work on those CoP facilities. The recommendations of this report outline the risks and reliability issues of the 47L circuit, for which FortisBC can place the needed improvements into the Capital Plan budgets. Any work to be completed on the City of Penticton facilities is expected to require the CoP approvals and coordination.

OVERVIEW OF THE LINE

The 47L 63kV circuit (previously named 41L-WAT) is approximately 3.1km in length (37 structures) and is a radial feed from the 41L/42L line switch taps outside the Huth Substation to the Waterford Substation. The 47L circuit is a single wood pole design with distribution underbuild and was originally constructed in 1980. Most of the original vintage structures are still in service and are generally in good overall condition, but may require more attention in future condition assessment cycle(s). Refer to Appendix I for a histogram of the pole vintages on 47L that are currently in service.

The 47L circuit is strung with single 477 AAC “Cosmos” conductor from the entirety of the line from structure 47LA to the Waterford Substation. The FortisBC distribution underbuild (47L1 to 47L26) is strung with 2/0 ACSR ‘Quail’ for the three phase circuit. The City of Penticton distribution underbuild (47L32 to 47L34) is strung with 477 AAC ‘Cosmos’ for the three phase circuit.

SUMMARY OF FINDINGS

The condition assessment records completed by DBS Energy produced detailed information in terms of the poles, hardware, framing, conductors, insulation, anchoring, and site information. This information is being updated into the 47L (old 41L-WAT) structure list and added to the permanent 47L line records.

The latest pole test and treat data for 47L was completed by Gilnockie Inspections in 2006. The data from the T&T records was used as a reference during the field assessment patrols of the 47L structures, and only a few discrepancies were found for inconsistencies of pole information (height/class/vintage). It should be noted that newer 1998 vintage structures near HUTH, which includes 47LA, 47LB, 47LC, as well as WAT-41L and WAT-42L 2-pole switch structures need to be included with future T&T inspection cycle(s).

There are a total of 21 structures requiring minor repairs on 47L, of which 3 are solely related to the City of Penticton distribution underbuild facilities. There are no structure replacements or brushing requirements needed on 47L at this time. A detailed summary of the recommended rehabilitation work for 47L can be found in Appendix II. A list of various generic issues on 47L as determined from the condition assessment patrols are listed below.

- Tighten loose hardware and add lock nuts and lock washers.
- Anchors with missing guy guards that need to be added.
- Minor repairs on the distribution underbuild facilities - Missing stirrups, damaged tangent pin insulators, broken ground wire, missing PIC#'s, etc.
- Replacement of rotten Tx arm and related insulation.
- Replace/repair structure number tags that are missing or faded.
- Follow-up engineering review for pole foundation strength and confirm transformer grounding.

There are 47L structures that still have older arms installed on the Dx underbuild that are using flat braces, where dry rot tends to occur around the flat brace bolts on these arms. These flat braces generally have smaller thru bolts, less structural strength, provide higher wood fibre stresses on the arms, are installed generally on much older vintage arms, and therefore are reaching end of life. There have also been several arm fires as experienced in the past that are aggravated by dry rot of the arms and the fact that the braces are not bonded. The remaining structures with these older arms and flat braces are not scheduled to be replaced with this recommended assessment work, but any major future work at these structure locations should include replacement of the arms and braces. The general replacement and condition of all flat braced arms can be re-evaluated during the next condition assessment cycle.

ESTIMATE OF WORK

This 47L Condition Assessment Review Summary (Appendix II) shows the work required on each structure and the +/-30% estimated construction costs. There are a total of 21 structures requiring rehabilitation repairs, 18 structures of which are related to FortisBC facilities and 3 structures related exclusively to City of Penticton distribution underbuild facilities. There are no structure replacements or brushing requirements for 47L at this time.

The urgent work refers to rehabilitation repairs that need to be done immediately, and the recommended work refers to the rehabilitation repairs that could be postponed for one to two years (if needed), but should still be done before the next assessment cycle. The table below shows the estimate summary and details the costs broken down into each section of the total rehabilitation cost. The estimate for the recommended 47L rehabilitation works is $12k for the FortisBC portion, which includes an additional $2.0k of engineering costs to deal with outstanding issues and development of construction packages), and $2k for the City of Penticton portion. The project cost for the entire rehabilitation work is $14k, which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the transmission rehabilitation work will be completed hot with 47L energized and construction techniques using the robotic arm. It may be possible during late fall and early spring for the distribution underbuild to be backed up from the WAT Substation, but has not been confirmed.

FortisBC	**Repair**	**Str Replace**	**Brushing**
# of Structures	18	0	0
Urgent Work	$ 0.6k	$ 0.0k	$ 0.0k
Recommended Work	$ 9.1k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 9.7k	$ 0.0k	$ 0.0k

City of Penticton	**CoP u/b Repair**	**CoP u/b Replace**	**CoP u/b Brushing**
# of Structures	3	0	0
Urgent Work	$ 0.0k	$ 0.0k	$ 0.0k
Recommended Work	$ 1.6k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 1.6k	$ 0.0k	$ 0.0k

Engr/Admin	$ 2.0k			Additional engr costs for development of construction packages.
	FortisBC	**CoP**		
Labor	$ 5.3k	$ 0.9k	55%	Approx 40 man-hours with Tx hot work. Includes salvage labor.
Brushing	$ 0.0k	$ 0.0k	0%	Brushing for the required areas.
Material	$ 1.9k	$ 0.3k	20%	Includes poles and hardware; transportation and overheads.
Engineering	$ 1.0k	$ 0.2k	10%	Engr review of outstanding issues; updates to line records.
PM	$ 0.6k	$ 0.1k	6%	Project management.
Misc	$ 0.9k	$ 0.1k	9%	For preliminary work, flagging, etc.
SUBTOTAL =	$ 9.7k	$ 1.6k		Does not include any FortisBC Capitalized Overheads.
20% Contingency	$ 2.3k	$ 0.3k		Allows for 20% contingency.
TOTAL =	**$ 12.0k**	**$ 1.9k**		Does not include any FortisBC Capitalized Overheads.

CONCLUSIONS AND RECOMMENDATIONS

All the assumptions to date for the engineering review of 47L have been based on the data collected from the DBS condition assessment patrols in conjunction with the Gilnockie pole test and treat data.

A detailed summary of the recommended rehabilitation work for 47L from the Huth Substation to the Waterford Substation can be found in Appendix II. There two structure location on 47L with repair work that is considered to be urgent and should be completed in 2010/2011.

- 47L7 – Urgent repair for tightening distribution hardware on the pin insulators and adding lock washers and lock nuts. Hardware is backing off of insulator pin bolt.
- 47L25 – Urgent repair for tightening neutral hardware and adding lock washers and lock nuts. Hardware is backing off of mounting bolt.

The remaining recommended work as listed in Appendix II should be completed before the next assessment cycle (ideally in the near future), and would be advantageous to complete these rehabs at the same time as the urgent work in order to capitalize on reduced overheads and mobilization costs. The total cost estimate for the 47L rehabilitation works is $14k (FortisBC-$12k and CoP-$2k), which includes a 20% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the transmission rehab work will be completed hot with 47L energized via the use of the robotic arm, considering the 47L circuit is a radial feed to the Waterford Substation.

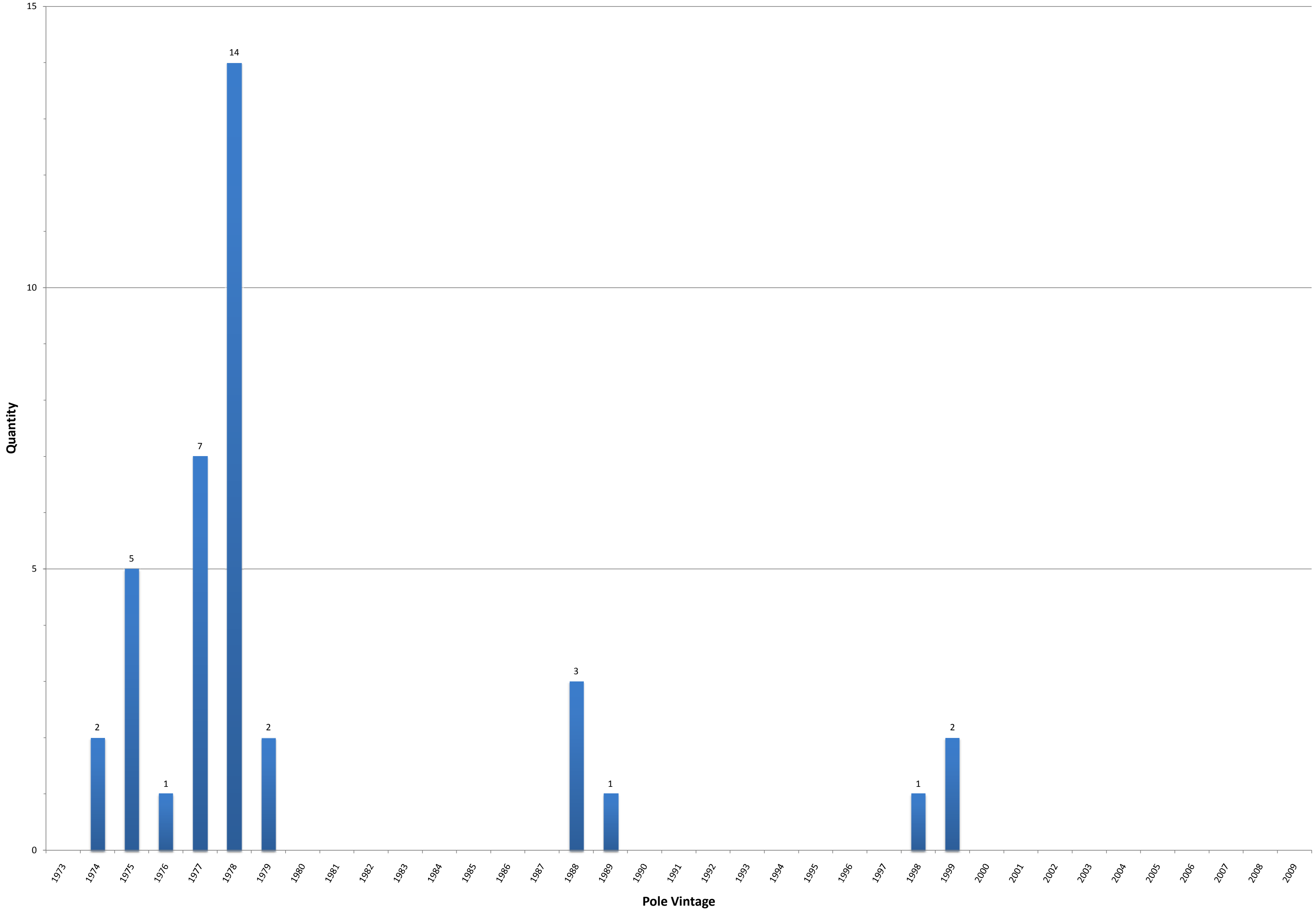
There are also some outstanding issues that require a follow-up engineering review, which are suggested to be done during the detailed design stage of the project. These concerns are shown in the

47L Condition Assessment Review Summary (Appendix II). The project estimate includes an additional $2k of engineering costs to deal with these outstanding issues. Any additional repairs that may be required as a result on these follow-up inspections have not been included in the total project costs, but are expected to be minimal if required and will have to be added as an extra cost.

The structures having distribution underbuild with older arms and flat braces still in service should be monitored closely during future condition assessment cycle(s) for dry rot or arm damage. These arms should be replaced and possibly replacement of the entire structure, if any significant work at these structure locations is needed.

Currently the 47L structure list and line records are being updated with the condition assessment records for any missing data. This updated 47L structure list will form part of the permanent FortisBC Engineering line records. The 47L line records have not been updated at all through recent years and need to be revised with any new work and planned future work on the line.

APPENDIX I - 47L POLE VINTAGE CHART



APPENDIX II - 47L CONDITION ASSESSMENT REVIEW SUMMARY

STR #	Priority	Type of Rehab	+/-30% Estimate ($k)	Comments of Work Needed	Ownership
B	✓	Repair	0.2	Repair str tag - Add 'B' to str tag #	FortisBC
C	✓	Repair	0.2	Repair str tag - Add 'C' to str tag #	FortisBC
1	✓	Repair	3.5	Replace Tx tangent arm and insulation	FortisBC
	✓	Repair	0.5	Add stirrup for xfmr	FortisBC
3	-	-	-	Engr Review - Confirm xfmr grounding	FortisBC
7	URGENT	Repair	0.3	Tighten Dx insul hardware; Add lockwasher and locknut	FortisBC
9	✓	Repair	0.3	Repair broken ground wire	FortisBC
10	✓	Repair	1.0	Replace Dx tangent insulation	FortisBC
11	✓	Repair	1.0	Replace Dx tangent insulation	FortisBC
22	✓	Repair	0.2	Replace faded str tag #	FortisBC
23	✓	Repair	0.2	Replace faded str tag #	FortisBC
24	✓	Repair	0.2	Replace faded str tag #	FortisBC
25	✓	Repair	0.2	Replace faded str tag # - Confirm	FortisBC
	URGENT	Repair	0.3	Tighten neutral hardware; Add lockwasher and locknut	FortisBC
26	✓	Repair	0.2	Replace faded str tag #	FortisBC
	✓	Repair	0.2	Add guy guard	FortisBC
27	✓	Repair	0.2	Replace faded str tag #	FortisBC
28	✓	Repair	0.2	Replace faded str tag #	FortisBC
29	✓	Repair	0.2	Replace faded str tag # - Confirm	FortisBC
30	✓	Repair	0.2	Replace faded str tag # - Confirm	FortisBC
31	✓	Repair	0.2	Replace faded str tag #	FortisBC
	-	-	-	Engr Review - Check condition of pole foundation	FortisBC
32	✓	Repair	0.5	Add stirrups for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
33	✓	Repair	0.5	Add stirrups for Dx tap	CoP
	✓	Repair	0.2	Add PIC#	CoP
34	✓	Repair	0.2	Future Reference - Cotter key coming out of insul BNC	FortisBC
	✓	Repair	0.2	Add PIC#	CoP

ESTIMATE OF URGENT AND RECOMMENDED WORK

FortisBC	**Repair**	**Str Replace**	**Brushing**
# of Structures	18	0	0
Urgent Work	$ 0.6k	$ 0.0k	$ 0.0k
Recommended Work	$ 9.1k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 9.7k	$ 0.0k	$ 0.0k

City of Penticton	**CoP u/b Repair**	**CoP u/b Replace**	**CoP u/b Brushing**
# of Structures	3	0	0
Urgent Work	$ 0.0k	$ 0.0k	$ 0.0k
Recommended Work	$ 1.6k	$ 0.0k	$ 0.0k
+/-30% Estimate	$ 1.6k	$ 0.0k	$ 0.0k

Engr/Admin $ 2.0k Additional engr costs for development of construction packages.

	FortisBC	**City of Penticton**		
Labor	$ 5.3k	$ 0.9k	55%	Approx 40 man-hours with Tx hot work. Includes salvage labor.
Brushing	$ 0.0k	$ 0.0k	0%	Brushing for the required areas.
Material	$ 1.9k	$ 0.3k	20%	Includes poles and hardware; transportation and overheads.
Engineering	$ 1.0k	$ 0.2k	10%	Engr review of outstanding issues; updates to line records.
PM	$ 0.6k	$ 0.1k	6%	Project management.
Misc	$ 0.9k	$ 0.1k	9%	For preliminary work, flagging, etc.
SUBTOTAL =	$ 9.7k	$ 1.6k		Does not include any FortisBC Capitalized Overheads.
20% Contingency	$ 2.3k	$ 0.3k		Allows for 20% contingency.
TOTAL =	**$ 12.0k**	**$ 1.9k**		Does not include any FortisBC Capitalized Overheads.

DBS ENERGY SERVICES INC.

20L and 27L Engineering Assessment Report

(Revised for 2011/12 Capital Plan)

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APPENDICES

1. INTRODUCTION

This 20L and 27L Engineering Assessment Report is meant 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 on both circuits to achieve a more reliable system. This report is revised from the original 20L and 27L Engineering Assessment Report (April 16 2008 version), and provides an updated summary of work and estimate while taking into account the recent planned and emergency works completed on the lines. Both circuits are 63kV single pole type structures with reasonably accessible terrain. This report provides a design review, assessment implications, and construction estimates for the on-going operational improvements for 20L/27L, and their inter-dependencies on each other. The intent from the recommendations of this report is to outline the risks and reliability issues of both circuits from which FortisBC can create a plan to make the needed improvements in a structured and cost effective manner that would fit into their Capital Plans over the foreseeable future.

There have been several budget attempts in the past to effect some change on the overall line performance and system reliability for both 20L and 27L, therefore this report also focuses on trying to bring a structured resolution with a planned engineered process to the upgrade requirements. Some urgent priority rehabilitation work has been completed on both 20L and 27L circuits through the past couple of years, with more significant work still remaining on the lines in order to bring them up to a more reliable overall state.

Both circuits are showing their age, which would generally be considered in below average condition, and have little option on re-routing or alternate supply for backup. The 20L facilities can be considered in generally poorer overall condition to that of 27L.

2. BACKGROUND

A. Overview

20L and 27L are operated radially (i.e. with normally open points), as part of a looped system between the FortisBC River Plant Generation and the Trail area grids. The lines are originally from vintages of 1931 and 1930 respectively, however the lines have had complete structure rebuilds at least once over their lifetime. The transmission conductors themselves have had only selected change-outs or re-conductoring in small portions of the original 90kcmil Copper (Hemp Core) conductor. During the last 30 years, there has been considerable focus paid to keeping the lines “functional” and not necessarily improved or upgraded. Parts of the circuits have seen field type designs incorporated into the lines, which have not always contributed to their efficient or trouble-free operation.

The 20L circuit, approximately 46kms of 63kV, which runs from Warfield Terminal Station (WTS) to Glenmerry (GLE) to Beaver Park (BEP) to Fruitvale (FRU) to Hearns (HER) to Salmo (SAL); in large part has three phase distribution underbuild (in particular from BEP to SAL). This BEP to SAL section is also largely along Road and Highway rights of way resulting in the tree proximity to the line typically formed at the Property Line along the Highway parallel. As a result of this, a large percentage of the outages over time have been a direct result of these tree related contacts. The 20L assessment and design information that is available for this report is from a detailed line patrol/inspection completed by FortisBC crews in 2006, as well as a McElhanney Design Survey (the design survey was originally to be Lidar based, but has been re-vamped to be a photogrammetric survey) and has been incorporated into a partial PLS-Cadd model of the line. The 20L circuit will be again due for an inspection cycle in 2014.

The 27L circuit; approximately 57.1kms of 63kV, runs from Corra Linn (COR) to Rosemont Switching Station (RSM) to Cottonwood (COT) to Ymir (YMR) to Salmo (SAL). 27L has a variety of configurations that consists mostly of a single pole design - partly single circuit transmission with no underbuild, partly single phase 7.5kV underbuild, but more frequently three phase 13kV underbuild. All of which vary with sections of significant setback from the highway and generally is not “On Highway” but on its own separate rights of way. Some structures within the Nelson area have City of Nelson Hydro underbuilt contacts. The 27L assessment and design information for this report is from a detailed condition assessment patrol completed by DBS Energy in 2007/2008, as well as a McElhanney Design Survey (photogrammetric), which has been incorporated into a partial PLS-Cadd model of the line. Forecasts and recommended rehabilitation work is based on the available data and used as the basis for the estimates.

Generally, both circuits can be considered in relatively poor condition with numerous steel stubbed structures and conductor splices, in particular within the original 90kcmil Copper conductor sections on 20L.

Over the past couple of years (2007-2009), some urgent/priority rehabilitation work on 20L and 27L has been completed, which included a provision for 477MCM reconductor for structure replacements. This rehabilitation work was initiated directly from the condition assessment patrols completed on the lines with all completed work reflected in the Pole Vintage Charts (20L-Appendix IV and 27L–Appendix V) from available as-built information. In preparation for the remaining rehabilitation work recommended for 20L/27L, a summary of work and accompanying estimate has been provided in Appendix I for 20L and Appendix II for 27L.

B. Past Outages and Problems

In past years there have been numerous issues with distribution and transmission outages, which in some circumstances have led to potentially serious outages for customers and the system. These issues have ranged from Motor Vehicle Accidents, to tree contacts, to inadequate circuit to circuit spacing under icing and snow loading conditions (where the transmission has sagged into the distribution conductors).

There have also been some reported problems concerning the context of line capacity for the 90kcmil copper. FortisBC has completed a load flow review that indicates the 90kcmil copper conductor can handle all of the existing FortisBC loads as projected into the foreseeable future; however, with the inclusion of City of Nelson loads, neither 20L nor 27L have the capacity as they are, to carry the entire load during contingency. It must also be noted though, that even with a re-conductoring of 20L and 27L to a 477 MCM type conductor, it still does not appear the City of Nelson loads could be carried as a radial feed. For future reference, there may however be other justification to a re-conductoring program (in whole or in part), for issues such as brittle copper, or the high splice frequency in some spans. It should be noted that this report could not find evidence for such justification, but should include a provision for a 477MCM reconductor for any structure replacements.

The distribution underbuilt specific outages that have occurred on the 20L/27L underbuilds could be the result of several issues ranging from the following: transmission circuit contacts, tree contacts, inadequate transformer grounding, lightning arrestors blown or misadjusted, lack of cutouts, fuse coordination, as well as generally poor condition of facilities. Rural area customers in many cases are susceptible to often lengthy outages due to the remote nature of the nearest District Office (Castlegar).

C. Recent Works Completed

There have been a number of smaller scale initiatives over the past several years to address the more serious and priority areas, which have been included so that a more comprehensive and thorough report could be completed. One of the initiatives involved a Primary Engineering Nov-2006 20L Line Outage Issue Report. Our findings however, disagree with many of the priorities, or at least focus details, presented by Primary Engineering. This current report tries to pay more attention to the underlying outage, design, and life assessment issues. A brief summary of more recent activities relating to 20L and 27L are listed below in a generally chronological order:

- 27L 2008 Life Assessment Urgent/Priority Repairs Construction Package - This was a scope of work produced from the urgent items arising from the 2007/2008 detailed patrols completed by DBS Energy. The work was mainly completed in 2009 with outstanding incomplete work to be completed by the end of 2010.
- 20L 2008 Priority Repairs Construction Package – This scope of work resulted from the 2006 detailed patrols completed by FortisBC personnel.
- Survey and land data was acquired from McElhanney using photogrammetric methods at the end of 2008 to be used for future designs.
- FortisBC initiative to infrared scan, jumpers and connections on 20L in particular with respect to copper conductor.
- 20L 2007 Life Assessment Urgent Repairs Construction Package – This was a scope of work produced from the urgent items arising from the 2006 detailed patrols completed by FortisBC personnel. The work was completed in 2008.
- 27L 2007 Urgent Repairs – This was a scope of work produced from the urgent items arising from FortisBC helicopter patrols.
- 20L 2007 Brushing – There was a brushing initiative completed in 2007 to attend to numerous tree encroachments and was mainly limited to brushing directly underneath and adjacent to the line. The scale of these initiatives seems to have

been limited as a result of the restricted right of way available. Most of the route consists of the use of Highway R/W with trees on nearby private lands.

- FortisBC 20 Line Outage Issue Report; by Primary Engineering Q4 2006
- 20L Condition Assessment and Patrols 2006 – This was a detailed line patrol completed by FortisBC crews. It was to identify condition, issues, age, and facilities on the line. This was to drive future projected work that would be identified thru engineering reviews.
- 20 Line – BCH 5L91 Crossing – This was a small package done to accommodate a re-rating review done by BCHydro on the 500kV crossing near Champion Lakes turnoff. This was completed in 2005.
- 20L Urgent and Severe Condition Packages – This was work that had been identified from the clearance study report that also included some serious structural condition issues as well. Work was completed in 2004.
- 20L Cct to Cct – Beaver Park to Salmo Clearance Study – This was a 2003 report and related patrols done by DBS Energy intended to address some serious priority transmission-distribution contact issues.
- 20L Reterminations into WTS – This included the reterminations of 20L from the old Tadanac Station into the new WTS station as part of the 230kV System development in 2003. It was rebuilt with 477 Cosmos.
- 27L Reconductoring and Rebuild through the YMIR area – This was a program that seemed to be undertaken over the period of 1994 to 1997 of approximately 25kms and reconductored the section to 477 Cosmos.
- 20L Reconductoring and Rebuild through the Trail area – This was a project that seemed to be undertaken over the period in about 1991 to 1992 of approximately 10kms. The section was reconductored to 3/0 AACSR.
- 27L Reconductoring and Rebuild through the COR to Nelson area – This was a program that seemed to be undertaken over the period in about 1985 of approximately 14kms of structure rebuilding and reconductored the section to 477MCM Hawk.
- There were also several small scattered areas that had minor or partial reconductoring on both 20L as well as 27L over the years.

D. Brushing

In past years the vast majority of outages relating to 20L in particular (as well as a large percentage of 27L outages), have been a direct result of tree related issues and contacts. There has been some brushing done in the areas surrounding 20L/27L, but due to the heights of trees and private land issues there has often been very limited brushing and danger tree removal. The brushing and tree related issues will likely remain as a major source of future outages unless handled more aggressively. It is assumed that the 20L and 27L right-of-way has been recently brushed out for growth underneath the line and any noticeable danger trees. Only minor brushing as outlined during recent field patrols is shown as still being required in the summary of work.

3. SUMMARY OF FINDINGS

Records from the original design are sparse at best, with ground profile records missing for almost the entirety of 20L and 27L alignments. There are original profiles only available from Corra Lynn to Nelson on 27L and Trail to Beaver Park on 20L. These existing profiles that are available, have for the most part, not been updated throughout the years. There are several structures that have been upgraded/moved throughout recent years and have not had the records or profiles updated. Also, much of the structure lists available for 20L/27L appear to contain few mark-ups in terms of as-built data and/or recent works completed for both lines. The conductor data included with these structure lists does not show the correct conductor type and has no available sag/tension data. Considering this lack of existing line information for 20L and 27L, it was decided that an extensive review be completed that would capture the missing data for these lines. The patrols and condition assessment records for 20L were completed by the Fortis personnel and 27L patrols completed to date were done by DBS Energy. The condition assessments produced detailed information in terms of the structure/pole, hardware, framing, conductors, insulation, underbuilds (if applicable), anchoring, and site information.

A. Urgent Priorities

There have been several attempts to improve the overall reliability of the 20L and 27L transmission ring through works completed over recent years. Urgent priorities on 20L and 27L included recent work to address the transmission and distribution contacts for the longer span areas. It was determined that the cause was due to the insufficient circuit to circuit spacing and was rectified by increased transmission to distribution circuit spacing and/or with mid span poles in some cases. It should be noted that these were listed as “urgent” repairs and there were numerous marginally acceptable spans that needed to be included in future designs.

Over recent years, 27L has received many other urgent repairs which mostly was the result of tree contacts, MVA’s, heavy snowfall, broken ties, and improper grounding & bonding techniques causing structure failure. Tree contacts have been the primary source of outages on the transmission line and distribution underbuild circuits. The recent condition assessment patrols have shown the areas of line requiring brushing for close proximity trees and removal of any large danger trees, which is assumed to be completed except for a few minor locations that need to be addressed and are shown in the 20L/27L summary of work. On both 20L and 27L, there are sections with tight rights of way and overgrown brush that has not been brushed out, also resulting in poor access in some circumstances. A major source of outages on 20L and 27L can be directly linked to the tall danger trees located on the highway parallel sections of the lines. These large danger trees should be removed, but will most likely require approvals from the adjacent landowners to do so.

There were a number of poles on 20L/27L that have been red tagged during the latest pole inspection completed in 2005 and/or red flagged by line crews. These structures were replaced during the 20L/27L urgent repair construction packages in 2007 and 2008.

B. Conductor

The conductors strung on both 20L and 27L is a combination of various conductor types and sizes, ranging from the original 90kcmil (hemp core) copper to newer 477 MCM conductor. A table displaying the ampacity ratings for each section as dictated by the structure numbering can be found in Appendix III. As shown from the table (20L and 27L Conductor Data and Ampacity Ratings) there are several small sections of 20L that have been reconductored with 477MCM in recent years, as well as 10km with 3/0 AACSR that was completed approximately 15-20 years ago. Also shown by this table is the significant amount of reconductoring that has occurred on 27L, mostly with 477 ACC Cosmos (approx 25.6km) and 477 ACSR Hawk (approx 14.7km).

The main concern relating to the conductor is the original 90kcmil copper that is still on sections of 20L (approx 31.4km) and 27L (approx 15.2km). This original 1930's vintage 90kcmil copper has shown no indication of physical degradation, other than what could be expected from a 70+ year old conductor. There is however a significant amount of conductor splicing on the 90kcmil copper, which could most likely be contributed to the numerous tree contacts over the years. The original 90ckmil copper has shown some deterioration with the hemp core, which can cause problems when trying to splice the conductor. When the hemp core has deteriorated, a new core (typically steel) must be inserted in the conductor in order for the splice to be reliable. The 90kcmil Copper has also been identified as one of the FortisBC "brittle copper" conductors, however the 90kcmil copper has not shown to cause any problems to date relating to this matter and no direct evidence has been found in doing the design assessment.

C. Structures

There are a considerable amount of structures currently on 20L that are of 60+ year old vintage, and of those structures a large amount have been steel stubbed for many years (all urgent and red tagged poles have been recently replaced). As detailed in the 20L Pole Vintage Chart located in Appendix IV, approximately one third of all structures on the line are stubbed and in need of replacement with several more structures requiring some additional work in terms of crossarm replacement, re-framing, etc.

In the case of 27L, the majority of the line has had recent works completed with newer structures (within the past 20 years). There are still a few older structures on 27L that have been steel stubbed or marked for replacement. The majority of the older vintage poles still on 27L are located on the east section of the line from Salmo to Ymir. The 27L Pole Vintage Chart found in Appendix V shows that only a select number of structures on the line are stubbed and in need of replacement based on the 27L test & treat data and condition assessment patrols. The main design concern with the 27L structures however, is not the condition of the poles, but rather the structure framing types that have been used. There are several structures framed with vertical posts on double wood arm that has shown to be a problem from the heavy snowfall between Nelson to Ymir. In this area the snow build-up on these double arms can become so severe that it covers the insulators completely and thus causing tracking to the arms and hardware, which has caused several poles and/or arms to burn off.

D. Insulation

The existing insulation on 20L is often a mixture of older structures with porcelain insulators, and older poles re-framed with newer arms and synthetic insulation. There is an abundance of original vintage 20L structures that have had the transmission/distribution arms and insulation replaced in hopes of deferring the replacement of the pole. While this strategy was effective at preserving capital expenditures in its time, it deferred the structure from being replaced, and these efforts resulted in compounding a backlog of structure change-outs. Alternatively, 27L has had a larger percentage of structure replacements resulting in newer synthetic insulation being installed on many structures. There are still several structures on both lines with the original porcelain type bell and pin insulators. There are no serious issues with the older porcelain insulation on both 20L and 27L but there is evidence that the porcelain glazing is being compromised significantly. There were no signs of Ohio Brass cement growth problems, although there are Ohio Brass porcelain bells present on these lines. This could be a result of lightly loaded conductors or by chance they were outside of the vintages of insulators that experienced the bad cement mixtures.

E. 63kV Line Switches

There have been concerns raised by FortisBC Operations group about the functionality of the 20L/27L single pole 63kV line switches located in Salmo. A brief condition assessment was completed on these switches with no observable deficiencies to note, other than one fatigued whip and another out of its finger holder in the closed position. The problems occurring from these switches may be due to the fact that full line tension is dead ended on the switch frames causing the switch and whips to become slightly misaligned. This problem could possibly be repaired by reframing, refurbishing and re-aligning the switches. The 20L/27L Salmo switches have motor operated disconnect (MOD) operation, which has shown some intermittent problems in the past, but may be able to be resolved with updated communications and controllers. Since the assessment patrols were completed, the 27L Salmo 63kV line switch has been replaced in 2009 and re-designed on a new structure. The 20L Salmo switch has continued operational problems to date and is suggested for replacement by the Operations group. A follow-up field review of this switch should be completed to evaluate the known issues and concerns of the switch. It is recommended that an Operations meeting take place in order to review the design, constructability, and functionality of the 20L Salmo switch.

The 27L switches at Cottonwood have recently been upgraded with new H-frame type 63kV line switches, located on either side of the new Cottonwood substation. These switches were installed at the same time as the Cottonwood station was built in 2007. These switches, to our knowledge, have shown no problems during manual or MOD operation.

The 20L single pole 63kV line switches at the Hearns substation can only be operated manually and have no known operation problems to date. The switch structure (20L293) immediately south of Hearns is in relatively poor condition, and the 63kV switch structure (20L295) to the north of the Hearns tap is still in acceptable condition. Neither of these switches would be recommended for energized operation, but do not require replacement at this point. It is suggested that refurbishment of these Hearns switches with grounding be completed.

F. Anchoring

The anchor locations and anchor rod condition were to be included with the 20L and 27L condition assessment patrols. There were no records of anchoring with the original design data and/or rebuilds throughout the years, which makes determining actual installed anchoring very difficult. From the patrols it was found that there are numerous anchor rod types installed along both lines with a variety of guy wire. The anchor rods ranged from 3/8” to 1” rods with the guy wire ranging from 3/8” to 1/2”, but mostly 7/16” and 1/2" guy wire was used. However, it is impossible to determine the type and capacity of the existing anchors buried in the ground. For design purposes, assumptions could be made for the anchoring capacity based on the anchor rod and guy wire size and type. Even determining the anchor rod can be uncertain as the rod may be completely buried, thus resulting in no way to determine the anchoring strength. In some cases where reconductoring with a 477MCM conductor has occurred, it is apparent that the existing anchoring is insufficient. There are also anchors existing that show signs of settling (possibly failure), and inadequate design capacity. The only means to be confident that the existing anchoring has the holding capacity required is to perform a pull test on the anchors or to replace them with new and modern anchoring.

G. Thermal Ratings

The ampacity ratings at 100°C for the conductor types found on 20L and 27L are shown in the table below. These values were calculated based on the Southwire conductor properties and the SWR ampacity rating program for steady-state current. Appendix III also shows a detailed ampacity rating by conductor type and line section. Typical industry accepted guidelines for the ampacity review were applied in these ampacity calculations, such as 2ft/sec wind conditions, 40°C ambient temperature for summer conditions and 0°C ambient temperature for winter conditions, 0.8 solar absorption factor, and 0.6 emissivity factor.

Conductor Type	**Ampacity Rating (A)**		**Capacity Rating (MVA)**	
	Summer	**Winter**	**Summer**	**Winter**
2/0 ACSR Quail	285	388	31.1	42.3
90kcmil Copper	296	399	32.3	43.5
3/0 AACSR	369	504	40.3	55.0
300MCM Copper	635	869	69.3	94.8
477 ASC Cosmos	675	929	73.7	101.4
477 ACSR Pelican	682	941	74.4	102.7
477 ACSR Hawk	696	961	75.9	104.9

The following table can be used as a quick reference for the maximum load capabilities of the substations along 20L and 27L routes. This table can be used to provide and compare the overall load capabilities during peak load conditions, which can help in showing the risk and liability exposure that may occur on these lines. Actual substation loads are typically significantly less than these transformer limits.

Substation Name	**Transformer Capacity**
City of Nelson	10MVA
Cottonwood	10MVA
Ymir	1.5MVA
Salmo	13.3MVA
Hearns	1.875MVA
Fruitvale	8MVA
Beaver Park	10MVA
Glenmerry	20MVA

H. Trespass and Land Issues

Much of the overall route for 20L and 27L exist along Road/Highway right of ways, which can be observed in the route maps found in Appendix VIII for 20L and Appendix VIII for 27L. These sections of line paralleling the Road/Highway are easily accessed, but have a major concern with the large tree growth on the adjacent landowner’s property. In many situations there are large danger trees on the adjacent property that have caused outages on the lines, which has occurred several times in the past. These danger trees should be cutdown to make 20L and 27L less susceptible to these tree contacts and making the lines more reliable in the future.

There are a number of sections for the existing 20L /27L alignments where FortisBC right of ways were obtained from private landowners. The problem with these rights of way is that they are for the most part quite narrow, making it again susceptible to tree contacts, as well as, not providing for adequate conductor blowout. There are also certain structures that require extended easements for anchoring on private property. In a few cases, anchoring easements were not acquired and therefore the anchor was never installed, or remains in trespass, or installed very tight to the pole, which undoubtedly reduced the structures lifespan and functionality. Another major issue not only for the transmission line, but for the operation of the distribution underbuild circuit is access to several structure site locations that can only be obtained through private property. These areas with anchoring trespass and structure site access issues through private property should be resolved with the affected landowners as designs affecting these areas are completed. Known or suspected areas where easements are needed have been incorporated into the summary of work.

I. Survey Information and Line Modeling

In efforts to deal with the design and potential land issues along both 20L and 27L, FortisBC has completed a photogrammetric survey and land/property alignment through McElhanney Associates and DBS Energy. This survey data was available for 2008/2009 designs and work, but was not fully incorporated into the PLS-Cadd design models due to cancellation of the project in 2009. Incorporating the 20L and 27L survey data into the PLS-Cadd should be done with all future work plans.

Accuracy levels of the 20L and 27L land imagery and survey data varies from 0.5m to 5m and can be reasonably considered as adequate for future work plans on the lines. Any possible trespass areas will need to be further examined with refined survey data.

4. RECOMMENDATIONS

A. Assumptions

All the assumptions to date for the condition and assessment of 20L/27L have been based on the 20L condition assessments patrols completed by FortisBC in 2006, the 27L condition assessment patrols completed by DBS Energy in 2007/2008, pole test and treat data of both lines, and any follow-up design review of the lines completed during recent works. The assumed number of structure replacements and additional refurbishments formed the basis behind the preliminary estimate for 20L and 27L Capital Plan.

The estimates provided have been assumed with the transmission conductor de-energized during construction with the distribution underbuild remaining energized for the majority, with only brief outages to be permitted. It is expected that the 20L and 27L transmission circuits will be able to switch loadings to allow for outages during construction time. However, lengthy outages on 20L/27L are not recommended considering the radial feed of these circuits, and therefore service would most likely have to be returned at the end of each day. The distribution underbuild must remain energized for the majority of work along 20L and 27L as the existing system predominantly does not have the ability to provide alternate feed to the customers and outages could be very lengthy. There are a few areas where the distribution underbuild could receive alternate feed and/or short term outages could be viable, but for the most part this is not considered an option at this point in time. The rebuild of the 20L and 27L structures has been assumed with a direct replacement at similar structure locations and framing types, as opposed to rebuilding portions of the lines on a completely new route. To reduce costs, a possibility was to build portions of the lines (20L in particular) on the opposite side on the Road/Highway parallel where a large amount of successive structures required replacement. This option was discouraged as it would increase the number of Highway crossings, cause conflicts with the existing Telus line, require significant outages for transmission and distribution, and the cost savings would not likely be realized without a complete reconductoring justification.

B. Priorities Concerns

From the line patrols that were conducted on 20L and 27L, there were numerous issues that needed to be addressed. The priority issues that were listed as urgent and/or severely lacking in meeting code requirements as outlined from the condition assessment patrols and engineering design review (i.e. poles that are red tagged, broken arms or insulators, cct-to-cct spacing, ground clearances, etc) were completed as part of the 2007/2008 urgent repair construction packages for both lines; however there remains some 20L structures with crossarms that are near failure, which needs to be addressed immediately. The remaining rehabilitation work that would still be required on 20L and 27L circuits can be completed in the subsequent years. This work does not have to be completed in a priority manner, but rather in a systematic fashion for ease of construction.

C. Design Considerations

From the condition assessment patrols that were conducted on 20L by FortisBC crews and on 27L by DBS Energy Services, there were numerous systematic type issues that can be directly related to the lack of detailed engineering completed on these lines over their lifetime. In addition to the CSA No.1-06 code requirements, some recommended extra design criteria that should be incorporated during engineering is as follows:

- Add a snow loading condition of 35mm (with density of 0.3gm/cm^3), in addition to the existing code requirement of 12.5mm radial ice, for 27L between Nelson to Ymir to allow for the heavier than usual snow fall through this area.
- Add a 1.2m buffer to the CSA code requirement for ground clearances of new construction in order to allow for extra snow cover, and for any unforeseeable survey or construction errors.
- Evaluate conductor uplift for structures and insulation at a -30°C weather condition.
- Evaluate the worst case circuit to circuit spacing; of the top transmission circuit at a 100°C maximum sag position and the bottom distribution underbuild circuit at a 15°C bare condition, or with Med B CSA loading on the transmission and 0°C on the distribution. An additional 0.3m buffer should be added to the minimum circuit separation dictated by the CSA code requirement.

i) Structure Types for Use

For the most part, the structure framing used on both 20L and 27L is satisfactory with the majority of tangent structures framed with vertical post insulators (FortisBC structure type 42101) and dead ends framed as vertical (FortisBC structure type 42410), the standard 63kV structure types can be found in Appendix VI. However, there are certain sections on both lines that have substandard structure framing and these issues should be addressed. These concerns are a combination of issues ranging from long span lengths with single pole structures, vertical double deadend structures with no jumper post insulation, pole grounding and bonding, and snow build-up on back-to-back double arm structures between Nelson and Ymir on 27L.

a) Single Pole Structures

Both transmission lines primarily utilize a single pole design philosophy due to the tight right of way and shorter span lengths. Single pole structures are usually limited by the span lengths as dictated by the phase spacing and limitations of the crossarm, as opposed to the pole strength being the limiting factor. The typical maximum span length for the 42101 tangent structures is in the order of 150m. It is recommended that any span lengths greater than 150m be dealt with individually, with the possibility of using an H-Frame type structure. Note however, that circuit-to-circuit issues will likely govern considerably before the 150m span lengths are reached. An H-frame structure (type 42124) has the increased phase spacing, but also requires a wider right of way.

b) Vertical DDE Structures

It has been shown from the assessment patrols of 20L/27L that a large number of vertical double deadend structures are installed without jumper posts. For many of these dead ends with lighter deflections, the jumper wire is within 0.3m of the pole, which is less than the wet flashover distance for 63kV. For vertical double deadend structures that have a deflection greater than 60 degrees, these horizontal jumper post insulators are not necessarily needed. It is recommended that a horizontal jumper post be installed on all vertical DDE structures with a deflection less than 60 degrees. Several vertical double deadend structures on 27L with this issue have been dealt with in the 2008 urgent repairs construction package.

c) Double Arm Structures

Snowfall can be very heavy at times from Nelson to Ymir, which can cause an excess build-up of snow on the back-to-back double arm tangent and light angle structures. The snow build-up on these double arms can become so severe that it covers the insulators completely causing tracking to the arms and hardware, which can cause the pole and/or arm to burn down. Under normal snow/winter conditions this snow build-up usually has time to slowly melt away from the insulation, but this is not the case on 27L during heavy snowfall conditions. A suitable recommendation would be to replace the existing double arm with 138kV horizontal post insulators (structure type 42176 modified with 138kV horizontal post insulators). However, this alteration to existing structures is dependent on acceptable span lengths for the 138kV horizontal post insulators and transverse strength for the light angle structures, and would require a design review to determine the most suitable structure re-frame option. These horizontal posts will have significantly less area for snow build-up, as well as, providing increased insulation from the pole due to the additional length of 138kV insulation. In some situations an H-frame structure in suspension (type 42124) could be used as a suitable replacement, but is only recommended for tangent replacements where there is sufficient right of way width. New construction design with double arm structures should be avoided, if possible.

d) Grounding and Bonding

The ground wire and bonding is absent on most older/original structures with the majority of the newly installed structures having only bonding wire installed on the transmission hardware. This lack of grounding and bonding provides an increased risk and liability for pole fires and thus possible forest fires in the surrounding areas, as both 20L and 27L are located primarily in heavily treed regions. The grounding and bonding issue will only become more and more severe as facilities continue to age.

It is recommended that all new 20L/27L structures with distribution underbuild have complete grounding and bonding as part of the structure framing detail. For the portion of 27L from Nelson to Ymir, it is recommended that existing double arm structures that are not to be re-framed, be installed with only the transmission hardware bonded together (i.e. no ground wire installed); and their anchors installed with insul-link rods, if applicable. The absence of the ground wire is meant to provide additional protection against circuit trips and possible pole burn down due to tracking caused by the large amount of snow build-up on these double arms.

ii) Circuit to Circuit Spacing

In general, the circuit to circuit spacing (transmission to distribution) is a smaller issue for 27L, as many portions of the line does not have distribution underbuild and the portions of 27L that does have underbuild consist of relatively shorter span lengths. Most of the major circuit to circuit spacing issues on 27L were resolved by the urgent work completed in the 2007 packages designed by DBS Energy, but not all work was completed. There are still some Tx-Dx circuit spacing concerns on 27L that need to be addressed as noted in the recommended work summary for 27L.

On the other hand, 20L has had many problems in the past with circuit to circuit spacing due to the fact that many older/original poles are shorter and have the distribution underbuild crowded up on the pole to allow for proper ground clearances. Most of the major circuit to circuit spacing issues on 20L were resolved by the urgent work completed in the 2003 packages designed by DBS Energy. In the design evaluation of the circuit spacing, it was generally found that spans approaching 120m or more will start to experience problems. Therefore, all spans near and exceeding 120m with distribution underbuild should be evaluated for correct circuit to circuit spacing based on the criteria specified in the design considerations. It is recommended that any circuit to circuit spacing problems that do arise should be dealt with on a structure specific basis for a solution which could consist of either; installing a new midspan structure, replacing the existing structure with a taller pole, or increasing the transmission to distribution arm spacing on the existing pole if ground clearance will allow.

iii) Phase Spacing

In the past, phase to phase spacing has not shown to be an issue on either 20L or 27L transmission conductors, but it is a very difficult issue to track. Phase spacing problems can essentially only be observed from field assessments, as it is very difficult to determine if an outage was due to a brief phase contact. Typical phase spacing for 20L and 27L based on the Percy-Thomas method for a 90m span length with the 90kcmil copper would be 1.4m spacing, and with 477 AAC Cosmos would be 1.85m spacing. Many of the spans on both circuits involved are quite sheltered from wind disturbances, however could be subjected to short and concentrated winds in certain sections. Given the vertical separation between the phases, the phase spacing is not generally a large concern.

iv) Insulation

The existing insulation for 20L/27L is a combination of older structures with porcelain insulators, older structures with newer synthetic insulators, and newer structures with synthetic insulators. There are no serious issues evident with the older bell type porcelain insulation as there are no signs of cement growth problems from the historical Ohio Brass problems. There is however a large number of older porcelain pins and bells that shows signs of glazing deterioration on both lines. There have also been occasional problems with hunters shooting out the old porcelain bell and pin type insulation, whereas the synthetic insulation would be more resistant to gunshot damage. The insulation should generally be replaced with synthetic insulators for any future construction work, since synthetic change outs will also be beneficial for ease of construction and reliability of the lines.

D. Reconductoring of 90kcmil Copper

It should be noted that the existing 90kcmil copper has shown no immediate signs of damage and/or deterioration, other than what would be typically expected from a 70+ year old conductor. The reconductor of the 90ckmil conductor at this time would purely be required for loading and/or backup conditions. The reconductor of the 90kcmil copper conductor with a 477MCM conductor will require an extensive engineering design review. It would be beneficial to have a detailed engineering design review be completed for the sections of 20L and 27L at the time of any 90kcmil copper reconductoring, as well as any of the previously reconductored 90kcmil copper sections. This engineering review should give particular attention to the pole strength and anchoring capacity of existing facilities. All new designs, structure replacements, and upgrades have allowed for provision of a 477 MCM reconductor capacity.

E. Conductor Accessories

All 90kcmil copper conductor accessories (deadend clamps, trunnion clamps, splices, ampacts, etc.) must be malleable iron type hardware rated for use with copper conductor. Reconductoring of the existing 90kcmil copper must be completed with dead end structures installed at either end; under no circumstances can the 90kcmil copper be directly spliced into another conductor type. For when the 90ckmil copper hemp has deteriorated, a replacement steel core of equal size must be inserted into the conductor in order for the splice to be reliable. Any ampacts or splices used shall include a rigorous but non-destructive cleaning of the host wire and appropriate use of mechanical compression and installation devices.

F. Records and Data Integrity

The tracking of line records for construction changes and engineering design on 20L and 27L have been virtually non-existent throughout the years. However, updated structure lists and PLS-Cadd models of both 20L and 27L have been at least partly created for past 2007/2008 work affected areas based on the condition assessment patrol data and McElhanney survey information. This collection of line data is in-process, and it is recommended that both the structure lists and PLS-Cadd models be completed, reviewed, and finalized with future work on the lines. To be included with this information is updates to sag/tension data, plan and profile drawings, structure drawings with framing details, pictures of each structure location, and ArcFM model of the lines.

It is recommended, there be a formal record of the facilities to act as a master library that should be kept with the FortisBC engineering department. As well as, a strict record keeping procedure for all as-built data to be included with the master library to provide any field changes that were not part of the original released design. It is also suggested that a complete and comprehensive update of all old/existing records be produced.

G. Survey Data

Due to the lack of existing line data, a complete survey plan for both 20L and 27L was contracted through McElhanney Land Surveying to provide ground elevations along centerline and right of ways, conductor heights to be used for sag/tension information, pole and anchoring locations, crossing information, and legal plans. McElhanney used aerial photogrammetry to provide all survey information, as the remote sensing lidar was not possible due to weather conditions and a lengthy completion date. This survey data is essential in providing accurate and detailed engineering designs and must be maintained and updated for accurate line modeling and future engineering designs.

H. Maintenance and Patrols

The main purpose of these maintenance programs is to work towards improving the overall condition and functionality of 20L and 27L, as well as, the stability to provide a reliable contingency plan for the Trail-Nelson transmission ring. Through recent years there have been several practices and programs that should continue to be implemented. Programs such as the pole test and treat, condition assessment, and tree brushing must continue to be executed on a rigorous schedule as to provide 20L and 27L with reliable service in the future years.

i) Pole Test and Treat Program

The existing pole test and treat program since being established has for the most part been completed on an 8-year cycle with reliable results. It has also been noticed that not all previously tested poles are being examined for rot and shell thickness directly at the pole ground line. All poles along the transmission line route must be included with this program, including overhead guy poles and distribution mutt poles. It is recommended that the 8-year cycle for the pole test and treat program continue on schedule with the exclusion of newer poles that are less than 15 years old. A physical examination is only required on these newer poles. The next inspection scheduled for 20L and 27L is projected to be in 2013 and should be coordinated with the condition inspections. Each pole should be tagged with the company name, year of inspection, and action required, along with the data provided for the circumference, shell thickness, and notable comments for each structure. This pole test and treat program should be completed in conjunction with a detailed physical structure and condition assessment ground patrol, for which the pole data should be reconciled. None of these test and treat requirements are unique or special to the 20L/27L circuits and should fit in to the existing FortisBC Test and Treat Program and procedures.

ii) Condition Assessment Program

Without a detailed and rigorous condition assessment program, only a small percentage of deficiencies on average will be identified, which has been the case with FortisBC in the past. The purpose of the condition assessment program is to provide field data on a structure by structure basis to outline any deficiencies on the line. Considering the lack of existing line information and poor overall condition of both 20L and 27L, the recent condition assessments required an extensive review in terms of the structure, hardware, framing, conductor, insulator, and site information, etc. The condition assessment should be completed on an 8-year cycle concurrently with the pole test and treat program, with the next condition assessment patrol for 20L scheduled in 2014 and for 27L in 2015. Again, none one of these condition assessment requirements is unique or special to the 20L/27L circuits and should fit in to the existing FortisBC Condition Assessment Program and procedures.

I. Brushing Program

It would appear that the existing brushing program for 20L/27L has been generally completed quite effectively in the past couple years, which was the main cause for the excess of outages experienced in the years before. There are several sections where tree growth directly underneath the line will need to be addressed in the near future. The major problem with brushing occurs along the tight right of ways where 20L and 27L are paralleling the Road/Highway. These areas do not provide adequate falling distance for large danger trees that are located outside of the Road/Highway right of way on private property, and have not been removed due to obvious land issues. Brushing continues to be the main cause of outages on these transmission lines, in particular on 20L, and it is recommended that future considerations be taken into account for the large danger trees located on private property along the Road/Highway parallel sections. It should be noted that the brushing requirements outlined from the recent condition assessments are assumed to be recently completed, and therefore is not included in the 20L/27L estimates, except for only minor locations noticed during follow-up field inspections.

J. Long Term Plan

Once the needed rehabilitation work has been completed on both 20L and 27L, the main concern of these circuits' shifts from a priority/replacement issue to a more maintenance/upkeep concern. The long term plan would be accomplished through the maintenance and patrol programs as detailed above. The Pole Test and Treat, Condition Assessment, and Brushing Programs must continue to be executed on a rigorous schedule to maintain and preserve the functionality and reliability of 20L/27L along with the transmission ring system. These programs must be set up to outline the problem areas with repair action in place before they become a serious urgent issue again. Additionally, all future designs and work planned on the lines should include foresight into ultimate possible plans for re-conductoring, reliability improvements, and other special engineering considerations outlined in this report.

5. ESTIMATES

A. Recommended Capital Plan Investment

The recommended scope of work that should be done on both 20L and 27L is included on a detailed structure by structure basis, and is detailed in Appendix I and Appendix II, respectively. It is expected that the subsequent engineering to complete construction packages will include any follow-up design efforts that are needed, and review of expected summary of work. Generally, the recommendations provide for replacement of all stubbed and tested deficient structures, replacement of older structure with arm failures, reframe of crossarms and insulation, upgrades to all anchoring that may not be adequate, minor brushing in areas, repair of under-designed facilities, upgrade of facilities to FortisBC standards, and refurbishment of 20L Hearns switches & replacement and review of 20L Salmo switch. The urgent work refers to structures with failing crossarms that need immediate attention as observed from recent follow-up inspections. There are also several outstanding issues on 27L that require follow-up engineering review, which are suggested to be done during the design stage of the project. Review of these issues are included in the estimate (incorporated into the engineering costs), and any additional repairs that may be required as a result would be covered by the 20% contingency allowance. The following estimate tables are a summary of the recommended expenditures for the 20011/12 FortisBC Capital Plan and future costs.

20L ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	**Str Replace**	**Brushing**	
# of Structures	52	152	5	# OF URGENT STR REPLACEMENTS = 8
Urgent Work	$ 0.0k	$ 132.0k	$ 0.0k	# OF URGENT REPAIRS = 0
Recommended Work	$ 119.7k	$ 2583.0k	$ 6.0k	
± 20-25% Estimate	**$ 119.7k**	**$ 2715.0k**	**$ 6.0k**	Excludes contingency or FortisBC overheads.

Labor	$ 1136.3k	40%	Approx 9000 man-hours with 20L de-energized. Some Dx outages.
Salvage	$ 284.1k	10%	Salvage labor. Approx 2000 man-hours.
Brushing	$ 6.0k		Brushing of line assumed recently completed. Minor brushing required.
Material	$ 710.2k	25%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 255.7k	9%	Includes review of outstanding issues. Engr follow-up & design. P&P dwgs.
PM	$ 170.4k	6%	Project management.
Misc	$ 278.1k	10%	For preliminary work, building access, flagging, EVT, etc.
Land Easement	$ 30.0k		Place holder to deal with land easement issues.
SUBTOTAL =	$ 2870.7k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 287.1k	10%	Allows for 10% contingency.
TOTAL =	**$ 3157.8k**		Does not include any FortisBC Capitalized Overheads.

27L ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	Str Replace	Brushing	
# of Structures	84	14	1	# OF URGENT STR REPLACEMENTS = 0
Urgent Work	$ 14.0k	$ 0.0k	$ 0.0k	# OF URGENT REPAIRS = 3
Recommended Work	$ 166.3k	$ 364.5k	$ 1.5k	
± 20-25% Estimate	**$ 180.3k**	**$ 364.5k**	**$ 1.5k**	Excludes contingency or FortisBC overheads.

Labor	$ 234.9k	43%	Approx 1850 man-hours with 27L de-energized. Some Dx outages.
Salvage	$ 54.6k	10%	Salvage labor. Approx 400 man-hours.
Brushing	$ 1.5k		Brushing of 27L assumed recently completed. Minor brushing required.
Material	$ 120.2k	22%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 54.6k	10%	Includes review of outstanding issues. Engr follow-up & designs. P&P dwgs.
PM	$ 32.8k	6%	Project management.
Misc	$ 47.7k	9%	For preliminary work, building access, flagging, EVT, etc.
SUBTOTAL =	$ 546.3k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 109.3k	20%	Allows for 20% contingency.
TOTAL =	**$ 655.6k**		Does not include any FortisBC Capitalized Overheads.

B. Planning Based Reconductoring Option

There was a brief review of a current planning desire for a reconductoring option of the 90kcmil Copper and 2/0 ACSR conductors. It is estimated that the total costs to reconductor and rebuild those portions of both 20L and 27L (some 48kms), to 477MCM would be in the order of $19.2M. It was assessed that doing this reconductoring ahead of, or concurrently with, the refurbishment program would have a cost savings of approximately $0.8M. The time valuing for this significant capital investment up front would quickly eliminate this savings by even a simple delay in reconductoring of 1 year. From a load planning point of view, this delay would more likely be in excess of 10-20 years, even with current aggressive load projections. The current recommended capital forecasts do however include a provision for increased strength of any new work planned on these lines to allow for future reconductoring options down the road, which has been included into the structure replacement costs. This report could not justify the reconductoring due to either ampacity or conductor condition issues.

C. Alternate Options Reviewed

Two other alternatives that were briefly considered as options to resolve the condition, reliability, capacity, and system integrity issues for 20L and 27L were:

- Sections of the circuits could be rebuilt to the opposite side of the road, which could accommodate reduced outages, more efficient construction, and green field construction methods. Under closer review this option was determined to be less beneficial than expected, due to the limited property on opposite side of the highways, conflicts with Telus circuits, increased road crossings, private lands and brushing would need to be negotiated, and significant approval delays could be expected.
- Provide an alternate source of 63kV supply to any of the load centers affected. This can be quickly eliminated since there are no nearby sources that are readily available and it would still leave the old existing facilities in a decayed state of repair.

APPENDIX I - 20L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
28	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole & Tx/Dx arms in poor condition
33	✓	Repair	3.5	Reframe Dx to alley arm; Reframe Neut higher on pole for low clr issues
34	✓	Repair	1.0	Reframe Neut to arm
35	✓	Repair	1.0	Reframe Neut to arm
39	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is blue tagged (stubbed)
61	✓	Repair	1.5	Replace Tx tang insulation
70	✓	Repair	10.0	Reframe str to floating DDE H-Frame with crossbracing
72	✓	Repair	1.5	Replace Tx tang insulation
73	✓	Repair	35.0	Reconductor river crossing with 477 ACSR Hawk; Add marker balls
	✓	Repair	1.5	Install single Stockbridge dampers on Tx fore span
	✓	Repair	5.0	Salvage existing marker ball span and strs
74	✓	Str Replace	38.0	Replace DDE (3-Pole) str - Poles in poor condition
BEP	✓	Repair	3.0	Replace Tx insulation with synthetic
	✓	Repair	8.0	Reconductor aft span to 20L73 with 477 ACSR Hawk; Replace Tx drops
79	✓	Repair	0.3	Replace missing keeper pin on CP east Tx phase
	-	-	-	Engr Review - Check jumper insulation and arm - Possibe replace
87	✓	Repair	0.5	Remove old pole
88	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
89	✓	Repair	0.2	Add str tag #
90	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
91	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
92	✓	Repair	0.5	Add strirrup for xfmr
	✓	Repair	0.2	Add str tag #
	✓	Repair	1.0	Add new side anchor for angle
	-	-	-	Note: Easement required for new anchor or possible push brace
	✓	Brushing	1.0	Brushing required on fore span
94	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
	-	-	-	Note: Easement required for structure
96	-	-	-	Note: Easement required for existing anchor
97	URGENT	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed (Tx arm is failing)
98	URGENT	Str Replace	19.0	Replace tang str with Dx DDE u/b & xfmr - Pole is stubbed (Tx arm is failing)
99	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
100	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
101	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
102	✓	Repair	0.5	Add stirrup for Dx tap
	✓	Repair	0.2	Add str tag #
	✓	Repair	0.5	Remove old pole
103	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
106	✓	Repair	0.5	Remove old pole
109	✓	Str Replace	25.0	Replace angle str with Dx u/b; Reframe to DDE - Pole is stubbed
	-	-	-	Note: Easement required for structure
110	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
111	✓	Repair	0.5	Remove old pole
113	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
114	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
117	✓	Str Replace	19.0	Replace angle str with Dx u/b - Pole is stubbed
118	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
119	✓	Str Replace	17.0	Replace tang str with Dx DDE u/b - Pole is stubbed
120	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
123	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
130	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
131	✓	Str Replace	17.0	Replace tang str with Dx DDE u/b - Pole is stubbed
132	✓	Str Replace	18.0	Replace tang str with Dx u/b & taps - Pole is stubbed
133	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
134	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
135	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed

APPENDIX I - 20L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
136	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
137	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
139	✓	Str Replace	24.0	Replace tang str with Dx u/b & xfmr/tap, OHG pole - Pole is stubbed
140	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
141	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
142	✓	Str Replace	20.0	Replace tang str with Dx u/b & tap - Pole is stubbed
	-	-	-	Note: Reconductor Dx tap with #2 ACSR (exisitng #8 Cu)
143	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
144	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
145	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
146	✓	Str Replace	19.0	Replace tang str with Dx DDE u/b & tap - Pole is stubbed
147	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
149	✓	Str Replace	18.0	Replace tang str with Dx u/b & taps - Pole is stubbed
150	✓	Str Replace	17.0	Replace tang str with Dx DDE u/b - Pole is stubbed
151	✓	Str Replace	21.0	Replace angle str with Dx u/b & taps - Pole is stubbed
	-	-	-	Note: Easement required for new anchor
152	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
	-	-	-	Note: Easement required for structure
153	✓	Repair	0.2	Add str tag #
159	✓	Str Replace	18.0	Replace tang str with Dx u/b & tap, breast anchor - Pole is stubbed
160	✓	Str Replace	18.0	Replace tang str with Dx u/b & xfmr/tap - Pole is stubbed
161	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
162	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
163	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
164	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
165	✓	Str Replace	18.0	Replace tang str with Dx u/b & xfmr/tap - Pole is stubbed
166	✓	Str Replace	18.0	Replace tang str with Dx u/b & tap, breast anchor - Pole is stubbed
167	✓	Str Replace	18.0	Replace tang str with Dx u/b & tap, breast anchor - Pole is stubbed
168	✓	Str Replace	18.0	Replace tang str with Dx u/b & tap, breast anchor - Pole is stubbed
169	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
170	✓	Str Replace	19.0	Replace tang str with Dx u/b & taps - Pole is stubbed
171	✓	Str Replace	20.0	Replace angle str with Dx u/b & xfmr - Pole is stubbed
192	✓	Repair	2.0	Replace Dx tang arm
	✓	Repair	1.0	Refarme Dx tap off pole - May need to add conductor
	-	-	-	Engr Review - Anchoring support for Dx tap needs review
206	✓	Repair	0.2	Add str tag #
214	✓	Str Replace	19.0	Replace light angle str with Dx u/b & tap - Pole is stubbed
215	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
	-	-	-	Note: Easement required for new anchor
216	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
219	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
220	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole in poor condition
221	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
223	✓	Str Replace	18.0	Replace tang str with Dx u/b with xfmr/tap - Pole is stubbed
224	✓	Str Replace	19.0	Replace light angle str with Dx u/b & dip - Pole is stubbed
225	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
228	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
229	✓	Repair	0.2	Add str tag #
233	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
	✓	Repair	5.0	Replace secondary tap str
	✓	Brushing	1.0	Brushing required for secondary tap
234	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
236	✓	Str Replace	19.0	Replace angle str with Dx u/b - Pole is stubbed
238	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole in poor condition
239	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole in poor condition
240	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed

APPENDIX I - 20L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
241	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
242	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Replace with adjacent strs
	✓	Brushing	1.5	Brushing Required in forespan
243	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Replace with adjacent strs
244	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
246	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
247	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
248	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
249	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
250	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
252	URGENT	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed (Dx arm is failing)
253	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
	-	-	-	Note: Review secondary Hwy clearances
254	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
255	URGENT	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed (Tx arm is failing)
257	✓	Str Replace	18.0	Replace tang str with Dx u/b & xfmr/tap - Pole is stubbed
258	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
259	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
261	✓	Repair	1.0	Add new anchor for Dx tap
	✓	Repair	0.5	Add stirrups for Dx tap; Add elephant ears to Dx cutout
263	✓	Repair	0.2	Add str tag #
264	URGENT	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed (Dx arm is failing)
265	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
266	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
267	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
268	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
269	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
270	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
271	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
272	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
273	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
	-	-	-	Note: Easement may be required for new anchor
274	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
275	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
276	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
277	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
278	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
279	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
281	✓	Str Replace	19.0	Replace light angle str with Dx u/b & tap - Pole is stubbed
282	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
283	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
284	✓	Str Replace	19.0	Replace light angle str with Dx u/b & xfmr - Pole is stubbed
286	✓	Repair	0.2	Add str tag #
	-	-	-	Note: xfmr not in service - Should be de-energized
287	✓	Str Replace	18.0	Replace light angle str with Dx u/b & guy - Pole is stubbed
	-	-	-	Note: xfmr not in service - Should be de-energized
288	✓	Repair	0.2	Replace str tag # to '20L288'
	-	-	-	Note: Dx dbl cct DDE arm guyed to str #287 - Repair with future work
289	✓	Str Replace	19.0	Replace light angle str with Dx dbl cct u/b - Pole & Dx arm in poor condition
290	✓	Repair	0.2	Replace str tag # to '20L290'
	-	-	-	Note: Anchoring needs to be re-designed with future str replacement
291	✓	Repair	0.2	Replace str tag # to '20L291'
292	✓	Repair	0.2	Replace str tag # to '20L292'
293	✓	Repair	10.0	Refurbishment of Tx switch
	-	-	-	Note: Dx dbl cct DDE arm guyed to str #294 - Repair with future work
295	✓	Repair	10.0	Refurbishment of Tx switch

APPENDIX I - 20L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
297	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
298	-	-	-	Future Reference - Possible str replacement next assessment cycle
301	✓	Repair	0.5	Remove old pole
305	✓	Repair	0.5	Repair WP hole at Tx skypin bolt
312	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
313	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
314	URGENT	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed (Dx arm is failing)
315	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
316	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Replace with adjacent strs
317	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole in poor condition
321	✓	Repair	3.0	Add push brace for angle
	✓	Repair	0.2	Add str tag #
330	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
336	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole & Tx arm in poor condition
337	✓	Repair	0.2	Repair str tag #
339	-	-	-	Future Reference - Possible str replacement next assessment cycle
340	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
341	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
342	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
343	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
344	✓	Repair	1.0	Add new anchor for Dx tap
	✓	Repair	0.5	Reframe Neut tap 0.6m higher - Rubbing on Telus
350	-	-	-	Future Reference - Possible str replacement next assessment cycle
351	-	-	-	Future Reference - Possible str replacement next assessment cycle
354	✓	Repair	0.2	Add str tag #
361	✓	Repair	1.0	Add stirrup and cutout/lightning arrestor for xfmr
364	URGENT	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed (Arm is failing)
365	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
366	-	-	-	Future Reference - Possible str replacement next assessment cycle
369	✓	Repair	0.2	Repair str tag #
371	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
372	✓	Str Replace	15.0	Replace tang str with Dx u/b - Replace with adjacent strs
373	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
378	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
379	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
380	✓	Str Replace	17.0	Replace tang str with Dx u/b & xfmr - Pole is stubbed
385	✓	Repair	0.2	Add str tag #
389	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
389A	✓	Repair	0.2	Add str tag #
396A	✓	Repair	0.2	Add str tag #
398	-	-	-	Note: Mior chip in Tx RØ insulation - OK to leave
404	✓	Repair	1.0	Add new anchor for Dx tap
	-	-	-	Note: Easement required for new anchor
411	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
413	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
415	✓	Str Replace	17.0	Replace tang str with Dx u/b & openers - Pole is stubbed
416	✓	Str Replace	15.0	Replace tang str with Dx u/b - Replace with adjacent strs
417	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole in poor condition
418	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
419	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
420	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
429	✓	Repair	0.3	Repair ground wire
430	✓	Repair	0.2	Add str tag #
431	✓	Repair	0.2	Add str tag #
432	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
433	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed

APPENDIX I - 20L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
434	URGENT	Str Replace	17.0	Replace tang str with Dx u/b & openers - Pole is stubbed (Tx arm is failing)
438	✓	Repair	0.2	Add staples for downlead
452	✓	Repair	0.2	Add staples for downlead
453	✓	Repair	0.2	Add staples for downlead
460	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
461	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
462	✓	Str Replace	15.0	Replace tang str with Dx u/b - Replace with adjacent strs
468	✓	Str Replace	17.0	Replace tang str with Dx u/b & openers - Pole is stubbed
473	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
474	✓	Brushing	1.0	Brushing required for Dx tap span
479	✓	Repair	0.5	Remove old pole
480	✓	Repair	0.2	Add str tag #
481	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
483	✓	Brushing	1.5	Brushing required on fore and aft spans
488	✓	Repair	0.2	Add str tag #
489	✓	Repair	0.2	Add str tag #
496	✓	Str Replace	17.0	Replace tang str with Dx u/b & tap - Pole is stubbed
498	✓	Repair	1.0	Add anchor for 3Ø Dx tap
499	✓	Str Replace	50.0	Replace DDE str with Dx u/b & tap - Pole is stubbed
500	✓	Repair	0.2	Add str tag #
503	✓	Str Replace	120.0	Replace Tx switch str with Dx u/b - Design review of switch is needed

ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	**Str Replace**	**Brushing**
# of Structures	52	152	5
Urgent Work	$ 0.0k	$ 132.0k	$ 0.0k
Recommended Work	$ 119.7k	$ 2583.0k	$ 6.0k
± 20-25% Estimate	**$ 119.7k**	**$ 2715.0k**	**$ 6.0k**

OF URGENT STR REPLACEMENTS = 8

OF URGENT REPAIRS = 0

Excludes contingency or FortisBC overheads.

Labor	$ 1136.3k	40%	Approx 9000 man-hours with 20L de-energized. Some Dx outages.
Salvage	$ 284.1k	10%	Salvage labor. Approx 2000 man-hours.
Brushing	$ 6.0k		Brushing of line assumed recently completed. Minor brushing required.
Material	$ 710.2k	25%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 255.7k	9%	Includes review of outstanding issues. Engr follow-up & design. P&P dwgs.
PM	$ 170.4k	6%	Project management.
Misc	$ 278.1k	10%	For preliminary work, building access, flagging, EVT, etc.
Land Easement	$ 30.0k		Place holder to deal with land easement issues.
SUBTOTAL =	$ 2870.7k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 287.1k	10%	Allows for 10% contingency.
TOTAL =	**$ 3157.8k**		Does not include any FortisBC Capitalized Overheads.

APPENDIX II - 27L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
6	✓	Repair	1.5	Add horizontal jumper posts
11	✓	Repair	0.5	Repair WP holes
23	✓	Repair	6.0	Replace OHG structure - Pole in poor condition & low road clearance
29	✓	Repair	0.5	Repair WP holes
56	✓	Repair	1.5	Replace CØ pole top insulator - Poor access
58	✓	Repair	0.5	Salvage old pole
64	✓	Repair	0.6	Reframe Fiber & add protective cable cover - Rubbing on Neut on aft span
86	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
91	✓	Repair	0.2	Add str tag #
98	✓	Repair	0.5	Repair WP holes
	-	-	-	Engr Review - Check condition of Tx arm - Possibly tighten hardware
102	URGENT	Repair	2.0	Install new anchors (fore & aft) on RP - Check guy clr over road - Confirm
	✓	Repair	0.5	Repair WP holes on LP and CP
108	-	-	-	Engr Review - Str appears to have 100lbs of uplift at -30°C - Should be OK
113	-	-	-	Engr Review - Check condition of Tx arm and insulators - Should be OK
122	-	-	-	Note: Vertical DDE without horiz jumpers posts - OK to leave
125	✓	Repair	0.5	Repair WP holes
130	✓	Repair	0.3	Rosemont Station - Replace missing keys on Tower-Y adapters
138	✓	Repair	0.5	Repair WP holes
151	-	-	-	Note: Auto DE on 477 Hawk to be replaced - Assumed to be done - Confirm
	-	-	-	Note: Anchor to be added NW for full DDE - Assumed to be done - Confirm
155	✓	Repair	0.5	Salvage old pole - Transfer secondary (Nelson Hydro) & Telus
156	✓	Repair	0.5	Salvage old pole - Transfer secondary (Nelson Hydro) & Telus
	✓	Repair	0.2	Add str tag #
161	✓	Repair	0.2	Add str tag #
162	✓	Repair	0.5	Tighten Tx pole top hardware; Add lock nuts and lock washers
163	-	-	-	Note: Str needs re-design for 477 reconductor provision
165-172	✓	Repair	1.0	Add str tag #
168	-	-	-	Engr Review - Str appears to have 50lbs of uplift at -30°C - Should be OK
170	✓	Repair	0.5	Repair WP holes
174	-	-	-	Reframe Dx u/b crossing to floating DDE (Nelson Hydro)
	-	-	-	Replace secondary attachment hardware (Nelson Hydro)
176	✓	Repair	0.2	Re-number str - Add str tag # '27L175'
176A	✓	Repair	0.2	Re-number str - Add str tag # '27L176'
178	✓	Repair	1.5	Add horizontal jumper posts
197	-	-	-	Salvage old pole underneath line at +48m (Nelson Hydro)
204	✓	Repair	0.2	Replace str tag #
207-212	✓	Repair	1.0	Add str tag #
221-227	✓	Repair	1.0	Add str tag #
230	✓	Repair	0.2	Add str tag #
231	✓	Repair	0.2	Add str tag #
233-245	✓	Repair	2.0	Add str tag #
247	-	-	-	Future Reference - Possible str replacement next assessment cycle
248	-	-	-	Future Reference - Possible str replacement next assessment cycle
249	URGENT	Repair	10.0	Replace Tx DDE arms & insulation - Arm badly splitting; Add inline anchors
250	-	-	-	Future Reference - Possible str replacement next assessment cycle
253	✓	Brushing	1.5	Brushing required on aft span
257	✓	Repair	0.2	Re-number str - Add str tag # '27L257A'
	✓	Repair	3.5	Replace Tx tang arm and insulation
258	✓	Repair	0.5	Replace Neut spool - Possibly reframe to Dx arm
	✓	Repair	0.5	Repair WP holes
260	✓	Repair	0.2	Add str tag #
266	✓	Repair	2.0	Add new anchors (fore & aft) - For full 477 deadend capacity
	✓	Repair	1.0	Reframe outside phase jumpers to suspension
270	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design
271	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design
273	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design
276	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design
277	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design

APPENDIX II - 27L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
280	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design
281	✓	Repair	5.0	Reframe Tx dbl arm due to snow load concerns - Needs str re-design
284	✓	Repair	0.2	Add guy guard
286-302	✓	Repair	2.0	Add str tag #
289	✓	Repair	8.0	Reframe Tx to floating DDE (flat) on arm
	-	-	-	Engr Review - Str appears to have 400lbs of uplift at -30°C - Confrim design
302	-	-	-	Engr Review - Check arm and anchor capacity - Should be OK
306	✓	Repair	2.0	Add new anchors (fore & aft) - For full 477 deadend capacity
	✓	Repair	1.0	Reframe outside phase jumpers to suspension
	✓	Repair	0.2	Add str tag #
325	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
327	✓	Str Replace	15.0	Replace tang str with Dx u/b - Pole is stubbed
336	✓	Repair	8.0	Reframe Tx to floating DDE (flat) on arm
	-	-	-	Engr Review - Str appears to have ~500lbs of uplift at -30°C - Confirm design
337	✓	Str Replace	17.0	Replace light angle str with Dx u/b - Pole is stubbed
347	-	-	-	Note: Auto DE on 477 Cosmos (Hwy slackspan) - Replace with future work
349	✓	Repair	3.5	Replace Tx tang arm and insulation
355	✓	Repair	0.3	Replace Dx ties
	-	-	-	Note: Tx-Dx spacing is insufficient - Cannot lower Dx arm due to low clr
356	✓	Repair	0.3	Replace Dx ties
359	✓	Repair	0.3	Replace Dx ties
360	✓	Repair	0.3	Replace Dx ties
361	✓	Repair	2.0	Reframe 1Ø Dx arm 1m lower
364	✓	Repair	2.0	Reframe 1Ø Dx arm 1m lower
365	✓	Repair	4.0	Replace Tx light angle arm and insulation
366	✓	Repair	4.0	Replace Tx light angle arm and insulation
	✓	Repair	1.0	Add stirrup for Dx tap
370	✓	Repair	2.0	Reframe 1Ø Dx arm 1m lower
	✓	Repair	1.0	Reframe Dx tap lower; Add stirrup for Dx tap
	-	-	-	Engr Review - Check condition of Tx arm - Should be OK
371	✓	Repair	4.0	Replace Tx light angle arm and insulation
376	✓	Str Replace	25.0	Replace vertical DDE str - Pole in poor condition
377	✓	Str Replace	25.0	Replace vertical DDE str - Pole is stubbed
384	✓	Repair	3.5	Replace Tx tang arm and insulation
385	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
386	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
401	✓	Repair	1.5	Add horizonatal jumper posts
	✓	Repair	0.5	Tighten guy wires
406	-	-	-	Future Reference - Possible str replace next assessment cycle
407	✓	Str Replace	12.5	Replace tang str - Pole is stubbed
408	✓	Str Replace	12.5	Replace tang str - Pole in poor condition
409	✓	Str Replace	12.5	Replace tang str - Pole is stubbed
410	-	-	-	Future Reference - Possible str replace next assessment cycle
411	✓	Repair	0.3	Add split bolt to pole top
424	✓	Repair	1.0	Add new anchor for Dx - Confirm
	-	-	-	Note: Tx CØ not changed out with recent work - Replace with future work
	-	-	-	Note: Minor burn marks on the pole - OK to leave
429	-	-	-	Note: Minor chip in LØ Tx insulator - OK to leave
433	URGENT	Repair	2.0	Replace Dx 3Ø tap arm; Add stirrups for Dx tap
437	✓	Repair	3.0	Reframe Dx arm 1m lower; Reframe Neut to Dx arm
438	✓	Repair	1.0	Reframe Neut to arm - Low clearance
439	✓	Repair	1.0	Reframe Neut to arm - Low clearance
440	✓	Repair	1.0	Reframe Neut to arm - Low clearance
441	✓	Repair	1.0	Reframe Neut to arm - Low clearance
	✓	Repair	0.5	Add stirrup for Dx tap
	✓	Repair	0.5	Tighten guy wires
446	-	-	-	Note: Reframe Dx arm 1m lower; Neut on arm - Assumed to be done - Cofirm
447	-	-	-	Note: Replace tang str with Dx u/b - Assumed to be done - Confirm
448	-	-	-	Note: Replace angle str with Dx DDE - Assumed to be done - Confirm

APPENDIX II - 27L Work Summary & Estimate

Str #	Priority	Type of Rehab	± 20-25% Estimate ($k)	Comments
450	-	-	-	Note: Str in slight uplift at -30°C - Should be OK
452	✓	Repair	0.5	Salvage old pole
455	-	-	-	Note: Tx CØ insulator not changed out - Replace with future work
456	✓	Repair	1.0	Reframe Neut to DDE
	-	-	-	Engr Review - Check Tx arm capacity - Should be OK
458	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
461	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
	✓	Repair	0.5	Add stirrups for Dx tap
462	-	-	-	Engr Review - Check condition of Tx arm and insulation - Should be OK
467	-	-	-	Engr Review - Check condition of pole (burn marks) - Should be OK
468	-	-	-	Engr Review - Check Neut clearance on fore span
471	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
472	✓	Repair	4.5	Replace Tx arm and insulation with dbl arms and angle pin insulators
476	-	-	-	Note: Neut rubbing on guy wire - Add insul-link rod with future work
479	-	-	-	Note: Cotter key on Dx tap deadend shoe is not all the way in
480	✓	Repair	2.5	Replace Tx insulation with dbl angle pin insulators (re-use Tx arms)
484	✓	Repair	0.5	Tighten guy wires
491	-	-	-	Note: Cap bank not in service - Add stirrups if re-energized
498	✓	Repair	0.3	Tighten Neut hardware; Add lock nut and lock washer
500	✓	Repair	0.2	Add str tag #
501	-	-	-	Note: Minor chip on Tx CØ skypin insulator - OK to leave
512-515	✓	Repair	0.2	Add str tag #
533	✓	Repair	0.5	Salvage old pole
543	✓	Repair	0.2	Add str tag #
555	✓	Repair	0.5	Add backfill for Tx anchor - Confirm
	✓	Repair	0.1	Preform on OHG pole bottom guy wire not completed - Confirm
556	✓	Repair	0.5	Add backfill for Dx tap anchor - Confirm
568	✓	Str Replace	40.0	Replace tang str with dbl Dx u/b and Tx/Dx taps; Replace OHG pole
568A	✓	Str Replace	25.0	Replace str and reframe to Tx deadend with dbl Dx tang u/b
568B	✓	Str Replace	25.0	Replace str and reframe to dbl Dx DDE; Salvage Tx
569	✓	Str Replace	30.0	Replace light angle str with dbl Dx u/b & xfmr; Replace OHG pole
570	✓	Str Replace	70.0	Replace tang str with dbl Dx u/b and Tx/Dx taps
571	✓	Str Replace	40.0	Replace tang str with dbl Dx u/b & xfmr and 2x Tx taps; Replace OHG pole

ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	Str Replace	Brushing
# of Structures	84	14	1
Urgent Work	$ 14.0k	$ 0.0k	$ 0.0k
Recommended Work	$ 166.3k	$ 364.5k	$ 1.5k
± 20-25% Estimate	**$ 180.3k**	**$ 364.5k**	**$ 1.5k**

OF URGENT STR REPLACEMENTS = 0

OF URGENT REPAIRS = 3

Excludes contingency or FortisBC overheads.

Labor	$ 234.9k	43%	Approx 1850 man-hours with 27L de-energized. Some Dx outages.
Salvage	$ 54.6k	10%	Salvage labor. Approx 400 man-hours.
Brushing	$ 1.5k		Brushing of 27L assumed recently completed. Minor brushing required.
Material	$ 120.2k	22%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 54.6k	10%	Includes review of outstanding issues. Engr follow-up & designs. P&P dwgs.
PM	$ 32.8k	6%	Project management.
Misc	$ 47.7k	9%	For preliminary work, building access, flagging, EVT, etc.
SUBTOTAL =	$ 546.3k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 109.3k	20%	Allows for 20% contingency.
TOTAL =	**$ 655.6k**		Does not include any FortisBC Capitalized Overheads.

APPENDIX III - 20L/27L CONDUCTOR TYPES & AMPACITY RATINGS

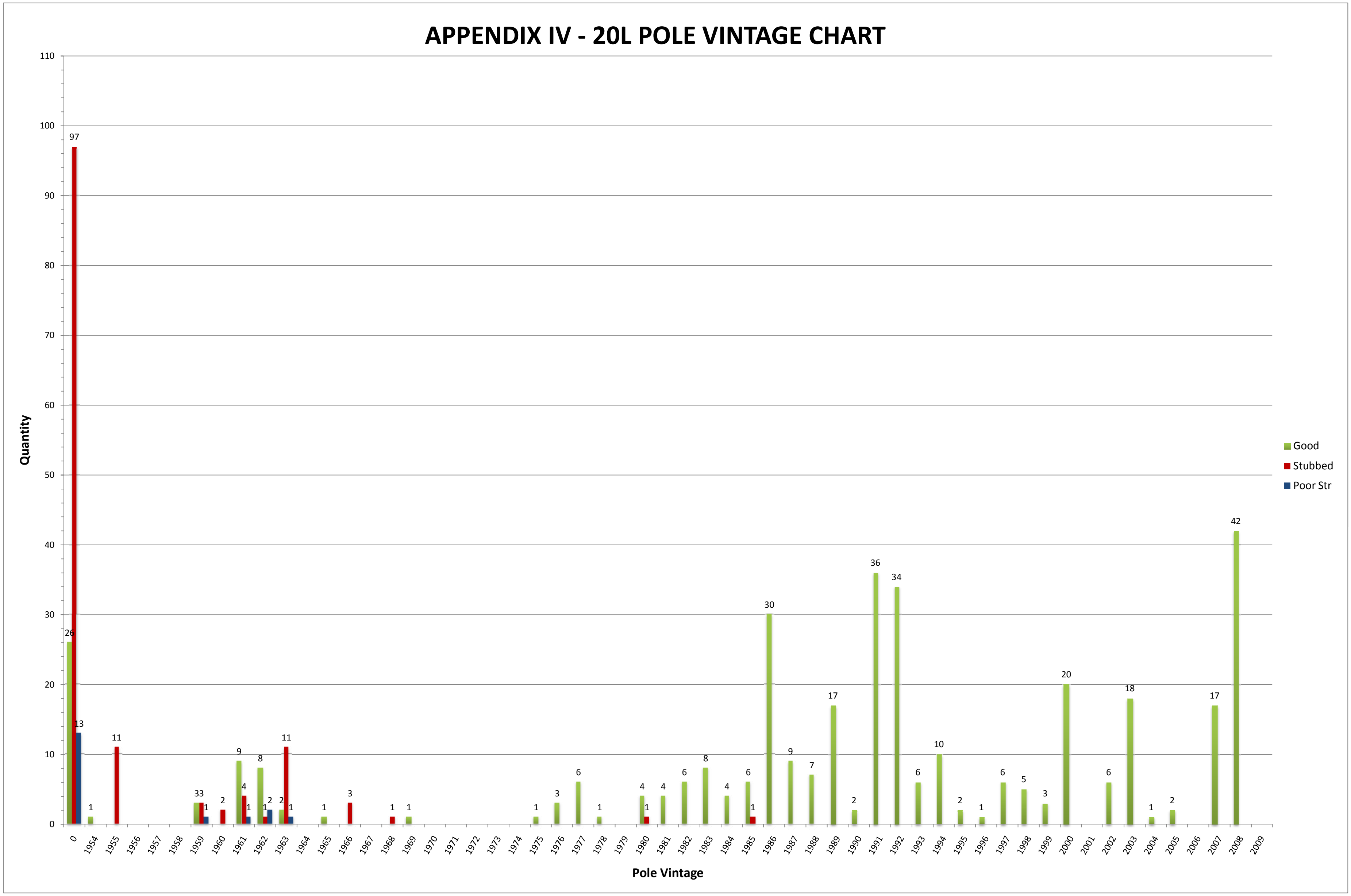
20L CONDUCTOR DATA

From Str #	To Str #	Conductor Type	Conductor Ampacity Rating		Length	Comments
			Summer	Winter		
1	**7**	477 ACSR Hawk	696	961	1.0 km	Warfield Terminal Station
7	**8**	300MCM Copper	635	869	0.4 km	
8	**73**	3/0 AACSR	369	504	9.5 km	
73	**74**	90kcmil Copper	296	399	0.4 km	To be reconductored to 477 Hawk
74	**79**	477 ACSR Hawk	696	961	0.5 km	
79	**174**	90kcmil Copper	296	399	7.2 km	
174	**176**				0.1 km	Strs in Fruitvale Substation
176	**196**	477 ACSR Hawk	696	961	1.3 km	
196	**293**	90kcmil Copper	296	399	7.2 km	
293	**295**	2/0 ACSR Quail	285	388	0.1 km	
295	**394**	90kcmil Copper	296	399	8.3 km	
394	**399**	2/0 ACSR Quail	285	388	0.6 km	
399	**504**	90kcmil Copper	296	399	7.5 km	Salmo Substation
					44.1 km	

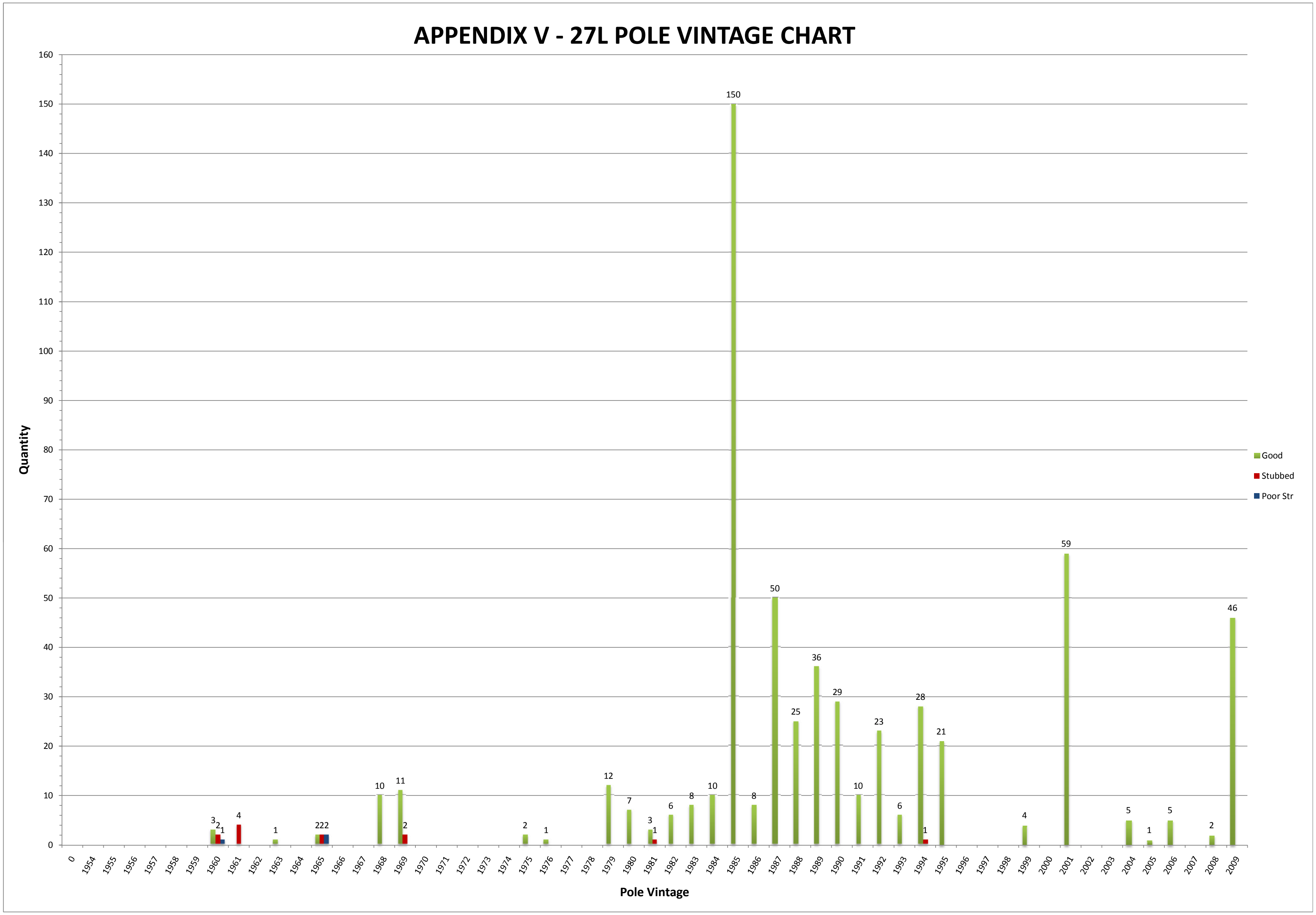
27L CONDUCTOR DATA

From Str #	To Str #	Conductor Type	Conductor Ampacity Rating		Length	Comments
			Summer	Winter		
1	**131**	477 ACSR Hawk	696	961	14.0 km	Carra Lynn Substation
131	**138**	90kcmil Copper	296	399	0.5 km	Rosemont Substation (Nelson)
138	**144**	477 ASC Cosmos	675	929	0.4 km	
144	**151**	477 ACSR Hawk	696	961	0.7 km	
151	**249**	90kcmil Copper	296	399	9.1 km	
249	**252**	2/0 ACSR Quail	285	388	0.3 km	
252	**256**	477 ACSR Pelican	682	941	0.4 km	
256	**266**	2/0 ACSR Quail	285	388	0.9 km	
266	**524**	477 ASC Cosmos	675	929	24.6 km	2/0 ACSR jumpers on str 27L524
524	**573**	90kcmil Copper	296	399	3.4 km	Salmo Substation
					54.3 km	

NOTE:
- Conductor ampacity ratings are based on a maximum steady state temperature of 100°C, 2.0 ft/s wind, coefficient of Emissivity at 0.6, and coefficient of Absorption at 0.8.
- Summer ampacity caclulated with ambient temperature of 40°C (Based on June 10, 2:00PM Date)
- Winter ampacity caclulated with ambient temperature of 0°C (Based on December 10, 2:00PM Date)



APPENDIX IV - 20L POLE VINTAGE CHART


APPENDIX V - 27L POLE VINTAGE CHART
Quantity
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
Pole Vintage
0
1954
1955
1956
1957
1958
1959
1960
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1962
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3
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6
8
10
150
8
50
25
36
29
10
23
6
28
1
21
4
59
5
1
5
2
46
🟩 Good
🟥 Stubbed
🟦 Poor Str

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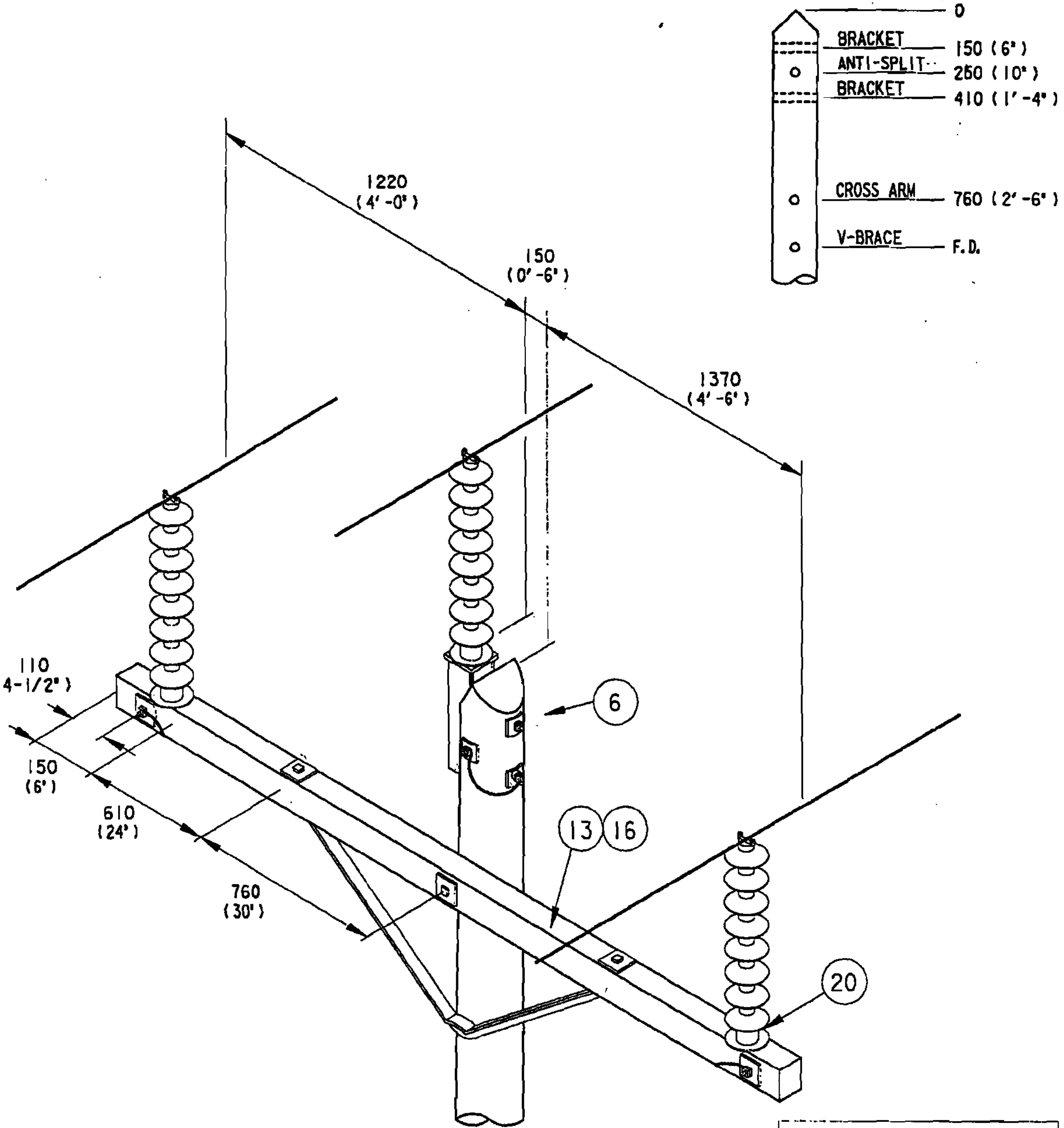

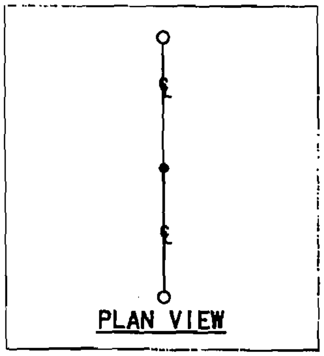

PLAN VIEW

NOTES:

1 - BOND ALL METALLIC PARTS WITHIN 150mm (6") OF ONE ANOTHER

2 - UNLESS OTHERWISE SPECIFIED,
-ALL DIMENSIONS ARE IN MILLIMETRES
-ALL HOLES DRILLED 13/16" DIAMETER

Revision Date	Description
Checked	
Approved	

63 kV SINGLE POLE TANGENT SINGLE ARM

Original - Design / Checked	Original - Approved	Date Created			Drawing Number	Sheet
JS		03-09-16	NOT TO SCALE	Aquila Networks Canada	700-42101	1/1

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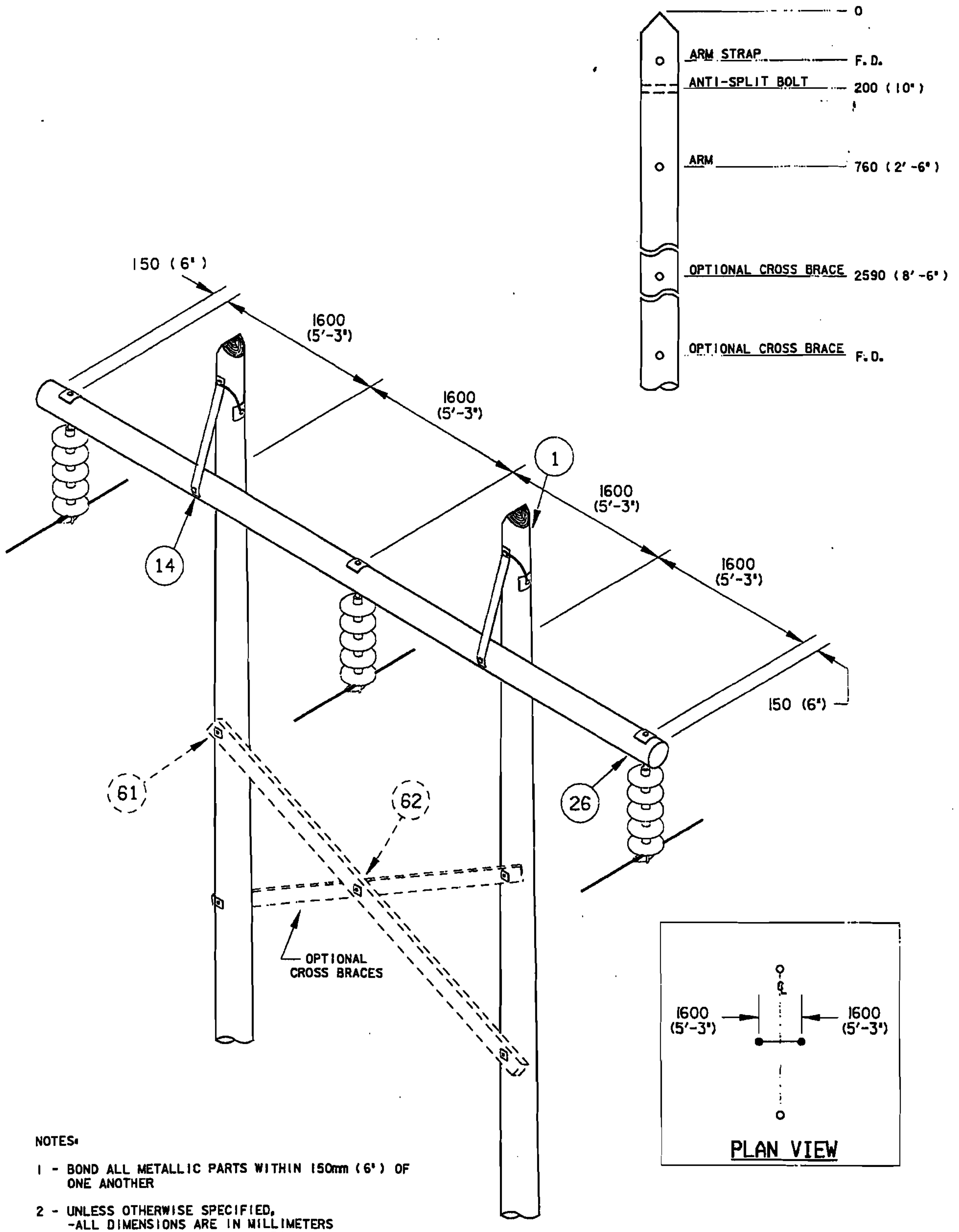

NOTES:

1 - BOND ALL METALLIC PARTS WITHIN 150mm (6") OF ONE ANOTHER

2 - UNLESS OTHERWISE SPECIFIED,
-ALL DIMENSIONS ARE IN MILLIMETERS
-ALL HOLES DRILLED 13/16" DIAMETER

Revision Date	Description
Checked	
Approved	

63 kV H - FRAME TANGENT WITH ALUMINUM PIPE ARM

Original - Design / Checked	Original - Approved	Date Created			Drawing Number	Sheet
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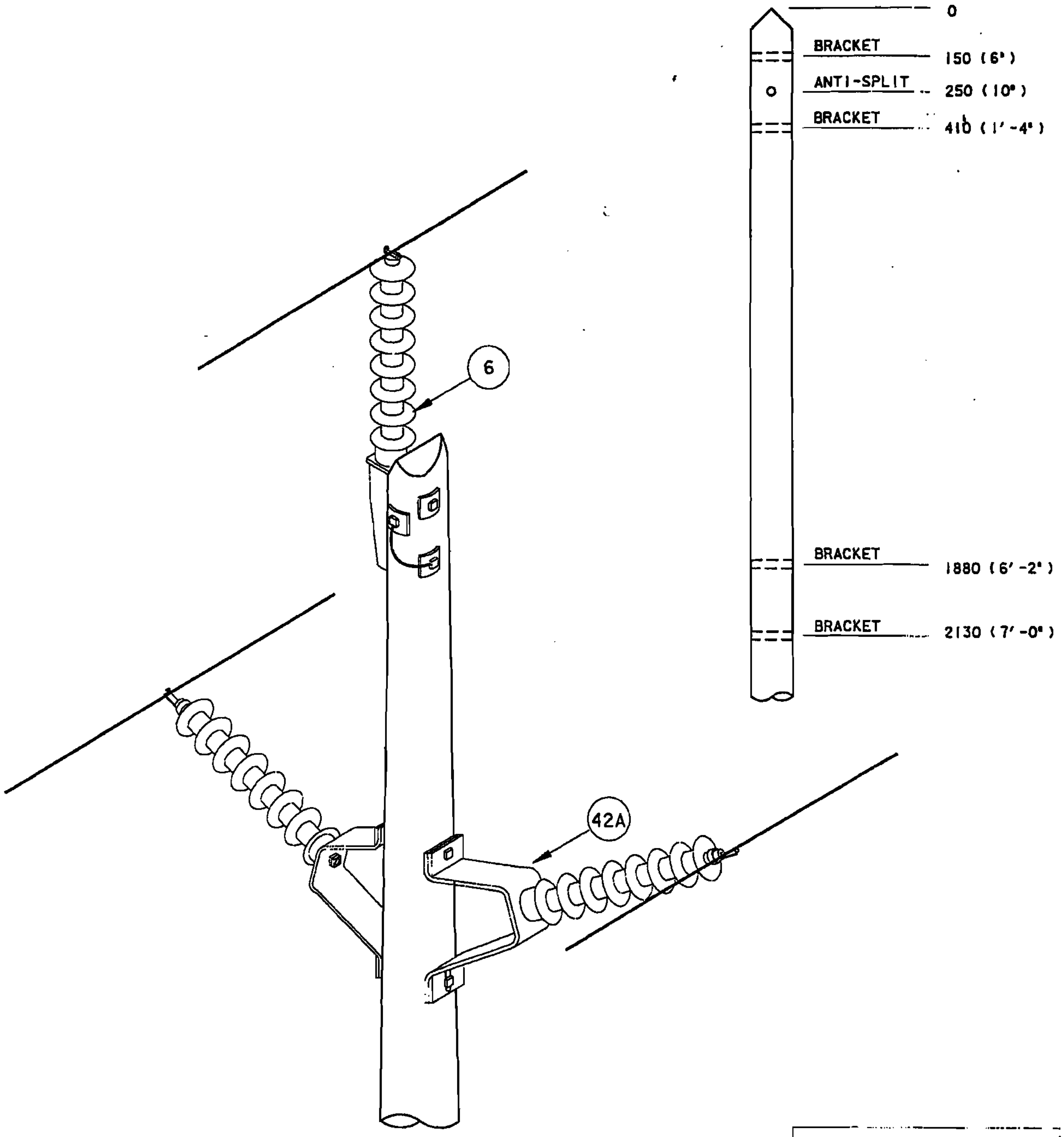

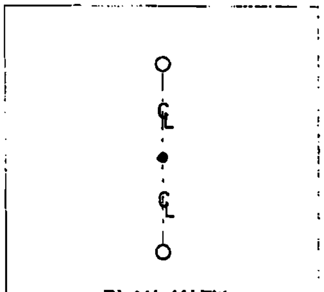

PLAN VIEW

NOTES:

1 - BOND ALL HARDWARE WITHIN 150mm (6") OF ONE ANOTHER

2 - UNLESS OTHERWISE SPECIFIED,
-ALL HOLES ARE DRILLED TO 13/16" DIAMETER
-ALL DIMENSIONS ARE IN MILLIMETRES

Description
Revision Date
Checked
Approved
Original Design / Checked
Original Approved
Date Created 03-09-17
NOT TO SCALE

63kV SINGLE POLE TANGENT DELTA CONFIGURATION

Aquila Networks Canada
Drawing Number 700-42176
Sheet 1 / 1

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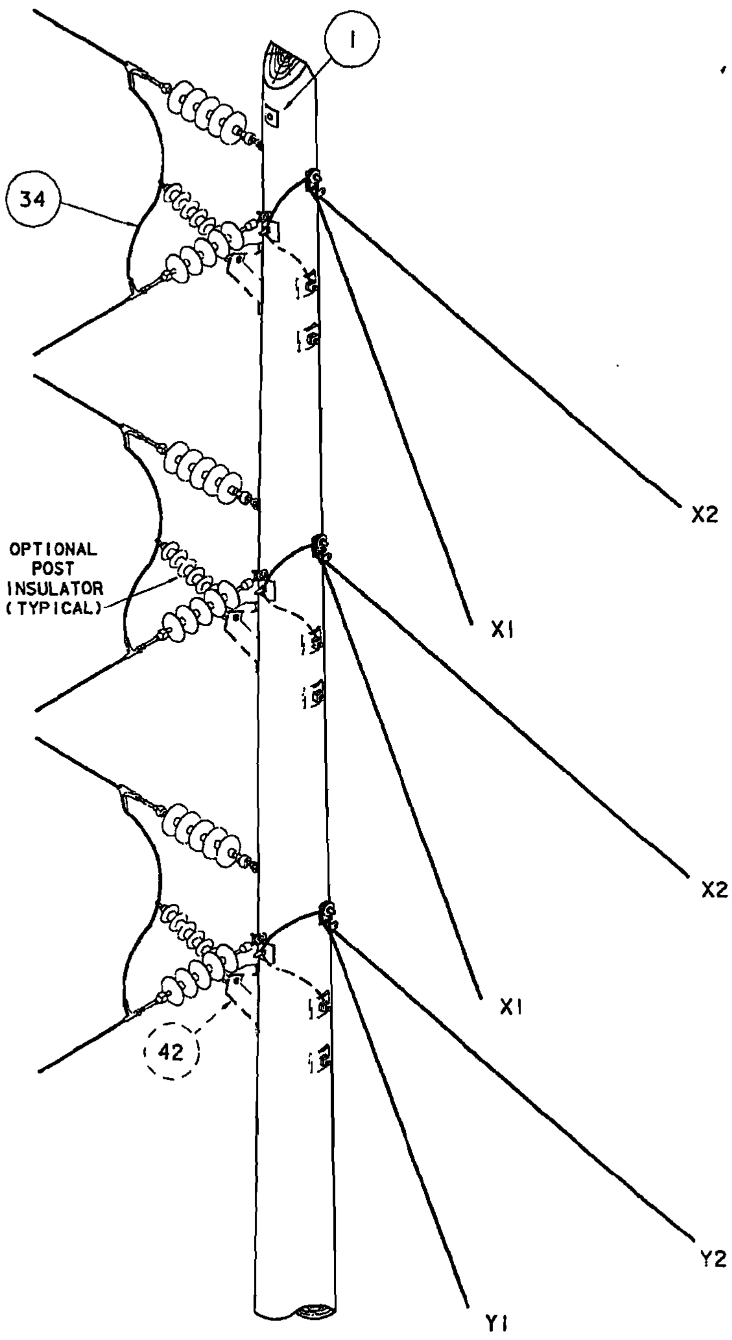
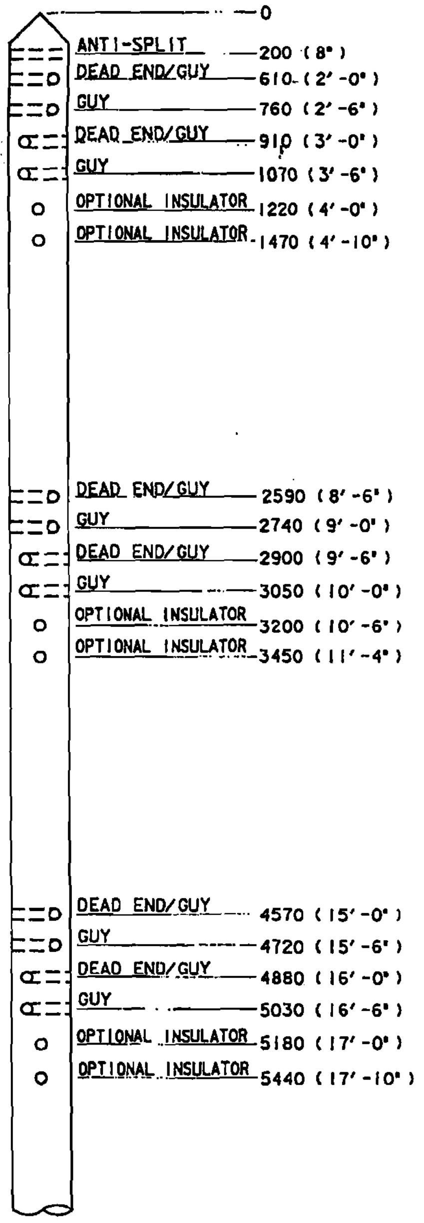
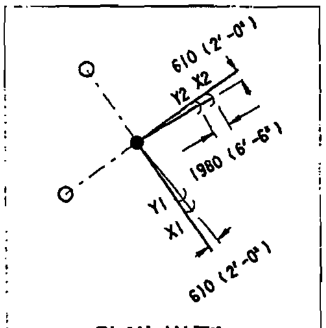




DRILLING DETAIL



PLAN VIEW

NOTE:

1 - BOND ALL METALLIC PARTS WITHIN 150mm (6") OF ONE ANOTHER

2 - THE STRUCTURE MAY NEED TO BE MODIFIED WITH A HORIZONTAL POST INSULATOR ON SHALLOW DEFLECTIONS (<45°)

3 - UNLESS OTHERWISE SPECIFIED,
- ALL HOLES ARE DRILLED TO 13/16" DIAMETER
- ALL DIMENSIONS ARE IN MILLIMETRES

4 - CHECK PHASE TO GUY CLEARANCE ON SHALLOW DEFLECTIONS

Revision Date	Description
Checked	
Approved	

63 kV SINGLE POLE VERTICAL DEAD END WITH DEFLECTION

Original Design / Checked	Original - Approved	Date Created			Drawing Number	Sheet
DS.	JV	03-11-26	NOT TO SCALE	Aquila Networks Canada	700-42410	1/1

DBS Energy Services

21L-24L Engineering Assessment Report

2008-07-24

Table of Contents

1. INTRODUCTION

This 21L through 24L engineering assessment was initiated as a result of concerns of the overall decayed state of these lines and the reliability to maintain supply between the river generation plants. This report is to bring a consolidated approach to the options and alternatives for rehabilitation/rebuild work of these circuits to achieve the best long term design solution. All four of these circuits (21L, 22L, 23L, and 24L) are 63kV circuits with single pole type structures and have considerably short span lengths; 3-pole structures are used in a few locations with longer spans. These lines are all built within the same corridor, which is for the most part on a steep side slope paralleling between Highway 3A and the CPR Railway tracks. This report is meant to provide assessment implications for possible risks of these lines and to provide a design review with construction estimates based on several options that may implemented. The design options that have been considered as detailed in this report include; rebuilding the existing circuits like-for-like and replacing structures as required, rebuilding on existing alignments with optimized span lengths, rebuilding 23L and 24L as a double circuit with 21L and 22L remaining as single circuits, and completely rebuilding 21L-24L with two high capacity lines.

There have been basically no attempts in the past to upgrade the overall status of these lines. The only work completed on these lines has been due to urgent replacements or to accommodate new circuit ties into the stations as part of the upgrades for the generation plants.

2. BACKGROUND

The 21L-24L circuits interconnect the FortisBC Kootenay River Generation Plants (Cora Linn, Upper Bonnington, Lower Bonnington, and South Slocan). These lines were originally installed in the early 1900's and have been re-constructed again in the 1940's to 1950's during expansion of the generation plants. The transmission conductors on all four lines are for the most part the original 300MCM Copper that was installed during the reconstruction of the lines. Limited re-conductoring of the 300MCM Copper has only occurred recently when new terminations were installed at each generation station and was re-conductored with either 477 AAC Cosmos or 1272 Narcissus.

The 21L 63kV circuit is approximately 1.5km in length and runs directly from Lower Bonnington to South Slocan. The 22L 63kV circuit is approximately 3.3km in length and runs directly from Upper Bonnington to South Slocan. The 23L 63kV circuit is approximately 4.9km in length and runs from Corra Linn to South Slocan with direct taps in Upper Bonnington and Lower Bonnington. The 24L 63kV circuit is approximately 4.9km and is a direct feed from Corra Linn to South Slocan. All four lines are located within the same right of way with circuit spacing of approximately 6m from centerline to centerline. The right of way corridor for the most part is accessible with minor road work required; however some structure locations will need extensive road work for access with a line truck. Also paralleling 21L-24L on the East side of the right of way is a single three phase 2300V distribution circuit used exclusively for station service.

The assessment data and design information that was available for this report includes the 21L-24L detailed line patrols/inspections completed by Arrow Installations crews in January of 2008, and pole test & treat data completed by Gilnockie in 2007 and 2008. The McElhanney survey data for 21L-24L was not available at the time of this report, but is currently underway and to be completed in 2008. The pole test and treat data has remained unreliable as the structure numbering and pole information does not consistently match-up with field data collected from the assessment patrols. The condition assessments were used for the basis behind the design review and estimating purposes. Original design and line information is non-existent in terms of structure and line information, as well as plan & profile drawings.

Generally, all four circuits can be considered in relatively poor condition with the majority of the poles from original 1950's vintage, and as a result, a large amount of the poles are stubbed or will require replacement within the next cycle.

A. Past Outages and Problems

The main concern for past outages on 21L-24L as seen from a structural point of view is that numerous arm burn-offs have occurred, which have been repaired by replacing the transmission arm and post insulators. These arm failures are most likely due to the aged condition of the insulation and structures.

In past years there have not been too many issues seen on 21L-24L circuits that would raise concerns with transmission outages, considering single circuit contingency on any one of these lines will not cause loading problems as the other three lines can easily pick-up the accompanying load of one circuit. If any two circuits experience an outage, there could be generation lost, but this is a less likely situation. The final overall design considerations for these lines must account for full capacity of the circuits during emergency circumstances.

B. Recent Works Completed

The only recent works completed on 21L-24L that have been documented are the upgrades to existing line facilities during re-terminations involved with the station upgrades at each generation plant. This engineering report pays close attention to the overall long term engineering design solution for the 21L-24L River lines while trying to incorporate the recent upgrades that have been completed, as listed below. A brief summary of more recent activities relating to 21L through 24L are listed below and presented generally in a chronological order:

- **Survey Data** – McElhanney is currently working on providing survey data for 21L-24L and is expected to be completed for 2008. The design survey was originally to be Lidar based, but has been changed to photogrammetric for timing issues.
- **21L-24L Condition Assessment and Patrols 2008** – This was a detailed line patrol completed by Arrow Installations crews. This assessment was to identify condition issues, line data, and facilities on these river lines. This was to drive future projected work that would be identified through engineering reviews.
- **Pole Test & Treat Program in 2007/2008** – This was completed by Gilnockie for all 21L-24L poles. The 22L-24L poles were tested in 2007 with follow-up testing completed on the 21L poles in 2008.
- **Arrow Experimental Survey Data 2007** – This was a pilot project to determine the accuracy of Arrow survey data. There were notable discrepancies with this survey information and it considered not accurate enough for design purposes.
- **21L-24L Re-terminations into South Slocan 2004** – This project was undertaken in 2004 and includes the re-termination of all four lines into the South Slocan Station. The new 22L and 23L ties were re-conductored with 477 AAC Cosmos.
- **22L and 23L Re-terminations into USS 2003** – This project included new 22L and 23L terminations into the new USS station and adjacent 22L and 23L structure replacements. These new ties into USS were reconductored with 1272 AAC Narcissus.
- **21L Re-terminations into Lower Bonnington 2003** – This project was undertaken in 2003 and includes the re-termination of 21L into LBO. The new 21L tie was re-conductored with 477 AAC Cosmos.

3. SUMMARY OF FINDINGS

The records from the original design are absent with ground profile drawings and structure lists missing for all 21L-24L circuits. Therefore, any changes or upgrades to these lines have not been documented throughout the years. Considering this lack of available line information for 21L-24L, it was decided that an extensive review be completed that would capture the missing data for these lines. The patrols and condition assessment records for all four lines were completed by Arrow Installations in January of 2008. These patrols had to be deemed accurate as there was no existing line data available for comparison and the pole test & treat data could not be relied upon for correct structure numbering. These condition assessments produced detailed information regarding the pole/structure, framing types, insulation, conductors, anchoring, and overall site information.

A. Structures

There are a considerable amount of original vintage structures on 21L-24L, and of those older structures a large amount have been stubbed for many years and even red tagged in some circumstances. All of these stubbed structures should be included as priority replacements and incorporated into the follow-up design. As shown in the 21L- 24L Condition Assessment Record Summary found in APPENDIX I, approximately one half of all the existing structures on 21L-24L are in need of priority replacement with the majority of the remaining structures nearing the end of their life cycle.

There is an abundance of wire transposition structures on each line, which for the most part utilize short spans (in the order of 30m) to transpose the wire with the center phase going flat to an arm on the adjacent structure. These multiple wire transposition structures are not necessary, and therefore could be eliminated if the circuit was to be rebuilt (assuming the phasing was matched at each station).

B. Insulation

The existing insulation on 21L-24L is a combination of mostly original vintage structures with the original porcelain type bell and pin insulators, as well as a small number of newer structures with synthetic type insulation. On the older porcelain insulation there is evidence that the porcelain glazing has deteriorated significantly due to the fact these insulators are nearing the end of their life span. This deterioration of the porcelain insulation has caused several arm burn-offs in recent years. There has been no evidence shown that the porcelain insulators on the 21L-24L circuits are from the Ohio Brass era that contained “cement growth” problems.

C. Conductor

The type of conductor strung on all 21L-24L circuits is predominantly 300MCM copper with small sections rebuilt to 477 AAC Cosmos and the new 23AL tap into USS reconductored with 1272 AAC Narcissus. There have been no significant issues with the 300MCM as outlined from the condition assessment patrols, only what could be expected for a 60+ year old conductor. For a rebuild situation of 21L-24L, a suitable replacement conductor for the 300MCM copper would be a 477MCM conductor (most likely 477 ACSR Pelican) or 1272 AAC Narcissus for larger capacity scenarios. The ampacity ratings for these conductors can be found in APPENDIX II.

D. Generation Load Flow

The maximum load that any one of these lines may experience is during contingency planning where one or more lines may be out of service. The total combined capacity of these lines must be able to handle the generation output of the three Generation River Plants north of South Slocan, which includes Corra Linn, Upper Bonnington (UBO), and Lower Bonnington (LBO). At the South Slocan station the load is then distributed out on various transmission lines. The maximum generation capacities of these three plants are shown in the table below.

Generation Plant	Total Capacity	Amps at 3Ø-66kV
Corra Linn	45MVA	394Amps
Upper Bonnington	64MVA	560Amps
Lower Bonnington	55MVA	481Amps
Total	**164MVA**	**1435Amps**

E. Terrain

The 21L thru 24L lines are located within the same right of way corridor for the majority. The existing right of way parallels between Highway 3A and the CPR Railway, which follows the Kootenay River. The right of way can be considered fairly rugged terrain with many structures located on steep side slopes and rocky areas. There are numerous existing structure locations that are rock holes and these structures will require additional excavation work when replacement of the pole is required.

Considering this type of rough terrain on 21L-24L, access to structure locations may be difficult. There is existing access roads to many pole locations, which still would require some minor road work. However, there are many structure locations with no apparent access, and creating an access road will require extensive work with particular attention to environmental concerns. The access to each structure location must be accounted for during design review and was included in the attached estimates.

F. Brushing

It would appear that the existing brushing program for 21L-24L has been generally quite effective through recent years as tree contacts has not been a significant source of outages on these lines. The condition assessment patrols and an engineering field review revealed that there are several sections where tree growth underneath the line should be addressed in the near future, as well as the removal of large danger trees outside of the R/W. A complete tree brushing of the 21L-24L is most likely due, as it appears that roughly 10 years ago was the last comprehensive brushing through this area (based on the existing tree growth of the right of way).

G. Station Capacities

At the time of release of this report, the substation capacities and particulars/details were not available.

4. DESIGN OPTIONS AND ESTIMATES

The assumptions used for the basis of this engineering review of 21L-24L have been derived from the assessment patrols completed in January of 2008 by Arrow Installations crew. The existing pole count and structure condition have been assumed from this data to determine urgent replacements and additional work required on these lines. Preliminary experimental survey data from Arrow Installations was used to determine the total number of new structures required for each option discussed below. It should be noted that there are notable discrepancies with this Arrow survey data, but the centerline profiles were assumed adequate for estimating purposes. More dependable survey data from McElhanney is to be provided in 2008 and shall be used for actual engineering design. The design options listed below are the most realistic choices for an overall long term plan of the 21L-24L circuits and are discussed in detail. The complete estimates, basis for structure costs, and single line diagrams pertaining to each individual option can be found in APPENDIX III, APPENDIX IV, and APPENDIX V, respectively.

A. Option 1: Replace 21L-24L Structures Like-For-Like

This option will re-use the existing 21L thru 24L alignments with the work required on the existing structures completed either on a priority basis or by replacing all original structures to new standards. The structures will be replaced like-for-like with similar framing configuration and pole sizes used; the total number of structures per line will remain approximately the same. Both alternatives will make use of the existing structures that have been upgraded in recent years, as well as re-using the existing 300MCM Copper conductor. Construction wise, this option is favorable as the circuit being worked on can be de-energized for a lengthy period of time with the remaining river lines carrying the additional load (energized circuits are expected to have reclose blocking during construction). This option is also favorable as it will have contingency for multiple line outages due to the redundancy of the circuits.

i. Priority Repairs Only

By only attending to the 21L-24L urgent issues as they arise, the initial repair costs and the additional rehabilitation work will remain lower on a per year basis. There are approximately 100 priority structures to be replaced within the next year, and another 100 structures that will need to be replaced in the foreseeable future (approximately 10-15 years). Although the total number of structure replacements is higher for this option, the total estimate will be cost effective as half the structures can be replaced at a later date. Also the 300MCM Copper conductor is to be re-used for this option saving money on new conductor and stringing costs. The existing 300MCM Copper has shown no deficiency issues as outlined from the assessment patrols.

ii. Replacement of all Original Structures

This option would not be the most cost effective solution, as not all older structures necessarily need to be replaced with the next year. Approximately 100 older structures are currently not tagged to be stubbed and most likely still have a minimum life span of 10-15 years remaining. By not replacing these older structures until absolutely necessary, there will be a cost savings carrying forward, making Option 1(i) the more logical approach. In addition, the cost of completely replacing all of the original vintage structures like-for-like on 21L-24L will have a substantial premium opposed to optimizing the span lengths (Option 2). The overall cost (as shown in the estimates) does not reflect this premium, as Option 1 is estimated with the original 300MCM Copper conductor and the remaining options are estimated with the lines completely reconductored. This option will allow for the pole sizes to remain quite low, but the overall immediate structure change outs will be considerably higher than the remaining options, making the rebuild cost unnecessarily high.

B. Option 2: Replace 21L-24L on Existing Alignments with Optimized Span Lengths

This option is similar to Option 1 with the existing 21L-24L alignments to be re-used (see APPENDIX V). The main difference from Option 1 is that the total number of new structures installed would be drastically reduced with the span lengths increased and optimized for structure locations. The existing structures that have been replaced recently would be re-used where possible with all original vintage structures removed and/or replaced (assumed all structures were replaced for estimating purposes). Unlike Option 1, the existing 300MCM Copper conductor is estimated as being reconductored with a corresponding 477MCM conductor (typically 477 ACSR Pelican) that has a similar ampacity rating, see APPENDIX II.

Construction could be completed with one circuit de-energized and rebuilt with the remaining lines carrying the additional load. The typical 63kV structure types for this option would be single pole tangent and light angle structure framed with vertical post insulators, and heavy angle and dead end structures framed as vertical. The span lengths and new structure locations were based on allowable 63kV phase and circuit spacing for the framing types mentioned, and the preliminary centerline profile for ground clearance and uplift concerns.

The cost saving for optimizing the span lengths is not initially evident with the estimates provided. With only around 50 less structures than Option 1, this saving on structure replacements is overshadowed by the cost of new conductor and stringing. Note that the 300MCM Copper conductor does not necessarily need to be replaced, but should be reconductored if the lines were to be completely rebuilt.

C. Option 3: Replace 21L-24L with 23L/24 Double Circuit and 21L/22L Single Circuits

This option consists of double circuiting 23L and 24L for the entire length from South Slocan station to Corra Linn, and rebuilding 21L and 22L with single circuit structures on the existing alignments (see APPENDIX V). It was not advantageous to double circuit 21L and 22L as these two circuits only parallel for a very short length. This option requires that virtually all the existing structures be replaced (newly rebuilt tie sections into the plants can be re-used) and the 300MCM copper reconductored with 477 ACSR Pelican. This option requires that the 300MCM Copper be reconductored for ease of construction when rebuilding with double circuit structures. The typical 63kV structure types for this option would be double circuit tangent and light angle structure framed with back-to-back horizontal post insulators, and dead ends framed as two single pole verticals. The single circuit structures used would be similar to Option 1 and Option 2. The span lengths and new structure locations were based on the allowable 63kV circuit and phase and circuit spacing for the framing types mentioned, and the ground profile for clearance and uplift concerns.

The new alignment for the double circuit would have to be constructed on the existing 24L centerline, with 24L de-energized during construction of the new poles and 23L most likely with reclose blocking. This would allow for the new 23L/24L double circuits to be constructed with only one circuit de-energized, and the 23L station taps can be transferred over (with 23L de-energized) to the double circuit structures once 24L is re-energized. Construction for these double circuit structures will be more difficult than the other options due to the proximity of adjacent circuits and transferring of the lines. The construction of 21L and 22L would be done in a similar fashion as Option 1 and Option 2 with one circuit de-energized and rebuilt with the remaining three lines carrying the additional load.

This option also makes FortisBC more susceptible to a lengthy outage between Corra Linn and Upper Bonnington due to a single pole failure on any one of the 23L/24L double circuit structures in this section. If a pole failure was to occur on this section of line, the associated outage would result in generation lost from Corra Linn. However, it may be possible to back-up this section of line with 27L and 28L via the Nelson station.

D. Option 4: Replace 21L-24L with Two High Capacity Circuits

This option would require the replacement of virtually all existing 21L-24L structures (including newer structures) with two new high capacity lines. One of these circuits (shown as 24L) would be a direct express feed from Corra Linn to South Slocan and the other circuits would feed from Corra Linn to South Slocan with in/out taps of LBO and UBO (see APPENDIX V). The 300MCM copper would need to be reconductored with single 1272 AAC Narcissus conductor, or a conductor with similar specifications and ampacity rating. The 1272 Narcissus would be able to handle the current maximum capacity of Corra Linn, LBO, and UBO under contingency loading criteria with the conductor temperature allowed to reach up to 120°C for short term. The ampacity rating for the 1272 AAC Narcissus at 120°C is 1464 amps compared to the maximum 1435 amps produced by the river plants. The ampacity rating and the criteria used for the ampacity calculations of 1272 Narcissus at 100°C and 120°C can be found in APPENDX II.

The typical 63kV structure types for this option would be tangent and light angle structure framed with vertical post insulators, and dead ends framed as single pole verticals. Modifications would need to be done to these structure types to allow for the increased capacity needed for a larger conductor like the 1272 AAC Narcissus. The span lengths and new structure locations were based on the allowable 63kV circuit and phase spacing for the framing types mentioned, and the ground profile for clearance and uplift concerns. The poles used in this estimated design would typically need to be a higher class pole than the previous options to allow for the additional capacity required for the larger diameter/strength of the 1272 conductor.

These two new high capacity circuits could be constructed on existing alignments with only taking an outage on one of the existing 21L-24L circuits at a time during construction of that section. The new express feed from Corra Linn to South Slocan could be rebuilt on the existing 24L alignment and should be rebuilt after the other high capacity line is completed and operational. The single line diagram for this option can be found in APPENDIX V.

The drawback to replacing the existing 21L-24L with only two circuits is that there will only be single contingency between the River Plants. In the unlikely event that both high capacity circuits were to go down, then all generation from Corra Linn, UBO, and LBO could be lost.

There are also concerns that the existing station equipment, specifically the circuit breakers and switches, will not be able to support the required 1435 amps for contingency planning. It is believed that the existing station equipment is rated for 2000 amps, and therefore was not included in the estimate. At the time of this report, the station equipment and capacities could not be confirmed. If any additional work is required to the existing station configuration, the overall cost for this option would drastically increase to the point where this option would not be favorable.

E. Comparison Summary of Options

The following table is a summary of each option discussed in this section and details pertaining to the risks and benefits.

Design Option	Pros	Cons	Total Estimate
Option 1i – Replace Like for Like (Priorities Only)	• Pole size can be smaller • Initial cost is low • Rebuild/budget across several years • Outages are not a concern for ease of construction • Multiple ccts for contingency	• Circuits will still have old strs with shortened lifespan remaining • O&M str failures are more likely • Additional O&M will continue	$1.49M
Option 1ii – Replace Like for Like (All Original Strs)	• Pole size can be smaller • Outages are not a concern for ease of construction • Multiple ccts for contingency • Reduced immediate O&M dollars needed	• Not cost effective • High str replacements	$2.83M
Option 2 – Replace on Existing Alignments with Optimized Span Lengths	• Total strs are lower than Option 1i and 1ii • Outages are not a concern for ease of construction • Multiple ccts for contingency • Reduced immediate O&M dollars needed	• Outages will be lengthy during construction	$2.88M
Option 3 – Replace with 23L/24L Double Circuit & 21L/22L Single Circuits	• Total number of strs is low in comparison • Reduced immediate O&M dollars needed	• Taller poles required • Construction is difficult • Increased risk of common mode outages between Corra Linn and UBO	$2.74M
Option 4 – Replace with Two High Capacity Circuits	• Total number of strs is low in comparison • Cleanest overall configuration • Lower str overall maintenance • Reduced immediate O&M dollars needed	• Single contingency • Larger conductor needed • Added pole strength needed • Possible work required at stations for increased capacity • Increased risk of common mode outages	$2.90M

5. RECOMMENDATIONS

The final configuration of the 21L-24L circuits must be able to provide a reliable supply for the maximum loads from the river generation plants, while still providing adequate contingency planning for emergency situations. Based on the estimates for each option, replacing the structures like-for-like on a priority basis (Option 1(i)) appears to be the most probable solution. From an engineering perspective and judgment, a more ideal option would be for a complete rebuild of the 21L-24L lines, unfortunately the estimates just do not support this desire. Option 1(i) is the best selection as it provides more than adequate circuit redundancy for backup, and by replacing all the priority structures (approximately 100) the state of the lines will be in a more reliable state. There have not been many outages of large volume for O&M work in recent years and with the replacement of all poorly rated structures this will only get better. Overall Option 1(i) will also be the most cost effective of all the options, based on the present valuing of the remaining structure change-outs (approximately 100) needed in 10-15 years or more. The existing 300MCM Copper is also not a concern as there have been no issues raised about its condition and there are still many years remaining in its lifespan.

There are several sections where tree growth underneath the line will need to be addressed in the near future, as well as possible danger trees outside of the right of way. Taking into consideration the narrow corridor for 21L-24L, it is recommended that the existing right of way be completely brushed out with the removal of any potential danger trees. This brushing is independent of the options considered and has been included in each of the estimates provided.

The tracking of line records on 21L-24L has been virtually non-existent throughout the years. It is recommended that new line records be produced upon rehab/rebuild of these lines. These records should include structure lists, sag/tension data, plan and profile drawings, structure drawings with framing details, pictures of each structure location, and computerized model of the lines. This data can be accumulated from the recent condition assessment records, new 21L-24L designs, and the survey data being completed by McElhanney. A complete survey plan for 21L-24L has been contracted through McElhanney Land Surveying to provide ground elevations along centerline and right of ways, conductor heights to be used for sag/tension information, pole and anchoring locations, crossing information, and legal plans. McElhanney will be using aerial photogrammetry to provide all survey information. The survey data from McElhanney will be provided in the form of a PLS CADD bak file.

APPENDIX I – 21L-24L CONDITION ASSESSMENT SUMMARY

APPENDIX I - 21L CONDITION ASSESSMENT RECORD SUMMARY

GOOD - Structure is in fair or better condition and does not require replacing immediately.
STUBBED - Structure is stubbed OR marked to be stubbed and should be replaced.
REPLACE - Structure is not stubbed, but should be replaced for various reasons. (i.e. low clearance, poor arm or pole condition)

	POLE VINTAGE		GOOD				STUBBED				REPLACE					
Structure Number	Assess. Records	Test & Treat	TAN	ANG Flat	ANG Vert	DDE	TAN	ANG Flat	ANG Vert	DDE	TAN	ANG Flat	ANG Vert	DDE	Tx Conductor	Comments
21L Sub															477? AAC	
1	1999					1									300MCM Cu	
2	0										1				300MCM Cu	
3	0		1												300MCM Cu	
4	0						1								300MCM Cu	
5	0			1											300MCM Cu	No guy guard
6	0			1											300MCM Cu	
7	0										1				300MCM Cu	Wire transpose on long span (~90m)
8	0										1				300MCM Cu	Wire transpose on long span (~90m)
9	0											1			300MCM Cu	Pole in poor condition, WP holes bad
10	0			1											300MCM Cu	
11	0										1				300MCM Cu	
12	0											1			300MCM Cu	Pole in poor condition, WP holes
13	0											1			300MCM Cu	Pole in poor condition, WP holes, Dbl arm
14	0		1												300MCM Cu	Dbl arm
15	0		1												300MCM Cu	
16	0			1											300MCM Cu	CØ Insul bottom skirt broken, Dbl arm
17	0						1								300MCM Cu	
18	0		1												300MCM Cu	
19	0		1												300MCM Cu	Wire transpose
20	0		1												300MCM Cu	
21	0		1												300MCM Cu	
22	0					1									300MCM Cu	Inline DDE, Dbl arm
23	0										1				300MCM Cu	
23A	0										1				300MCM Cu	Pole in poor condition
24	0		1												300MCM Cu	
25	0					1									300MCM Cu	2x Bells broken, Low clr to fiber
26	0										1				300MCM Cu	
27	0					1									300MCM Cu	
28	2002		1												300MCM Cu	
29	2002			1											300MCM Cu	
30	2002					1									300MCM Cu	
		TOTAL →	**9**	**5**	**0**	**5**	**2**	**0**	**0**	**0**	**7**	**3**	**0**	**0**		
		SUM →	**19**				**2**				**10**					

APPENDIX I - 22L CONDITION ASSESSMENT RECORD SUMMARY

GOOD - Structure is in fair or better condition and does not require replacing immediately.
STUBBED - Structure is stubbed OR marked to be stubbed and should be replaced.
REPLACE - Structure is not stubbed, but should be replaced for various reasons. (i.e. low clearance, poor arm or pole condition)

	POLE VINTAGE		GOOD				STUBBED				REPLACE					
Structure Number	**Assess. Records**	**Test & Treat**	**TAN**	**ANG Flat**	**ANG Vert**	**DDE**	**TAN**	**ANG Flat**	**ANG Vert**	**DDE**	**TAN**	**ANG Flat**	**ANG Vert**	**DDE**	**Tx Conductor**	**Comments**
22L Sub															477 AAC	
1	2003					1									477 AAC	Dbl arm
2	2003					1									477 AAC	
3	2003		1												477 AAC	Dx crossing
4	2002					1									300MCM Cu	Inline DDE, Dbl arm
5	0						1								300MCM Cu	
6	0							1							300MCM Cu	Dbl arm
7	0						1								300MCM Cu	
8	0		1												300MCM Cu	
9	0						1								300MCM Cu	
10	0				1										300MCM Cu	Dbl insul on each phase
11	0						1								300MCM Cu	
12	0						1								300MCM Cu	Dbl arm
13	0						1								300MCM Cu	Wire Transpose
14	0		1												300MCM Cu	
15	0					1									300MCM Cu	3-Pole DDE, Missing guy guards, loose guys
16	0		1												300MCM Cu	
17	0				1										300MCM Cu	
18	0									1					300MCM Cu	3-Pole DDE (1-pole stubbed)
19	0						1								300MCM Cu	
20	0						1								300MCM Cu	
21	0						1								300MCM Cu	Blue tagged
22	0						1								300MCM Cu	Red tagged
23	0		1												300MCM Cu	
24	0						1								300MCM Cu	Red tagged
25	0										1				300MCM Cu	Pole top poor
26	0		1												300MCM Cu	
27	0				1										300MCM Cu	Missing guy guards
28	1999					1									300MCM Cu	Missing guy guards, No jumper posts (23°)
29	0						1								300MCM Cu	Rail Crossing
30	0					1									300MCM Cu	No jumper posts (45°)
31	0			1											300MCM Cu	Dbl arm, Rockset
32	0			1											300MCM Cu	Dbl arm, Missing guy guard
33	0		1												300MCM Cu	Dbl arm
34	0		1												300MCM Cu	
35	0			1											300MCM Cu	Dbl arm
36	0										1				300MCM Cu	Replace str (Arm in poor condition)
37	0										1				300MCM Cu	Pole top poor
38	0						1								300MCM Cu	Blue tagged (to be stubbed)
39	0						1								300MCM Cu	
40	0						1								300MCM Cu	Blue tagged (to be stubbed), Wire transpose
41	0		1												300MCM Cu	
42	0		1												300MCM Cu	
43	0										1				300MCM Cu	Replace str (Arm in poor condition)
44	0									1					300MCM Cu	Urgent replace
45	0							1							300MCM Cu	
46	0							1							300MCM Cu	
47	0											1			300MCM Cu	Replace str (Old insul, Fiber gnd clr)
48	2002					1									477 AAC	
49	2005					1									477 AAC	DDE on Dbl arm
		TOTAL →	**10**	**3**	**3**	**8**	**15**	**3**	**0**	**2**	**4**	**1**	**0**	**0**		
		SUM →	**24**				**20**				**5**					

APPENDIX I - 23L CONDITION ASSESSMENT RECORD SUMMARY

GOOD - Structure is in fair or better condition and does not require replacing immediately.
STUBBED - Structure is stubbed OR marked to be stubbed and should be replaced.
REPLACE - Structure is not stubbed, but should be replaced for various reasons. (i.e. low clearance, poor arm or pole condition)

	POLE VINTAGE		GOOD				STUBBED				REPLACE					
Structure Number	Assess. Records	Test & Treat	TAN	ANG Flat	ANG Vert	DDE	TAN	ANG Flat	ANG Vert	DDE	TAN	ANG Flat	ANG Vert	DDE	Tx Conductor	Comments
23L Sub																
1	0		1												300MCM Cu	Rail crossing
2	0									1					300MCM Cu	
3	0						1								300MCM Cu	
4	0						1								300MCM Cu	Urgent repair
5	0						1								300MCM Cu	
6	0						1								300MCM Cu	Dx crossing
7	0						1								300MCM Cu	
8	1999		1												300MCM Cu	
9	1999		1												300MCM Cu	
10	1999		1												300MCM Cu	
11	0						1								300MCM Cu	
12	0						1								300MCM Cu	
13	0						1								300MCM Cu	
14	0		1												300MCM Cu	
15	1996				1										300MCM Cu	
16	1994				1										300MCM Cu	
17	0						1								300MCM Cu	Red tagged
18	0		1												300MCM Cu	Dx DDE (u/b fore span)
19	0		1												300MCM Cu	Dx DDE (u/b back span)
20	0						1								300MCM Cu	
21	1999		1												300MCM Cu	
22	0				1										300MCM Cu	Newer str
23	0								1						300MCM Cu	
24	0		1												300MCM Cu	Wire transpose
25	2003		1												300MCM Cu	Tap into USS on 23AL (1272 AAC)
23AL1	2003					1									1272 AAC	Tap into USS Bay
26	2003		1												300MCM Cu	Dx DDE crossing, Remove old pole
27	0			1											300MCM Cu	Newer str
28	0					1									300MCM Cu	Newer str, Inline vert DDE, Wire transpose
29															300MCM Cu	NO STRUCTURE
30															300MCM Cu	NO STRUCTURE
31	0						1								300MCM Cu	
32	0			1											300MCM Cu	Dbl arm, No guy guard
33	0		1												300MCM Cu	
34	0		1												300MCM Cu	
35	0						1								300MCM Cu	
36	0				1										300MCM Cu	Dbl insul per phase
37	0						1								300MCM Cu	
38	0						1								300MCM Cu	Dbl arm
39	0		1												300MCM Cu	Wire transpose
40	0		1												300MCM Cu	
41	0									1					300MCM Cu	3-Pole DDE (2-poles stubbed), Guys loose
42	0		1												300MCM Cu	
43	0				1										300MCM Cu	
44	0		1												300MCM Cu	
45	0										1				300MCM Cu	Pole top poor, DE tap into Lower Bonn
46 Tap	0						1								300MCM Cu	Str is on tap alignment, Back anchored?
47 Tap	0					1									300MCM Cu	Str is on tap alignment, Tap into Bay
48	0					1									300MCM Cu	3-Pole DDE, Missing guy guard
49	0						1								300MCM Cu	
50	0						1								300MCM Cu	
51	0		1												300MCM Cu	
52	0		1												300MCM Cu	
53	0		1												300MCM Cu	
54	0		1												300MCM Cu	
55	0						1								300MCM Cu	
56	0		1												300MCM Cu	
57	0				1										300MCM Cu	
58	0													1	300MCM Cu	Pole top poor, No jumper posts (~24°)
59	0		1												300MCM Cu	Rail crossing, Dbl arm
60	0													1	300MCM Cu	Pole top poor, No jumper posts (~45°)
61	0											1			300MCM Cu	Pole in poor condition
62	0			1											300MCM Cu	Dbl arm, Missing guy guard
63	0		1												300MCM Cu	Dbl arm
64	0		1												300MCM Cu	
65	0			1											300MCM Cu	Dbl arm, Loose guys, Missing guy guard
66	0		1												300MCM Cu	
67	0		1												300MCM Cu	
68	0						1								300MCM Cu	
69	0										1				300MCM Cu	Pole top poor, Wire transpose
70	0		1												300MCM Cu	
71	0										1				300MCM Cu	Pole top poor
72	0										1				300MCM Cu	Pole in poor condition, Anchored?
73	0		1												300MCM Cu	
74	0					1									300MCM Cu	Flat DDE, NØ bell broken, Missing guy guard
75	0											1			300MCM Cu	Pole in poor condition, Dbl arm
76	0											1			300MCM Cu	Pole in poor condition
77	0						1								300MCM Cu	Blue tagged (to be stubbed)
78	2001					1									477 AAC	
79	2001					1									477 AAC	Flat DDE
		TOTAL →	29	4	6	7	20	0	1	2	4	3	0	2		
		SUM →	46				23				9					

APPENDIX I - 24L CONDITION ASSESSMENT RECORD SUMMARY

GOOD - Structure is in fair or better condition and does not require replacing immediately.
STUBBED - Structure is stubbed OR marked to be stubbed and should be replaced.
REPLACE - Structure is not stubbed, but should be replaced for various reasons. (i.e. low clearance, poor arm or pole condition)

	POLE VINTAGE		GOOD				STUBBED				REPLACE					
Structure Number	Assess. Records	Test & Treat	TAN	ANG Flat	ANG Vert	DDE	TAN	ANG Flat	ANG Vert	DDE	TAN	ANG Flat	ANG Vert	DDE	Tx Conductor	Comments
24L Sub																
1	0						1								300MCM Cu	Rail crossing, Wire transpose
2	0		1												300MCM Cu	
3	2000		1												300MCM Cu	
4	0									1					300MCM Cu	2x Bells broken, Missing guy guards
5	1999		1												300MCM Cu	
6	0										1				300MCM Cu	Pole in poor condition, Dx crossing
7															300MCM Cu	NO STRUCTURE
8	1999		1												300MCM Cu	
9	0		1												300MCM Cu	
10	0						1								300MCM Cu	Red tagged
11	1999		1												300MCM Cu	
12	1999		1												300MCM Cu	
13	0						1								300MCM Cu	
14	0						1								300MCM Cu	
15	1999		1												300MCM Cu	
16	1999		1												300MCM Cu	
17	0								1						300MCM Cu	
18	0								1						300MCM Cu	
19	0						1								300MCM Cu	
20	1999		1												300MCM Cu	Wire transpose
21	0						1								300MCM Cu	
22	0		1												300MCM Cu	Dx crossing (uplift)
23	0		1												300MCM Cu	
24	1999		1												300MCM Cu	
25	0				1										300MCM Cu	Newer str
26	0								1						300MCM Cu	
27	0							1							300MCM Cu	
28	0						1								300MCM Cu	Dx arm (unused)
29	0		1												300MCM Cu	Wire transpose
30	0						1								300MCM Cu	
31	0			1											300MCM Cu	Brushing required
32	0			1											300MCM Cu	
33	0							1							300MCM Cu	Red tagged
34	0						1								300MCM Cu	
35	0		1												300MCM Cu	
36	0						1								300MCM Cu	
37	0				1										300MCM Cu	Dbl insul, Missing guy guards
38	0						1								300MCM Cu	
39	0						1								300MCM Cu	Dbl arm
40	0		1												300MCM Cu	Wire transpose
41	0		1												300MCM Cu	Tighten hardware
42	0					1									300MCM Cu	3-Pole DDE, Guys loose
43	0		1												300MCM Cu	
44	0				1										300MCM Cu	Anchored to pole
45	0		1												300MCM Cu	
46	0									1					300MCM Cu	3-Pole DDE, (1-pole stubbed), Guys loose
47	0						1								300MCM Cu	
48	0						1								300MCM Cu	
49	0						1								300MCM Cu	
50	0						1								300MCM Cu	
51	0						1								300MCM Cu	
52	0		1												300MCM Cu	
53	0						1								300MCM Cu	
54	0		1												300MCM Cu	
55	0				1										300MCM Cu	Missing guy guards
56	0					1									300MCM Cu	No jumper posts (~28°)
57	0		1												300MCM Cu	Rail crossing, Dbl arm
58	0					1									300MCM Cu	No jumper posts (~45°)
59	0			1											300MCM Cu	
60	0			1											300MCM Cu	Dbl arm, Missing guy guards
61	0		1												300MCM Cu	Dbl arm
62	0		1												300MCM Cu	
63	0			1											300MCM Cu	Dbl arm
64	0										1				300MCM Cu	Pole and arms in poor condition, Dbl arm
65	0						1								300MCM Cu	Red tagged
66	0						1								300MCM Cu	
67	0						1								300MCM Cu	Wire transpose
68	0						1								300MCM Cu	
69	0						1								300MCM Cu	
70	0							1							300MCM Cu	
71	0					1									300MCM Cu	Floating DDE, Remove xfmr, Broken bells
72	0								1						300MCM Cu	Dbl insul, Missing guy guards
73	0							1							300MCM Cu	Dbl arm
74	0						1								300MCM Cu	
75	1999		1												300MCM Cu	
76	2002					1									300MCM Cu	Wire transpose, Missing guy guards
77	0					1									300MCM Cu	Newer pole, Flat DDE
		TOTAL →	**25**	**5**	**4**	**6**	**24**	**4**	**4**	**2**	**2**	**0**	**0**	**0**		
		SUM →	**40**				**34**				**2**					

APPENDIX II – CONDUCTOR AMPACITY RATINGS

APPENDIX II – AMPACITY RATING FOR 300 kcmil, 19 Strand, HD Copper

```
Construction Information:                        Calculation Conditions:
Construction:                Single              Ambient:             40°C
Overall diameter:            0.6285 in.          Wind:                2.0 FPS
Trap Wire Type:              N/A                 Wind Angle:          90°
Trap Wire Layers:            N/A
                                                 Coef of Emissivity:  0.6
Copper Info:                                     Coef of Absorption:  0.8
Material:                    HD Copper           Atmosphere:          Clear
Conductivity:                96.2% IACS
Number of strands:           19                  Local Time:          14:00 Hrs
Strand Diameter:             0.1257 in.          Date for Local Time: Jun.  10
Diameter over Copper:        0.6285 in.
                                                 North Latitude:      49°
Core Information:                                Azimuth of Line:     0°  (N-S)
Material:                    Homogeneous         Altitude:            2000 ft.
Conductivity:                N/A
Number of strands:           N/A
Strand diameter:             N/A
Core diameter:               N/A

Resistance Information:
Reference Low Temperature:   25°C
Reference Low Resistance:    0.1988  Ohms/mi
Reference High Temperature:  75°C
Reference High Resistance:   0.2353  Ohms/mi


    Given a maximum steady state temperature of: 100°C (212°F)
    The steady-state current rating is:          635 amperes

    Loss Variables:
         Qs:       3.84   Watts/ft
         Qc:       18.10  Watts/ft
         Qr:       5.08   Watts/ft
         Rac:      0.2536 Ohms/mi
```

APPENDIX II - AMPACITY RATING FOR 477.0 kcmil, 18/1, ACSR "Pelican"

```
Construction Information:                      Calculation Conditions:
Construction:              Single              Ambient:              40°C
Overall diameter:          0.814 in.           Wind:                 2.0 FPS
Trap Wire Type:            N/A                 Wind Angle:           90°
Trap Wire Layers:          N/A
                                               Coef of Emissivity:   0.6
Aluminum Info:                                 Coef of Absorption:   0.8
Material:                  1350 Al.            Atmosphere:           Clear
Conductivity:              61.2% IACS
Number of strands:         18                  Local Time:           14:00 Hrs
Strand Diameter:           0.1628 in.          Date for Local Time:  Jun.  10
Diameter over Aluminum:    0.814 in.
                                               North Latitude:       49°
Core Information:                              Azimuth of Line:      0°  (N-S)
Material:                  Coated Steel        Altitude:             2000 ft.
Conductivity:              8% IACS
Number of strands:         1
Strand diameter:           0.1628 in.
Core diameter:             0.1628 in.

Resistance Information:
Reference Low Temperature:   25°C
Reference Low Resistance:    0.1950  Ohms/mi
Reference High Temperature:  75°C
Reference High Resistance:   0.2331  Ohms/mi


    Given a maximum steady state temperature of: 100°C (212°F)
    The steady-state current rating is:          682 amperes

    Loss Variables:
         Qs:       4.97   Watts/ft
         Qc:       20.63  Watts/ft
         Qr:       6.58   Watts/ft
         Rac:      0.2522 Ohms/mi
```

Appendix II - AMPACITY RATING FOR 1272 kcmil, 61 Strand, AAC "Narcissus"

```
Construction Information:                       Calculation Conditions:
Construction:             Single                Ambient:             40°C
Overall diameter:         1.3 in.               Wind:                2.0 FPS
Trap Wire Type:           N/A                   Wind Angle:          90°
Trap Wire Layers:         N/A
                                                Coef of Emissivity:  0.6
Aluminum Info:                                  Coef of Absorption:  0.8
Material:                 1350 Al.              Atmosphere:          Clear
Conductivity:             61.2% IACS
Number of strands:        61                    Local Time:          14:00 Hrs
Strand Diameter:          0.1444 in.            Date for Local Time: Jun.  10
Diameter over Aluminum:   1.300 in.
                                                North Latitude:      49°
Core Information:                               Azimuth of Line:     0°  (N-S)
Material:                 Homogeneous           Altitude:            2000 ft.
Conductivity:             N/A
Number of strands:        N/A
Strand diameter:          N/A
Core diameter:            N/A

Resistance Information:
Reference Low Temperature:   25°C
Reference Low Resistance:    0.0772  Ohms/mi
Reference High Temperature:  75°C
Reference High Resistance:   0.0912  Ohms/mi


    Given a maximum steady state temperature of: 100°C (212°F)
    The steady-state current rating is:          1243 amperes


    Given a maximum steady state temperature of: 120°C (248°F)
    The steady-state current rating is:          1466 amperes

    Loss Variables:
         Qs:       7.94   Watts/ft
         Qc:       34.87  Watts/ft
         Qr:       15.35  Watts/ft
         Rac:      0.1038 Ohms/mi
```

APPENDIX III – 21L-24L PRELIMINARY ESTIMATES

APPENDIX III - PRELIMINARY ESTIMATES FOR OPTION 1i

This option includes only the replacement of priority/urgent structures with the remaining structures to stay as-is. Costs include loaded labor and equipment rates, but do not include special FortisBC Capitalized Overhead Loadings or AFUDC. Costs for Project Management, Engineering, Material Loads, and Flagging are all included in the overall cost of each structure type. Extra costs have been provided for possible rock/blast sites and has been assumed for one third of all new structures. Any costs for surveying of R/W and land has been assumed budgeted under a seperate project. Complete brushing of the entire R/W length (approx 5km) has been assumed and accounted for. Extensive road work is required for access to some structure sites and has been included based on the number of new structure sites. All rebuilds have been assumed with the Tx circuit de-energized and the remaining Tx circuits energized and providing backup. It has been assumed that all work is to be done during snow free conditions. This estimate uses a structure-by-structure basis for replacements with the existing 300MCM Copper conductor to be re-used. The structures replacement costs are typically based on 50/1 poles with standard 63kV framing types. The quantity for structure change outs and refurbishments were based on the condition assessment patrols completed by Arrow in January of 2008 and placement of new poles were based on the preliminary survey data that was provided by Arrow Installations in 2007. Ground clearances have been assumed to meet CSA Code requirements with a minimum of 1.5m buffer zone. This estimate is considered accurate to +/- 30-40% and has been developed ahead of detailed engineering.

			Structure Type					
Line #	**Work Description**		**Tangent**	**Lt Angle**	**Hvy Angle**	**DDE**	**General**	**SUBTOTALS**
21L-24L								
	Str Replacements		$ 7,274	$ 8,693	$ 10,946	$ 16,288		
		Quantity	74	14	5	8		**101**
		Total	$ 538,276	$ 121,702	$ 54,730	$ 130,304	$ -	**$ 845,012**
	Special Excavation (Rock/Blast holes)		$ 49,333	$ 9,333	$ 3,333	$ 5,333	$ -	**$ 67,333**
	Conductor (Re-use 300MCM Cu)						$ -	**per meter**
		Length (m)					0	**$ -**
		Stringing	$ -	$ -	$ -	$ -	$ -	**$ -**
		Tying-in	$ 106,560	$ 20,160	$ 8,400	$ 23,040	$ -	**$ 158,160**
		Heli Contingency	$ -	$ -	$ -	$ -	$ -	**$ -**
	Refurbishments						$ 2,500	**each**
		Quantity					20	
			$ -	$ -	$ -	$ -	$ 50,000	**$ 50,000**
	Brushing						$ 20,000	**per km**
		Length (km)					5	
			$ -	$ -	$ -	$ -	$ 100,000	**$ 100,000**
	Road Work						$ 500	**per site**
		Quantity					101	
			$ -	$ -	$ -	$ -	$ 50,500	**$ 50,500**
	Salvage		640	765	964	1434	250	
		Quantity	74	14	5	8	20	**121**
		Total	$ 47,390	$ 10,714	$ 4,819	$ 11,472	$ 5,000	**$ 79,394**
	Salvage Credit (300MCM Copper)						$ 2	**per lbs**
		90% Total Length					$ -	**$ -**
	Contingency (10%)							**$ 135,040**

OPTION 1i: **TOTAL 21L-24L LINE COSTS = $1485K**

(With Salvage Included)

APPENDIX III - PRELIMINARY ESTIMATES FOR OPTION 1ii

This option includes the like-for-like replacement of all older (original vintage) 21L-24L structures. Costs include loaded labor and equipment rates, but do not include special FortisBC Capitalized Overhead Loadings or AFUDC. Costs for Project Management, Engineering, Material Loads, and Flagging are all included in the overall cost of each structure type. Extra costs have been provided for possible rock/blast sites and has been assumed for one third of all new structures. Any costs for surveying of R/W and land has been assumed budgeted under a seperate project. Complete brushing of the entire R/W length (approx 5km) has been assumed and accounted for. Extensive road work is required for access to some structure sites and has been included based on the number of new structure sites. All rebuilds have been assumed with the Tx circuit de-energized and the remaining Tx circuits energized and providing backup. It has been assumed that all work is to be done during snow free conditions. This estimate uses a structure-by-structure basis for replacements with the existing 300MCM Copper conductor to be re-used. The structures replacement costs are based typically on 50/1 poles with standard 63kV framing types. The quantity for structure change outs and refurbishments were based on the condition assessment patrols completed by Arrow in January of 2008 and placement of new poles were based on the preliminary survey data that was provided by Arrow Installations in 2007. Ground clearances have been assumed to meet CSA Code requirements with a minimum of 1.5m buffer zone. This estimate is considered accurate to +/- 30-40% and has been developed ahead of detailed engineering.

				Structure Type				
Line #	**Work Description**		**Tangent**	**Lt Angle**	**Hvy Angle**	**DDE**	**General**	**SUBTOTALS**
21L-24L								
	Str Replacements		$ 7,274	$ 8,693	$ 10,946	$ 16,288		
		Quantity	133	30	16	22		**201**
		Total	$ 967,442	$ 260,790	$ 175,136	$ 358,336	$ -	**$ 1,761,704**
	Special Excavation (Rock/Blast holes)		$ 88,667	$ 20,000	$ 10,667	$ 14,667	$ -	**$ 134,000**
	Conductor (Re-use 300MCM Cu)						$ -	**per meter**
		Length (m)					0	**$ -**
		Stringing	$ -	$ -	$ -	$ -	$ -	**$ -**
		Tying-in	$ 191,520	$ 43,200	$ 26,880	$ 63,360	$ -	**$ 324,960**
		Heli Contingency	$ -	$ -	$ -	$ -	$ -	**$ -**
	Refurbishments						$ 2,500	**each**
		Quantity					0	
			$ -	$ -	$ -	$ -	$ -	**$ -**
	Brushing						$ 20,000	**per km**
		Length (km)					5	
			$ -	$ -	$ -	$ -	$ 100,000	**$ 100,000**
	Road Work						$ 500	**per site**
		Quantity					201	
			$ -	$ -	$ -	$ -	$ 100,500	**$ 100,500**
	Salvage		640	765	964	1434	250	
		Quantity	133	30	16	22	0	**201**
		Total	$ 85,173	$ 22,959	$ 15,419	$ 31,548	$ -	**$ 155,099**
	Salvage Credit (300MCM Copper)						$ 2	**per lbs**
		90% Total Length					$ -	**$ -**
	Contingency (10%)							**$ 257,626**

OPTION 1ii: **TOTAL 21L-24L LINE COSTS = $2833K**

(With Salvage Included)

APPENDIX III - PRELIMINARY ESTIMATES FOR OPTION 2

This option includes the replacement of all 21L-24L structures on the existing alignments with optimized span lengths. Costs include loaded labor and equipment rates, but do not include special FortisBC Capitalized Overhead Loadings or AFUDC. Costs for Project Management, Engineering, Material Loads, and Flagging are all included in the overall cost of each structure type. Extra costs have been provided for possible rock/blast sites and has been assumed for half of all new structures. Any costs for surveying of R/W and land has been assumed budgeted under a seperate project. Complete brushing of the entire R/W length (approx 5km) has been assumed and accounted for. Extensive road work is required for access to some structure sites and has been included based on the number of new structure sites. All rebuilds have been assumed with the Tx circuit de-energized and the remaining Tx circuits energized and providing backup. It has been assumed that all work is to be done during snow free conditions. This estimate uses a structure-by-structure basis for replacements with new 477 ACSR Pelican conductor to be installed on all circuits with the existing 300MCM Copper salvaged out at $2/lbs credit for approximately 90% of the total wire length. The structures replacement costs are based typically on 50/1 & 55/1 poles with standard 63kV framing types. The quantity for structure change outs and refurbishments were based on the condition assessment patrols completed by Arrow in January of 2008 and placement of new poles were based on the preliminary survey data that was provided by Arrow Installations in 2007. Salvage costs are based on the total number of existing structures and framing types. Ground clearances have been assumed to meet CSA Code requirements with a minimum of 1.5m buffer zone. This estimate is considered accurate to +/- 30-40% and has been developed ahead of detailed engineering.

			Structure Type					
Line #	**Work Description**		**Tangent**	**Lt Angle**	**Hvy Angle**	**DDE**	**General**	**SUBTOTALS**
21L-24L								
	Str Replacements		$ 7,274	$ 8,693	$ 10,946	$ 16,288		
		Quantity	85	12	25	31		**153**
		Total	$ 618,290	$ 104,316	$ 273,650	$ 504,928	$ -	**$ 1,501,184**
	Special Excavation (Rock/Blast holes)		$ 85,000	$ 12,000	$ 25,000	$ 31,000	$ -	**$ 153,000**
	Conductor (New 477 Pelican)						$ 6	**per meter**
		Length (m)					64200	**$ 385,200**
		Stringing	$ 81,600	$ 11,520	$ 36,000	$ 59,520	$ -	**$ 188,640**
		Tying-in	$ 122,400	$ 17,280	$ 42,000	$ 89,280	$ -	**$ 270,960**
		Heli Contingency	$ 16,320	$ 2,304	$ 7,200	$ 11,904	$ -	**$ 37,728**
	Refurbishments						$ 2,500	**each**
		Quantity					0	
			$ -	$ -	$ -	$ -	$ -	**$ -**
	Brushing						$ 20,000	**per km**
		Length (km)					5	
			$ -	$ -	$ -	$ -	$ 100,000	**$ 100,000**
	Road Work						$ 500	**per site**
		Quantity					153	
			$ -	$ -	$ -	$ -	$ 76,500	**$ 76,500**
	Salvage		640	765	964	1434	250	
		Quantity	151	31	18	34	0	**234**
		Total	$ 96,700	$ 23,724	$ 17,347	$ 48,756	$ -	**$ 186,527**
	Salvage Credit (300MCM Copper)						$ 2	**per lbs**
		90% Total Length (m)					55029	**$ 347,595**
	Contingency (10%)							**$ 324,733**

OPTION 2: **TOTAL 21L-24L LINE COSTS = $2876K**

(With Salvage Included)

APPENDIX III - PRELIMINARY ESTIMATES FOR OPTION 3

This option includes the rebuild of 21L-24L with 23L & 24L double circuited and 21L & 22L to remain single circuit on existing alignments. Costs include loaded labor and equipment rates, but do not include special FortisBC Capitalized Overhead Loadings or AFUDC. Costs for Project Management, Engineering, Material Loads, and Flagging are all included in the overall cost of each structure type. Extra costs have been provided for possible rock/blast sites and has been assumed for half of all new structures. Any costs for surveying of R/W and land has been assumed budgeted under a seperate project. Complete brushing of the entire R/W length (approx 5km) has been assumed and accounted for. Extensive road work is required for access to some structure sites and has been included based on the number of new structure sites. All rebuilds have been assumed with the Tx circuit de-energized and the remaining Tx circuits energized and providing backup. It has been assumed that all work is to be done during snow free conditions. This estimate uses a structure-by-structure basis for replacements with new 477 ACSR Pelican conductor to be installed on all circuits with the existing 300MCM Copper salvaged out at $2/lbs credit for approximately 90% of the total wire length. The structures replacement costs are based typically on 60/1 & 60/H1 poles with standard 63kV single and double circuit framing types. The quantity for structure change outs and refurbishments were based on the condition assessment patrols completed by Arrow in January of 2008 and placement of new poles were based on the preliminary survey data that was provided by Arrow Installations in 2007. Salvage costs are based on the total number of existing structures and framing types. Ground clearances have been assumed to meet CSA Code requirements with a minimum of 1.5m buffer zone. This estimate is considered accurate to +/- 30-40% and has been developed ahead of detailed engineering.

						Structure Type						
Line #	**Work Description**		**Tangent**		**Lt Angle**		**Hvy Angle**		**DDE**	**General**		**SUBTOTALS**
			Sgl Pole	Dbl Cct	Sgl Pole	Dbl Cct	Sgl Pole	Dbl Cct	Sgl/Dbl Cct			
21L-24L												
	Str Replacements		$ 7,274	$ 9,148	$ 8,693	$ 11,109	$ 10,946	$ 21,536	$ 16,288			
		Quantity	22	36	10	6	6	9	31			**120**
		Total	$ 160,028	$ 329,328	$ 86,930	$ 66,654	$ 65,676	$ 193,824	$ 504,928	$ -	**$**	**1,407,368**
	Special Excavation (Rock/Blast holes)		$ 22,000	$ 36,000	$ 10,000	$ 6,000	$ 6,000	$ 9,000	$ 31,000	$ -	**$**	**120,000**
	Conductor (New 477 Pelican)									$ 6	**per meter**	
		Length (m)								64200	**$**	**385,200**
		Stringing	$ 21,120	$ 69,120	$ 9,600	$ 11,520	$ 8,640	$ 25,920	$ 59,520	$ -	**$**	**205,440**
		Tying-in	$ 31,680	$ 86,400	$ 14,400	$ 14,400	$ 10,080	$ 23,760	$ 89,280	$ -	**$**	**270,000**
		Heli Contingency	$ 4,224	$ 13,824	$ 1,920	$ 2,304	$ 1,728	$ 5,184	$ 11,904	$ -	**$**	**41,088**
	Refurbishments									$ 2,500	**each**	
		Quantity								0		
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$**	**-**
	Brushing									$ 20,000	**per km**	
		Length (km)								5		
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,000	**$**	**100,000**
	Road Work									$ 500	**per site**	
		Quantity								120		
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,000	**$**	**60,000**
	Salvage		640	805	765	978	964	1896	1434	250		
		Quantity	151	0	31	0	18	0	34	0		**234**
		Total	$ 96,700	$ -	$ 23,724	$ -	$ 17,347	$ -	$ 48,756	$ -	**$**	**186,527**
	Salvage Credit (300MCM Copper)									$ 2	**per lbs**	
		90% Total Length (m)								55029	**$**	**347,595**
	Contingency (10%)										**$**	**312,322**

OPTION 3: **TOTAL 21L-24L LINE COSTS = $2740K**

(With Salvage Included)

APPENDIX III - PRELIMINARY ESTIMATES FOR OPTION 4

This option includes the rebuild of 21L-24L with two new high capacity lines to be built on existing alignmnets. Costs include loaded labor and equipment rates, but do not include special FortisBC Capitalized Overhead Loadings or AFUDC. Costs for Project Management, Engineering, Material Loads, and Flagging are all included in the overall cost of each structure type. Extra costs have been provided for possible rock/blast sites and has been assumed for half of all new structures. Any costs for surveying of R/W and land has been assumed budgeted under a seperate project. Complete brushing of the entire R/W length (approx 5km) has been assumed and accounted for. Extensive road work is required for access to some structure sites and has been included based on the number of new structure sites. All rebuilds have been assumed with the Tx circuit de-energized and the remaining Tx circuits energized and providing backup. It has been assumed that all work is to be done during snow free conditions. This estimate uses a structure-by-structure basis for replacements with new 1272 AAC Narcissus conductor to be installed on all circuits with the existing 300MCM Copper salvaged out at $2/lbs credit for approximately 90% of the total wire length. The structures replacement costs are based typically on 50/H1 & 55/H1 poles with standard 63kV framing types. The quantity for structure change outs and refurbishments were based on the condition assessment patrols completed by Arrow in January of 2008 and placement of new poles were based on the preliminary survey data that was provided by Arrow Installations in 2007. Salvage costs are based on the total number of existing structures and framing types. Ground clearances have been assumed to meet CSA Code requirements with a minimum of 1.5m buffer zone. This estimate is considered accurate to +/- 30-40% and has been developed ahead of detailed engineering.

			Structure Type					
Line #	**Work Description**		**Tangent**	**Lt Angle**	**Hvy Angle**	**DDE**	**General**	**SUBTOTALS**
21L-24L								
	Str Replacements		$ 8,478	$ 9,897	$ 12,778	$ 20,005		
		Quantity	76	7	16	21		**120**
		Total	$ 644,328	$ 69,279	$ 204,448	$ 420,105	$ -	**$ 1,338,160**
	Special Excavation (Rock/Blast holes)		$ 76,000	$ 7,000	$ 16,000	$ 21,000	$ -	**$ 120,000**
	Conductor (New 1272 Narcissus)						$ 23	**per meter**
		Length (m)					32100	**$ 738,300**
		Stringing	$ 72,960	$ 6,720	$ 23,040	$ 40,320	$ -	**$ 143,040**
		Tying-in	$ 109,440	$ 10,080	$ 26,880	$ 60,480	$ -	**$ 206,880**
		Heli Contingency	$ 14,592	$ 1,344	$ 4,608	$ 8,064	$ -	**$ 28,608**
	Refurbishments						$ 2,500	**each**
		Quantity					0	
			$ -	$ -	$ -	$ -	$ -	**$ -**
	Brushing						$ 20,000	**per km**
		Length (km)					5	
			$ -	$ -	$ -	$ -	$ 100,000	**$ 100,000**
	Road Work						$ 500	**per site**
		Quantity					120	
			$ -	$ -	$ -	$ -	$ 60,000	**$ 60,000**
	Salvage		640	765	964	1434	250	
		Quantity	151	31	18	34	0	**234**
		Total	$ 96,700	$ 23,724	$ 17,347	$ 48,756	$ -	**$ 186,527**
	Salvage Credit (300MCM Copper)						$ 2	**per lbs**
		90% Total Length (m)					55029	**$ 347,595**
	Contingency (10%)							**$ 326,911**

OPTION 4: **TOTAL 21L-24L LINE COSTS = $2900K**

(With Salvage Included)

APPENDIX IV – 21L-24L BASIS FOR STRUCTURE COST ESTIMATES

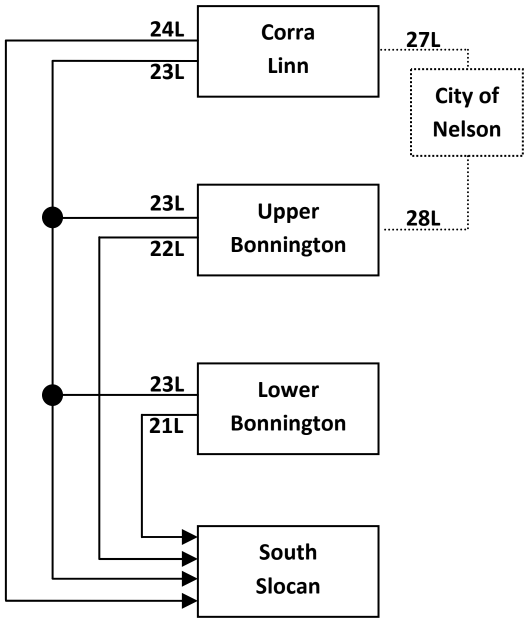
APPENDIX IV - BASIS FOR STRUCTURE COST ESTIMATES

63KV STRUCTURE TYPE - NO UNDERBUILD

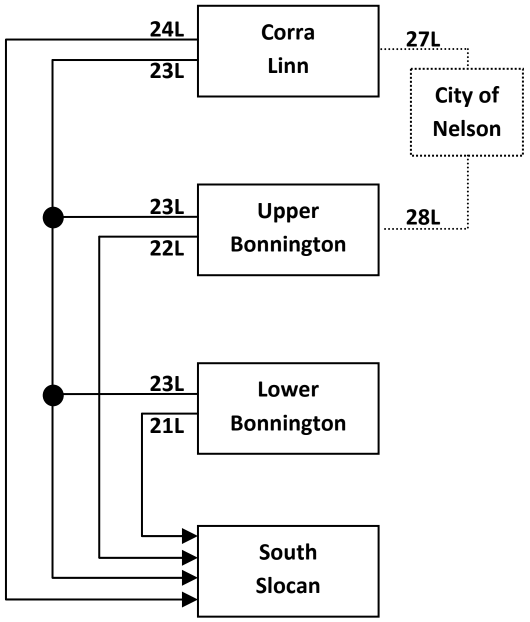
	Tangent			**Light Angle**			**Heavy Angle**			**Double Deadend**		**Comments**
	Sgl Pole	High Cap Sgl Pole	Dbl Cct	Sgl Pole	High Cap Sgl Pole	Dbl Cct	Sgl Pole	High Cap Sgl Pole	2-pole Dbl Cct	Vertical	High Cap Vertical	
Material	2900	3900	5000	3450	4450	6000	5050	6300	11400	7500	9500	Typical 60/1 & 60/H1 poles for dbl cct; 50/1 & 55/1 poles for sgl cct; 50/H1 & 55/H1 poles for high capacity cct.
Frame & Set	2400	2400	1920	2880	2880	2400	3120	3360	5280	4800	5760	4-man crew @ $120/hr
Contractor	375	375	375	450	450	450	450	450	450	525	525	Contractor @ $75/hr
Switching	145	195	250	173	223	300	253	315	570	375	475	For cct load transfer
Non-Prod Time	584	594	509	701	711	630	765	825	1260	1140	1352	Assumed @ 20% for safety, travel, etc.
Salvage	640	746	805	765	871	978	964	1125	1896	1434	1761	Assumed with 3-man crew @ $120/hr and Contractor @ $75/hr
Project Manager	352	411	443	421	479	538	530	619	1043	789	969	Assumed @ 5%
Engineering	518	603	651	619	704	791	779	910	1533	1159	1424	Assumed @ 7%
Total	**7914**	**9224**	**9954**	**9458**	**10768**	**12087**	**11910**	**13903**	**23432**	**17722**	**21766**	
Total w/o Salvage	**7274**	**8478**	**9148**	**8693**	**9897**	**11109**	**10946**	**12778**	**21536**	**16288**	**20005**	

APPENDIX V – 21L-24L SINGLE LINE DIAGRAMS

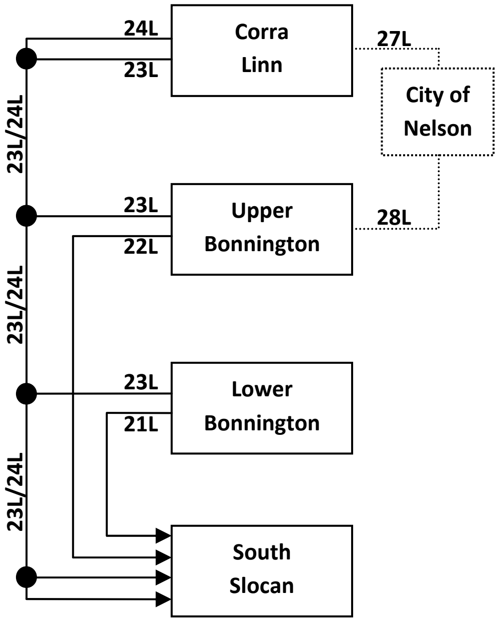
EXISTING CONFIGURATION



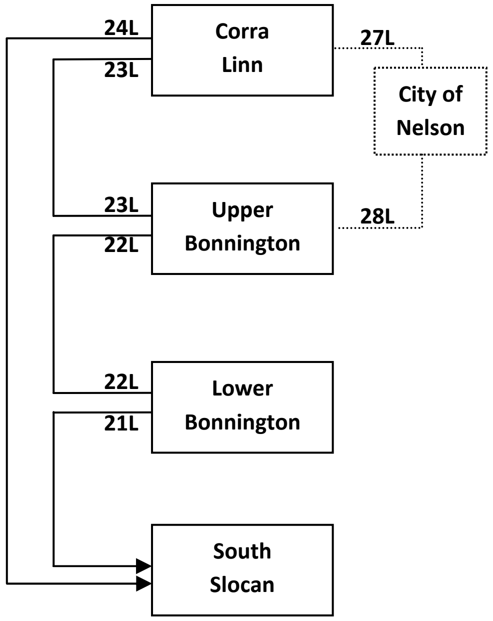
OPTIONS 1 & 2 CONFIGURATION
(Same as Existing)



OPTION 3 CONFIGURATION



OPTION 4 CONFIGURATION



DBS ENERGY SERVICES INC.

21L-24L Engineering Assessment Report

(Revised for 2011/12 Capital Plan)

Table of Contents

1. INTRODUCTION

This 21L through 24L engineering assessment was initiated as a result of concerns of the overall decayed state of these lines and the reliability to maintain supply between the river generation plants. This report is to bring a consolidated approach to the options and alternatives for rehabilitation work and to achieve the best long term design solution. All four of these circuits (21L, 22L, 23L, and 24L) are 63kV circuits with single pole type construction for considerably short span lengths; 3-pole structures are used in a few locations with longer spans. These lines are all built within the same corridor, which is for the most part on a steep side slope paralleling between Highway 3A and the CPR Railway tracks between South Slocan and Corra Linn. This report is meant to provide assessment implications for possible risks of these lines and to provide a design review with construction estimates of recommended work for structure repairs/replacements for required work on the lines. The recommended work is based on the data collected from the condition assessment patrols completed in 2008 by Arrow Installations crews and the Test & Treat data completed by Gilnockie in 2007/2008. Several additional design alternatives for the 21L-24L configuration were previously investigated in the original 2008 21L-24L Engineering Assessment Report and ruled out by FortisBC. These design alternatives included: replacing all older vintage structures like-for-like, rebuilding the entire lines on existing alignments with optimized span lengths, rebuilding 23L and 24L as a double circuit with 21L and 22L remaining as single circuits, and completely rebuilding 21L-24L with two high capacity lines.

There have been basically no attempts in the past to upgrade the overall status of these lines in an organized program. The only work completed on 21L-24L has been due to urgent replacements or to accommodate new circuit ties into the stations as part of the upgrades for the generation plants.

2. BACKGROUND

The 21L-24L circuits interconnect the FortisBC Kootenay River Generation Plants (Corra Linn, Upper Bonnington, Lower Bonnington, and South Slocan). These lines were originally installed in the early 1900's and have been re-constructed in the 1940's to 1950's during expansion of the generation plants. The transmission conductors on all four lines are for the most part the original 300MCM Copper that is believed to have been installed during the re-construction of the lines in 1940-1950's. Limited re-conductoring of the 300MCM Copper has only occurred recently when new terminations were installed at each generation station and was re-conductored with either 477 AAC Cosmos or 1272 Narcissus.

The 21L 63kV circuit is approximately 1.5km in length and runs directly from the Lower Bonnington Station to the South Slocan Station. The 22L 63kV circuit is approximately 3.3km in length and runs directly from the Upper Bonnington Station to the South Slocan Station. The 23L 63kV circuit is approximately 4.9km in length and runs from the Corra Linn Station to the South Slocan Station with direct taps to the Upper Bonnington Station and the Lower Bonnington Station. The 24L 63kV circuit is approximately 4.9km and is a direct feed from the Corra Linn Station to the South Slocan Station. All four lines are located within the same right-of-way with circuit spacing of approximately 6m from centerline to centerline. The right-of-way corridor for the most part is accessible with some road work required to access structure locations; however, some areas will need extensive road work for access with a line truck. Also, paralleling 21L-24L on the east side of the right-of-way is a single three phase 2300V distribution circuit that is used exclusively for station service.

The assessment data and design information that was available for this report includes the 21L-24L detailed line patrols/inspections completed by Arrow Installations crews in January of 2008, and pole Test & Treat data completed by Gilnockie in 2007/2008. The McElhanney survey data for 21L-24L has been collected, but the data has not been processed and therefore is not available for this report. It is expected that final designs and the related project work will fund these survey processing costs. The pole Test and Treat data has remained unreliable as the structure numbering and pole information does not consistently match-up with field data collected from the assessment patrols. The condition assessments were used for the basis behind the design review and estimating purposes. Original design and line information is non-existent in terms of structure and line information, in addition to plan & profile drawings.

Generally, all four circuits can be considered in relatively poor condition with the majority of the poles from 1950's vintage, and as a result, a large amount of the poles are stubbed or in poor overall condition and will require replacement to ensure system integrity.

A. Past Outages and Problems

The main concern for past outages on 21L-24L, as seen from a structural point of view, is the numerous arm burn-offs that have occurred, which have been repaired by only replacing the transmission arm and insulation while leaving the older poles still in service. These arm failures are most likely due to the aged condition of the insulation and end-of-life status of the arms.

In past years there have not been too many issues seen on 21L-24L circuits that would raise concerns with transmission and generation system outages, considering that single circuit contingency on any one of these lines will not cause loading problems as the other three lines can easily pick-up the accompanying load of one circuit. If any two circuits experience an outage, there could be generation lost, but this is a less likely situation. The final overall design considerations for these lines must account for full capacity of the circuits during emergency circumstances.

B. Recent Works Completed

The only recent works completed on 21L-24L that have been documented are the upgrades to existing line facilities during re-terminations involved with the station upgrades at each generation plant. A brief summary of more recent activities relating to 21L through 24L are listed below and presented generally in a chronological order.

- **Survey Data** – McElhanney was contracted to provide survey data for 21L-24L in 2008 by means of photogrammetric methods. The ortho photography was obtained concurrently with the 27L data and ortho photos delivered, but processing of the survey data points was put on hold until an overall assessment of the lines was completed to determine the survey data that was actually needed for design of 21L-24L. The design survey was originally to be LiDAR based, but has been changed to photogrammetric for timing and cost issues.
- **21L-24L Condition Assessment and Patrols 2008** – This was a detailed line patrol completed by Arrow Installations crews. This assessment was to identify condition issues, line data, and facilities on these river lines. This was to drive future projected work that would be identified through engineering reviews.
- **Pole Test & Treat Program in 2007/2008** – This was completed by Gilnockie for all 21L-24L poles. The 22L-24L poles were tested in 2007 with follow-up testing completed on the 21L poles in 2008.
- **Arrow Experimental Survey Data 2007** – This was a pilot project to determine the accuracy of Arrow field survey methods. There were notable discrepancies with this survey information and it was considered not accurate enough for preliminary design purposes.
- **21L-24L Re-terminations into South Slocan 2004** – This project was undertaken in 2004 and includes the re-termination of all four lines into the South Slocan Station. The new 22L and 23L ties were re-conductored with 477 AAC Cosmos.
- **22L and 23L Re-terminations into USS 2003** – This project included new 22L and 23L terminations into the new USS station and adjacent 22L and 23L structure replacements. These new ties into USS were reconductored with 1272 AAC Narcissus.
- **21L Re-terminations into Lower Bonnington 2003** – This project was undertaken in 2003 and includes the re-termination of 21L into LBO. The new 21L tie was re-conductored with 477 AAC Cosmos.

3. SUMMARY OF FINDINGS

The records from the original design are absent with ground profile drawings and structure lists missing for all 21L-24L circuits. Therefore, any changes or upgrades to these lines have not been documented throughout the years. Considering this lack of available line information for 21L-24L, it was decided that an extensive review be completed that would capture this missing data. The patrols and condition assessment records for all four lines were completed by Arrow Installations in January of 2008. These patrols had to be deemed accurate as there was no existing line data available for comparison and the pole Test & Treat data could not be totally relied upon for correct structure numbering, which required extensive reconciliation. These condition assessments produced detailed information regarding the pole/structure, framing types, insulation, conductors, anchoring, and overall site information, which were reconciled to the Test and Treat data as best as possible. Draft structure lists have been created for each line using the detailed assessment data and available records from the recent re-termination projects.

A. Structures

There are a considerable amount of older vintage structures on 21L-24L, and of those structures a large amount have been stubbed for many years and even red tagged in some circumstances. All of these stubbed structures should be included as priority replacements and incorporated into the follow-up design. As shown in the 21L-24L Summary of Work found in Appendix I, approximately one half of all the existing structures on 21L-24L are in need of priority replacement with the majority of the remaining structures nearing the end of their life cycle. It should be noted that there are 14 urgent replacement structures due to failing arms or red tagged (reject) poles as specified from the 2007 patrols. This urgent work is still to be done and needs to be completed in the very near future. A summary of the 21L-24L pole vintages can be found in Appendix II.

There is an abundance of wire transposition structures on each line, which for the most part utilizes short spans (in the order of 30m) to transpose the wire with the center phase going flat to an arm on the adjacent structure. These multiple wire transposition structures are not necessary, and therefore could be eliminated if the circuit was to be rebuilt or re-conductored (assuming the phasing was matched at each station). This will need to be evaluated in final design.

B. Insulation

The existing insulation on 21L-24L is a combination of mostly 1950’s vintage structures with porcelain type bell and pin insulators, as well as a small number of newer structures with synthetic type insulation. On the older porcelain insulation, there is evidence that the porcelain glazing has deteriorated significantly due to the fact these insulators are nearing the end of their lifespan. This deterioration of the porcelain insulation is most likely the cause of several arm burn-offs in recent years. There has been no evidence shown that the porcelain insulators on the 21L-24L circuits are from the Ohio Brass era that contained “cement growth” problems.

C. Conductor

The type of conductor strung on all 21L-24L circuits is predominantly 300MCM copper with small sections rebuilt to 477 AAC Cosmos. The new 23AL tap into USS is reconductored with 1272 AAC Narcissus. There have been no significant issues with the 300MCM as outlined from the condition assessment patrols, only what could be expected from a 60+ year old conductor. The ampacity rating for the 300MCM conductor can be found in Appendix III.

D. Generation Load Flow

The maximum load that any one of these lines may experience is during contingency planning where one or more lines may be out of service. The total combined capacity of these lines must be able to handle the generation output of the three Generation River Plants north of South Slocan, which includes Corra Linn, Upper Bonnington (UBO), and Lower Bonnington (LBO). At the South Slocan Station, the load is then distributed out on various transmission lines. The maximum generation capacities of these three plants are shown in the table below.

Generation Plant	**Total Capacity**	**Amps at 3Ø-66kV**
Corra Linn	45MVA	394Amps
Upper Bonnington	64MVA	560Amps
Lower Bonnington	55MVA	481Amps
Total	**164MVA**	**1435Amps**

E. Terrain

The 21L through 24L lines are located within the same right-of-way corridor for the majority. The existing right-of-way parallels between Highway 3A and the CPR Railway tracks, and generally follows the Kootenay River. The right-of-way can be considered fairly rugged terrain with many structures located on steep side slopes and rocky areas. There are numerous existing structure locations that are rock holes and these structures will require additional excavation work for drilling/blasting when replacement of the structure is required.

Considering this type of rough terrain on 21L-24L, access to structure locations may be difficult. There is existing access roads to many pole locations, which still would require some minor road work. However, there are many structure locations with no apparent access, and creating an access road will require extensive work with particular attention to environmental concerns. The access to each structure location must be accounted for during design review and was included in the attached estimates.

F. Brushing

It would appear that the existing brushing program for 21L-24L has been generally quite effective through recent years as tree contacts have not been a significant source of outages on these lines. The condition assessment patrols and follow-up engineering field review revealed that there are several sections where tree growth underneath the line should be addressed in the near future, as well as the removal of large danger trees outside of the right-of-way corridor. A complete tree brushing plan for the 21L-24L right-of-way is most likely due, as it appears that roughly 6 years ago was the last comprehensive brushing through this area (based on the existing tree growth of the right-of-way).

4. DESIGN OPTIONS

The assumptions used for the basis of this engineering review of 21L-24L have been derived from the assessment patrols completed in January of 2008 by Arrow Installations crews and the Test & Treat data completed in 2007/2008 by Gilnockie. The existing pole count and structure condition have been assumed from this data to determine urgent replacements and additional rehabilitation work required on these lines.

The design option for 21L-24L, as selected by FortisBC from the original 2008 21L-24L Engineering Assessment Report completed by DBS Energy, is to re-use the existing alignments with the replace/repair work completed on a priority basis as required. There are approximately 99 structures to be replaced as a priority, of which 14 are urgent replacements due to failing arms or red tagged (reject) poles. There are also 34 structures requiring minor rehabilitation repairs. On the 21L-24L circuits there are roughly another 100 older vintage structures that will need to be replaced in the foreseeable future (approximately 10-15 years). Also, the existing 300MCM Copper conductor is to be re-used as it has shown no deficiency issues as outlined from the assessment patrols. The single line diagram for the existing 21L-24L configuration can be found in Appendix IV, with the existing layout of the 21L-24L route maps shown in Appendix V.

Detailed engineering design for 21L through 24L should include building a computerized model (i.e. PLS-Cadd) of the lines, which will require the McElhanney survey data to be fully processed. The preliminary experimental survey data from Arrow Installations had notable discrepancies and will not be adequate for designs, and should not be relied upon.

A. Alternative Design Options

Alternative design options for the 21L-24L circuit configuration that were previously investigated are summarized below. These options were have been ruled out by FortisBC as not being cost effective solutions.

- **Replace all older vintage structures –** This option would re-use the existing 21L through 24L alignments with the work required on the existing structures completed by replacing all older vintage structures to new standards. The structures would be replaced like-for-like with similar framing configuration and pole sizes while re-using the existing 300MCM Copper conductor. This option would allow for the pole sizes to remain quite low, but the overall immediate structure change outs will be considerably higher than the other options, making the rebuild cost unnecessarily high.
- **Replace 21L-24L on existing alignments with optimized span lengths –** This option would make use of the existing alignments to rebuild the entire circuits with the span lengths increased and optimized for structure locations. The total number of new structures installed would be drastically reduced (by approximately 50 structures) as compared to the existing configuration, and the existing structures that have been recently replaced could be re-used where possible with all older vintage structures removed and/or replaced. The existing 300MCM Copper conductor would be re-conductored with a corresponding 477MCM conductor (typically 477 ACSR Pelican) that has a similar ampacity rating**.**
- **Replace 21L-24L with 23L/24L as double circuit and 21L/22L as single circuits –** This option consists of double circuiting 23L and 24L for the entire length from the South Slocan Station to the Corra Linn Station, and rebuilding 21L and 22L with single circuit structures on the existing alignments with optimized span lengths. This option requires that virtually all the

existing structures be replaced (newly rebuilt tie sections into the plants could be re-used) and the existing 300MCM copper re-conductored with 477 ACSR Pelican.

- **Replace 21L-24L with two high capacity circuits –** This option would require the replacement of virtually all existing 21L-24L structures (including newer structures) with two new high capacity lines. One of these new circuits would be a direct express feed from Corra Linn to South Slocan and the other circuit would feed from Corra Linn to South Slocan with in/out taps of LBO and UBO. The 300MCM copper would need to be re-conductored with a single 1272 AAC Narcissus conductor, or a conductor with similar specifications and ampacity rating. The 1272 Narcissus would be able to handle the current maximum capacity of Corra Linn, LBO, and UBO under contingency loading criteria. Considerable station works would also be required with this option.

B. Comparison Summary of Options

The following table is a summary of existing and alternative circuit configuration options that were looked at with details pertaining to the risks and benefits.

Design Option	**Pros**	**Cons**
Replace like-for-like (urgent & priority str replacements only) **This option is to be implemented **	• Pole size can be smaller • Initial cost is low • Rebuild/budget across several years • Outages are not a concern for ease of construction • Multiple ccts for contingency	• Circuits will still have old strs with shortened lifespan remaining • O&M str failures are more likely • Additional O&M will continue

Alternative design options that have been previously ruled out by FortisBC		
Replace like-for-like (replacement of all older vintage strs)	• Pole size can be smaller • Outages are not a concern for ease of construction • Multiple ccts for contingency • Reduced immediate O&M dollars needed	• Not cost effective • High str replacements
Replace entire circuit strs on existing alignments with optimized span lengths	• Total number of strs are lower • Outages are not a concern for ease of construction • Multiple ccts for contingency • Reduced immediate O&M dollars needed	• Outages will be lengthy during construction
Replace existing circuits with 23L/24L as double circuit and 21L/22L as single circuits	• Total number of strs is low in comparison • Reduced immediate O&M dollars needed	• Taller poles required • Construction is difficult • Increased risk of common mode outages between Corra Linn and UBO
Replace existing circuits with two high capacity circuits	• Total number of strs is low in comparison • Cleanest overall configuration • Lower str overall maintenance • Reduced immediate O&M dollars needed	• Single contingency • Larger conductor needed • Added pole strength needed • Possible work required at stations for increased capacity • Increased risk of common mode outages

5. ESTIMATE OF WORK

The recommended scope of work that should be done on the 21L through 24L circuits is included on a detailed structure by structure basis, and is detailed in Appendix I along with the ±20-25% estimates. It is expected that the subsequent engineering to complete the construction packages will include any follow-up design efforts that are needed, and review of expected summary of work. Generally, the recommendations provide for replacement of all stubbed and tested deficient structures, replacement of older structures with arm failures, minor structure repairs, and brushing of the complete right-of-way. The urgent work refers to structures that are red tagged (reject) poles or structures with failing crossarms that need immediate attention within the next six months. There are also some outstanding issues on the lines that require follow-up engineering review, which are suggested to be done during the design stage of the project. Engineering review of these issues are included in the estimate (incorporated into the engineering costs), and any additional repairs that may be required as a result would be covered by the contingency allowance. The following estimate table is a summary of the recommended expenditures for 21L-24L facilities. The total estimate for the 21L-24L rehabilitation works is $1.73M, which includes a 10% contingency allowance, but excludes any FortisBC capitalized overheads. It is expected that the majority of the rehabilitation work will be completed with circuit being worked on de-energized.

ESTIMATE OF URGENT AND RECOMMENDED WORK

	Repair	Str Replace	
# of Structures	34	99	TOTAL # OF URGENT STR REPLACEMENTS = 14
Urgent Work	$ 0.0k	$ 192.5k	TOTAL # OF URGENT REPAIRS = 0
Recommended Work	$ 14.7k	$ 1234.0k	
± 20-25% Estimate	**$ 14.7k**	**$ 1426.5k**	Excludes contingency or FortisBC overheads.

Labor	$ 533.2k	37%	Approx 4150 man-hours with the circuit being worked on de-energized.
Salvage	$ 144.1k	10%	Salvage labor. Approx 1050 man-hours.
Material	$ 331.5k	23%	Includes poles and hardware, as well as transportation and overheads.
Engineering	$ 144.1k	10%	Includes review of outstanding issues. Engr follow-up & designs. P&P dwgs.
PM	$ 86.5k	6%	Project management.
Misc	$ 201.8k	14%	For preliminary work, foundations, building access, flagging, EVT, etc.
Brushing	$ 100.0k		Complete brushing of the 21L-24L right-of-way for 5kms.
Survey	$ 30.0k		Processing of survey data from already acquired aerial ortho photography.
SUBTOTAL =	$ 1571.2k		Does not include any FortisBC Capitalized Overheads.
Contingency	$ 157.1k	10%	Allows for 10% contingency.
TOTAL =	**$ 1728.3k**		Does not include any FortisBC Capitalized Overheads.

The estimate provided here is roughly 20% higher than the previous estimated value in the 2008 21L-24L Engineering Assessment Report. The amount of repairs and structure replacements is comparable between the estimates, however the main reasons for the increased cost estimate value can be attributed to several reasons, which include; escalation is structure replacement costs, added EVT and minor flagging costs, increased foundation and access work, additional McElhanney survey processing, and further engineering work to produce a computerized model of the lines and create P&P data. These additional costs would also be required for the alternative design options that have been ruled out.

6. RECOMMENDATIONS

The final configuration of the 21L-24L circuits must be able to provide a reliable supply for the maximum loads from the river generation plants, while still providing adequate contingency planning for emergency situations. Replacing the structures like-for-like on a priority basis as needed has been selected by FortisBC for the design solution on 21L-24L. From an engineering perspective and judgment, a more ideal option would be for a complete rebuild of the 21L-24L lines, but the selected option is more cost effective and provides more than adequate circuit redundancy for backup. By replacing all the 99 priority structures (14 of which are urgent replacements), the state of the lines will be in a more reliable state. The urgent replacement structures are suggested to be changed-out within the next six months, at the most. There has been a few outages in recent years and with the replacement of all poorly rated structures this will only improve. The existing 300MCM Copper is also not a concern as there have been no issues raised about its condition and there are still many years remaining in its lifespan. The 300MCM Copper conductor has seen relatively low electrical and mechanical stresses over the years.

There are several sections where tree growth underneath the line will need to be addressed in the near future, as well as possible danger trees outside of the right-of-way. Taking into consideration the narrow corridor for 21L-24L, it is recommended that the existing right-of-way be completely brushed out with the removal of any potential danger trees.

The tracking of line records on 21L-24L has been virtually non-existent throughout the years. It is recommended that new line records be produced upon rehabilitation work of these lines. These records should include structure lists, sag/tension data, plan and profile drawings, structure drawings with framing details, pictures of each structure location, and computerized model of the lines. This data can be accumulated from the recent condition assessment records, new 21L-24L designs, and the survey data. A complete survey plan for 21L-24L was originally contracted through McElhanney Land Surveying to provide ground elevations along centerline and right-of-way, conductor heights to be used for sag/tension information, pole and anchoring locations, crossing information, and legal plans. McElhanney has acquired the aerial ortho photography, but processing of the survey data points was put on hold until a final project for the lines approved in order to determine the survey data that was actually needed for design of the lines. Survey costs to complete the processing of the data have been provided in the total cost estimate for the 21L-24L work. The survey data from McElhanney should be supplied in the form of a PLS-Cadd bak file (or equivalent) for design modeling of the lines.

Telecom, Protection and Control, SCADA Planning Estimate

Project Number	Kelowna Loop Fibre Option A
Date	25-May-11
Estimate Type	Class 4
Additional Info	
Contingency	30%

						Quantity									Hours		
	Sites	1	2	3	4	5	6	7	8	9	Material	Contract	Planning	Design	Drafting	Install	Commissioning
Item#	Item	NEW	SEX	HOL	GLR	REC	SAU	OKM	BEV	BLK	(000s)	(000s)					
1	Radio - PtMP 200-900 MHz	4	2	2	2	2	2	2	2		$360.00	$0.00	432.0	288.0	144.0	288.0	180.0
2	Planning (additional hours)	100									$0.00	$0.00	100.0	0.0	0.0	0.0	0.0
3	Install (additional hours)	50									$0.00	$0.00	0.0	0.0	0.0	50.0	0.0
4	Equipment Shelter	1									$100.00	$40.00	24.0	60.0	30.0	100.0	0.0
5	Site Clearing	1									$0.00	$20.00	0.0	0.0	0.0	0.0	0.0
6	Tower - 25m Road Access	1									$60.00	$190.00	40.0	0.0	0.0	0.0	0.0
7	Land Acquisition & Environmental for new site	1									$0.00	$70.00	40.0	40.0	0.0	0.0	0.0
8	900 MHz MHSB PtP Radio	1								1	$40.00	$8.00	120.0	80.0	20.0	48.0	48.0
	Totals										**$560.00**	**$328.00**	**$64,260.00**	**$39,780.00**	**$16,490.00**	**$48,600.00**	**$22,800.00**

* Price reflects new SCADA and Data radios

* Includes relocation cost to Black Knight Mountain

Summary	
Material	$560,000.00
Contract	$328,000.00
Engineering	$120,530.00
C&M	$71,400.00
Contingency	$323,979.00
Total * Unloaded	**$1,403,909.00**

Telecom, Protection and Control, SCADA Planning Estimate

Project Number	Kelowna Loop Fibre Option D
Date	25-May-11
Estimate Type	Class 4
Additional Info	
Contingency	30%

						Quantity								Hours		
		Sites	1	2	3	4	5	6	7	8	Material	Contract	Planning	Design	Drafting	Install	Commissioning
Item#	Item		NEW	SEX	HOL	GLR	REC	SAU	OKM	BEV	(000s)	(000s)					
1	N/A		0	0	0	0	0	0	0	0	$0.00	$0.0	0.0	0.0	0.0	0.0	0.0
2	HV Entrance Protection		1	1	1	1	1	1	1	1	$96.00	$0.0	0.0	160.0	160.0	800.0	64.0
3	Analogue Modem		7	5	9	5	5	7	7	5	$25.00	$0.0	100.0	400.0	400.0	400.0	200.0
	Totals										**$121.00**	**$0.00**	**$8,500.00**	**$47,600.00**	**$47,600.00**	**$120,000.00**	**$26,400.00**

Summary	
Material	$121,000.00
Contract	$0.00
Engineering	$103,700.00
C&M	$146,400.00
Contingency	$111,330.00
Total * Unloaded	**$482,430.00**

Telecom, Protection and Control, SCADA Planning Estimate

Project Number	Kelowna Loop Fibre Option E
Date	25-May-11
Estimate Type	Class 4
Additional Info	
Contingency	30%

						Quantity									Hours		
		Sites	1	2	3	4	5	6	7	8	Material	Contract	Planning	Design	Drafting	Install	Commissioning
Item#	Item		All	SEX	HOL	GLR	REC	SAU	OKM	BEV	(000s)	(000s)					
1	Fibre - 72 Strand LV Transmission - Existing(km)		2.75								$0.00	$151.25	8.3	0.0	2.8	0.0	5.5
2	Fibre - 72 Strand Transmission - New(km)										$0.00	$0.00	0.0	0.0	0.0	0.0	0.0
3	Fibre - 72 Strand Distribution - Existing(km)		4.1								$0.00	$266.50	12.3	0.0	4.1	0.0	8.2
4	Fibre - 72 Strand Duct - Existing (km)										$0.00	$0.00	0.0	0.0	0.0	0.0	0.0
5	Fibre - IRU per fibre/km/year										$0.00	$0.00	0.0	0.0	0.0	0.0	0.0
6	KELOWNA MESH JMUX INSTALL - PER SITE			1	1	1	1	1	1	1	$0.00	$1,423.08	0.0	0.0	0.0	0.0	0.0
	Totals										**$0.00**	**$1,840.83**	**$1,746.75**	**$0.00**	**$582.25**	**$0.00**	**$1,370.00**

Summary

Material	$0.00
Contract	$1,840,826.92
Engineering	$2,329.00
C&M	$1,370.00
Contingency	$553,357.78
Total * Unloaded	**$2,397,883.70**

Telecom, Protection and Control, SCADA Planning Estimate

Project Number	Kelowna Loop Fibre Option F
Date	25-May-11
Estimate Type	Class 4
Additional Info	
Contingency	30%

							Quantity								Hours		
		Sites	1	2	3	4	5	6	7	8	Material	Contract	Planning	Design	Drafting	Install	Commissioning
Item#	Item		All	SEX	HOL	GLR	REC	SAU	OKM	BEV	(000s)	(000s)					
1	Fibre - 72 Strand LV Transmission - Existing(km)		8.6								$0.00	$473.00	25.8	0.0	8.6	0.0	17.2
2	Fibre - 72 Strand Transmission - New(km)										$0.00	$0.00	0.0	0.0	0.0	0.0	0.0
3	Fibre - 72 Strand Distribution - Existing(km)		4.1								$0.00	$266.50	12.3	0.0	4.1	0.0	8.2
4	Fibre - 72 Strand Duct - Existing (km)		1.5								$0.00	$15.00	0.0	0.0	0.0	0.0	0.0
5	Fibre - IRU per fibre/km/year										$0.00	$0.00	0.0	0.0	0.0	0.0	0.0
6	KELOWNA MESH JMUX INSTALL - PER SITE			1	1	1	1	1	1	1	$0.00	$1,423.08	0.0	0.0	0.0	0.0	0.0
	Totals										**$0.00**	**$2,177.58**	**$3,238.50**	**$0.00**	**$1,079.50**	**$0.00**	**$2,540.00**

Summary	
Material	$0.00
Contract	$2,177,576.92
Engineering	$4,318.00
C&M	$2,540.00
Contingency	$655,330.48
Total * Unloaded	**$2,839,765.40**

MMK CONSULTING

— BC HYDRO —

CONSTRUCTION COST TRENDS AND OUTLOOK

— SPRING 2010 —

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FINAL DRAFT - May 19, 2010

Contents

1. Introduction and Executive Summary

The purpose of this report is to assist BC Hydro in establishing cost inflation allowances for its future major construction projects. The report scope includes a review of relevant price and activity trends in British Columbia, Canada and the US, as well as electric utility equipment price trends in Japan and Korea. The report also presents recommended cost inflation allowances for BC Hydro's major construction projects.

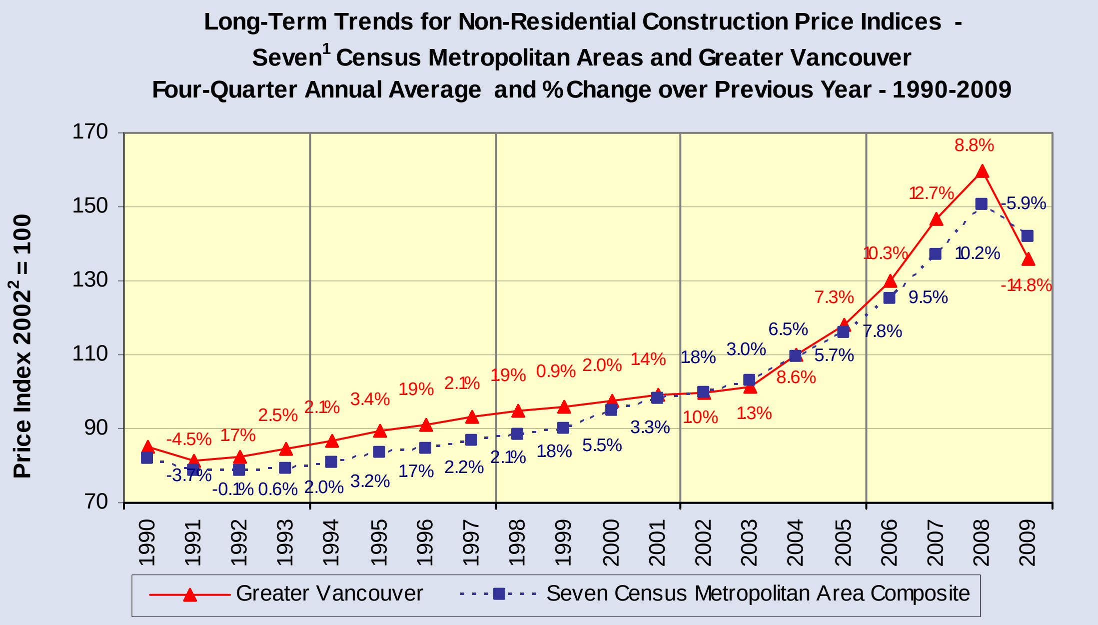
This Spring 2010 edition is the sixth in a series of reviews performed by MMK Consulting for BC Hydro over the past several years.

1.1 Non-residential construction price and activity trends

The year 2009 saw a continuation of the dramatic reversal of the strong upward non-residential construction price index trends between 2003 and mid-2008. As illustrated in Exhibit 1a, the average annual non-residential price index for Greater Vancouver decreased by 14.8% between 2008 and 2009. On a quarterly basis, the sharpest drop in price indices was recorded between the third quarter of 2008 and first quarter of 2009, with more moderate declines recorded during the balance of 2009.

British Columbia's non-residential construction activity levels, as measured by the value of building permits, declined by 14.1% in 2009 over 2008, after having declined by 7.1% in 2008 over 2007.

Exhibit 1a – Annual construction cost trends in the non-residential sector



1 Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver
2 Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous report
Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly

1.2 Price trends in the electric utility industry

The year 2009 also saw a flattening or reversal of the upward electric utility construction price index trends of 2003 to 2008, although not to the same degree as for the overall non-residential construction industry. As measured by Statistics Canada, the Distribution Systems price index declined 0.3% in 2009 after having risen 0.9% in 2008, and the Transmission Lines price index also decreased 0.3% in 2009 after having increased 2.0% in 2008. By contrast, the Substations construction price index actually increased 2.4% in 2009, albeit at a lower rate than the 4.9% recorded for 2008.

For many years, electric utility price indices in Canada have risen at less than half the rate of the broader industrial construction price index, and thus the more muted response of price indices to the economic downturn is not entirely unexpected.

Quarterly price indices are not available for the Canadian electric utility industry. However, quarterly US and Japanese/Korean suppliers' indices for electric utility equipment tended to show declining price index trends between the third quarter of 2008 and first quarter of 2009, then generally flat trends for the balance of 2009.

In early 2010, BC Hydro staff members are reporting much strongly market competition for Hydro construction projects than in most recent years, with very competitive pricing on tenders. The costs to BC Hydro of procuring materials and equipment internationally have been helped by the strength of the Canadian dollar.

1.3 Price trends for component costs

Labour rate trends for construction labour have softened considerably in 2009 and early 2010 from the annual increases that prevailed between 2005 and 2008 (generally in the range of 2.3% to 3.5% annually). For example, the International Brotherhood of Electrical Workers recently agreed to a two-year contract that calls for no increase in wages between 2010 and 2012. In addition, the BC Government and the BC Government Employees Union announced in March 2010 a two-year agreement calling for no wage increases.

Price index trends for concrete materials were mixed in 2009, with ready mix costs declining but sand & gravel and cement & concrete prices increasing moderately. Steel, aluminum and copper prices were generally lower in 2009 than in 2008, with most of the drop having occurred by the first quarter of 2009. Similar patterns were recorded for diesel fuel and asphalt.

Contrary to most trends, construction machinery and equipment price indices rose significantly between the second quarter of 2008 and first quarter of 2009, before stabilizing for the balance of 2009.

1.4 Regional trends in BC

Price index data are not available on a regional basis in BC. However, based on building permit values, activity levels varied widely by region. Between 2008 and 2009, building permit values were up by 20-22% in the Vancouver Island/Coast, Thompson/Okanagan, and Kootenay regions. On the other hand, building permit values were down by 17% in the Mainland/Southwest region, and by 30% or more in the Cariboo, North Coast & Nechako, and Northeast regions.

1.5 Other agencies' estimates and forecasts

Other agencies and industry sources have continued last years' trends towards lower forecasts of construction price level increases. For example, BTY's December 2008 projection was for 3% construction cost inflation in 2009 and 5% in 2010; its more recent December 2009 forecast is for 2% in 2010 and 2%–3% in 2011.

1.6 Recommended construction cost inflation allowances

With the downturn in construction price indices, the differences between the shorter-term and longer-term historical trends have been reduced:

- **Longer term allowances** — Looking back over a 10 to 15 year horizon, the average annual increases in Canadian and US electric utility construction price indices have been in the range of 1.9%% to 2.8%. By contrast, Canadian industrial construction price indices have increased 4.6% to 5.6% annually on average.

  We recommend that the longer term allowance be based on this historical experience, with a greater weighting given to the industry-specific electric utility price index trends. Accordingly, we recommend that BC Hydro use a longer term construction cost allowance range of 2% to 4%.

- **Short to medium term allowances** — Looking back over a three to five year horizon, average annual increases have been somewhat higher. However, given the negative price index trends since mid-2008, we recommend that BC Hydro use the same 2% to 4% construction cost inflation allowance for shorter to medium term projects.

  As illustrated in Exhibit 1b, these recommendations are consistent with those of our most recent April 2009 report.

Exhibit 1b — Recommended construction cost inflation allowances

		Up to 2010	2011 onwards
Previous reports			
Mar. 2007	• Generation (heavy construct.) • Utility transmission/distribut.	4% to 6% 2% to 4%	2.5% to 4% 2% to 4%
Sep. 2007	• All construction projects	4% to 6%	3% to 4%
Apr. 2008	• All construction projects	4% to 6%	3% to 4%
Sep. 2008	• All construction projects	4% to 6%	3% to 4%
Apr. 2009	• All construction projects	2% to 4%	2% to 4%
This report		**Up to 5 year horizon**	**10 to 15 year horizon**
Apr. 2010	**• All construction projects**	**2% to 4%**	**2% to 4%**

1.7 Interpretation of results

These recommended allowances apply to “hard” construction costs only, and do not apply to project design and management costs. They also assume that BC Hydro takes appropriate measures in its contracting procedures to mitigate the impact of construction cost inflation. They also assume that the efforts in 2009 and 2010 to stimulate the US and Canadian economy through public infrastructure spending continue and are at least moderately successful.

Finally, we caution that all projections and forecasts are by nature uncertain. Neither MMK Consulting not BC Hydro can represent that any of the projections contained in this report will necessarily be achieved.

2. General Price Index and Activity Level Trends

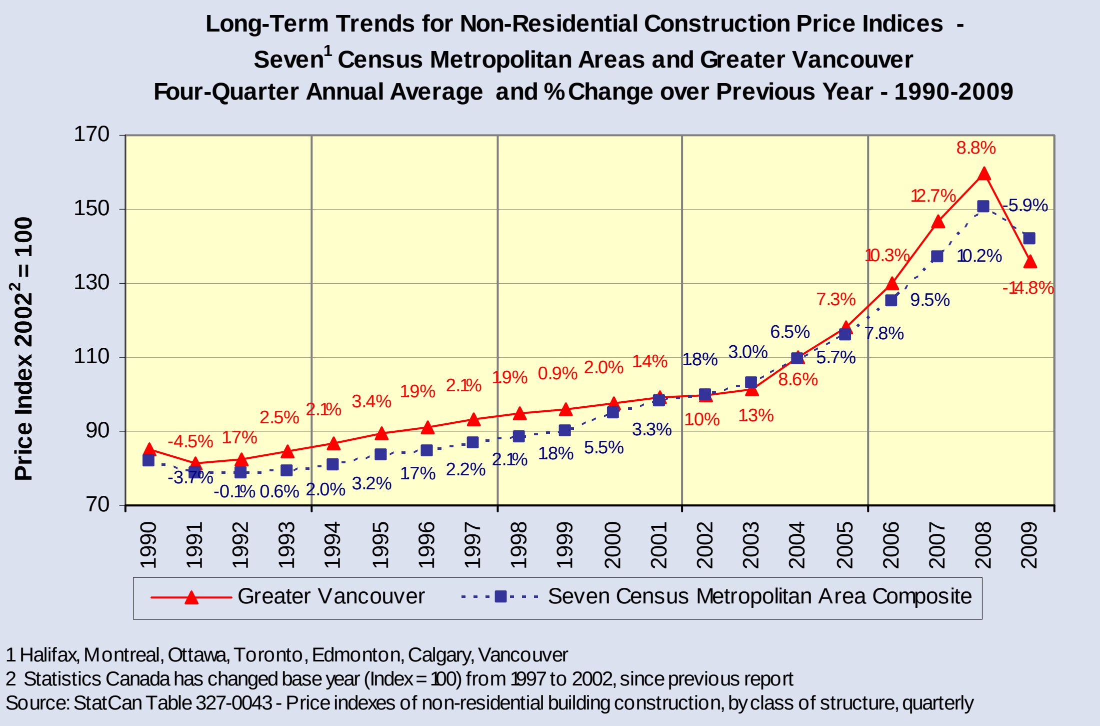
This chapter presents price index and activity level trends for the overall non-residential construction sector, as well as for the three sub-sectors tracked by Statistics Canada — commercial, industrial and institutional/government construction.

2.1 Overall non-residential construction price trends

a) Annual trends

Non-residential construction price index[1] trends for Greater Vancouver, as well as the composite index for seven Canadian metropolitan areas, are illustrated in Exhibit 2a.

Exhibit 2a — Annual construction cost trends in the non-residential sector



Long-Term Trends for Non-Residential Construction Price Indices - Seven[1] Census Metropolitan Areas and Greater Vancouver
Four-Quarter Annual Average and % Change over Previous Year - 1990-2009

1 Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver
2 Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous report
Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly

Non-residential price index trends were moderately upward between 1992 and 2003, increasing approximately 1.9% per year on average. However, non-residential construction price indices increased by an average of 9.1% annually between 2003 and 2008 in Greater Vancouver, and by an average of 8.3% annually for the seven-CMA composite.

---

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

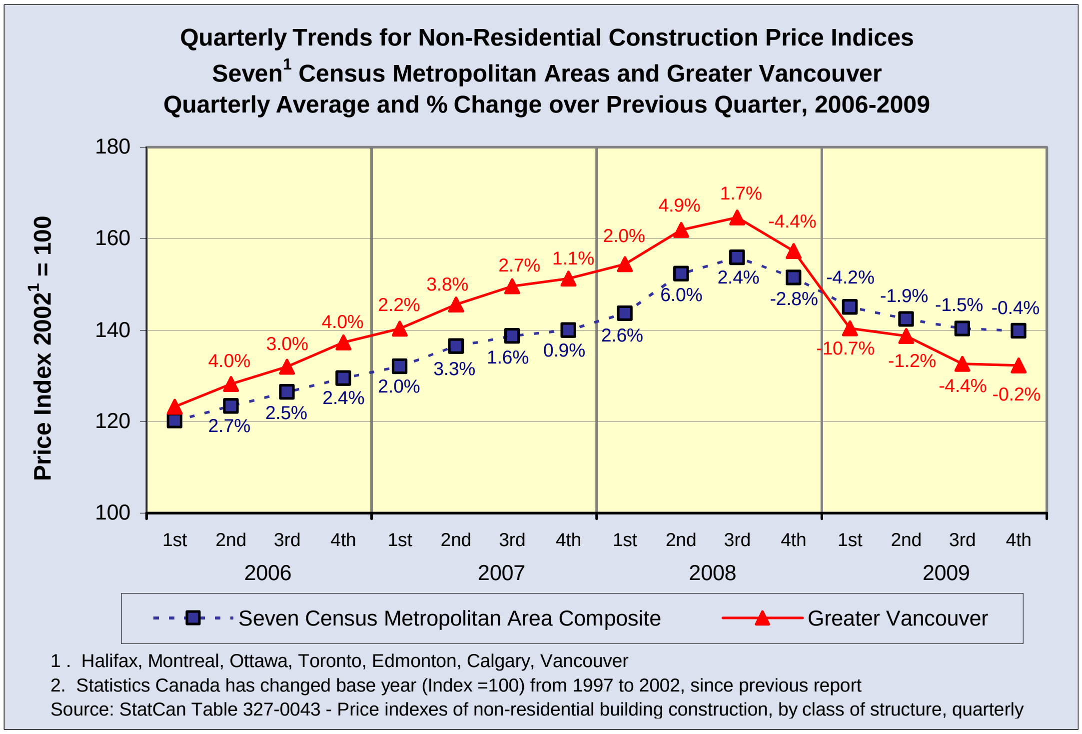
The situation changed dramatically starting in mid-2008, and the Vancouver non-residential construction price index dropped 14.8% in 2009. The seven-CMA composite index also declined, but by the lower rate of 5.9%.

Despite the downturn, non-residential construction price index levels in 2009 were still higher than the historical 1991-2003 trend line.

b) Quarterly trends

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

Exhibit 2b — Quarterly trends for non-residential construction price indices



1 . Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver

2. Statistics Canada has changed base year (Index =100) from 1997 to 2002, since previous report

Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly

The quarterly data illustrate the significant decline in construction price indices since the third quarter of 2008. In Vancouver, the decline over 15 months (3rd quarter 2008 to 4th quarter 2009) was 19.5%. For the seven-CMA composite, the decline over the same 15-month period was less dramatic, but was still 10.4%.

---

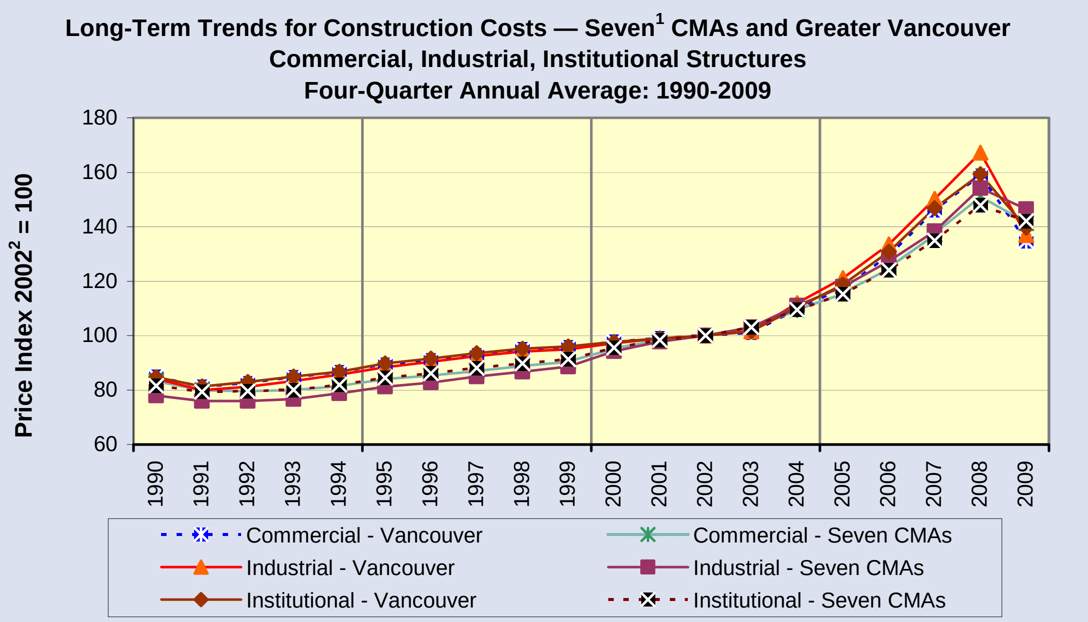
[1] For BC Hydro, the Vancouver index in more relevant to smaller Lower Mainland projects, while the seven-City CMA composite (Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver) is more relevant to larger nationally-sourced projects.

2.2 Breakout by commercial, industrial, and institutional

a) Annual trends — all indices

Statistics Canada's non-residential construction price index is comprised of three sub-categories — (1) commercial, (2) institutional/government and (3) industrial construction. Exhibit 2c(i) illustrates long-term annual trends for each of these three sub-categories, for both Greater Vancouver and the seven-city CMA composite.

Exhibit 2c(i) – Non residential construction price index trends, by sub-sector



Long-Term Trends for Construction Costs — Seven[1] CMAs and Greater Vancouver
Commercial, Industrial, Institutional Structures
Four-Quarter Annual Average: 1990-2009

1 . Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver

2 Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous report

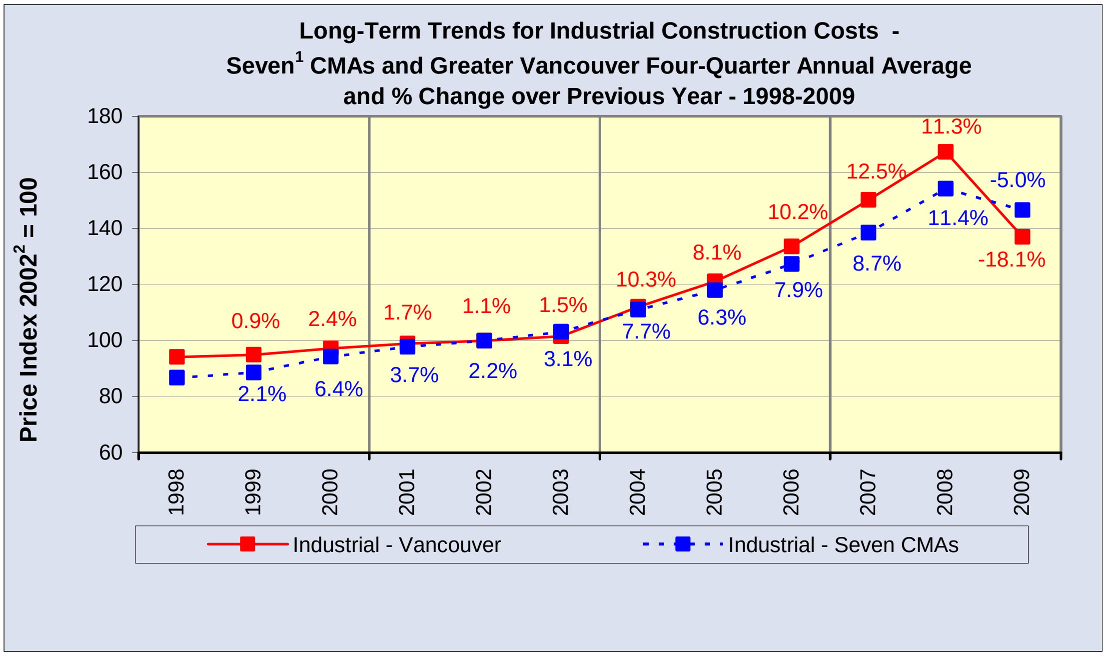
Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly

While the six indices tend to move in similar patterns, price index increases between 2002 and 2008 were greatest for Vancouver-area industrial construction. However, the downward trend in 2009 was also greatest for Vancouver industrial construction, bringing it back in line with longer-term trends for the other indices.

b) Annual trends — industrial construction index

Of the three indices, the industrial construction index is generally considered most relevant to BC Hydro's major construction projects. Exhibit 2c(ii) focuses on the annual trends in the industrial construction price index in recent years, including year-over-year percentage changes.

Exhibit 2c(ii) — Annual Industrial construction price index trends



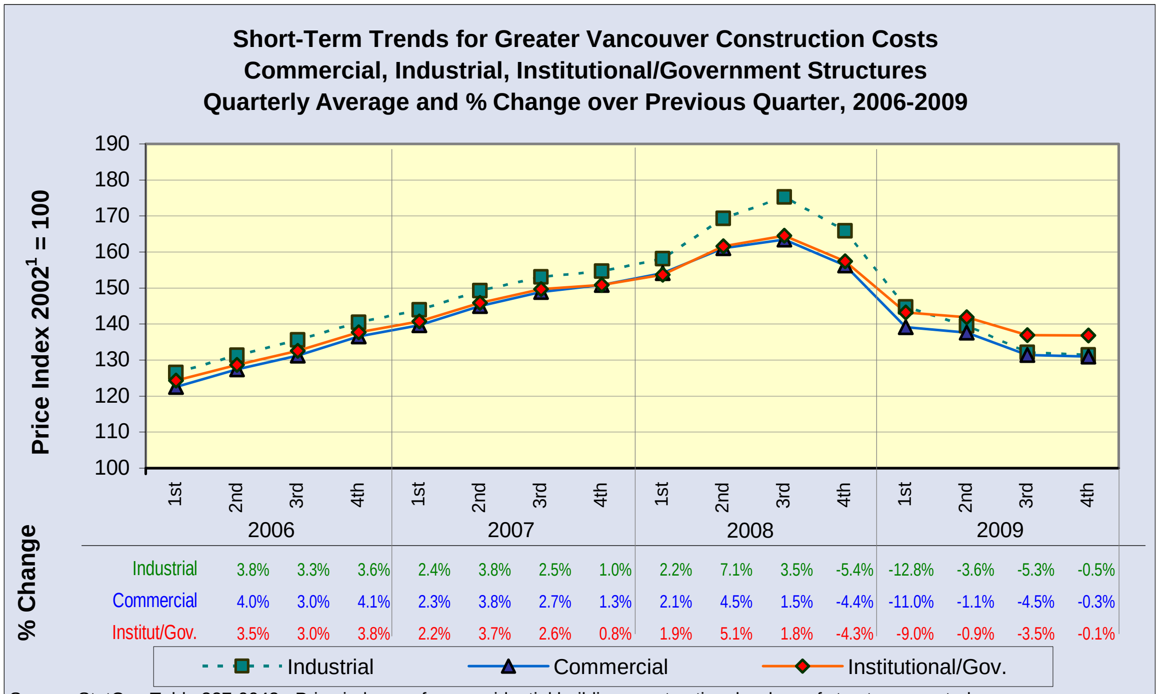
The Vancouver industrial construction price index, after increasing by more than 60% between 2002 and 2008, decreased by 18.1% in 2009. However, even with this decline, price index levels in 2009 were still nearly 40% higher than in 2002, and well above the historical price index trends recorded between1991 and 2003.

Nationally, the seven-city CMA industrial construction price index increased less rapidly than the Vancouver index between 2002 and 2008, but also decreased by much less in 2009. Seven-year price index trends (2002-2009) are now higher for the seven-CMA composite than for Vancouver.

c) Quarterly trends

As illustrated in Exhibit 2d, the Vancouver industrial construction price index was trending slightly higher than the indices for the other two sub-categories, on a quarterly basis, from 2006 through the third quarter of 2008. However, the non-residential construction price index recorded a steeper decline between the third quarter of 2008 and the fourth quarter of 2009, bringing the industrial construction index trends back into line with recent-year trends in the other subsectors.

Exhibit 2d — Quarterly price index trends for non-residential construction, by subsector



	2006				2007				2008				2009			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Industrial	3.8%	3.3%	3.6%	2.4%	3.8%	2.5%	1.0%	2.2%	7.1%	3.5%	-5.4%	-12.8%	-3.6%	-5.3%	-0.5%	
Commercial	4.0%	3.0%	4.1%	2.3%	3.8%	2.7%	1.3%	2.1%	4.5%	1.5%	-4.4%	-11.0%	-1.1%	-4.5%	-0.3%	
Institut/Gov.	3.5%	3.0%	3.8%	2.2%	3.7%	2.6%	0.8%	1.9%	5.1%	1.8%	-4.3%	-9.0%	-0.9%	-3.5%	-0.1%	

Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly
1. Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous report

2.3 Building construction activity levels

a) Annual trends

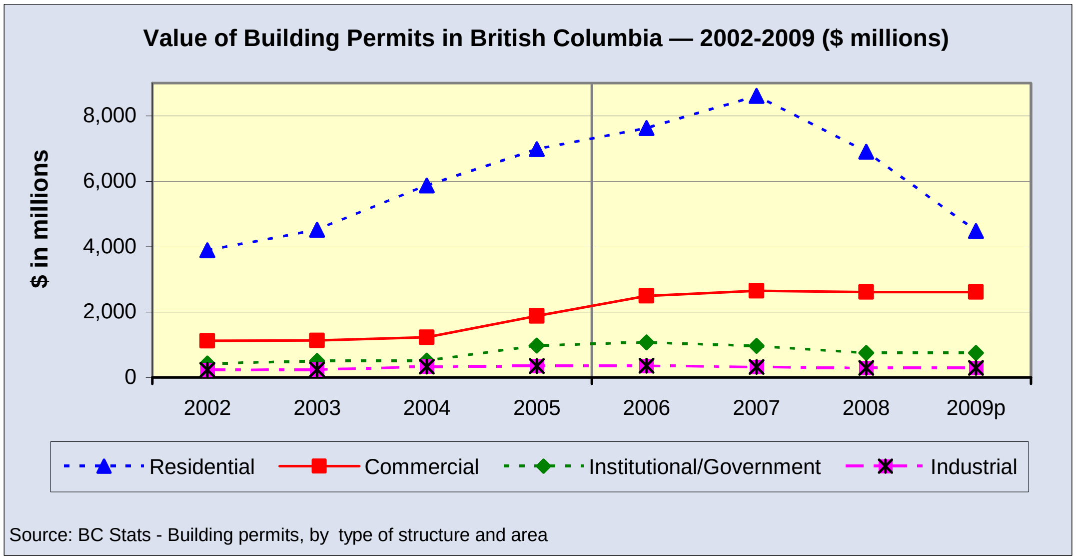
As illustrated in Exhibits 2e and 2f, the total value of building permits more than doubled in BC between 2002 and 2007. The value of building permits was on pace during the first half of 2008 to reach an all-time high for the year, but then sharply during the second half of the year. Building permit values continued to decline in 2009, dropping to approximately 2002 levels of construction activity after allowing for construction price inflation.

For industrial construction, the value of building permits in 2009 was similar to 2003 levels, representing a significant decline in activity levels after allowing for construction price inflation.

Exhibit 2e — Value of BC building permits ($ million) by sector

	2001	2002	2003	2004	2005	2006	2007	2008	% Change 2007 to	2009	% Change 2008 to
British Columbia (Total)											
Total value	4,954.7	5,659.4	6,394.2	7,938.7	10,191.1	11,541.6	12,544.7	10,556.6	-15.8%	7,619.5	-27.8%
Non-residential											
Industrial	221.0	230.0	244.0	328.0	346.2	358.2	323.9	291.7	-9.9%	244.8	-16.1%
Commercial	1,171.0	1,117.0	1,130.0	1,228.0	1,886.4	2,491.4	2,647.9	2,617.0	-1.2%	1,759.9	-32.8%
Institutional/Govnt	732.0	424.0	506.0	514.0	979.5	1,067.4	961.2	746.7	-22.3%	1,135.1	52.0%
Total non-residential	2,124.0	1,771.0	1,880.0	2,070.0	3,212.1	3,917.0	3,933.0	3,655.4	-7.1%	3,139.8	-14.1%
Residential	2,830.7	3,888.4	4,514.2	5,868.7	6,979.0	7,624.1	8,611.7	6,901.2	-19.9%	4,479.6	-35.1%

Exhibit 2f — Value of BC building permits ($ million) by sector, 2002 to 2009 (Graphic format)



Value of Building Permits in British Columbia — 2002-2009 ($ millions)

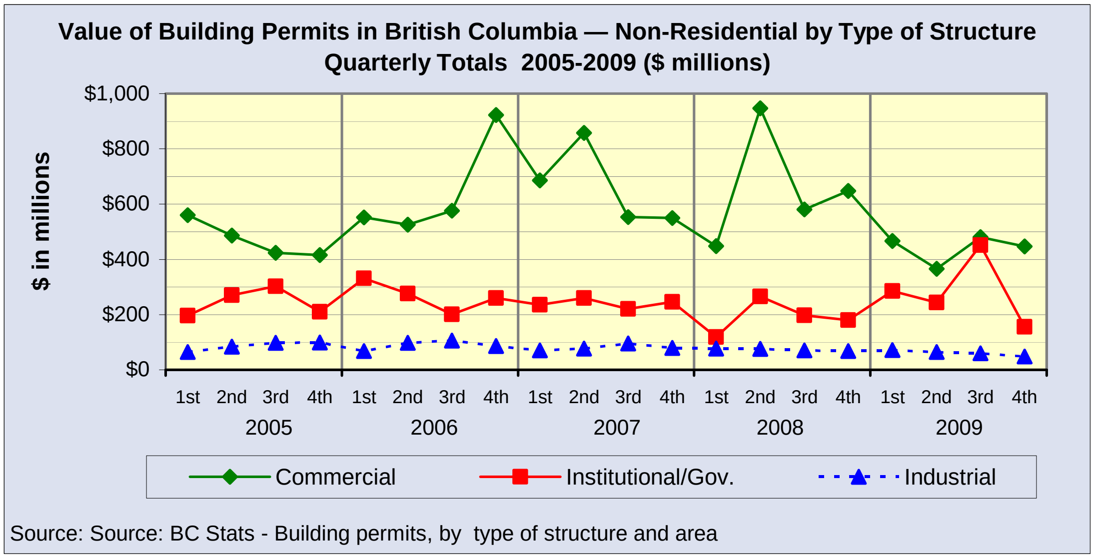
Source: BC Stats - Building permits, by type of structure and area

b) Quarterly trends

Exhibit 2g illustrates the quarterly trends in commercial, institutional/government and industrial construction activity levels in 2009 and prior years. Quarterly trends in commercial construction were steadier in 2009 than in 2008, at lower activity levels.

Industrial building activity, the type of construction most relevant to BC Hydro projects, continued to be a fairly small segment of the overall non-residential construction market.[1]

Exhibit 2g — Quarterly trends in BC non-residential building permit values, by type of structure



Source: Source: BC Stats - Building permits, by type of structure and area

2.4 Canadian regional trends

Bidders for BC Hydro's major construction projects are typically larger firms operating at national and international levels. All significantly-sized industrial construction contractors in BC are affected, directly or indirectly, by trends in other jurisdictions.

2.4.1 Price index trends — Toronto, Calgary, Vancouver

a) *Annual trends*

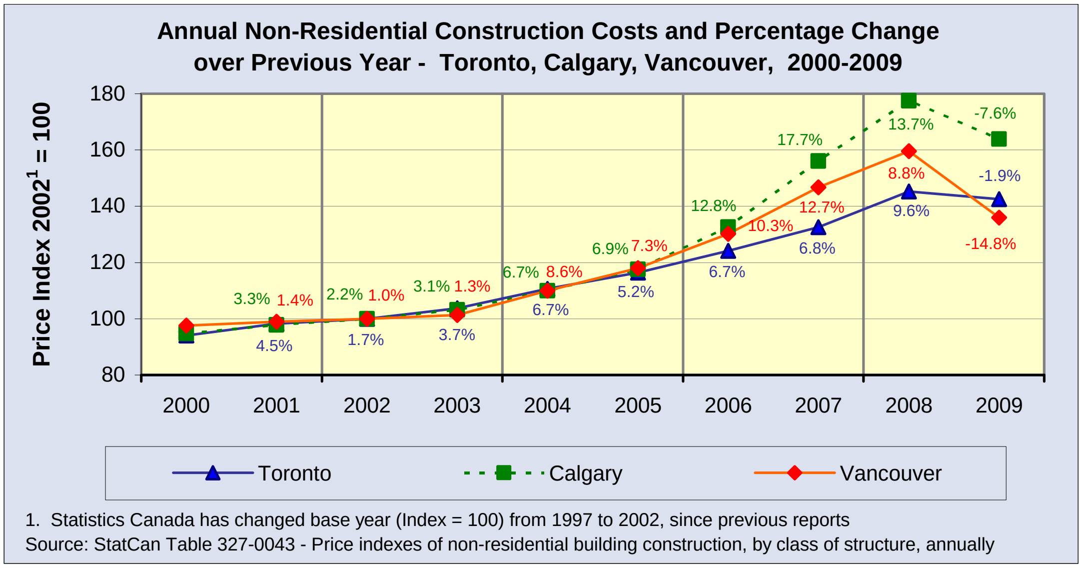
Exhibit 2h compares annual price index trends for non-residential construction in Toronto, Calgary and Vancouver:

- Vancouver's non-residential construction price index declined by 14.8%, highest among the three cities. This drop, following a 60% increase between 2002 and 2008, results in Vancouver having the lowest cumulative increase in non-residential construction prices since 2002 among the three cities.
- Calgary's index declined by 7.6%, second highest among the cities. Combined with the nearly 80% increase between 2002 and 2008, Calgary has been the highest overall increase in non-residential construction prices since 2002.
- Toronto's index declined by just 1.9%, bringing Toronto's overall increase since 2002 to just over 40%, lower than for Calgary but higher than for Vancouver.

---

[1] Note: Some types of industrial construction (e.g. BC Hydro projects) are not captured in building permit data.

Exhibit 2h — Annual non-residential construction price index trends — Toronto, Calgary, Vancouver



1. Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous reports
Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, annually

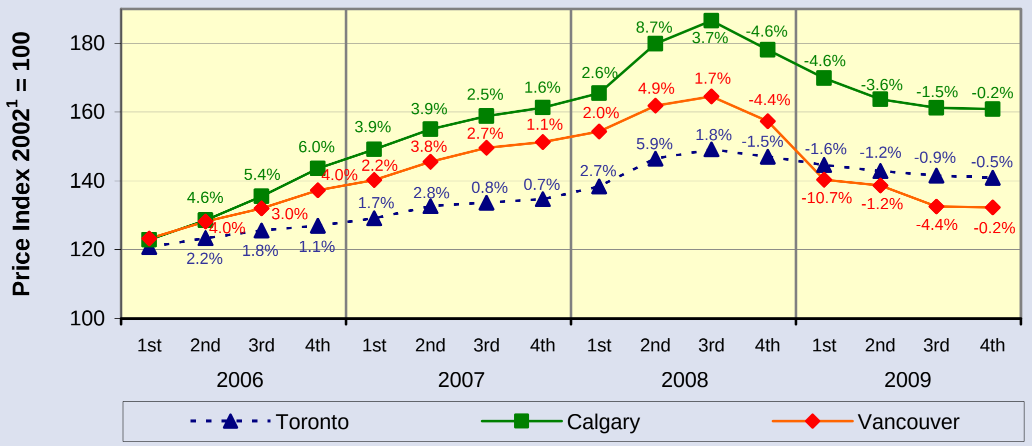
b) *Quarterly trends*

Exhibit 2i illustrates the quarterly price index trends for Toronto, Calgary and Vancouver, both for the overall non-residential construction sector and for the industrial construction sub-sector.

Quarterly trends are fairly consistent across the three cities, for both the overall non-residential construction sector and the industrial construction sub-sector. Price indices declined sharply between the third quarter of 2008 and the second quarter of 2009, before starting to flatten out in the third and fourth quarters of 2009.

Exhibit 2i – Recent quarterly trends for non-residential and industrial construction costs — Toronto, Calgary and Vancouver

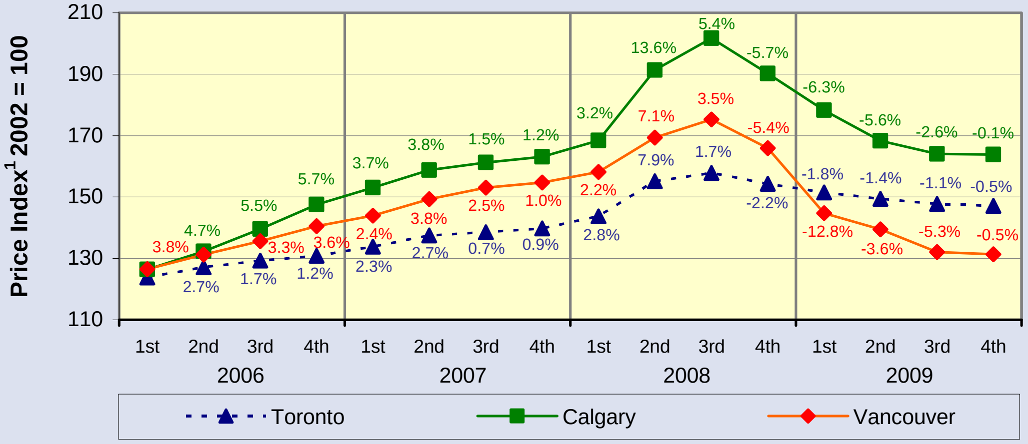
Quarterly Trends for Non-Residential Construction Costs and Percentage Change over Previous Quarter - Toronto, Calgary, Vancouver, 2006-2009



1. Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous report

Source: StatCan Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly

Quarterly Trends for Industrial Construction Costs and Percentage Change over Previous Quarter - Toronto, Calgary, Vancouver, 2006-2009



1. Statistics Canada has changed base year (Index = 100) from 1997 to 2002, since previous report

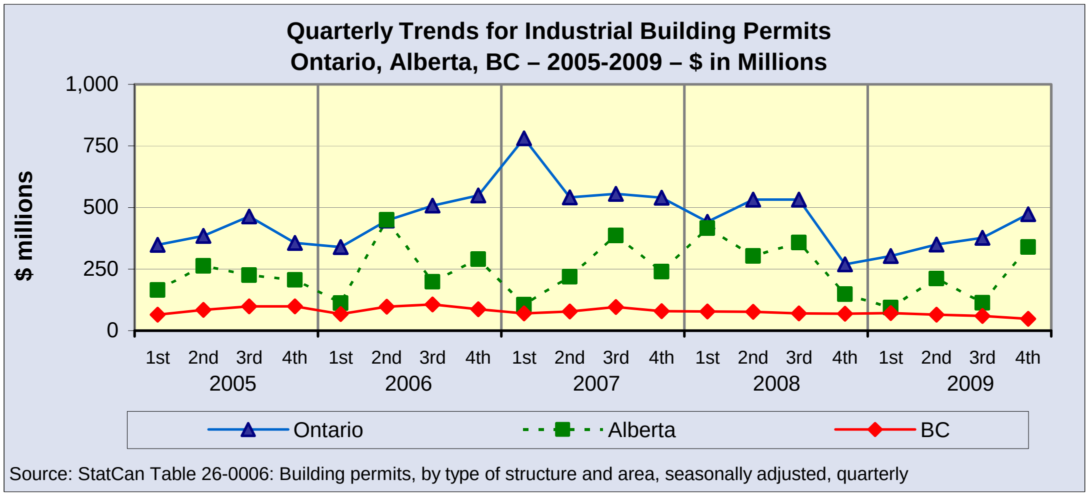
Source: StatCan Table 327-0043 - Price indexes of industrial building construction, by class of structure, quarterly

2.4.2 Activity level trends — Ontario, Alberta and BC

Quarterly trends in the value of industrial building permits for Ontario, Alberta and BC, are compared in Exhibit 2j.

The quarterly results for 2009 show some evidence of a recovery in activity levels in Alberta and Ontario, but not yet in British Columbia.

Exhibit 2j – Quarterly activity trends — Ontario, Alberta, BC



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

2.5 US construction price trends

On an annual basis, US construction price index[1] trends in have been similar to those in Canada. As illustrated in Exhibit 2k(i), the heavy construction price index declined 7.6% in 2009, following strong increases between 2003 and 2008.

On a quarterly basis, US construction price index trends were also similar to those in Canada. As illustrated in Exhibit 2k (ii), price indices dropped sharply between the third quarter of 2008 and the first quarter of 2009, before flattening out in the second quarter and increasing slightly between the second and fourth quarters.

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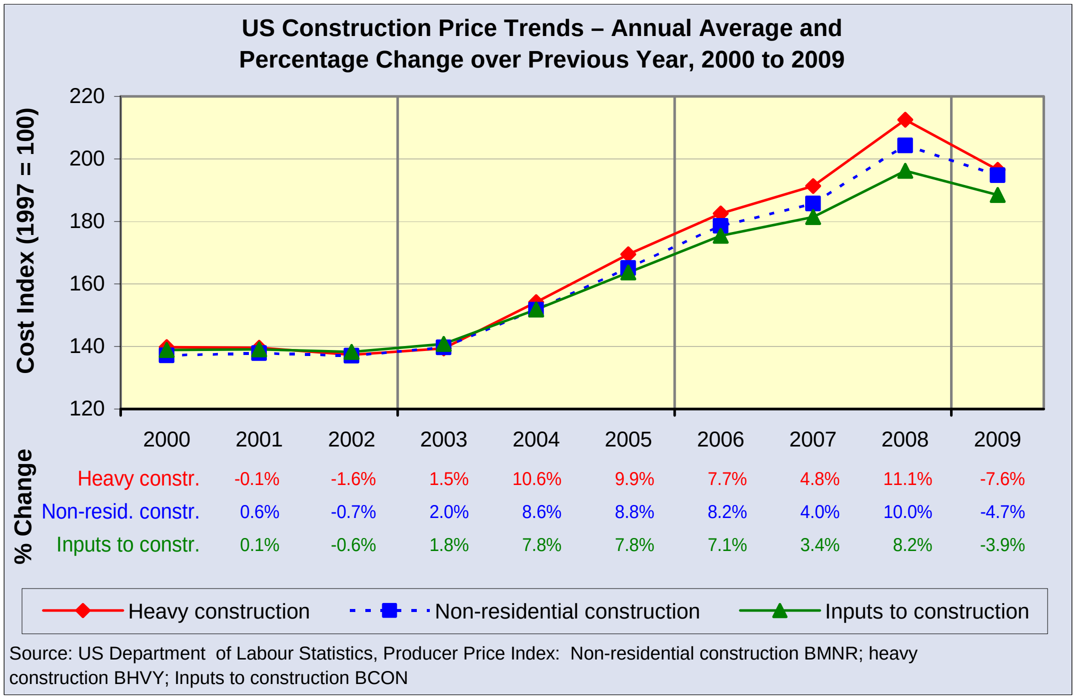
[1] US non-residential construction price indices are defined as follows by Bureau of Labor Statistics:

- **Non-residential construction** price indices represent output price measures for four types of new non-residential building structures: warehouse, school, office, industrial/manufacturing. To achieve an output price, BLS combines the detailed material and installation (labor and related equipment) cost data, which are updated quarterly by a cost-estimating firm, with margin (overhead and profit) data collected monthly by BLS directly from building construction contractors. Therefore, the BLS non-residential construction price indices measure changes in the input costs for non-residential structures, plus the change in contractor markups.
- **Inputs to construction** industries price indices are derived from the primary product indices for:
  (1) New construction, weighted at 69.77%, for: (a) residential (31.08%); (b) non-residential (14.01%) - industrial, warehouse, school, and office; (c) highway and street construction (6.01%); and (d) other heavy construction (18.67%).
  (2) Maintenance and repair construction, weighted at 30.23%, for (a) residential (10.46%) and non-residential (19.77%).
- **Heavy construction** price index is a subset of “inputs to construction” and is weighted at 18.67% of total “inputs to construction”.

Exhibit 2k – US construction price trends
(i) Annual construction price trends

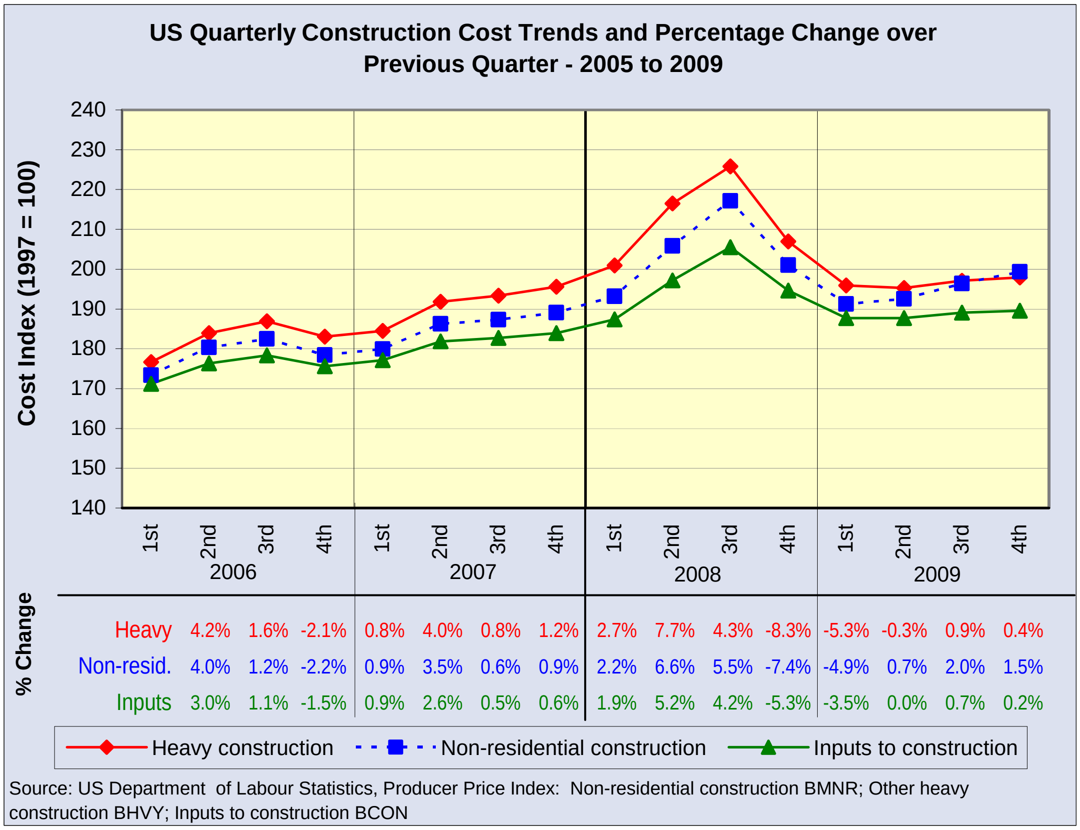


US Construction Price Trends – Annual Average and Percentage Change over Previous Year, 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Heavy constr.	-0.1%	-1.6%	1.5%	10.6%	9.9%	7.7%	4.8%	11.1%	-7.6%	
Non-resid. constr.	0.6%	-0.7%	2.0%	8.6%	8.8%	8.2%	4.0%	10.0%	-4.7%	
Inputs to constr.	0.1%	-0.6%	1.8%	7.8%	7.8%	7.1%	3.4%	8.2%	-3.9%	

Source: US Department of Labour Statistics, Producer Price Index: Non-residential construction BMNR; heavy construction BHVY; Inputs to construction BCON

(ii) Quarterly construction price trends



US Quarterly Construction Cost Trends and Percentage Change over Previous Quarter - 2005 to 2009

	2006				2007				2008				2009			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Heavy	4.2%	1.6%	-2.1%	0.8%	4.0%	0.8%	1.2%	2.7%	7.7%	4.3%	-8.3%	-5.3%	-0.3%	0.9%	0.4%	
Non-resid.	4.0%	1.2%	-2.2%	0.9%	3.5%	0.6%	0.9%	2.2%	6.6%	5.5%	-7.4%	-4.9%	0.7%	2.0%	1.5%	
Inputs	3.0%	1.1%	-1.5%	0.9%	2.6%	0.5%	0.6%	1.9%	5.2%	4.2%	-5.3%	-3.5%	0.0%	0.7%	0.2%	

Source: US Department of Labour Statistics, Producer Price Index: Non-residential construction BMNR; Other heavy construction BHVY; Inputs to construction BCON

3. Price and Activity Trends — Electric Utility Industry

This chapter analyzes the industry-specific price and activity level information that is particularly relevant to the Canadian electric utility industry.

3.1 Canadian electric utilities price trends

Exhibit 3a presents the Statistics Canada's price index data for Canada-wide electric utility costs with respect to (1) distribution systems, (2) transmission lines, and (3) substations. Data are provided by Statistics Canada on an annual basis only.

3.1.1 Longer-term annual trends

Long-term price index trends for electric utility construction in Canada have been significantly lower than for the broader non-residential construction price indices:

- As illustrated in Exhibit 3a(i), the cumulative 17-year increase in price indices for the three categories of electric utilities was 50% between 1992 and 2009 — an average annual increase (compounded) of 2.4%.
- By contrast, as illustrated earlier in Exhibit 2a, the 17-year increases in the broader non-residential construction price indices between 1992 and 2007 was approximately 80% (depending on the specific index) — an average annual increase (compounded) of 3.4%.

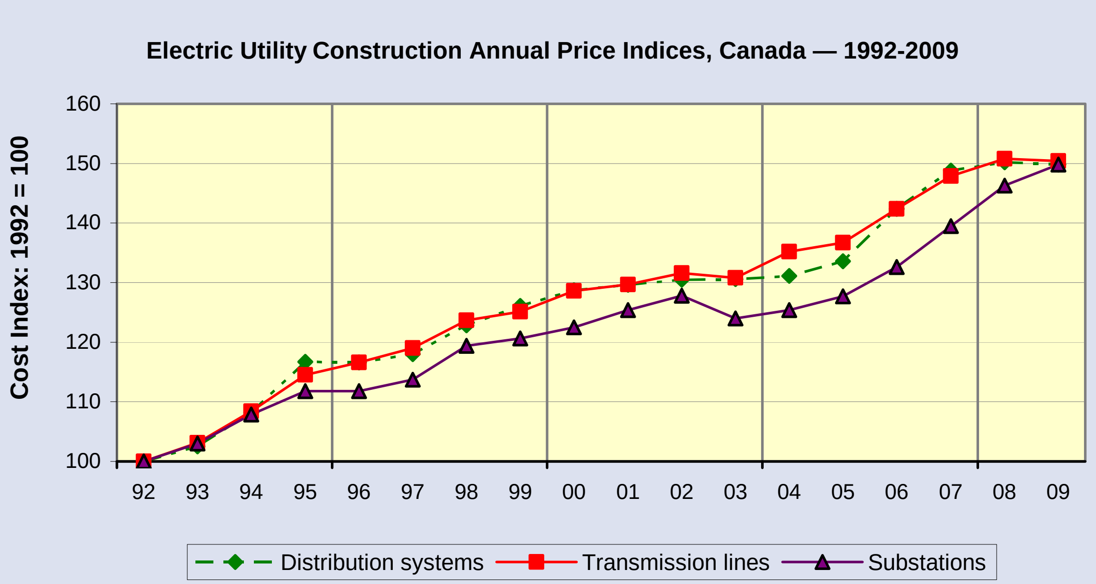
3.1.2 Recent-year annual trends

Recent-year annual percentage changes are illustrated in Exhibit 3a(ii). During 2009, price index trends were essentially flat for distribution systems and transmission lines, but increased 2.4% for substations. The results for 2009 represent a significant shift from the upward price index trends in previous years.

While the shifts in electric utility price index trends have reflected those of the broader-based indices, the magnitude of these shifts has been lower. When non-residential price indices were increasing rapidly, they increased at a relatively lower rate for electrical utility price indices. When non-residential price indices dropped between 2008 and 2009, electric utility price indices softened, but did not turn significantly negative. This issue is discussed in more detail in the following section.

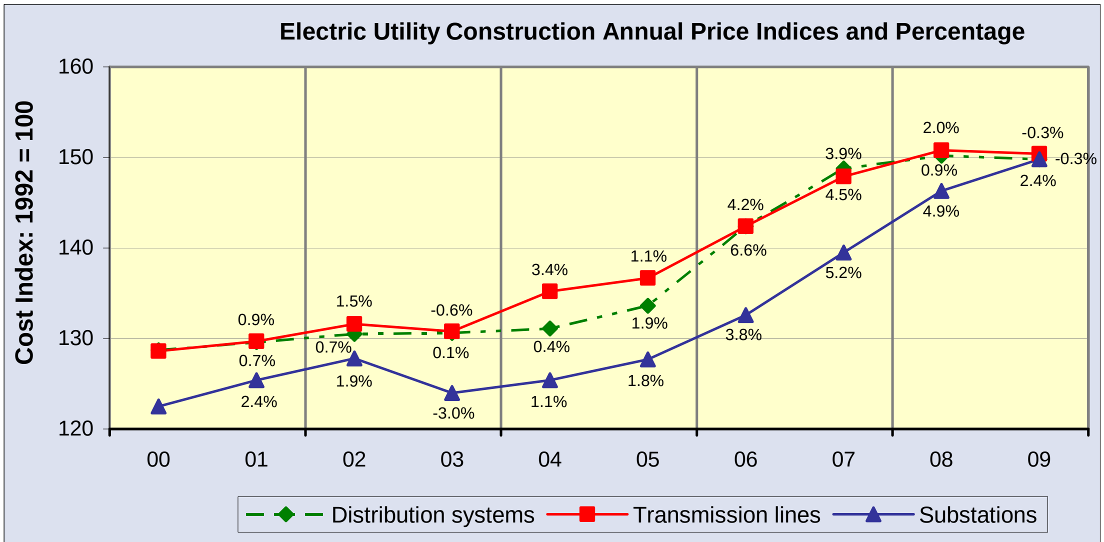
Quarterly data are not available for the Canadian electric utility industry.

Exhibit 3a — Electric utility construction price trends — Canada
(i) Long-term annual trends



Sources: StatsCan: Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (Index, 1992=100): Distribution systems V735224; Transmission lines V735255; Substations V735284

(ii) Recent-year annual trends

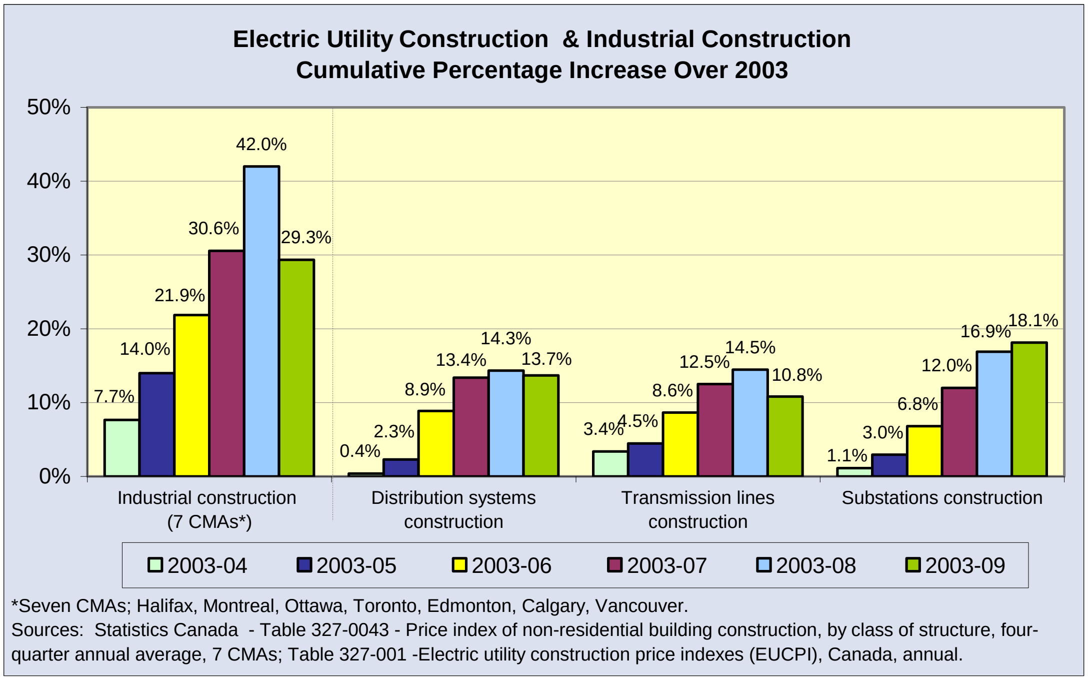


Sources: StatsCan: Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (Index, 1992=100): Distribution Systems V735224; Transmission lines V735255; Substations V735284

3.1.3 Comparison of electric utility vs. industrial construction price indices

Exhibit 3b compares five-year cumulative trends in Statistics Canada's electric utility construction indices to the cumulative trends in the industrial construction price index.

Exhibit 3b – Comparison of industrial construction price index with electric utility indices



*Seven CMAs; Halifax, Montreal, Ottawa, Toronto, Edmonton, Calgary, Vancouver.
Sources: Statistics Canada - Table 327-0043 - Price index of non-residential building construction, by class of structure, four-quarter annual average, 7 CMAs; Table 327-001 -Electric utility construction price indexes (EUCPI), Canada, annual.

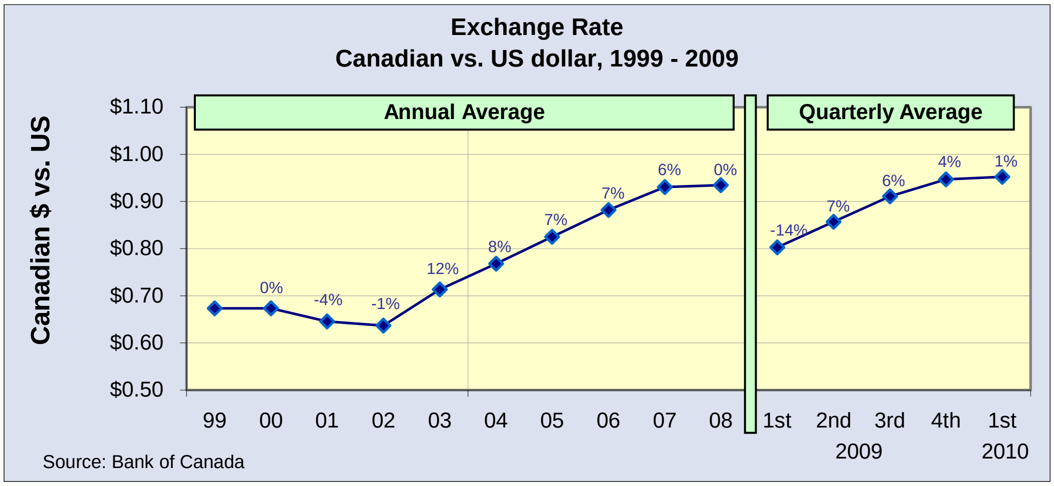
Over the past six years, Statistics Canada's distribution system, transmission, and substation price indices have increased by between 10.8% and 18.1% - far less than the 29.3% increase in the seven-city composite industrial construction price index during the same period.

A number of factors have been identified as likely contributing to the differences in reported trends:

- One factor is the specialized nature of the utility-based industrial construction segment. There may be a somewhat limited ability of firms specializing in electric utility construction to cross over into other construction industry market segments, and vice versa.
- Another factor is the concentrated nature of the Canadian electric utility industry (limited number of major customers, limited number of companies with the capacity to perform large construction projects). The concentrated nature of the industry may contribute to more stable markets.
- A third likely factor is the increase in the value of the Canadian dollar since 2003, as illustrated in Exhibit 3c. Canadian electric utility companies typically purchase significant quantities of imported electric utility materials (e.g. cables) and equipment (e.g. transformers). A stronger Canadian dollar tends to reduce the cost of these purchases. As illustrated in Exhibit 3c, the Canadian dollar strengthened

considerably against the US dollar between 2002 and early 2008, and after weakening during the second half of 2008 has strengthened again in late 2009 and early 2010.

Exhibit 3c – Exchange rate trends: Canadian vs. US dollar



Source: Bank of Canada

3.2 US electric utility price trends

a) US construction price trends

Price index trends for US electric utility construction, as measured by the US Bureau of Reclamation,[1] are illustrated in Exhibit 3d.

As illustrated in Exhibit 3d(i), price index trends for switchyards/substations were flat in 2009, following several years of strong increases. For steel tower transmission lines, the 5.2% decline in 2009 followed the strong upward trends of the previous several years. For wood pole transmission lines, the price index dropped 9.3%.

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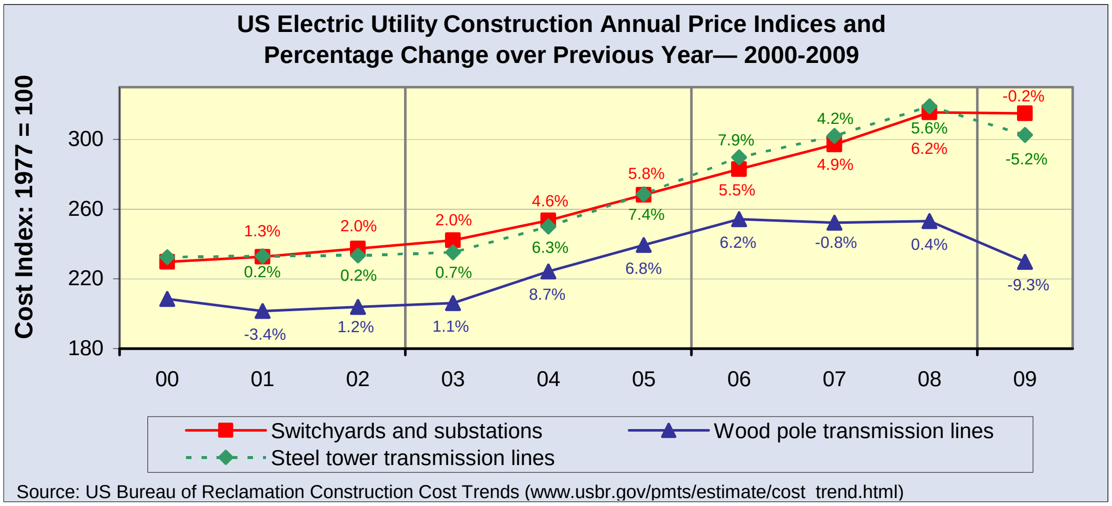
[1] The US Bureau of Reclamation manages, develops, and protects water and related resources. It has developed Construction Cost Trends to track construction relevant to the primary types of projects being constructed by the organization. Cost models consisting of appropriate labor, equipment, and materials types are used as the principal costs reference. Data for the models are primarily extracted from:
- Producer Price Indexes [PPI], US Department of Labor, Bureau of Labor Statistics
- Price Trends for Federal-Aid Highway Construction, US Department of Transportation
- Engineering News-Record, weekly publication of McGraw-Hill.
Actual field data, when available, is used to confirm the reasonableness of the models.

Exhibit 3d – US electric utility construction price indices
(i) Annual trends, 2000 to 2009



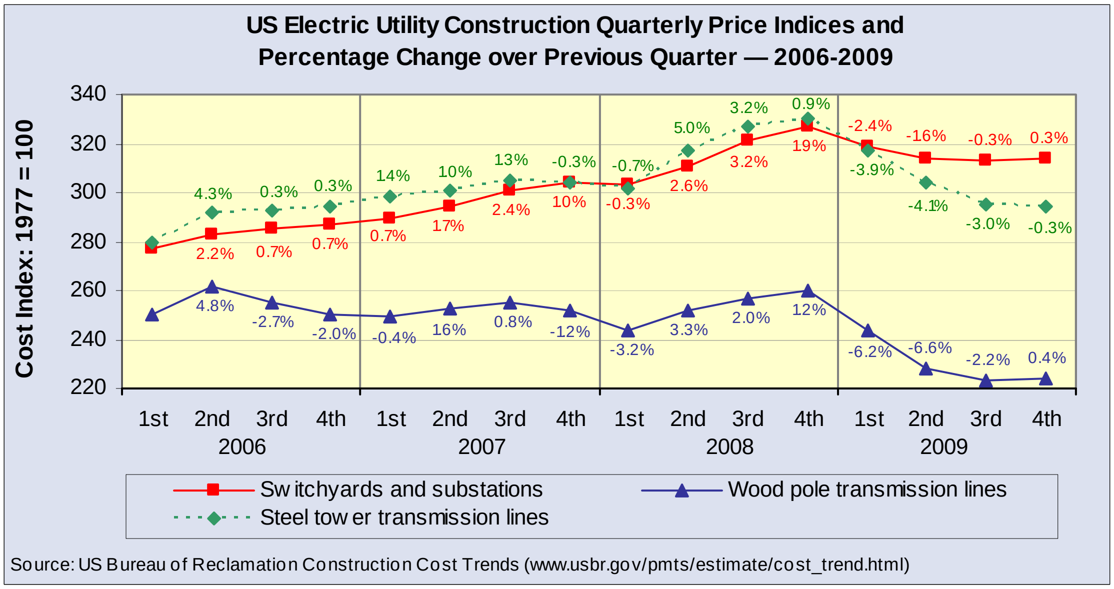
US Electric Utility Construction Annual Price Indices and Percentage Change over Previous Year— 2000-2009

Source: US Bureau of Reclamation Construction Cost Trends (www.usbr.gov/pmts/estimate/cost trend.html)

One likely explanation of the relatively weaker price index trends for wood pole transmission lines is that the industry may be moving away from wood poles, towards steel poles, and that this technology shift may be impacting the supply-demand relationships in the markets for wood poles.

On a quarterly basis, Exhibit 3d(ii) illustrates that the price level decreases occurred primarily between the fourth quarter of 2008 and the third quarter of 2009.

(ii) Quarterly trends, 2006 to 2009



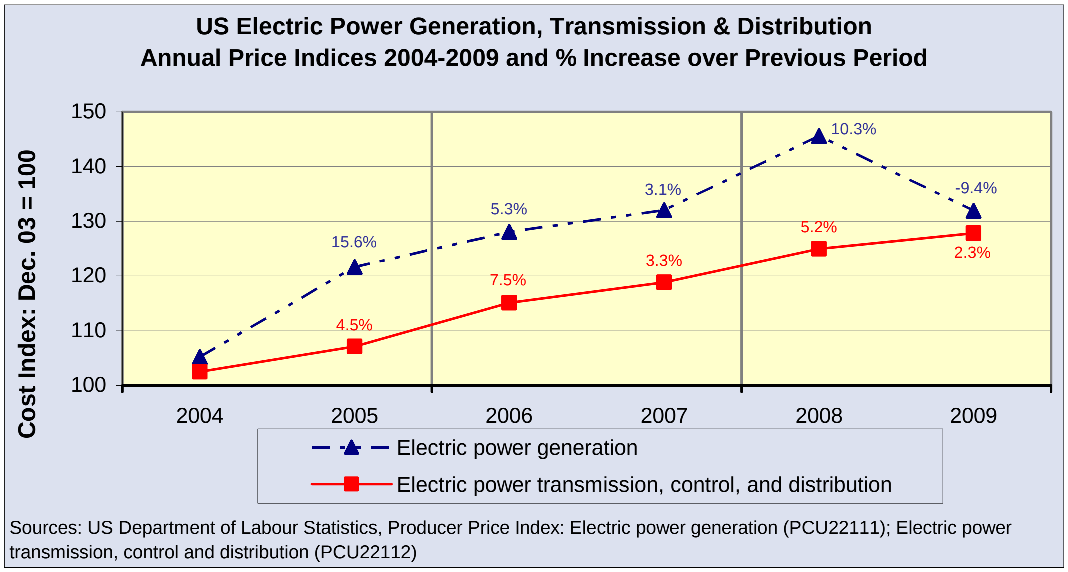
US Electric Utility Construction Quarterly Price Indices and Percentage Change over Previous Quarter — 2006-2009

Source: US Bureau of Reclamation Construction Cost Trends (www.usbr.gov/pmts/estimate/cost_trend.html)

b) *US producer price trends*

US producer price trends for electric power generation, transmission and distribution are illustrated in Exhibit 3e.

Exhibit 3e – US electric power generation, transmission & distribution — (i) Annual trends 2004-09

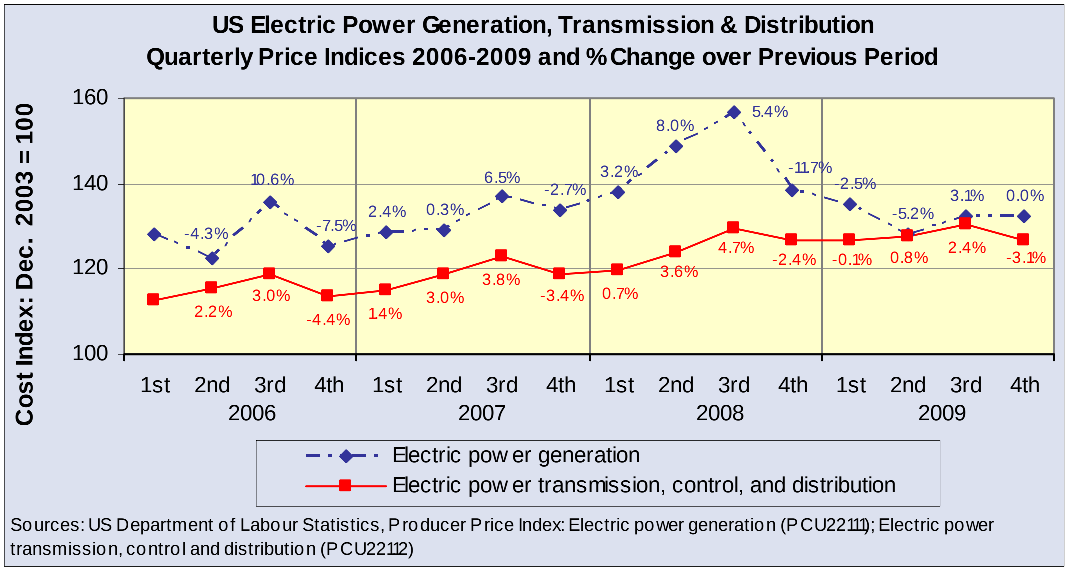


Sources: US Department of Labour Statistics, Producer Price Index: Electric power generation (PCU22111); Electric power transmission, control and distribution (PCU22112)

For electric power generation, producer prices in 2009 fell by 9.4%, back to 2007 levels, after having increased significantly in 2008. For electric power transmission, control and distribution, producer prices increased by 2.3%, a softening of their upward trend of the past few years.

As illustrated in Exhibit 3e(ii), , the quarterly results for electric power generation show declining price trends in the first and second quarter, followed by an increase in the third quarter and flat trends in the fourth quarter. Quarterly price index trends for electric power transmission, control and distribution show an increase in the third quarter and a decrease in the fourth quarter, consistent with the seasonal patterns of previous years.

Exhibit 3e – US electric power generation, transmission & distribution (ii) Quarterly trends 2006-2009



US Electric Power Generation, Transmission & Distribution
Quarterly Price Indices 2006-2009 and % Change over Previous Period

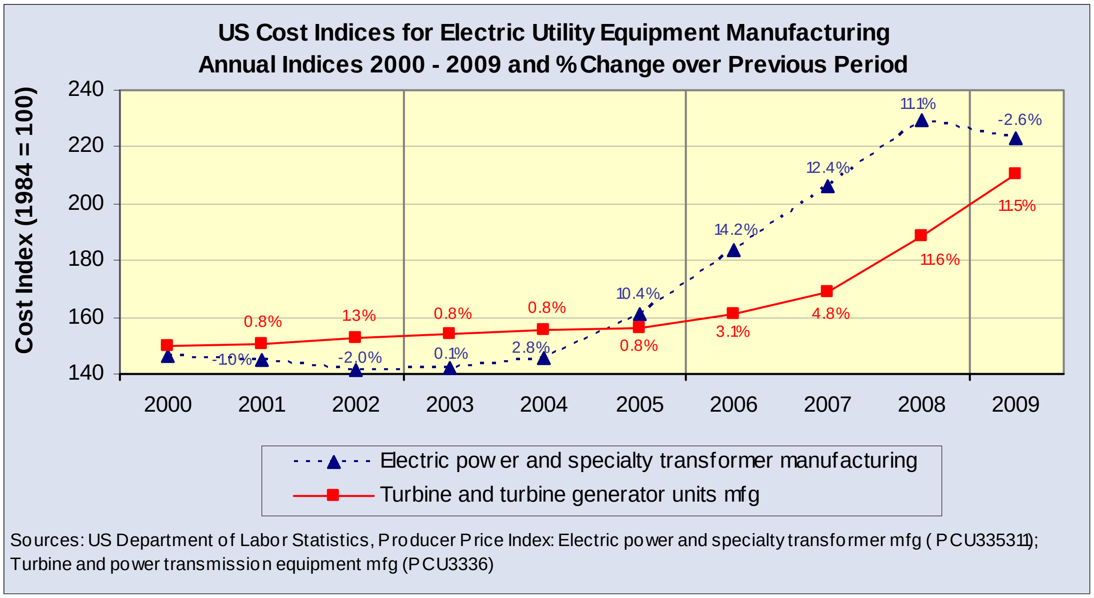
Sources: US Department of Labour Statistics, Producer Price Index: Electric power generation (PCU2211); Electric power transmission, control and distribution (PCU2212)

c) *US utility equipment manufacturing price trends*

On an annual basis (Exhibit 3f(i)), the US electric power and specialty transformer equipment manufacturing price index decreased by 2.6% in 2009, following four years of price index increases of more than 10% annually. By contrast, the turbine and power transmission equipment manufacturing price index increased by 11.5%, in 2009, continuing the strong 11.6% upward trend between 2007 and 2008.

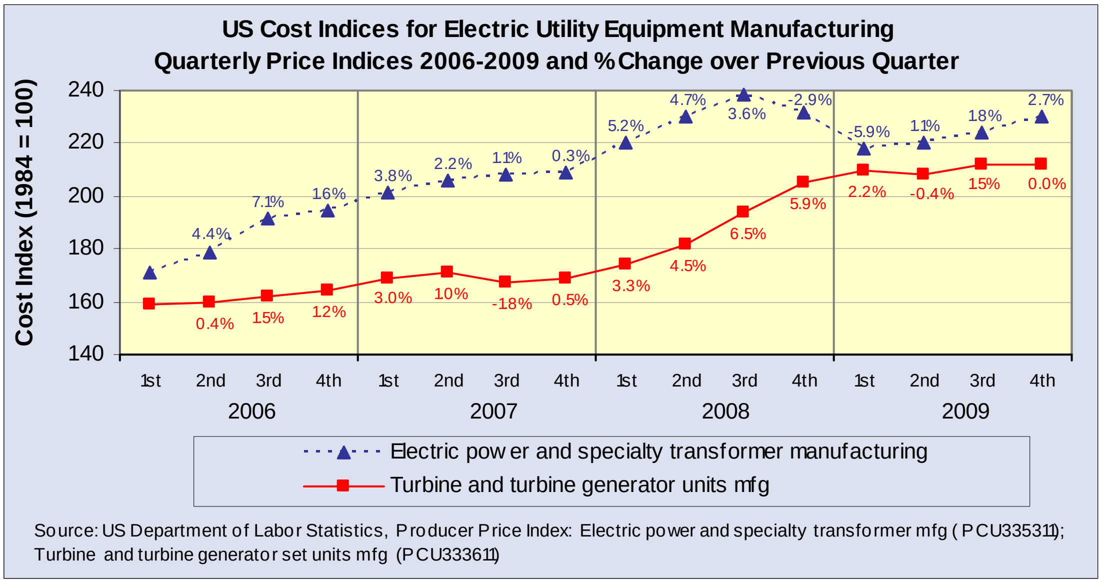
On a quarterly basis (Exhibit 3f(ii)), the electric power and specialty transformer equipment manufacturing price index dropped sharply between the third quarter of 2008 and the first quarter of 2009, before partly recovering during the balance of the year. By contrast, the turbine and power transmission manufacturing price index increased significantly between the third quarter of 2008 and the first quarter of 2009, at a time when most other relevant price indices were either flat or declining.

Exhibit 3f – US electric utility equipment manufacturing
(i) Annual trends 2000-09



Sources: US Department of Labor Statistics, Producer Price Index: Electric power and specialty transformer mfg (PCU335311); Turbine and power transmission equipment mfg (PCU3336)

(ii) Quarterly trends 2005 to 2009



Source: US Department of Labor Statistics, Producer Price Index: Electric power and specialty transformer mfg (PCU335311); Turbine and turbine generator set units mfg (PCU333611)

d) US construction activity trends

The need for major re-investment in the aging US electric utility infrastructure network is widely acknowledged. According to a September 2007 report prepared for the **Edison Foundation**[1]:

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[1] Source: "Rising Utility Construction Costs: Sources and Impacts", The Battle Group, September 2007. Prepared for The Edison Foundation. (p.5 and 6)

- **"**Utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon. …Investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030."

The Edison report also indicated a shortage of spare shop capacity in the electric equipment and machinery manufacturing sector, as a result of increasing activity in electric utilities construction.

As late as the summer of 2008, **Reed Construction Data News** (Reed) was predicting that power construction spending in the US would increase by 32% in 2008 and 15% in 2009, writing that:

- "…Capacity addition information published by the US Department of Energy suggests that the surge in power facility construction will continue for several more years although at a somewhat reduced pace. "

- "…Non-cyclical forces account for most of the surge in power facility construction and they will continue, probably strengthen, during the weak period in the economy during 2008-2010. These include mandates to reduce air pollution, to generate electricity with renewable fuel which requires new power stations and distribution lines, …to develop new oil and gas fields and new technology…".

In 2010, Reed (renamed CanaData) has significantly reduced its projections for US electric power construction expenditures. Expressed in current dollars, CanaData is projected that US construction put in place for electric power will drop from USD $87.5 billion in 2009, to USD $80.3 billion in 2010 and USD $77.0 in 2011 – a 12% drop over two years.

3.3 Equipment price trends — South Korea

3.3.1 Power generation and distribution equipment

As illustrated in Exhibit 3g, South Korea's domestic price index[1] increased 10.3% for power transformers and 8.9% for electric generators between 2008 (average for the year) and 2009 (average for the year). These results were slightly lower than the very strong increases recorded between 2007 and 2008, but were very strong in relation to US/Canada trends.

The quarterly results for 2009 were fairly flat, indicating that the increases in South Korean domestic price levels occurred primarily during 2008.

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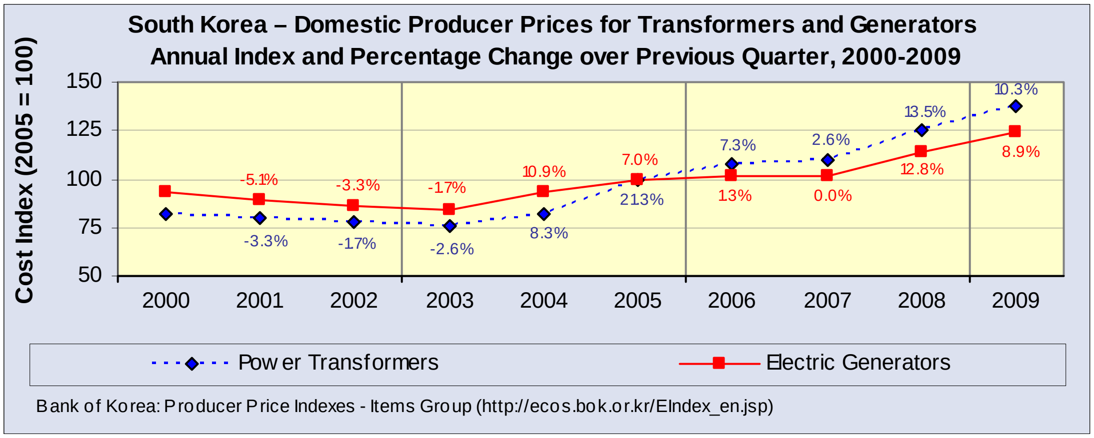
[1] Not adjusted for Canada/Korea exchange rate considerations.

Exhibit 3g – Price trends for power generation equipment, South Korea

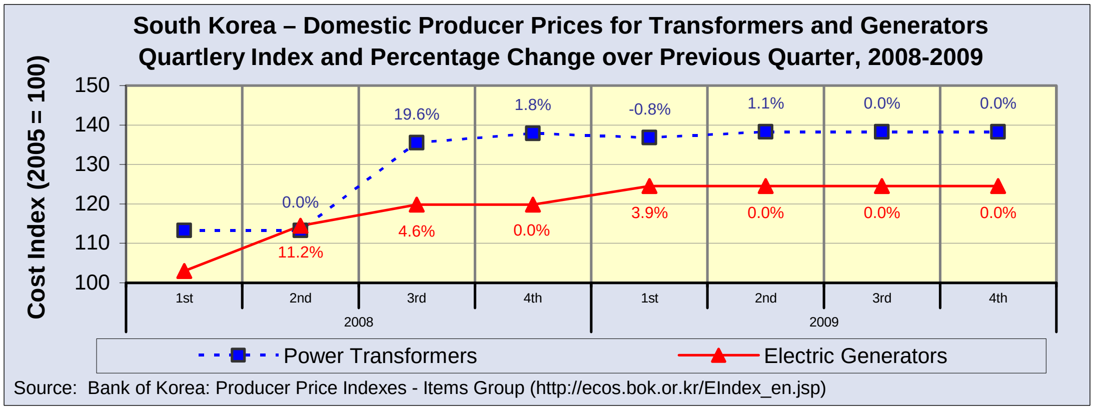
(i) Annual trends



South Korea – Domestic Producer Prices for Transformers and Generators
Annual Index and Percentage Change over Previous Quarter, 2000-2009

Bank of Korea: Producer Price Indexes - Items Group (http://ecos.bok.or.kr/EIndex_en.jsp)

(ii) Recent quarterly trends



South Korea – Domestic Producer Prices for Transformers and Generators
Quartlery Index and Percentage Change over Previous Quarter, 2008-2009

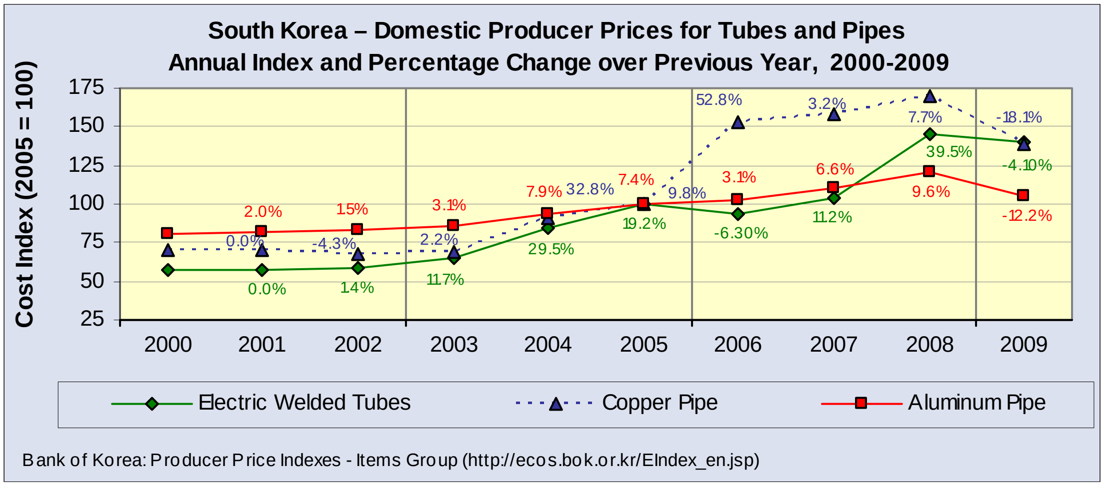
Source: Bank of Korea: Producer Price Indexes - Items Group (http://ecos.bok.or.kr/EIndex_en.jsp)

3.3.2 Other construction equipment and materials

As illustrated in Exhibit 3h, Korean domestic price index trends for selected other types of construction equipment and materials showed declines in 2009 of 18.1% for copper pipe, 12.2% for aluminum pipe, and 4.0% for electric welded tubes.

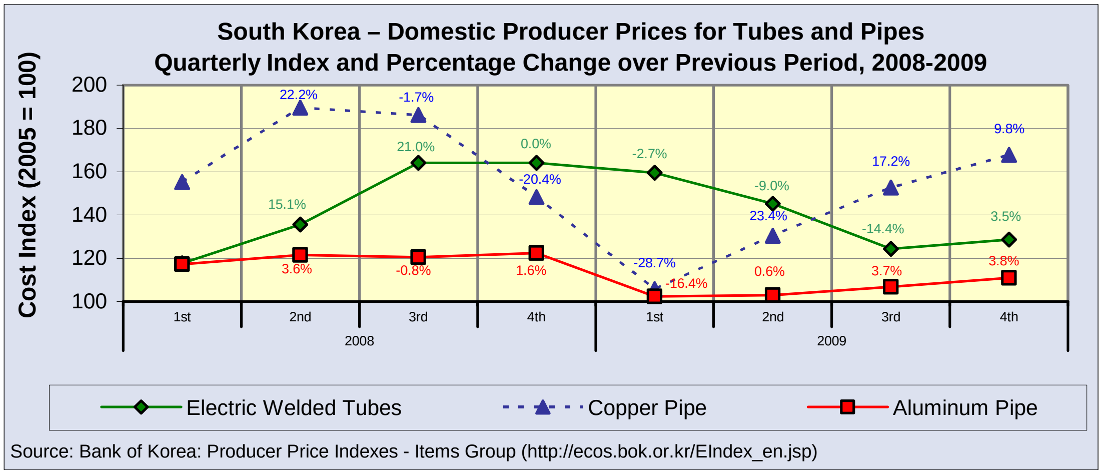
Quarterly data illustrates that copper and aluminum prices dropped between the third quarter of 2008 and first quarter of 2009, before partially recovering during the balance of 2009. Electric welded tube price indices declined for the first three quarters of 2009, before increasing during the fourth quarter.

Exhibit 3h – Cost trends for tubes and pipes, South Korea
(i) Annual trends



Bank of Korea: Producer Price Indexes - Items Group (http://ecos.bok.or.kr/EIndex_en.jsp)

(ii) Recent quarterly trends



Source: Bank of Korea: Producer Price Indexes - Items Group (http://ecos.bok.or.kr/EIndex_en.jsp)

3.3.3 Exchange rate impacts - Korea

As illustrated in Exhibit 3i, currency exchange rates between Canada and South Korea were fairly stable between 2003 and 2007, following which the Canadian dollar appreciated against the Korean between 2007 and early 2009. For BC Hydro, the appreciation in the value of the Canadian dollar has helped to offset the South Korean domestic price index increases indicated in Exhibits 3g and 3h.[1]

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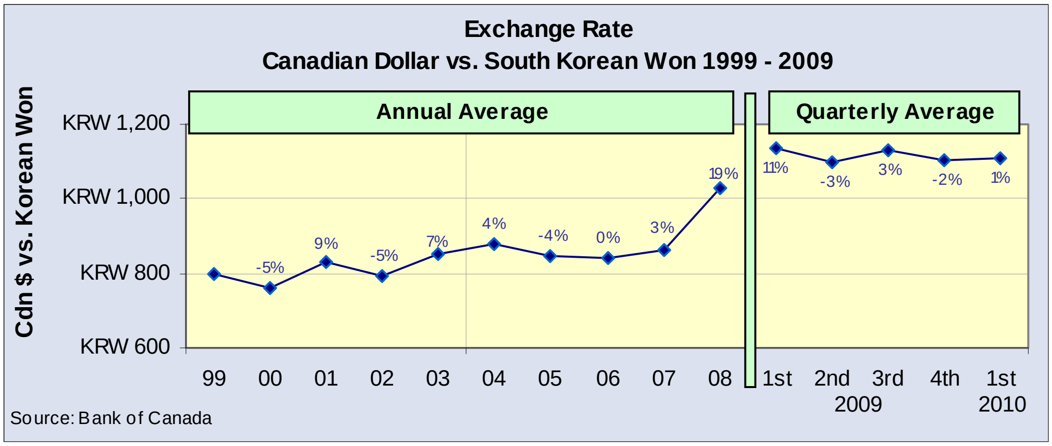
[1] The price indices illustrated in Exhibits 3g and 3h are for domestic sales within South Korea, which may limit to some extent their relevance to export prices available to BC Hydro and other international customers.

Exhibit 3i – Exchange rates — Canadian dollar versus South Korean won



Source: Bank of Canada

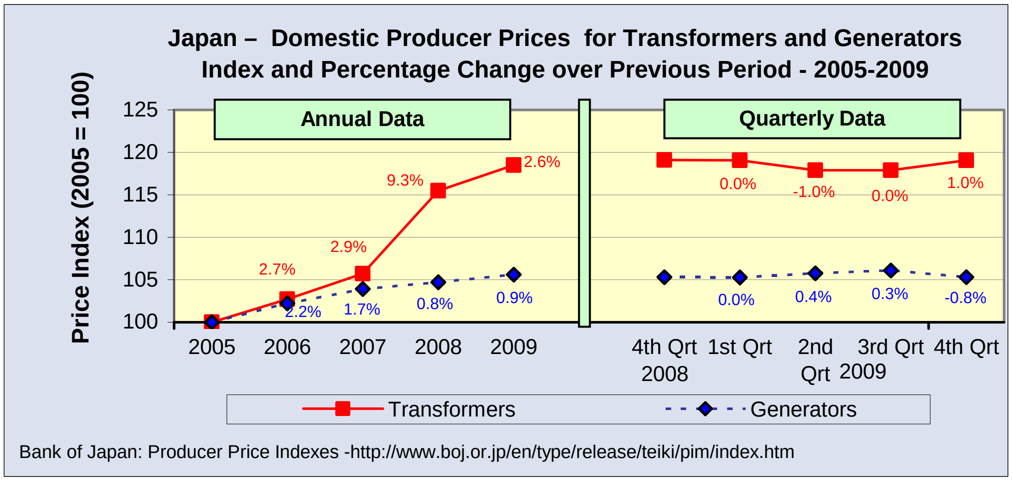
3.4 Equipment price trends — Japan

3.4.1 Power generation and distribution equipment

Domestic price trends for Japanese power generation and transformer equipment, measured in Japanese yen, are presented in Exhibit 3j. For generators, domestic annual price trends in 2009 continued their generally flat trends of previous years.

For transformers, price indices increased by 2.6% in 2009 over 2008, after having increased by 9.3% during the previous year. Quarterly trends for transformers were flat during 2009.

Exhibit 3j – Domestic prices for transformers and generators

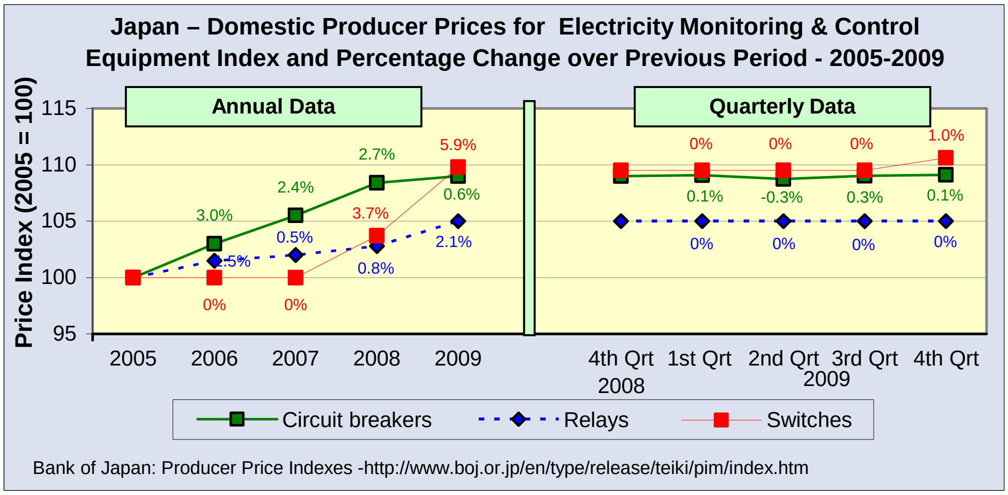


Bank of Japan: Producer Price Indexes -http://www.boj.or.jp/en/type/release/teiki/pim/index.htm

3.4.2 Electricity monitoring and control equipment

Japanese domestic price trends for electricity monitoring and control equipment are illustrated in Exhibit 3k. On an annual basis, all price indexes were up in 2009 over 2008 – circuit breakers by 0.6%, relays by 2.1%, and switches by 5.9%. On a quarterly basis, quarterly price index trends during 2009 were flat for each type of equipment.

Exhibit 3k – Domestic prices for electricity monitoring & control equipment



Japan – Domestic Producer Prices for Electricity Monitoring & Control Equipment Index and Percentage Change over Previous Period - 2005-2009

Bank of Japan: Producer Price Indexes -http://www.boj.or.jp/en/type/release/teiki/pim/index.htm

3.4.3 Exchange rate impacts - Japan

As illustrated in Exhibit 3l, the Canadian dollar appreciated significantly against the Japanese yen between 2000 and 2007. However, this trend was dramatically reversed in 2008 and 2009, as the Canadian dollar lost approximately one quarter of its value against the yen. In early 2010 the Canadian dollar was trading at close to 2003-04 levels.

The weakening of the Canadian dollar against the yen since 2007 tends to increase the cost to BC Hydro of importing Japanese-manufactured electrical equipment.[1]

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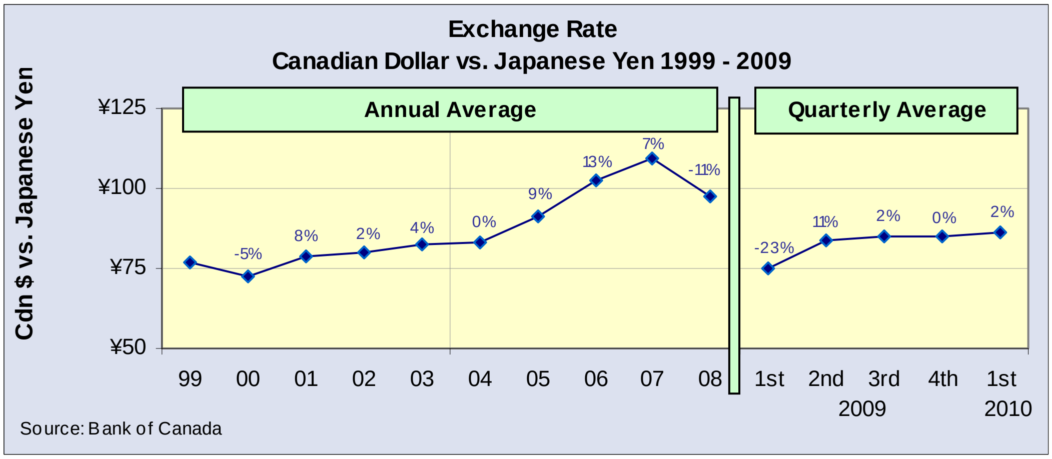
[1] The price indices illustrated in Exhibits 3j and 3k are for domestic prices within Japan, which may limit their applicability to export prices available to BC Hydro and other international customers.

Exhibit 31 - Exchange rates — Canadian dollar versus Japanese yen



Source: Bank of Canada

3.5 Recent BC Hydro purchasing experience

In the 2006 through 2008 editions of this report, BC Hydro staff members were reporting significant increases in international equipment prices. For example:

- The purchase cost of a major 500 kV autotransformer unit in March 2008 was 54% higher than an equivalent unit in August 2005 — an average annual increase of approximately 20%.
- For smaller equipment, price increases through mid-2008 varied by type of unit. An internal BC Hydro analysis in 2008 estimated two-year price increases of 4% to 14% for comparable circuit breaker units, and two-year increases of 0% to 27% for comparable surge arrestor units.

By early 2009, the situation has changed significantly, with BC Hydro staff reporting significantly lower purchasing price levels in most (but not all) cases. For some Canadian-manufactured equipment (e.g. steel poles), prices had dropped dramatically from 2008 levels, while domestic materials and equipment had in general returned to 2005-2006 levels. For some offshore-sourced major equipment (e.g. transformers from Korea), prices had dropped, possibly reflecting the strengthening of the Canadian dollar. However, for some US-sourced materials and equipment (e.g. thermal turbines and generators), BC Hydro had not seen significant price reductions.

In early 2010, BC Hydro indicates that:

- The price-competitiveness of the materials and equipment market has remained high in 2009 and early 2010. The cost to BC Hydro of procuring US and international materials and equipment has been helped by the strength of the Canadian dollar against most other currencies (i.e. the US dollar and Korean won, but not the Japanese yen.)
- Market competition for BC Hydro construction projects has been strong. For example, a recently tendered major construction project in Northeast BC, historically a difficult region in which to attract competitive bids, attracted no less than six competitive bids.

3.6 Conclusion — Electric utility construction price and activity trends

The economic recession starting in 2008 has led to a significant slowdown in electric utility construction activity levels and price trends, and price trends reversing the strong activity and price level increases experienced between 2003 and mid-2008.

Despite the short-term impact of the recession, massive investments will still be required in the longer term to replace and upgrade the aging North American electric utility infrastructure.

4. Price Trends — By Cost Component

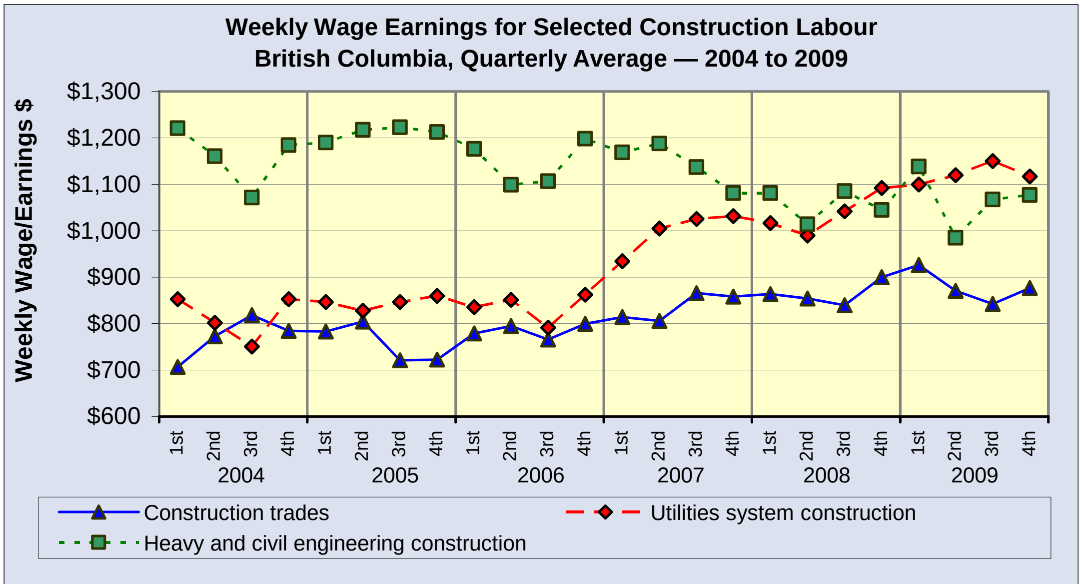
This chapter analyzes price index trends in many of the component cost factors (labour, materials, fuel, etc.) that typically underlie industrial construction cost estimates and contractor bid prices.

4.1 Construction labour

a) Quarterly trends in wage earnings

As illustrated in Exhibit 4a, the apparent trends in wage earnings vary according to the specific index selected for analysis. However, in general, reported weekly wage earnings were fairly stable in 2008 and 2009, after allowing for seasonal fluctuations.

Exhibit 4a — Weekly wage earnings for selected construction labour in British Columbia



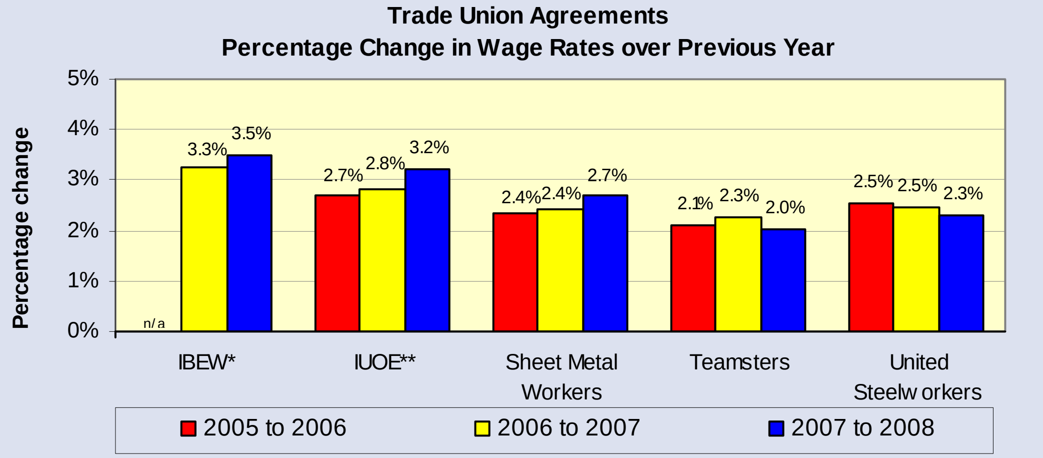
Source: Statistics Canada Tables: 282-0069: Average Weekly wage rate (LFS), BC, construction trades V2576579. Table 281-0026: Weekly earnings (SEPH), BC, all employees, excl. overtime: Utilities system construction V21639051; Other heavy and civil engineering construction V21639054.

b) Trade union wage rate agreements

A number of collective trade agreements, last renewed in BC in 2006-2007, are coming up for renewal in 2010. As illustrated in Exhibit 4b, annual wage rate increases (excluding benefits and other adjustments) for pre-2008 contracts were generally in the range of 2.0% to 3.5%.

However, the economic recession starting in 2008 is putting significant downward pressure on 2010 contract negotiations. For example, the International Brotherhood of Electrical Workers recently agreed to a two-year contract that calls for no increase in wages between 2010 and 2012. In addition, the BC Government Employees Union announced in March 2010 a two-year agreement calling for no wage increases.

Exhibit 4b — Wage rate increases for sample union trade and other positions (i) 2008 and prior years



*IBEW = International Brotherhood of Electrical Workers: 2005-2006 rates not available.

**IUOE = International Union of Operating Engineers

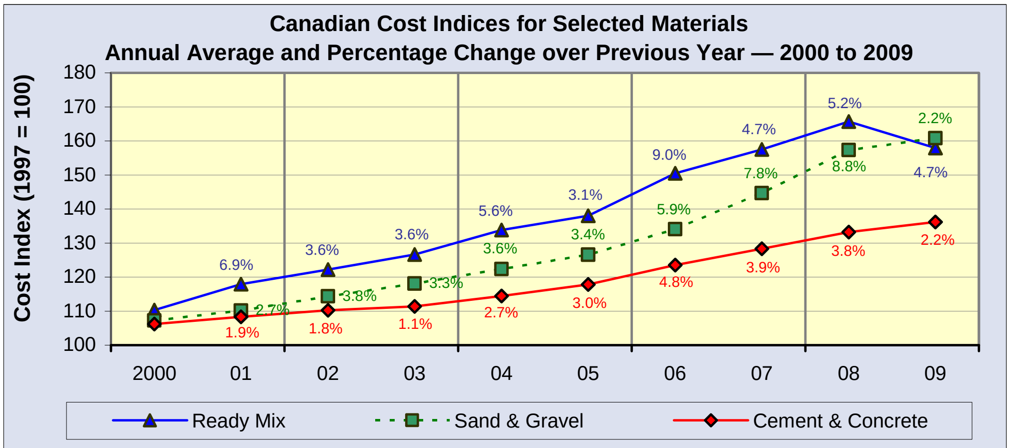
Source: Collective agreements, Labour Relations Board, BC (http://www.lrb.bc.ca/cas/)

4.2 Concrete materials

On an annual basis, and as illustrated in Exhibit 4d(i), the 2009 price index for ready-mix decreased by 4.7%, following strong increases over the past several years. For sand & gravel and cement & concrete, price indices for 2009 were up by 2.2% over 2008, a lower rate of increase than in recent years.

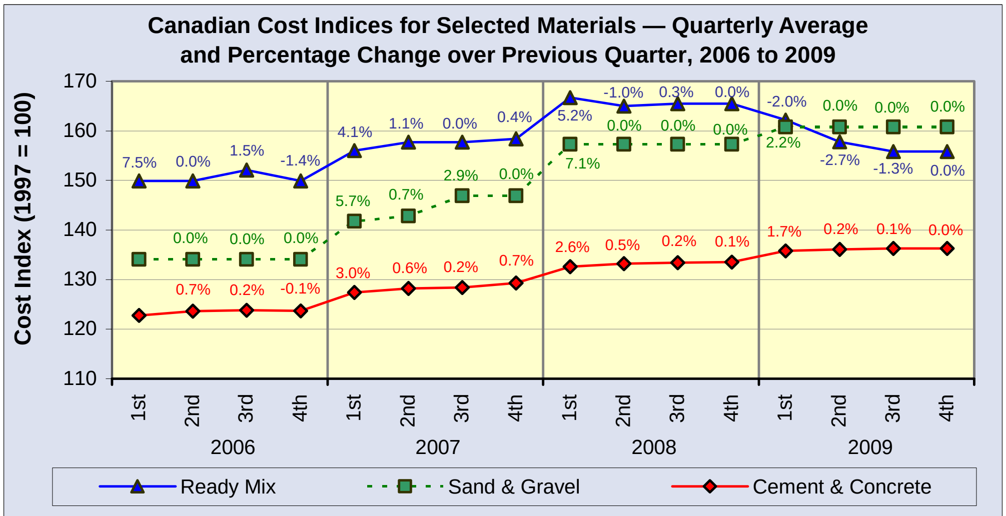
On a quarterly basis (Exhibit 4d(ii)) the decrease in ready-mix prices occurred between the fourth quarter of 2008 and third quarter of 2009, before prices flattened out for the balance of the year. As in prior years, the increase in sand & gravel and cement & concrete price indices occurred mainly between the fourth quarter of 2008 and first quarter of 2009.

Exhibit 4d — Cost indices for selected construction materials - (i) Annual trends



Source: Statistics Canada: Table 329-0047 Ready Mix, Canada V1575811; Table 329-0046 Cement and concrete products, Canada V1575794; Table 330-0006 Sand & gravel, Canada V1576515

(ii) Quarterly trends



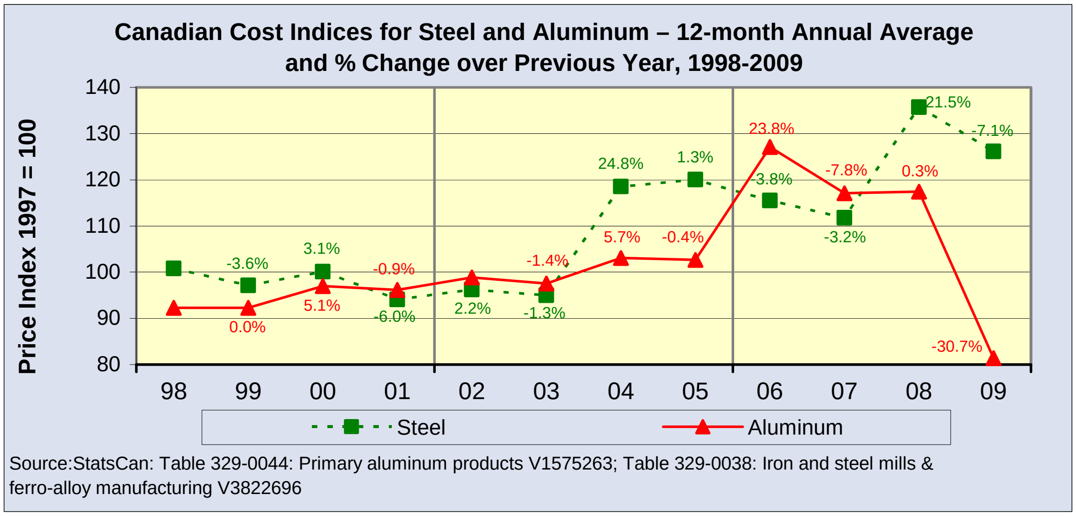
Source: Statistics Canada: Table 329-0047 Ready Mix, Canada V1575965; Table 329-0046 Cement and concrete products, Canada V1575794; Table 330-0006 Sand & gravel, Canada V1576515

4.3 Metal prices[1]

a) Annual trends

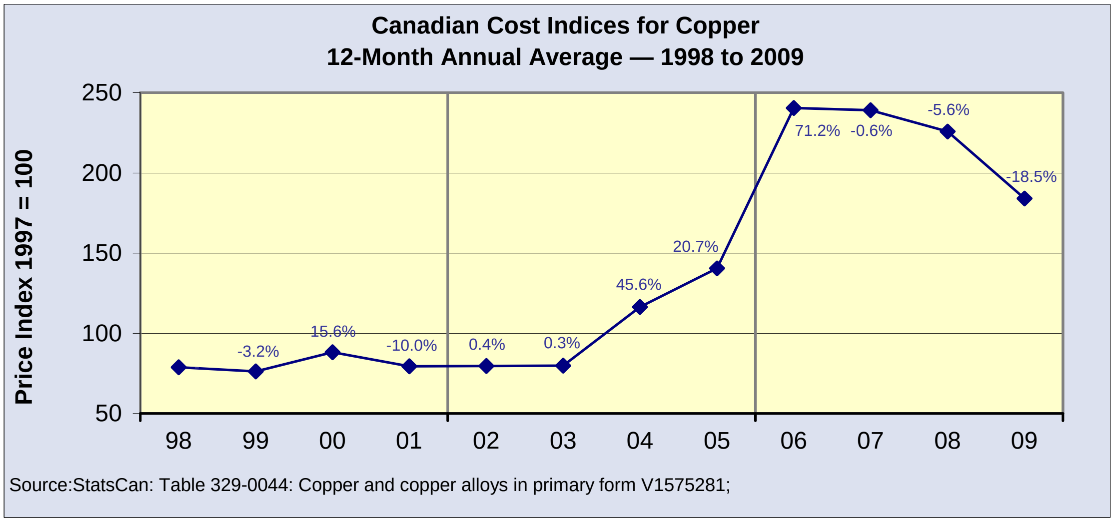
Exhibit 4e illustrates annual Canadian trends in steel, copper and aluminum.

Exhibit 4e – Selected metal cost trends — Canada
(i) Steel and aluminum



Source:StatsCan: Table 329-0044: Primary aluminum products V1575263; Table 329-0038: Iron and steel mills & ferro-alloy manufacturing V3822696

(ii) Copper



Source:StatsCan: Table 329-0044: Copper and copper alloys in primary form V1575281;

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[1] Caution should be used in assessing the implications of metal price trends for electric utility construction costs. Metal commodity prices may not be indicative of the short and medium term trends in the cost of metal materials used in major utility construction projects, since these trends may be outweighed by industry-specific supply and demand trends.

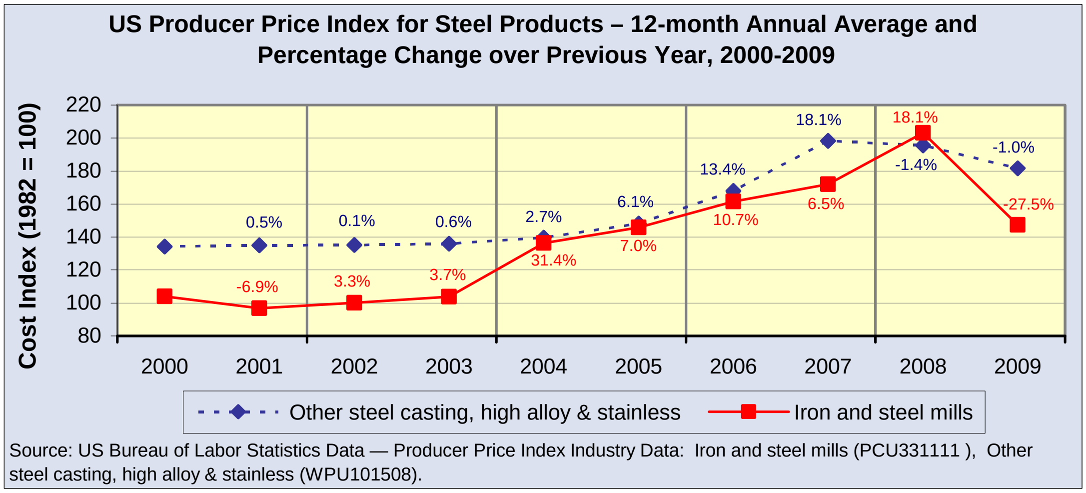
On an annual basis:

- **Steel** price levels dropped 7.1% in 2009, partially reversing the increase of 21.5% in 2008.
- **Aluminum** price indices decreased by 30.7%, to price levels not seen in more than a decade.
- **Copper** price indices decreased 18.5% in 2009, more steeply than the decreases of 2007 and 2008, but were still high in relation to pre-2005 levels.

Annual US price index trends, for selected metal products, are illustrated (in US dollars) in Exhibit 4f. Canadian and US indices tend to move in similar patterns, after adjusting for exchange rate trends.

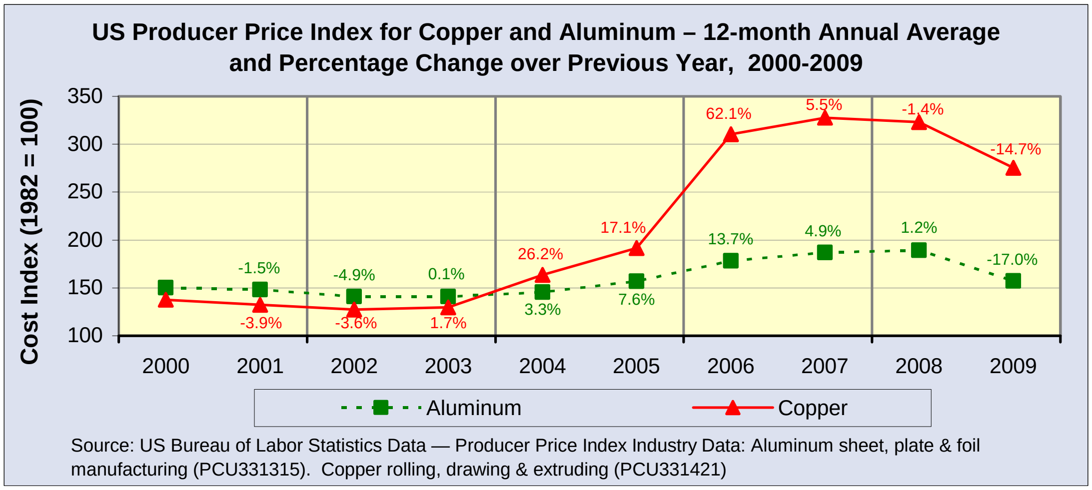
Exhibit 4f — US producer price index for selected metal products

(i) Steel products


US Producer Price Index for Steel Products – 12-month Annual Average and Percentage Change over Previous Year, 2000-2009

Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Iron and steel mills (PCU331111), Other steel casting, high alloy & stainless (WPU101508).

(ii) Copper and aluminum


US Producer Price Index for Copper and Aluminum – 12-month Annual Average and Percentage Change over Previous Year, 2000-2009

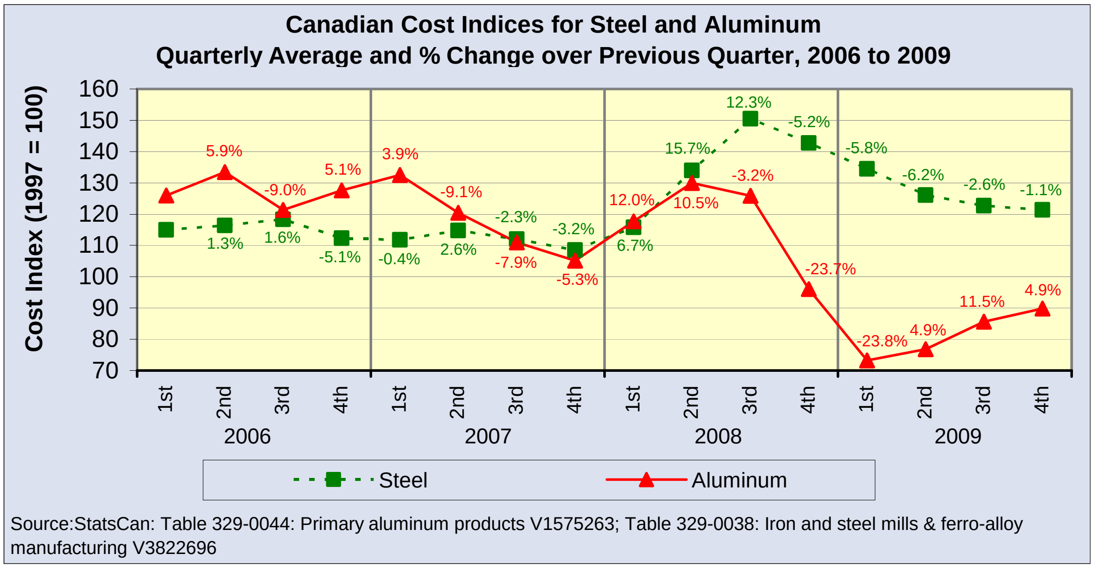
Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Aluminum sheet, plate & foil manufacturing (PCU331315). Copper rolling, drawing & extruding (PCU331421)

b) *Canadian quarterly trends*

Canadian quarterly index trends for steel, aluminum and copper are illustrated in Exhibit 4g:

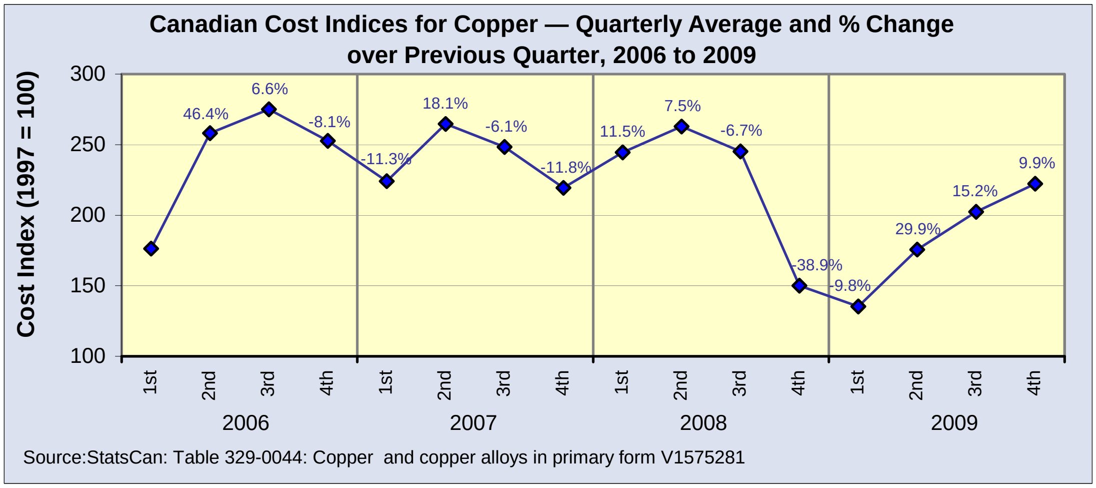
- **Steel** prices declined rapidly starting in the fourth quarter of 2008, with the rate of decline flattening in the third and fourth quarters of 2009
- **Aluminum** prices fell by more than 40% between the second quarter of 2008 and first quarter of 2009, before partially recovering during the balance of 2009
- **Copper** prices also fell by more than 40% between the second quarter of 2008 and first quarter of 2009, but recovered more strongly during the balance of the year.

Exhibit 4g — Canadian indices for selected metals
(i) Steel and aluminum


Canadian Cost Indices for Steel and Aluminum
Quarterly Average and % Change over Previous Quarter, 2006 to 2009

Source:StatsCan: Table 329-0044: Primary aluminum products V1575263; Table 329-0038: Iron and steel mills & ferro-alloy manufacturing V3822696

(ii) Copper

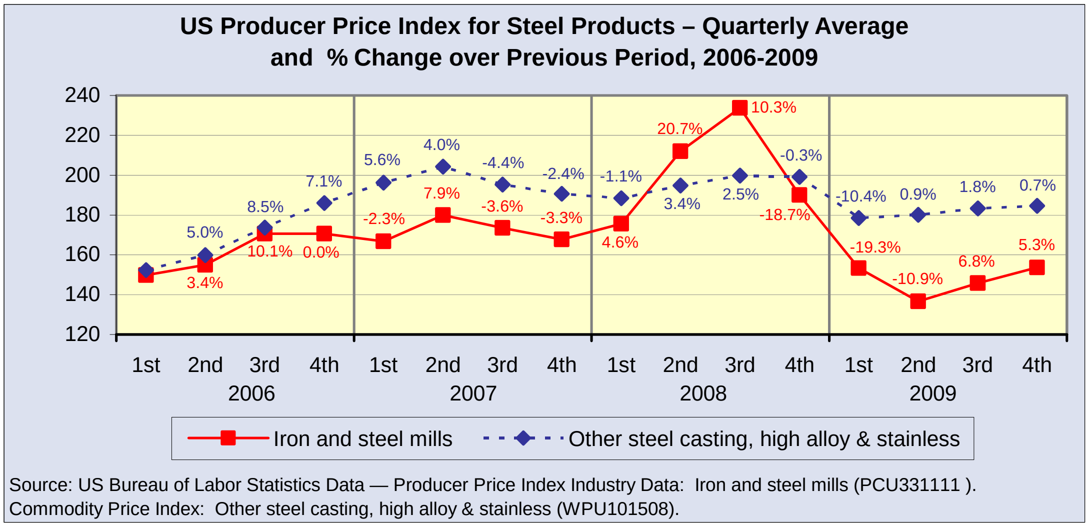

Canadian Cost Indices for Copper — Quarterly Average and % Change over Previous Quarter, 2006 to 2009

Source:StatsCan: Table 329-0044: Copper and copper alloys in primary form V1575281

c) US quarterly trends

US quarterly index trends for steel, aluminum and copper are illustrated in Exhibit 4h. US and Canadian patterns, adjusted for exchange rate trends, tend to be similar.

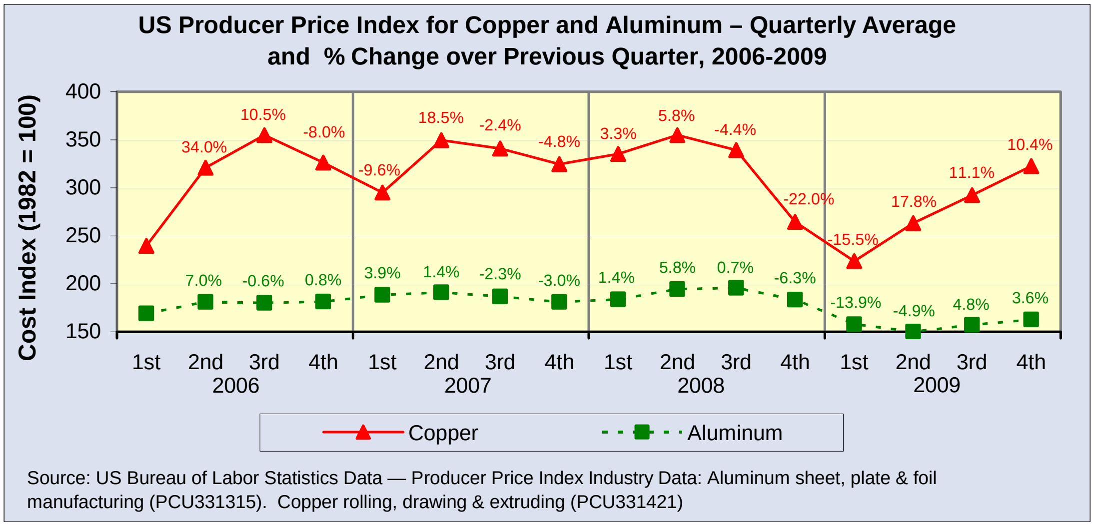
Exhibit 4h — US price indices for selected metals
(i) Steel



US Producer Price Index for Steel Products – Quarterly Average and % Change over Previous Period, 2006-2009

Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Iron and steel mills (PCU331111). Commodity Price Index: Other steel casting, high alloy & stainless (WPU101508).

(ii) Copper and aluminum



US Producer Price Index for Copper and Aluminum – Quarterly Average and % Change over Previous Quarter, 2006-2009

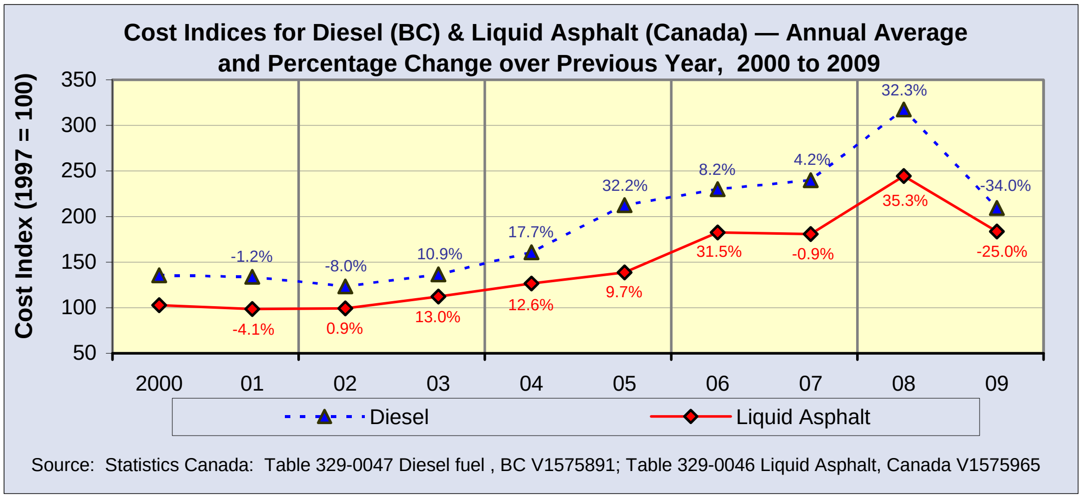
Source: US Bureau of Labor Statistics Data — Producer Price Index Industry Data: Aluminum sheet, plate & foil manufacturing (PCU331315). Copper rolling, drawing & extruding (PCU331421)

4.4 Diesel fuel and asphalt

Annual and quarterly price index trends for diesel fuel and asphalt are illustrated in Exhibit 4i. On an annual basis, the 34.0% decrease in diesel prices and 25% decrease in liquid asphalt prices tended to offset the increases in 2008, bringing price indices back to 2007 levels.

On a quarterly basis, both commodities experienced a very sharp drop in price indices between the second quarter of 2008 and first quarter of 2009, followed by a moderate recovery during the balance of the year. One exception to the general tendency of these indices to move in tandem came in the fourth quarter of 2009, when the diesel price index increased while the liquid asphalt price index decreased.

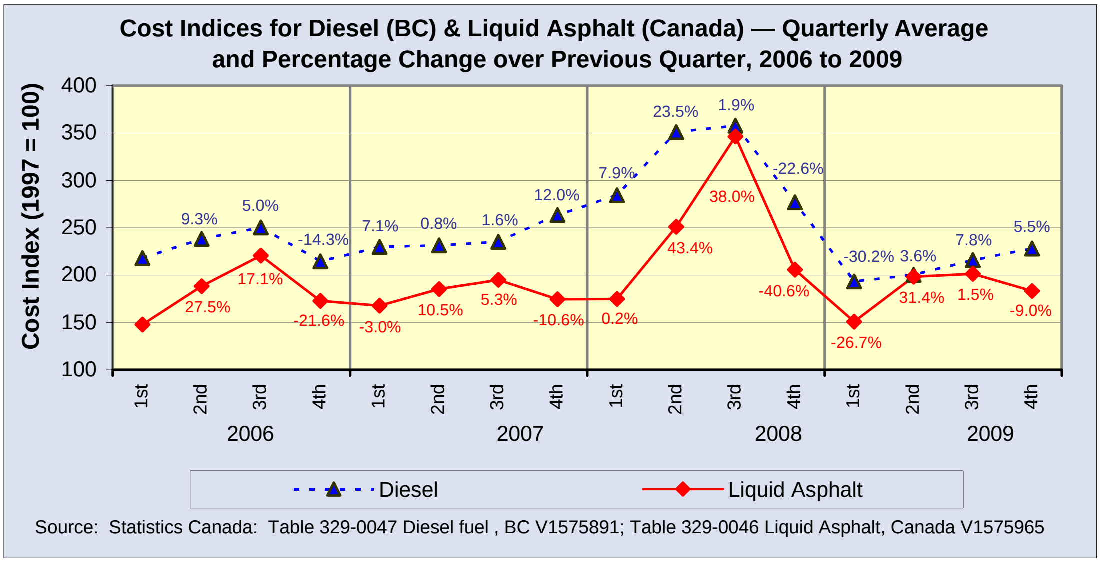
Exhibit 4i — Price indices for diesel and liquid asphalt
(i) Annual trends



Cost Indices for Diesel (BC) & Liquid Asphalt (Canada) — Annual Average and Percentage Change over Previous Year, 2000 to 2009

Source: Statistics Canada: Table 329-0047 Diesel fuel , BC V1575891; Table 329-0046 Liquid Asphalt, Canada V1575965

(ii) Quarterly trends



Cost Indices for Diesel (BC) & Liquid Asphalt (Canada) — Quarterly Average and Percentage Change over Previous Quarter, 2006 to 2009

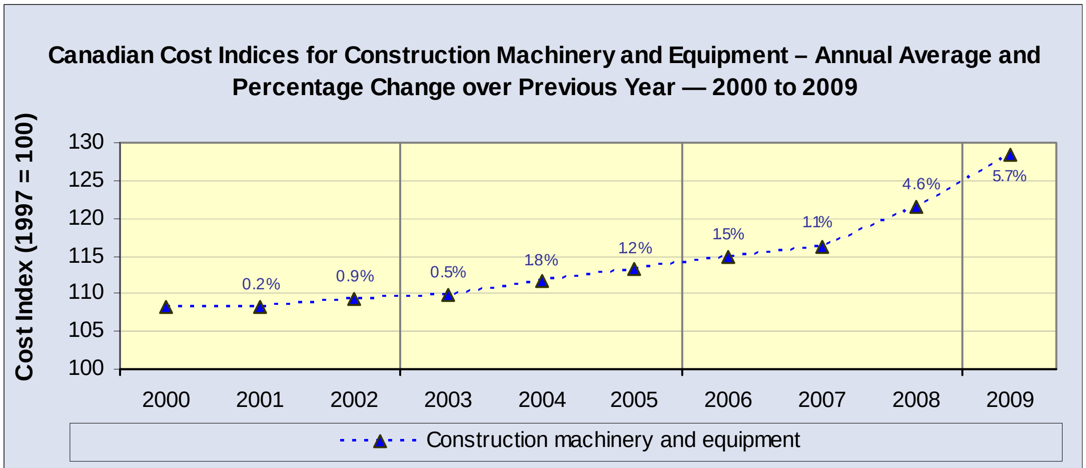
Source: Statistics Canada: Table 329-0047 Diesel fuel , BC V1575891; Table 329-0046 Liquid Asphalt, Canada V1575965

4.5 Construction machinery & equipment

As illustrated in Exhibit 4j, the Canadian price index for construction machinery and equipment continued its 2008 upward trend in 2009, following several years of low increases between 2000 and 2007. This trend is contrary to the generally flat or downward price index trends reported for most other component costs.

On a quarterly basis, the increase in price indices occurred between the second quarter of 2008 and first quarter of 2009, before flattening for the balance of 2009.

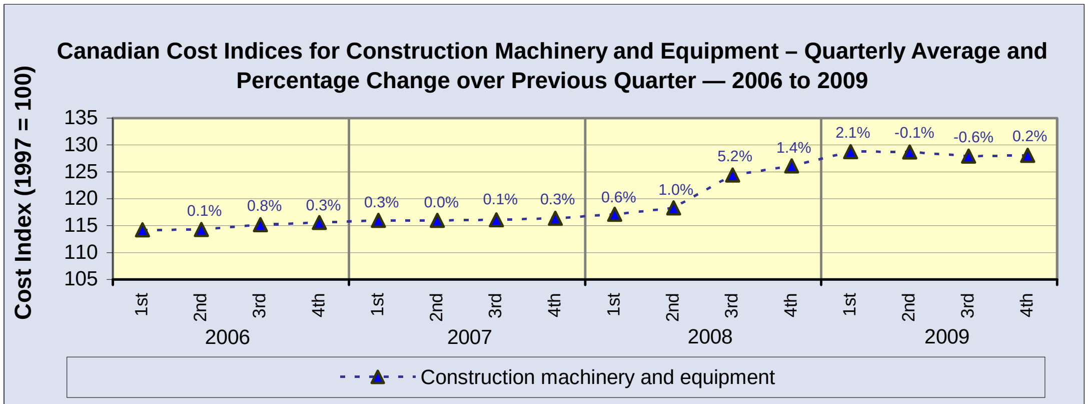
Exhibit 4j — Price indices for construction machinery and equipment
(i) Annual trends



Canadian Cost Indices for Construction Machinery and Equipment – Annual Average and Percentage Change over Previous Year — 2000 to 2009

Source: Statistics Canada: Table 329-0045 - Industry price indexes for machinery and equipment, autos, trucks and other transport equipment, Canada:
- Hydraulic power transmission equipment (V1575474), excluding mechanical power transmission equipment.
- Construction machinery and equipment (V1575466) - Includes mobile earth moving and allied equipment, attachments and parts; mixing and paving equipment - concrete, asphalt; sweepers and snow removal equipment. Excludes mining, quarrying and ore dressing machinery and parts; oil and gas field equipment and parts.

(ii) Quarterly trends



Canadian Cost Indices for Construction Machinery and Equipment – Quarterly Average and Percentage Change over Previous Quarter — 2006 to 2009

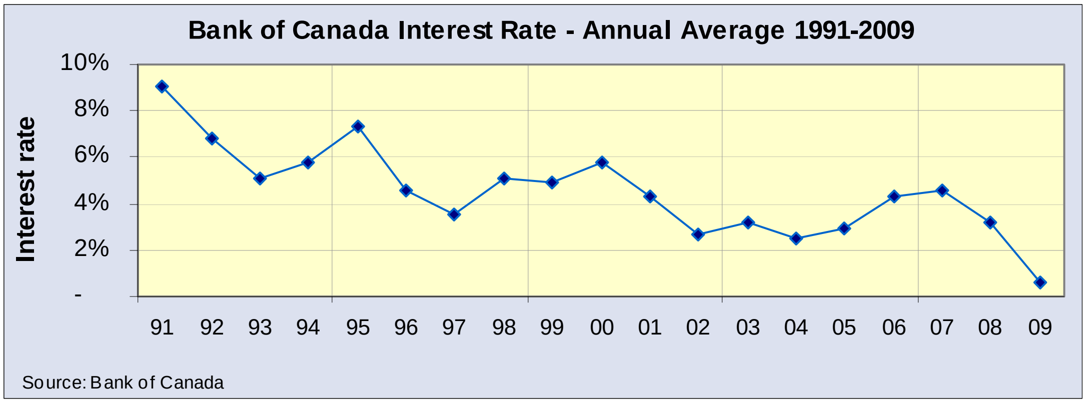
Source: Statistics Canada: Table 329-0045 - Industry price indexes for machinery and equipment, autos, trucks and other transport equipment, Canada (see above chart for details).

4.6 Trends in interest rates

a) Annual trends

Long-run trends in the Bank of Canada interest rate are illustrated in Exhibit 4k. They demonstrate the historically low interest rates that have prevailed during the past few years. Rates in 2009 were extremely low in relation to historical levels of the past two decades.

Exhibit 4k — Long-term Bank of Canada interest rates

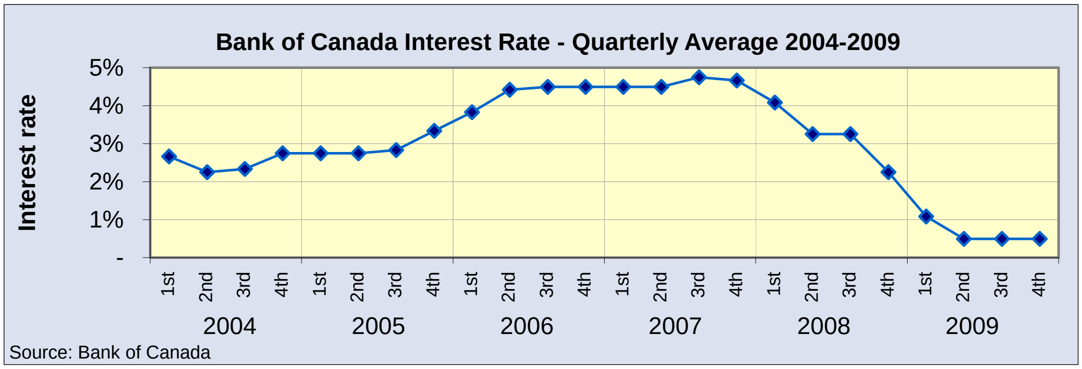


Source: Bank of Canada

b) Quarterly trends

Quarterly Bank of Canada interest rate trends are illustrated in Exhibit 4l. The Bank of Canada interest rate has declined from nearly 5% during the fourth quarter of 2007, to less than 1% between the second quarter of 2009 and early 2010.

Exhibit 4l — Quarterly Bank of Canada interest rates



Source: Bank of Canada

5. BC Regional Trends

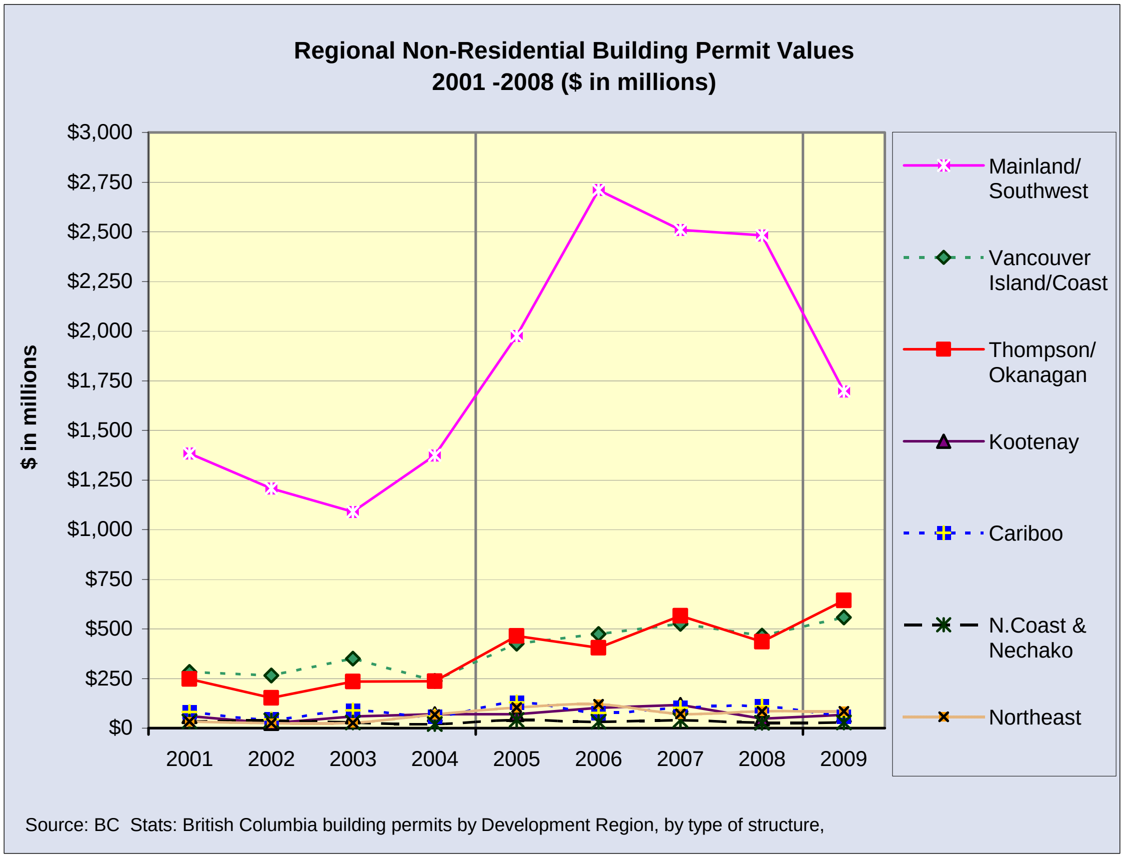
Within BC, construction price indices are not tracked regionally, and thus direct price trend information is not directly available. However, two regional activity indicators — building permit values and construction employment — provide indirect indications regarding those regions where construction price pressures may be more significant.

5.1 Regional trends in construction activity

Regional trends in non-residential building permit values are illustrated in Exhibit 5a, based on the detailed data contained in Exhibit 5b.

With regard to industrial construction, building permit values in BC were down 16.1% between 2008 and 2009 — a further drop from the 9.9% decline between 2007 and 2008. Results varied widely by region. Building permit values were up by 20-22% in the Vancouver Island/Coast, Thompson/Okanagan, and Kootenay regions. On the other hand, building permit values were down by 17% in the Mainland/Southwest region, and by 30% or more in the Cariboo, North Coast & Nechako, and Northeast regions.

Exhibit 5a — Regional annual trends in non-residential building permit values



Source: BC Stats: British Columbia building permits by Development Region, by type of structure,

Exhibit 5b — BC value of building permits, by region

	2001	2002	2003	2004	2005	2006	2007	2008	% Change '07 to '08	2009	% Change '08 to '09
British Columbia (Total)											
Total value	4,954.7	5,659.4	6,394.2	7,938.7	10,191.1	11,541.6	12,544.7	10,556.6	-15.8%	7,619.5	-27.8%
Non-residential											
Industrial	221.0	230.0	244.0	328.0	346.2	358.2	323.9	291.7	-9.9%	244.8	-16.1%
Commercial	1,171.0	1,117.0	1,130.0	1,228.0	1,886.4	2,491.4	2,647.9	2,617.0	-1.2%	1,759.9	-32.8%
Institutional/Govnt	732.0	424.0	506.0	514.0	979.5	1,067.4	961.2	746.7	-22.3%	1,135.1	52.0%
Total non-residential	2,124.0	1,771.0	1,880.0	2,070.0	3,212.1	3,917.0	3,933.0	3,655.4	-7.1%	3,139.8	-14.1%
Residential	2,830.7	3,888.4	4,514.2	5,868.7	6,979.0	7,624.1	8,611.7	6,901.2	-19.9%	4,479.6	-35.1%
Vancouver Island/Coast											
Total value	632.0	769.2	993.4	1,098.4	1,459.9	1,701.7	1,841.2	1,626.4	-11.7%	1,343.2	-17.4%
Non-residential											
Industrial	34.8	16.5	33.6	18.5	20.7	31.4	30.1	50.7	68.4%	37.3	-26.5%
Commercial	145.1	155.2	202.5	139.1	257.4	281.8	229.4	295.7	28.9%	312.0	5.5%
Institutional/Govnt	102.6	93.5	113.6	81.0	148.3	161.3	265.4	119.4	-55.0%	209.1	75.2%
Total non-residential	282.5	265.2	349.7	238.6	426.4	474.5	525.0	465.8	-11.3%	558.4	19.9%
Residential	349.5	504.0	643.7	859.8	1,033.5	1,227.2	1,316.2	1,160.6	-11.8%	784.8	-32.4%
Mainland/ Southwest											
Total value	3,396.6	4,028.3	4,165.0	5,371.6	6,387.3	7,451.1	7,829.3	6,372.8	-18.6%	4,413.6	-30.7%
Non-residential											
Industrial	150.5	162.7	129.8	198.4	187.7	227.9	173.6	172.9	-0.4%	143.2	-17.1%
Commercial	799.3	787.7	697.4	861.5	1,204.7	1,809.0	1,898.2	1,911.6	0.7%	1,099.8	-42.5%
Institutional/Govnt	433.9	257.7	262.7	315.1	582.9	673.3	437.9	398.1	-9.1%	455.1	14.3%
Total non-residential	1,383.7	1,208.1	1,089.9	1,375.0	1,975.3	2,710.1	2,509.7	2,482.6	-1.1%	1,698.2	-31.6%
Residential	2,012.9	2,820.2	3,075.1	3,996.6	4,412.0	4,741.0	5,319.6	3,890.2	-26.9%	2,715.4	-30.2%
Thompson/ Okanagan											
Total value	531.256	515.998	774.3	963.7	1,560.7	1,549.0	1,881.8	1,648.3	-12.4%	1,234.7	-25.1%
Non-residential											
Industrial	17.4	23.4	49.2	30.5	48.3	69.1	65.0	34.0	-47.7%	41.8	23.0%
Commercial	159.4	94.2	116.2	135.3	293.6	209.8	369.0	259.4	-29.7%	203.6	-21.5%
Institutional/Govnt	70.2	35.6	70.1	70.0	122.0	125.7	131.8	141.6	7.5%	397.6	180.7%
Total non-residential	247.0	153.2	235.5	235.8	464.0	404.6	565.7	435.1	-23.1%	643.0	47.8%
Residential	284.3	362.8	538.8	727.9	1,096.8	1,144.5	1,316.1	1,213.2	-7.8%	591.7	-51.2%
Kootenay											
Total value	174.291	164.2	239.4	244.6	369.7	404.0	493.3	447.6	-9.3%	268.9	-39.9%
Non-residential											
Industrial	8.8	6.5	6.7	13.9	8.9	13.7	14.2	8.2	-41.8%	10.0	21.1%
Commercial	18.3	13.5	28.6	33.4	22.9	32.9	47.1	34.3	-27.2%	34.6	0.8%
Institutional/Govnt	34.7	5.0	23.5	23.8	38.6	55.6	55.5	6.5	-88.3%	23.0	255.0%
Total non-residential	61.8	25.0	58.8	71.1	70.4	102.2	116.7	49.0	-58.0%	67.5	37.8%
Residential	112.5	139.2	180.6	173.5	299.3	301.8	376.6	398.6	5.8%	201.4	-49.5%
Cariboo											
Total value	115.2	88.5	125.4	121.2	203.0	170.3	257.4	236.9	-8.0%	158.6	-33.0%
Non-residential											
Industrial	4.0	10.2	6.5	16.2	38.0	7.2	10.4	6.2	-40.5%	3.0	-51.8%
Commercial	21.3	25.7	52.0	32.3	30.3	36.2	53.3	35.1	-34.3%	32.1	-8.6%
Institutional/Govnt	55.9	9.8	31.2	11.1	62.0	33.4	39.9	70.0	75.5%	23.8	-66.0%
Total non-residential	81.2	45.7	89.7	59.6	130.4	76.8	103.6	111.2	7.4%	58.8	-47.1%
Residential	34.0	42.8	35.7	61.6	72.6	93.5	153.8	125.7	-18.3%	99.8	-20.6%
North Coast and Nechako											
Total value	45.9	46.4	41.2	33.3	61.5	63.1	78.0	72.2	-7.5%	54.5	-24.5%
Non-residential											
Industrial	4.1	5.9	11.4	1.5	11.8	4.5	3.8	3.1	-19.1%	1.4	-55.0%
Commercial	11.8	10.9	13.1	7.7	10.8	21.9	19.5	19.1	-1.9%	9.2	-52.0%
Institutional/Govnt	18.3	21.3	4.0	10.9	18.8	5.2	16.2	4.7	-70.7%	17.9	276.8%
Total non-residential	34.2	38.1	28.5	20.1	41.3	31.6	39.5	26.9	-31.7%	28.4	5.5%
Residential	11.7	8.3	12.6	13.2	20.1	31.5	38.5	45.2	17.3%	26.1	-42.4%
Northeast											
Total value	59.5	46.7	55.6	105.9	149.1	202.4	163.7	152.4	-6.9%	146.0	-4.2%
Non-residential											
Industrial	1.7	5.0	6.8	49.0	30.8	5.1	26.8	16.7	-37.9%	8.1	-51.4%
Commercial	16.0	19.5	19.9	18.7	66.7	102.2	31.5	61.8	96.2%	68.7	11.3%
Institutional/Govnt	16.6	1.5	1.3	1.9	6.9	13.7	14.5	6.3	-56.3%	8.7	36.9%
Total non-residential	34.3	26.0	28.0	69.5	104.4	121.1	72.8	84.8	16.4%	85.5	0.9%
Residential	25.2	20.7	27.6	36.4	44.6	81.3	90.9	67.7	-25.6%	60.4	-10.7%

Source: BC Stats – British Columbia building permits, by type.

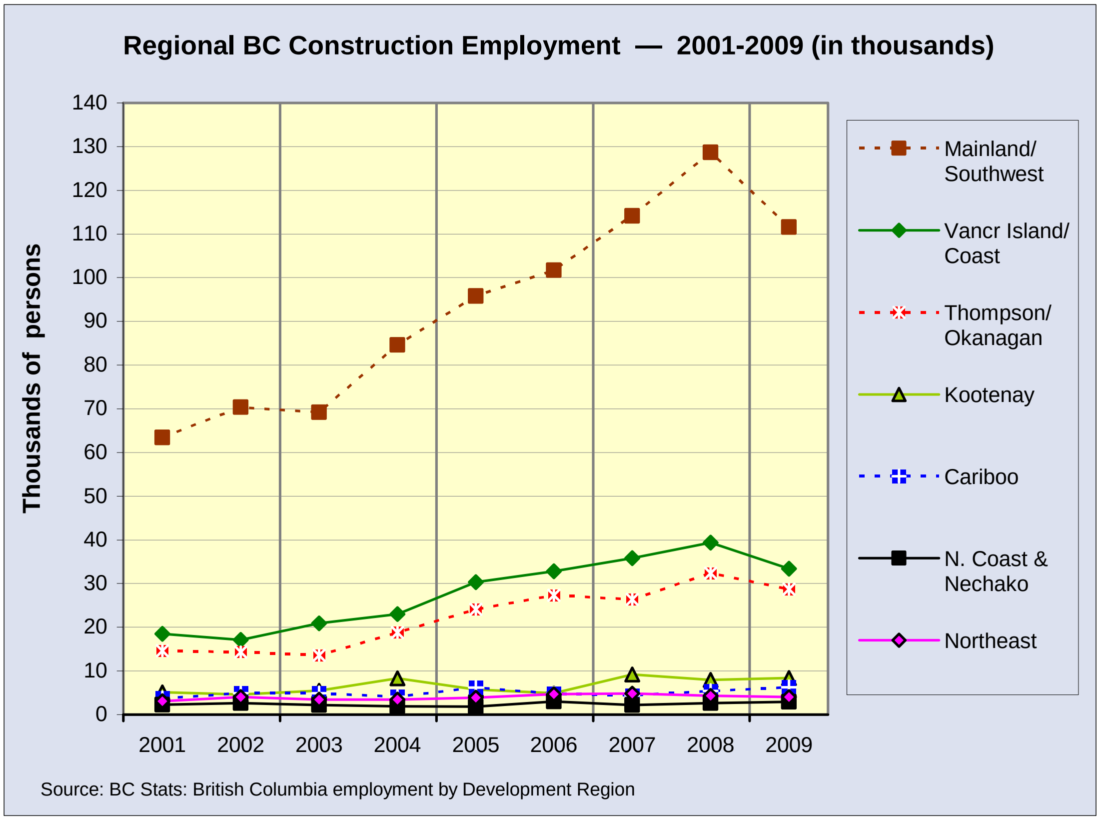
5.2 Regional trends in construction employment

a) Annual trends

Annual regional trends in construction employment are illustrated in Exhibit 5c (graph) and Exhibit 5d (table).

On an annual basis, the results show a 13.1% drop in construction employment in 2009 over 2008, compared with a 12.1% increase in 2008 over 2007.

Exhibit 5c — Regional construction employment trends 2001-2009 (000s)[1]



Source: BC Stats: British Columbia employment by Development Region

1. See also table next page.

Exhibit 5d — Table of regional construction employment trends 2001-2009 (000s)

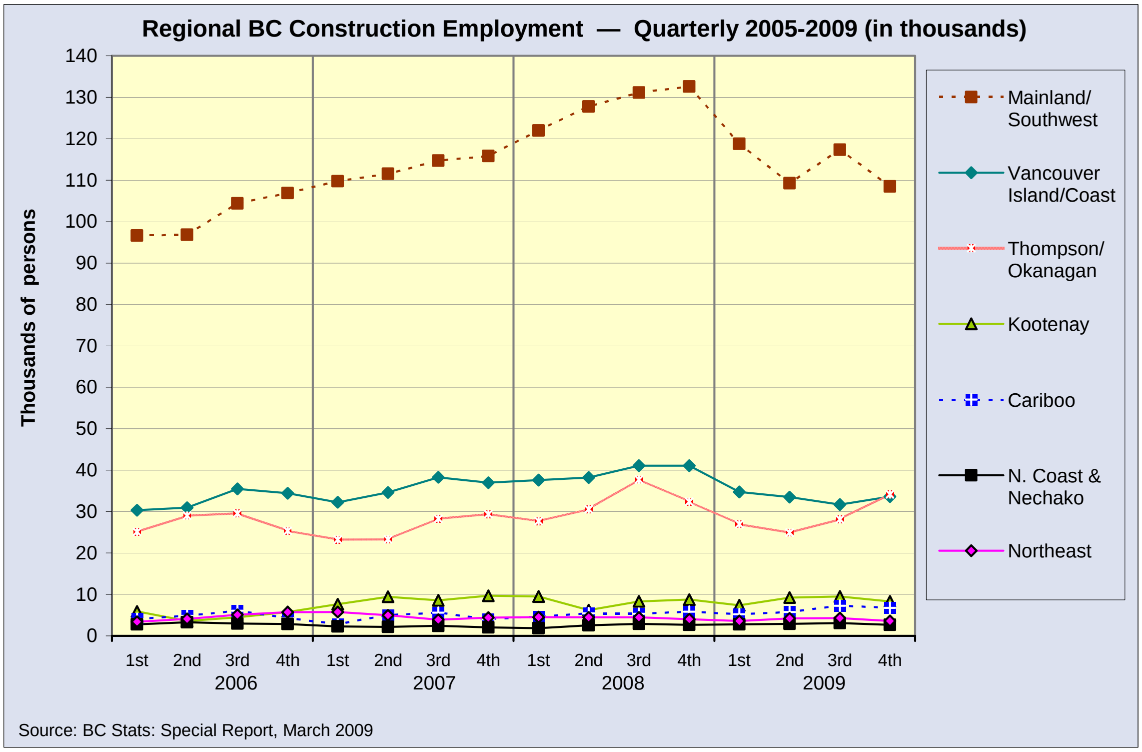
	2001	2002	2003	2004	2005	2006	2007	2008	% Change From 2007	2009	% Change From 2008
British Columbia											
Total employment	1,921.6	1,965.0	2,014.7	2,062.7	2,130.5	2,195.5	2,266.3	2,314.3	*2.1%*	2,259.4	-2.4%
Construction empl.	110.7	118.1	119.8	144.0	168.0	179.3	196.9	220.8	*12.1%*	195.3	-13.1%
- % of total empl.	*5.8%*	*6.0%*	*5.9%*	*7.0%*	*7.9%*	*8.2%*	*8.7%*	*9.5%*			
Vancouver Island/Coast											
Total employment	307.3	317.4	319.1	334.2	350.0	369.5	378.3	394.2	*4.2%*	379.4	*-3.9%*
Construction empl.	18.5	17.1	20.9	23.0	30.3	32.8	35.8	39.4	*10.1%*	33.4	*-18.0%*
- % of total empl.	*6.0%*	*5.4%*	*6.5%*	*6.9%*	*8.7%*	*8.9%*	*9.5%*	*10.0%*			
Mainland/Southwest											
Total employment	1,175.0	1,216.7	1,251.4	1,275.3	1,307.3	1,342.7	1,392.2	1,418.3	*1.9%*	1,399.8	*-1.3%*
Construction empl.	63.4	70.4	69.2	84.6	95.8	101.7	114.1	128.7	*12.8%*	111.6	*-15.3%*
- % of total empl.	*5.4%*	*5.8%*	*5.5%*	*6.6%*	*7.3%*	*7.6%*	*8.2%*	*9.1%*			
Thompson/Okanagan											
Total employment	210.2	208.1	218.8	229.7	244.0	253.7	256.7	265.0	*3.2%*	256.7	*-3.2%*
Construction empl.	14.6	14.3	13.6	18.8	24.1	27.3	26.4	32.4	*22.7%*	28.7	*-12.9%*
- % of total empl.	*6.9%*	*6.9%*	*6.2%*	*8.2%*	*9.9%*	*10.8%*	*10.3%*	*12.2%*			
Kootenay											
Total employment	70.4	66.6	67.4	67.1	69.2	69.5	77.1	71.5	*-7.3%*	70.4	*-1.6%*
Construction empl.	5.1	4.6	5.5	8.3	5.8	4.9	9.2	8.0	*-13.0%*	8.4	*4.8%*
- % of total empl.	*7.2%*	*6.9%*	*8.2%*	*12.4%*	*8.4%*	*7.1%*	*11.9%*	*11.2%*			
Cariboo											
Total employment	79.4	78.0	78.2	80.7	80.1	82.9	83.8	83.1	*-0.8%*	75.6	*-9.9%*
Construction empl.	3.7	4.9	4.9	4.1	6.2	4.8	4.4	5.4	*22.7%*	6.3	*14.3%*
- % of total empl.	*4.7%*	*6.3%*	*6.3%*	*5.1%*	*7.7%*	*5.8%*	*5.3%*	*6.5%*			
North Coast and Nechako											
Total employment	46.6	44.9	44.8	42.4	45.7	43.1	41.5	44.1	*6.3%*	40.6	*-8.6%*
Construction empl.	2.3	2.6	2.2	1.9	1.8	3.0	2.2	2.6	*18.2%*	2.9	*10.3%*
- % of total empl.	*4.9%*	*5.8%*	*4.9%*	*4.5%*	*3.9%*	*7.0%*	*5.3%*	*5.9%*			
Northeast											
Total employment	32.5	33.2	34.9	33.3	34.3	34.0	36.7	38.0	*3.5%*	36.9	*-3.0%*
Construction empl.	3.1	4.0	3.4	3.4	3.9	4.7	4.8	4.3	*-10.4%*	4.0	*-7.5%*
- % of total empl.	*9.5%*	*12.0%*	*9.7%*	*10.2%*	*11.4%*	*13.8%*	*13.1%*	*11.3%*			

Source: BC Stats: British Columbia employment by Development Region.

b) *Quarterly trends*

Regional quarterly construction employment trends for 2005 through 2009 are illustrated in Exhibit 5e. For most regions, the downturn in construction employment occurred mainly during the first half of 2009, with flat or upward trends recorded during the second half of 2009 in most regions.

Exhibit 5e – Regional BC construction employment



Source: BC Stats: Special Report, March 2009

6. Other Agencies' Estimates and Forecasts

Other agencies' cost inflation estimates and forecasts of future trends are illustrated in Exhibit 6a, and are discussed overleaf.

Exhibit 6a – Other agencies' cost inflation estimates and forecasts

Cost inflation estimates/forecasts		**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
StatsCan	Industrial Construction							
	• Seven CMAs	7.8%	8.7%	11.4%	-5.0%			
	• Vancouver	10.3%	12.6%	11.3%	-18.1%			
	Electric Utility Construction							
	• Distribution syst.	6.6%	4.5%	0.9%	-0.3%			
	• Transmiss. lines	4.2%	3.9%	2.0%	-0.3%			
	• Substations	3.8%	5.1%	4.9%	2.4%			
BTY	BC Lower Mainland Construction							
	• December 2005	11%	10%	10%	9%	8%		
	• December 2006	11%	5-7%	5%	3%	3%		
	• December 2007	-	-	7%	6%	5%	3%	
	• December 2008	-	-	-	3%	3%	5%	
	BC Construction							
	• December 2009					2%	2-3%	2-3%
CanaData (Reed Construction Data)								
Non-resid.	• 2008	-	-	6.5%	5.0%	3.8%	4.0%	
	• 2009	-	-	-	1.5%	3.5%		
	• 2010					3.5%	4.0%	3.5%
Residential	• 2008	-	-	5.0%	3.5%	3.2%	3.5%	
	• 2009	-	-	-	0.5%	2.5%		
	• 2010					2.5%	3.5%	3.5%
RLB (US)	Quarterly Costs Construction Report							
	• Actual							
	– Seattle cost index (actual)		8.2%	-0.7%	-11.6%			
	– US Overall cost index		9.0%	3.5%	-7.3%			
	• Predicted (US)							
	– 2009 report				0.0%			
	– 2010 report					0.0%		
BC MoTI	Construction Cost Allowances							
	• Property		10%	n/a				
	• Major projects			n/a				
	• Other projects (policy under review		5.2%	5%	5%	3%	3%	3%

6.1 Statistics Canada

Relevant Statistics Canada data have been analyzed in detail in earlier chapters, and are summarized in Exhibit 6a. They highlight the tremendous shift in price index trends for 2009 compared with prior years, both for industrial construction in general and for electric utility construction.

6.2 BTY Group

BTY Group is a Canadian-based construction project management and consulting firm that periodically issues construction price inflation forecasts. As illustrated in Exhibit 6a, BTY has significantly reduced its price inflation forecasts over the past few years, and is now projecting 2%-3% inflation rates over the next few years.

6.3 CanaData (Reed Construction Data)

CanaData, published by Reed Construction Data, is a well-known source of information for construction industry news. For non-residential construction, CanaData's most recent forecasts are for a 3.5% price increase in 2010, 4.0% in 2011, and 3.5% in 2012. CanaData has further commented that, with respect to engineering construction, "…the prospects for spending in 2010 are significantly improved [over 2009] on account of new energy projects…".

6.4 Rider Levett Bucknall (RLB)

Rider Levett Bucknall (RLB) is a US/UK firm specializing in construction project management, cost consulting and advisory services. RLB estimates that:

- Actual construction costs (US overall) decreased about 7.3% in 2009, after having increased 3.5% in 2008 and 9.0% in 2007.
- Actual Seattle construction costs decreased by 11.6% in 2009, following a 0.7% decrease in 2008 and 8.2% increase in 2007.

RLB is currently projecting 0% US construction cost inflation in 2010, as it did for 2009 in its 2009 estimates.

6.5 BC Ministry of Transportation and Infrastructure (MoTI)

In 2009, the Ministry's cost inflation allowances for smaller for construction projects were unchanged from 2008 — i.e. a 5% annual price inflation allowance for 2009, and a 3% annual inflation allowance for 2010 through 2012.[1]

In 2010, the Ministry advises that it is currently reviewing its policies and rates, but that it is generally experiencing "… a favourable marketplace with respect to the number of bidders… and the low bid in relation to the Ministry estimates."

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[1] These allowances are for the construction component of smaller projects only, and do not include real estate costs, which are individually developed by the Ministry's regional property group. For major capital projects, non-property cost escalation allowances are individually estimated on a project-by-project basis.

7. Recommended BC Hydro Cost Inflation Allowances

This final chapter provides the consultant's recommendations regarding BC Hydro's cost inflation allowances for its future major construction projects.

7.1 Previously recommended allowances

The cost inflation allowances recommended in previous reports are illustrated in Exhibit 7a. Most of these recommendations were developed during a period of increasing construction activity levels and price indices, and were lower than some other industry observers were recommending at the time (see Chapter 6). Our position at the time was that the cost inflation allowances should reflect the planning horizon being considered, and in particular that long-run inflationary allowances should not be overly reactive to short-run price trends.

Exhibit 7a — Previously recommended construction cost inflation allowances

Previous reports/updates		Up to 2010	2011 onwards
Mar. 2007	• Generation (heavy construct.) • Utility transmission/distribut.	4% to 6% 2% to 4%	2.5% to 4% 2% to 4%
Sep. 2007	• All construction projects	4% to 6%	3% to 4%
Apr. 2008	• All construction projects	4% to 6%	3% to 4%
Sep. 2008	• All construction projects	4% to 6%	3% to 4%
Apr. 2009	• All construction projects	2% to 4%	2% to 4%

In recommending longer term cost inflation allowances, this report follows the same general approach undertaken in previous editions — i.e. to base the recommendation primarily on longer term price and cost trends.

7.2 Historical trends

Exhibit 7b illustrates the three-year, five-year, ten-year and fifteen-year price index trends, both for the overall industrial construction sector and for the more specialized electrical utility construction sector (US and Canadian indices).

As illustrated in Exhibit 7b, the ten-year average price index increase (1999-2009) for the industrial price index is 5.8%, while the average increase for the Canadian electric utility construction industry is 1.9%. Shorter-term three to five year trends have been somewhat higher; however, with the downturn in construction price indices since 2008, the differences between the shorter-term and longer-term historical trends have been reduced.

In our view, the ten-year average rates of price index increase for electric utility construction (1.9%) and overall industrial construction (5.8%) represent the bounds of what could be considered a reasonable range for annual construction cost inflation allowances. In choosing an allowance within this range, we would also recommend that the electric utility industry construction price index be given more weight than the broader industrial construction price index.

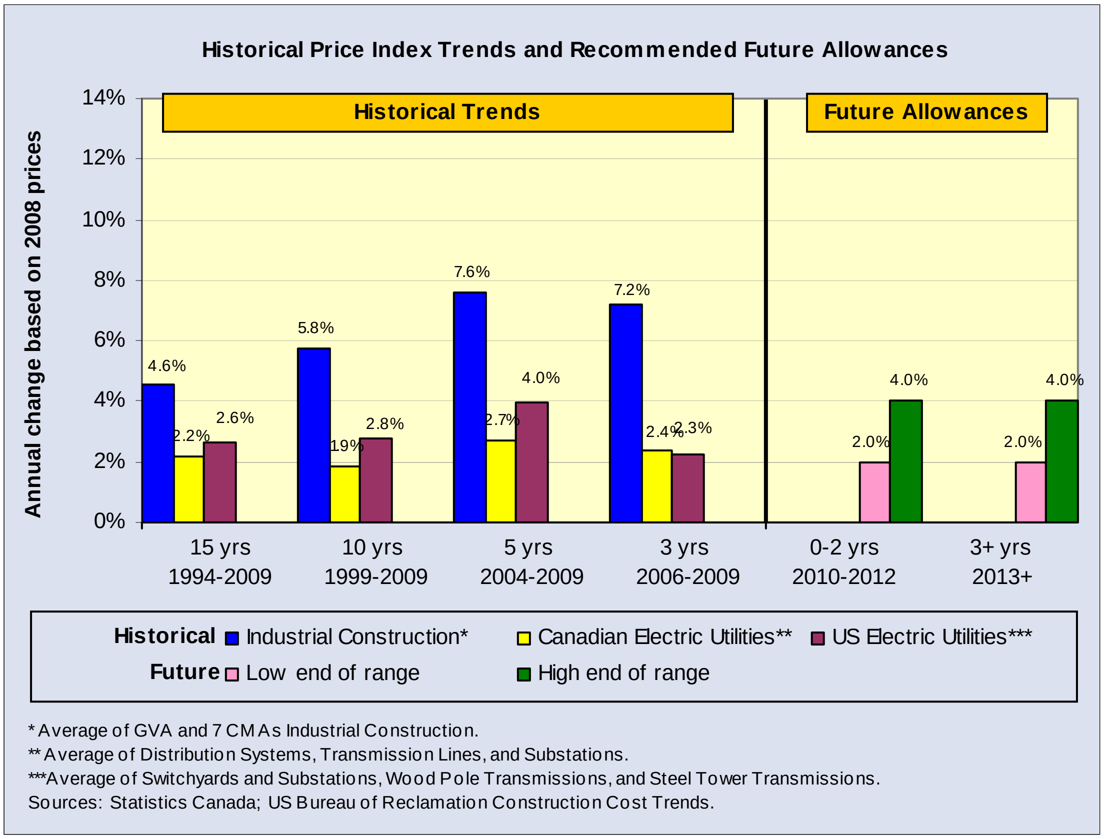
7.3 Recommended cost inflation allowances

Based on these considerations, we recommend that BC Hydro use a longer term construction cost allowance range of 2% to 4%, for longer-run projects with more than a ten-year planning horizon.

For projects to be undertaken over the shorter term, average annual price index increases have been somewhat higher than the longer-run trends. However, given the negative price index trends of the past year, we recommend that BC Hydro also use the same 2% to 4% construction cost inflation allowance for nearer term projects, as for longer term ones.

These recommendations are unchanged from the previous April 2009 edition of this report — i.e. that BC Hydro continue to apply an annual cost inflation allowance in the range of 2% to 4%, to both nearer-term and longer-term construction projects.

Exhibit 7b – Historical price index trends, and recommended future allowances

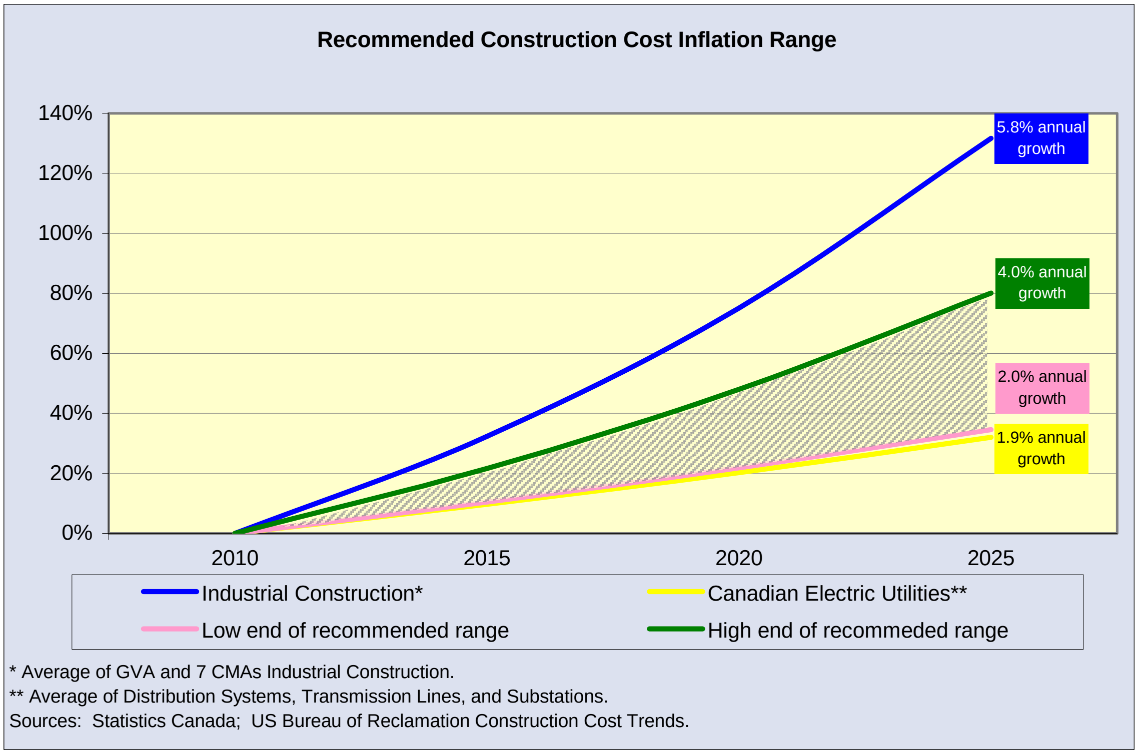


*Average of GVA and 7 CMAs Industrial Construction.
** Average of Distribution Systems, Transmission Lines, and Substations.
***Average of Switchyards and Substations, Wood Pole Transmissions, and Steel Tower Transmissions.
Sources: Statistics Canada; US Bureau of Reclamation Construction Cost Trends.

7.4 Implications for future construction cost estimates

The longer-run implications of applying the recommended range of annual cost inflation allowances are illustrated in Exhibit 7c. For a project to be undertaken in 2025, the recommended range of 2% to 4% annually results in an overall construction cost increase allowance in the range of 35% to 80%.

Exhibit 7c – Long-run implications of recommended cost inflation allowances



* Average of GVA and 7 CMAs Industrial Construction.
** Average of Distribution Systems, Transmission Lines, and Substations.
Sources: Statistics Canada; US Bureau of Reclamation Construction Cost Trends.

7.5 Interpretation of results

These recommended allowances should be interpreted in the following context:

- They are applicable to BC Hydro “hard” construction costs only, and exclude other “soft” project cost elements such as project design, administrative overheads, environmental mitigation, property acquisition, and other non-construction costs.
- They are based on the assumption that BC Hydro takes appropriate cost mitigation measures to reduce the impacts of construction cost inflation, through procurement strategies, value engineering, and other initiatives.
- They also assume that the efforts in 2009 and 2010 to stimulate the US and Canadian economy are at least moderately successful, and that the North America economy gradually recovers its momentum. There is some evidence that the electric utility construction industry in BC is already starting to recover its momentum, through new construction initiatives such as the Northwest Transmission Line, the proposed “Site C” major dam project, and many other proposed BC electricity generation and transmission capital projects.
- Finally, all forecasts and projections are by their nature subjective. Neither MMK Consulting nor BC Hydro can represent that any of the recommended allowances and projections in this report will be realized in whole or in part.

Transmission and Distribution Estimating Guidelines

Table of Contents

1. Estimating Requirements

On March 18, 2010, the BCUC published 2010 Certificates of Public Convenience and Necessity Application Guidelines G-50-10 (Appendix G). The document outlines the estimating guidelines/methodology that will be required for CPCN applications. The estimating methodology referenced is based on AACE Guidelines (Appendix B). In addition to adopting this methodology for its CPCN applications, FortisBC is adopting this methodology, in concept, for its capital expenditure plan submissions.

Different cost estimate classifications of projects are used at specific project stages to evaluate, approve, *and/or* fund projects. This document is intended to provide guidelines for applying the principles of estimate classification, specifically on project estimates for engineering, procurement and construction management for projects to be submitted in the Capital Expenditure Plan. The core of a capital project is the physical plant and its various components and elements. The better these elements and components are defined, the more accurate the resulting engineering, procurement, and construction cost estimate and schedule will be. Increasing the level of project definition is accomplished by performing the engineering work from the Identify stage through to the Operate stage (see Table 1). The class of estimate available is therefore related to, and dependent upon, the amount of planning and front end engineering design (FEED) work completed and the level of project/technical definition expressed as a percentage of complete project definition. The stages of Identify, Evaluate, Define, and Execute provide increased levels of information available for developing estimates of capital cost and project schedule. As the project passes through to the next stage, there should be an improved understanding of the project and a corresponding reduction in cost and schedule uncertainty.

Table 1:

AACE Classification	Project Stage	Description	FortisBC Usage
Class 5	Identify	Determine project feasibility and alignment with business strategy.	5 to 20 year plan window
Class 4	Evaluate	Select the preferred Development Option(s) & Execution Strategy.	3 to 5 year plan window
Class 3	Define	Finalize project scope, cost and schedule and Sanction Project. Prepare for Execute Phase.	1 to 2 year plan window (CEP approval window)
Class 2	Execute	Safely Produce an operating asset consistent with scope, cost & schedule.	Tracking execution
Class 1	Operate (or Audit level)	Evaluate & Operate asset to ensure performance to specifications and maximum return to the Client.	Quality Control or Close Out

The aim of these guidelines is to provide common terminology and a consistent methodology for developing, understanding and using cost estimates and schedules across the list of FortisBC generation, transmission, station, and distribution projects.

These estimate classifications, categorized relative to the degree of project/technical definition completed, are summarized in Table 2. These classifications are intended to convey the state of design development upon which an estimate is based, the probable range of variation of the estimated cost and the purpose for which each estimate class maybe used.

Estimates are a key input to the decision making process and their accuracy needs to be defined to quantify the reliability and variability of the information on which the decision is to be based. Estimates should therefore be a realistic attempt to define the extent of a project both in scope and cost. It should be noted that the information supporting an estimate often relies on an extensive list of assumptions around constructability in particular. These assumptions are progressively refined as engineering progresses, but need to be identified and addressed at all stages.

Table 2:

Classification	Expected Accuracy Range		Purpose	Project/Technical Definition	Estimating Methodology	FBC End Usage
	Low	High				
Class 5 'Identify Phase'	-20 to -50%	+30 to +100%	• Long range capital funding levels • Market studies • Preliminary Assessments • Conceptual evaluation of alternative schemes • Preliminary project/concept screening	• 0 to 2% • Conceptual level engineering • Route/locations identified through maps • Affected external stakeholders identified • System parameters identified	• 'Rule of Thumb' costing • Historical data • Judgment based	5 to 20 year plan window
Class 4 'Evaluate Phase'	-15 to -30%	+20 to +50%	• Detailed strategic planning • Business case assessment • Project screening at a more developed stage • Confirmation of economic and/or technical feasibility • Evaluation of alternative schemes	• 1 to 15% • Pre-FEED[1] to FEED[1] level engineering • Route/locations researched through land checks • Affected external stakeholders identified and risk assessed • System parameters defined • System limitations defined • Preliminary operational contingency plans identified • Equipment parameters identified • Major material list compiled • Project schedule at concept level	• Preliminary estimate with risk conceptualized • Historical data • Gross unit costs • Budgetary equipment and material quotes • Develop construction labour and equipment crew costs	3 to 5 year plan window

Classification	Expected Accuracy Range		Purpose	Project/Technical Definition	Estimating Methodology	FBC End Usage
Class 3 'Define Phase'	-10 to -20%	+10 to +30%	• Project Funding authorization • First control estimate or project budget • Approval to proceed to next stage or control gate	• 25 to 40% • FEED[1]-level engineering • Prepare Design Basis Memorandum • Final route/locations defined and researched • Operational contingency plans developed • Non standard equipment specifications • Material list • Project schedule at task level • Project Execution Plan	• Budget estimate with risk identified • Budgetary equipment and material pricing • Develop construction labour and equipment crew cost and incorporate in cost estimate • Budgetary pricing on work components (if required)	Capital Plan filing timeframe (1 to 2 year plan window)
Class 2 'Execute Phase'	-5 to -15%	+5 to +20%	• Detailed control estimate	• 50 to 70% • Detailed level engineering • Issue construction packages • Issue RFQs for equipment, materials, and bid documents for construction packages	• Control estimate • Equipment and material RFQs • Update construction, labour and equipment crew costs	Tracking execution
Class 1 'Operate Phase' or 'Close-Out Phase'	-3 to -10%	+3 to +15%	• Final control estimate • Used to track actual costs against the final control estimate • Used to monitor variations • Used to validate claims and disputes	• 75 to1 00% • Completed Engineering • Updated data from contractors and equipment and material vendors	• Control estimate • Use contractor and equipment and material vendors' actual costs	Quality control or close out

Notes: (1) FEED – Front End Engineering Design

The Guidelines, in addition to providing the classification criteria outlined in Table 1 and Table 2, consist of a series of checklists for each asset group which can be used to confirm documentation compliance with a given estimate class (Appendices C to F). The purpose of the checklists is to provide directions so that the employees with different levels of experience can create the documentation and produce an estimate to support the proper class and arrive at similar results. There is one sheet for each estimate class within each asset group. Each sheet has the requirements that are asset group specific. "Risk premium", contingency and other allowances need to be specifically addressed.

To aid in following the checklists, an "interpretation guide" has been developed for each checkbox to explain in more detail what it means (i.e. does "Site survey reviewed/considered" mean a current survey was commissioned, or is a paper tracing from 50 years ago being used?).

Historically, estimates were an educated guess based on past expenditures and experience with the work being done. Uncertainty was factored in through contingency or adjusting the values of a particular task. Looking forward, as it is difficult to identify and factor in all possible scenarios, we will be taking an approach by which we will determine the cost of the work with a risk factor to determine the potential high end of the work. All projects are to have an estimate which would contain the base estimate and contingency. In addition a risk factor (usually defined in dollars) is to be identified based on the specifics of the project.

Example

Project: PLN11-1066
Project Name: Ellison to Sexsmith Transmission tie
Estimate Level: 3
Estimate: $4,500,000 (includes contingency of $350,000)
Risk: $500,000 (potential 8 month delay in permitting and public consultation)

Therefore, the request for budgetary approval for this project would include $4,500,000 with the understanding that there is a potential risk of an additional $500,000 if the risks identified are realized.

2. Estimate Classes

Class 5

Class 5 estimates are ballpark and built on ‘rule of thumb’ costing and rudimentary (or limited) information. The level of effort required to prepare the estimate would depend on the scope of the project as well as the estimating cost data and tools available. It has fundamental definition of scope with typically only Planning and Engineering ‘signoffs’. These are projects that are typically beyond a 5 year horizon.

Class 4

Class 4 estimates are for evaluation purposes and are built on ‘rule of thumb’ costing adjusted to the project specifics at a group task level and involves ‘budgetary pricing’ from vendors on specific materials/work. It requires rudimentary (or limited) information with increased effort on definition of parameters and stakeholder input. The level of effort required to prepare the estimate would depend on the scope of the project as well as the estimating cost data and tools available. It has preliminary definition of scope with typically Planning, Engineering and Operations ‘signoffs’. These are projects that are typically in a 3 to 5 year horizon.

Class 3

Class 3 estimates are for budgetary approval and are built on detailed tasks and costs associated with those tasks. It involves specific prices based either in recent purchases/expenditures or quotations. It requires detailed information and clear definition of parameters and stakeholder input. The level of effort required to prepare the estimate would depend on the scope of the project as well as the estimating cost data and tools available. It has detailed definition of scope with typically Planning, Engineering, Operations and Project Management ‘signoffs’. These are projects that are in a budget approval year(s) or cycle.

This level does imply that all material quotes and tenders are ‘ready to go’ and would be executed once approval is given. Although this works an industry where approval to spend lies entirely with the owner, it does not work entirely in the regulated utility environment where approvals are from an external body and can take several years from project estimate/definition to approval of funds. Therefore we need to look at a hybrid of level 3 estimate with confidence level utilizing standard material, recent purchases/experience and budgetary quotations/pricing. This does not provide the same financial level of confidence as in the private sector. However, it does provide a level of confidence given similar circumstances.

Class 2

This is part of the project management philosophies/process and is not discussed within this document.

Class 1

This is part of the project management philosophies/process and is not discussed within this document.

APPENDIX A - Terms

Cost Estimate

A prediction of quantities, cost, and/or price of resources required by the scope of an asset investment option, activity, or project. As a prediction, an estimate must address risks and uncertainties. Estimates are used primarily as inputs for budgeting, cost or value analysis, decision making in business, asset and project planning, or for project cost and schedule control processes. Cost estimates are determined using experience and calculating and forecasting the future cost of resources, methods, and management within a scheduled time frame.

Escalation

The provision in actual or estimated costs for an increase in the cost of equipment, material, labor, etc., over that specified in the purchase order or contract due to continuing price level changes over time. Inflation may be a component of escalation, but non-monetary policy influences, such as supply-and-demand, are often components.

Contingency (AACE)

AACE International, the Association for the Advancement of Cost engineering, has defined contingency as "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience. Contingency usually excludes:

1. Major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or project;
2. Extraordinary events such as major strikes and natural disasters;
3. Management reserves; and
4. Escalation and currency effects.

Some of the items, conditions, or events for which the state, occurrence, and/or effect is uncertain include, but are not limited to, planning and estimating errors and omissions, minor price fluctuations other than general escalation), design developments and changes within the scope, and variations in market and environmental conditions. Contingency is generally included in most estimates, and **is expected to be expended**".

Project

Based on commonly used Project Management terminology, Project's definition is as follow: *"A temporary endeavor with a specific objective to be met within the* *prescribed time and monetary limitations and which has been assigned for definition or* Project Cost Estimating Guidelines Procedure #CRC-001 Rev. 2 **April, 27th 2009 Page 5 | 20** *execution" (AACE / PMI).* Regional Transmission projects are typically defined by the transmission owner as a result of the solution study. Projects are broken down by components in the RSP listing (Lines & Substations) but are typically permitted and reviewed as a whole for efficiency and resource/costs savings.

Project Scope

The sum of all that is to be or has been invested in and delivered by the performance of an activity or project. In project planning, the scope is usually documented (i.e., the scope document).

Change in Scope

A change in the defined deliverables or resources used to provide them.

Level of Project Definition

This characteristic is based upon percent complete of project definition (roughly corresponding to percent complete of engineering). The level of project definition defines maturity or the extent and types of input information available to the estimating process. Such inputs include project scope definition, requirements documents, specifications, project plans, drawings, calculations, learnings from past projects, reconnaissance data, and other information that must be developed to define the project.

Risk Sources

Events or conditions that have been defined for use in Risk Assessment that might affect the outcome of a project. Risk sources are frequently subdivided into the following groups, based on the underlying source of the source: 1) Business needs risks; 2) Results definition risks; 3) Scope definition risks; 4) Execution plan, mastery and processes risks; and 5) External risks.

Risk Types

A means of characterizing risk for use in risk assessment by the type of risk:

1. Inherited -derived from preceding stages of project;
2. Economic - associated with availability and costs of resources;
3. Commercial - associated with customer's needs and wants, competition, etc.;

4. Technological - associated with ability to achieve desired results, produce products, etc. life of current or new technology and compatibility of new technologies;
5. Implementation - ability to meet project plan and commitments due to human behavior or organizational factors.

APPENDIX B - AACE Guidelines

aace International

AACE International Recommended Practice No. 18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

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COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

February 2, 2005

PURPOSE

As a recommended practice of AACE International, the Cost Estimate Classification System provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The Cost Estimate Classification System maps the phases and stages of project cost estimating together with a generic maturity and quality matrix, which can be applied across a wide variety of industries.

This addendum to the generic recommended practice provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries. This addendum supplements the generic recommended practice (17R-97) by providing:

- a section that further defines classification concepts as they apply to the process industries;
- charts that compare existing estimate classification practices in the process industry; and
- a chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic standard, an intent of this addendum is to improve communications among all of the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the process industries.

It is understood that each enterprise may have its own project and estimating processes and terminology, and may classify estimates in particular ways. This guideline provides a generic and generally acceptable classification system for process industries that can be used as a basis to compare against. It is hoped that this addendum will allow each user to better assess, define, and communicate their own processes and standards in the light of generally-accepted cost engineering practice.

INTRODUCTION

For the purposes of this addendum, the term process industries is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) as primary scope defining documents. These documents are key deliverables in determining the level of project definition, and thus the extent and maturity of estimate input information.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this addendum may apply to portions of other industries, such as pharmaceutical, utility, metallurgical, converting, and similar industries. Specific addendums addressing these industries may be developed over time.

This addendum specifically does not address cost estimate classification in nonprocess industries such as commercial building construction, environmental remediation, transportation infrastructure, “dry” processes such as assembly and manufacturing, “soft asset” production such as software development, and similar industries. It also does not specifically address estimates for the exploration, production, or transportation of mining or hydrocarbon materials, although it may apply to some of the intermediate processing steps in these systems.

The cost estimates covered by this addendum are for engineering, procurement, and construction (EPC) work only. It does not cover estimates for the products manufactured by the process facilities, or for research and development work in support of the process industries. This guideline does not cover the significant building construction that may be a part of process plants. Building construction will be covered in a separate addendum.

This guideline reflects generally-accepted cost engineering practices. This addendum was based upon the practices of a wide range of companies in the process industries from around the world, as well as published references and standards. Company and public standards were solicited and reviewed by the AACE International Cost Estimating Committee. The practices were found to have significant commonalities that are conveyed in this addendum.

COST ESTIMATE CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES

The five estimate classes are presented in figure 1 in relationship to the identified characteristics. Only the level of project definition determines the estimate class. The other four characteristics are secondary characteristics that are generally correlated with the level of project definition, as discussed in the generic standard. The characteristics are typical for the process industries but may vary from application to application.

This matrix and guideline provide an estimate classification system that is specific to the process industries. Refer to the generic standard for a general matrix that is non-industry specific, or to other addendums for guidelines that will provide more detailed information for application in other specific industries. These will typically provide additional information, such as input deliverable checklists to allow meaningful categorization in those particular industries.

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

Figure 1. – Cost Estimate Classification Matrix for Process Industries

CHARACTERISTICS OF THE ESTIMATE CLASSES

The following charts (figures 2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the process industries. They are presented in the order of least-defined estimates to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class.

For each chart, the following information is provided:

- **Description:** a short description of the class of estimate, including a brief listing of the expected estimate inputs based on the level of project definition.
- **Level of Project Definition Required:** expressed as a percent of full definition. For the process industries, this correlates with the percent of engineering and design complete.
- **End Usage:** a short discussion of the possible end usage of this class of estimate.
- **Estimating Methods Used:** a listing of the possible estimating methods that may be employed to develop an estimate of this class.
- **Expected Accuracy Range:** typical variation in low and high ranges after the application of contingency (determined at a 50% level of confidence). Typically, this results in a 90% confidence that the actual cost will fall within the bounds of the low and high ranges.
- **Effort to Prepare:** this section provides a typical level of effort (in hours) to produce a complete estimate for a US$20,000,000 plant. Estimate preparation effort is highly dependent on project size, project complexity, estimator skills and knowledge, and on the availability of appropriate estimating cost data and tools.
- **ANSI Standard Reference (1989) Name:** this is a reference to the equivalent estimate class in the existing ANSI standards.
- **Alternate Estimate Names, Terms, Expressions, Synonyms:** this section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this Recommended Practice. The user is cautioned that an alternative name may not always be correlated with the class of estimate as identified in the chart.

CLASS 5 ESTIMATE	
Description: Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systemic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than an hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation. **Level of Project Definition Required:** 0% to 2% of full project definition. **End Usage:** Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	**Estimating Methods Used:** Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 5 estimates are - 20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances. **Effort to Prepare (for US$20MM project):** As little as 1 hour or less to perhaps more than 200 hours, depending on the project and the estimating methodology used. **ANSI Standard Reference Z94.2-1989 Name:** Order of magnitude estimate (typically -30% to +50%). **Alternate Estimate Names, Terms, Expressions, Synonyms:** Ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.

Figure 2a. – Class 5 Estimate

CLASS 4 ESTIMATE

Description:
Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists.

Level of Project Definition Required:
1% to 15% of full project definition.

End Usage:
Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.

Estimating Methods Used:
Class 4 estimates virtually always use stochastic estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques.

Expected Accuracy Range:
Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.

Effort to Prepare (for US$20MM project):
Typically, as little as 20 hours or less to perhaps more than 300 hours, depending on the project and the estimating methodology used.

ANSI Standard Reference Z94.2-1989 Name:
Budget estimate (typically -15% to + 30%).

Alternate Estimate Names, Terms, Expressions, Synonyms:
Screening, top-down, feasibility, authorization, factored, pre-design, pre-study.

Figure 2b. – Class 4 Estimate

CLASS 3 ESTIMATE

Description:
Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists.

Level of Project Definition Required:
10% to 40% of full project definition.

End Usage:
Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase “control estimates” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate may be the last estimate required and could well form the only basis for cost/schedule control.

Estimating Methods Used:
Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project.

Expected Accuracy Range:
Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.

Effort to Prepare (for US$20MM project):
Typically, as little as 150 hours or less to perhaps more than 1,500 hours, depending on the project and the estimating methodology used.

ANSI Standard Reference Z94.2-1989 Name:
Budget estimate (typically -15% to + 30%).

Alternate Estimate Names, Terms, Expressions, Synonyms:
Budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, development, basic engineering phase estimate, target estimate.

Figure 2c. – Class 3 Estimate

CLASS 2 ESTIMATE

Description:
Class 2 estimates are generally prepared to form a detailed control baseline against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the “bid” estimate to establish contract value. Typically, engineering is from 30% to 70% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.

Level of Project Definition Required:
30% to 70% of full project definition.

End Usage:
Class 2 estimates are typically prepared as the detailed control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program.

Estimating Methods Used:
Class 2 estimates always involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.

Expected Accuracy Range:
Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.

Effort to Prepare (for US$20MM project):
Typically, as little as 300 hours or less to perhaps more than 3,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.

ANSI Standard Reference Z94.2-1989 Name:
Definitive estimate (typically -5% to + 15%).

Alternate Estimate Names, Terms, Expressions, Synonyms:
Detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.

Figure 2d. – Class 2 Estimate

CLASS 1 ESTIMATE

Description:
Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor’s bid estimate, or to evaluate/dispute claims. Typically, engineering is from 50% to 100% complete, and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans.

Level of Project Definition Required:
50% to 100% of full project definition.

End Usage:
Class 1 estimates are typically prepared to form a current control estimate to be used as the final control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution.

Estimating Methods Used:
Class 1 estimates involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities.

Expected Accuracy Range:
Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.

Effort to Prepare (for US$20MM project):
Class 1 estimates require the most effort to create, and as such are generally developed for only selected areas of the project, or for bidding purposes. A complete Class 1 estimate may involve as little as 600 hours or less, to perhaps more than 6,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.

ANSI Standard Reference Z94.2 Name:
Definitive estimate (typically -5% to + 15%).

Alternate Estimate Names, Terms, Expressions, Synonyms:
Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Figure 2e. – Class 1 Estimate

COMPARISON OF CLASSIFICATION PRACTICES

Figures 3a through 3c provide a comparison of the estimate classification practices of various firms, organizations, and published sources against one another and against the guideline classifications. These tables permits users to benchmark their own classification practices.

INCREASING PROJECT DEFINITION

AACE Classification Standard	**ANSI Standard Z94.0**	**AACE Pre-1972**	**Association of Cost Engineers (UK) ACostE**	**Norwegian Project Management Association (NFP)**	**American Society of Professional Estimators (ASPE)**
Class 5	Order of Magnitude Estimate -30/+50	Order of Magnitude Estimate	Order of Magnitude Estimate Class IV -30/+30	Concession Estimate Exploration Estimate Feasibility Estimate	Level 1
Class 4	Budget Estimate -15/+30	Study Estimate	Study Estimate Class III -20/+20	Authorization Estimate	Level 2
Class 3		Preliminary Estimate	Budget Estimate Class II -10/+10	Master Control Estimate	Level 3
Class 2	Definitive Estimate -5/+15	Definitive Estimate	Definitive Estimate Class I -5/+5	Current Control Estimate	Level 4
Class 1		Detailed Estimate			Level 5 Level 6

Figure 3a. – Comparison of Classification Practices

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>Major Consumer Products Company (Confidential)</th><th>Major Oil Company (Confidential)</th><th>Major Oil Company (Confidential)</th><th>Major Oil Company (Confidential)</th></tr>
<tr><td rowspan="2">Class 5</td><td rowspan="2">Class S
Strategic Estimate</td><td rowspan="2">Class V
Order of Magnitude Estimate</td><td>Class A
Prospect Estimate</td><td rowspan="2">Class V</td></tr>
<tr><td>Class B
Evaluation Estimate</td></tr>
<tr><td rowspan="2">Class 4</td><td rowspan="2">Class 1
Conceptual Estimate</td><td rowspan="2">Class IV
Screening Estimate</td><td>Class C
Feasibility Estimate</td><td rowspan="2">Class IV</td></tr>
<tr><td rowspan="2">Class D
Development Estimate</td></tr>
<tr><td rowspan="3">Class 3</td><td rowspan="3">Class 2
Semi-Detailed Estimate</td><td rowspan="2">Class III
Primary Control Estimate</td><td rowspan="2">Class III</td></tr>
<tr><td rowspan="2">Class E
Preliminary Estimate</td></tr>
<tr><td rowspan="2">Class II
Master Control Estimate</td><td rowspan="2">Class II</td></tr>
<tr><td>Class 2</td><td rowspan="2">Class 3
Detailed Estimate</td><td>Class F
Master Control Estimate</td></tr>
<tr><td>Class 1</td><td>Class I
Current Control Estimate</td><td>Current Control Estimate</td><td>Class I</td></tr>
</table>

Figure 3b. – Comparison of Classification Practices

INCREASING PROJECT DEFINITION

<table>
<tr><th>AACE Classification Standard</th><th>J.R. Heizelman, 1988 AACE Transactions [1]</th><th>K.T. Yeo, The Cost Engineer, 1989 [2]</th><th>Stevens & Davis, 1988 AACE Transactions [3]</th><th>P. Behrenbruck, Journal of Petroleum Technology, 1993 [4]</th></tr>
<tr><td>Class 5</td><td>Class V</td><td>Class V
Order of Magnitude</td><td>Class III*</td><td>Order of Magnitude</td></tr>
<tr><td>Class 4</td><td>Class IV</td><td>Class IV
Factor Estimate</td><td rowspan="4">Class II</td><td rowspan="2">Study Estimate</td></tr>
<tr><td rowspan="2">Class 3</td><td rowspan="2">Class III</td><td rowspan="2">Class III
Office Estimate</td></tr>
<tr><td rowspan="2">Budget Estimate</td></tr>
<tr><td>Class 2</td><td>Class II</td><td>Class II
Definitive Estimate</td></tr>
<tr><td>Class 1</td><td>Class I</td><td>Class I
Final Estimate</td><td>Class I</td><td>Control Estimate</td></tr>
</table>

[1] John R. Heizelman, ARCO Oil & Gas Co., 1988 AACE Transactions, Paper V3.7
[2] K.T. Yeo, The Cost Engineer, Vol. 27, No. 6, 1989
[3] Stevens & Davis, BP International Ltd., 1988 AACE Transactions, Paper B4.1 (* Class III is inferred)
[4] Peter Behrenbruck, BHP Petroleum Pty., Ltd., article in Petroleum Technology, August 1993

Figure 3c. – Comparison of Classification Practices

ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Figure 4 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the process industries. The maturity level is an approximation of the degree of completion of the deliverable. The degree of completion is indicated by the following letters.

- None (blank): development of the deliverable has not begun.
- Started (S): work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- Preliminary (P): work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- Complete (C): the deliverable has been reviewed and approved as appropriate.

	ESTIMATE CLASSIFICATION				
General Project Data:	**CLASS 5**	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
Project Scope Description	General	Preliminary	Defined	Defined	Defined
Plant Production/Facility Capacity	Assumed	Preliminary	Defined	Defined	Defined
Plant Location	General	Approximate	Specific	Specific	Specific
Soils & Hydrology	None	Preliminary	Defined	Defined	Defined
Integrated Project Plan	None	Preliminary	Defined	Defined	Defined
Project Master Schedule	None	Preliminary	Defined	Defined	Defined
Escalation Strategy	None	Preliminary	Defined	Defined	Defined
Work Breakdown Structure	None	Preliminary	Defined	Defined	Defined
Project Code of Accounts	None	Preliminary	Defined	Defined	Defined
Contracting Strategy	Assumed	Assumed	Preliminary	Defined	Defined
Engineering Deliverables:					
Block Flow Diagrams	S/P	P/C	C	C	C
Plot Plans		S	P/C	C	C
Process Flow Diagrams (PFDs)		S/P	P/C	C	C
Utility Flow Diagrams (UFDs)		S/P	P/C	C	C
Piping & Instrument Diagrams (P&IDs)		S	P/C	C	C
Heat & Material Balances		S	P/C	C	C
Process Equipment List		S/P	P/C	C	C
Utility Equipment List		S/P	P/C	C	C
Electrical One-Line Drawings		S/P	P/C	C	C
Specifications & Datasheets		S	P/C	C	C
General Equipment Arrangement Drawings		S	P/C	C	C
Spare Parts Listings			S/P	P	C
Mechanical Discipline Drawings			S	P	P/C
Electrical Discipline Drawings			S	P	P/C
Instrumentation/Control System Discipline Drawings			S	P	P/C
Civil/Structural/Site Discipline Drawings			S	P	P/C

Figure 4. – Estimate Input Checklist and Maturity Matrix

REFERENCES

ANSI Standard Z94.2-1989. **Industrial Engineering Terminology: Cost Engineering**.
AACE International Recommended Practice No.17R-97, **Cost Estimate Classification System**.

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APPENDIX C - Station ‘Checklist’

Station Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

Station

Project class definitions and documentation required.

Class 5 (Identify)

Required Documentation

☐Planning Problem or Opportunity
  - Explanation of problem/opportunity.
  - Capital Planning Initiation Document (CPID) document initiated

☐Planning Project Definition
  - From problem /opportunity project definition developed (progress into scope document)

☐Planning Sketches – SLD
  - Lines, Feeders and Major Equipment only
  - Communications SLD

☐Planning Sketches – GA
  - Lines, Feeders and Major Equipment only

☐Planning System Documentation
  - Load Flow Values
  - Voltage Records
  - Load information
  - Customer information

☐Planning Initiation Document (CPID)
  - Initiated for every Project

☐General Site Location
  - Different site locations in the same general area

☐Options
  - Site Locations
  - Bus configurations
  - Major Equipment

☐FortisBC Equipment Standards
  - Identify any non-standard equipment

☐Schedule
  - 1, 2 or 3 or more Years

☐Class 5 Estimate
  - Produced from Planning Station Estimate Templates

☐Risks
  - Identify risks associated with the project not moving ahead

☐Assumptions
  - List of assumptions used in estimate that effects cost of project

☐Statistics
  - Pertinent Stats if available

☐Operational Problems
  - From SCC Outage Reports

☐Planning sign-off

☐Engineering sign-off

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 4 classification.

Class 4 (Evaluate)

Required Documentation

❐Planning Preliminary Scope Issued
  - Issued by Planning to Engineering

❐Preliminary Construction Plan
  - Starting quarter and ending quarter identified
  - Identify construction constraints including weather, remote location etc.

❐Preliminary SLD
  - Protection control SLD with relaying and metering identified.
  - Communications equipment Identified.
  - P&C Check CT, VT ratios & accuracies

❐Fault Current Study
  - To determine equipment ratings and the requirement for a grounding study

❐Preliminary Material List
  - Major long term delivery equipment identified

❐Final Site Location
  - Site location has been determined and surveys and Geotechnical studies approved

❐Preliminary Site Plan
  - Legal Plan acquired, station boundaries determined, footprint orientation determined

❐Preliminary GA
  - Equipment arrangement in progress with all locations being determined

❐Preliminary Sections
  - Verification of equipment locations
  - Identify salvaged equipment

❐Class 4 Estimate
  - Produced from Engineering Estimate Sheet

❐Preliminary Survey Data
  - In progress

❐Preliminary Geotechnical Data
  - In progress

❐Preliminary Schedule
  - Engineering, Construction, and Commissioning schedules are determined

❐Business case started
  - For Management/Directors approvals

❐Planning sign-off

❐Engineering sign-off

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 3 classification.

Class 3 (Define)

Required Documentation

- ☐Approved Planning Scope
  - Operations signoff
  - SCC sign-off
- ☐Approved Construction Plan
  - Contingency plan including any by-pass installation
  - Signoff by PMO and SCC
- ☐Approved SLD
  - Signoff by P&C Engineer
  - Signoff by Communications Engineer
- ☐Approved Logics
  - Signoff by P&C Engineer
- ☐Material list complete
  - Signoff by Electrical Engineer
- ☐Approved GA
  - Signoff by Electrical Engineer
- ☐Approved Sections
  - Signoff by Electrical Engineer
- ☐Approved Site Plan
  - Signoff by Electrical Engineer
- ☐Preliminary Conduit Plan
- ☐Preliminary Grounding Plan
  - Is there adequate insulating gravel
- ☐Approved Schedule
  - Signoff by PMO
  - Signoff by Project Engineer
  - Signoff by SCC
  - Signoff by Operations
- ☐Survey Data Complete
  - Incorporated into the project design
- ☐Geotechnical Data Complete
  - Incorporated into the project design
- ☐Grounding Study
  - Existing stations may have previous studies with soil resistivity measurements
- ☐Preliminary Budget Set

- ☐Class 3 Estimate
  - Produced from Class 4 Engineering Estimate Sheet
- ☐Business case completed

- ☐System Studies
  - Completed
- ☐Load Studies
  - Completed
- ☐Permits / Easements
  - Identify which are required

Once sign-offs are complete, the project can proceed to the Class 2 classification.

Class 2 (Execute)

Part of Project Management Process and therefore not defined in this document.

Class 1 (Operate)

Part of Project Management Process and therefore not defined in this document.

APPENDIX D - Transmission ‘Checklist’

FORTIS BC™

Transmission Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

Transmission

Project class definitions and documentation required.

Class 5 (Identify)

Required Documentation

- ☐Planning Problem or Opportunity
  - Explanation of problem/opportunity.
  - Capital Planning Initiation Document (CPID) document initiated
- ☐Planning Project Definition
  - From problem /opportunity project definition developed (progress into scope document)
  - Voltage, conductor/ampacity rating
- ☐Planning Sketches – SLD
  - Line routes, switching, taps, and major equipment only
- ☐Planning Sketches – Maps
  - Route maps
- ☐Planning System Documentation
  - Load Flow Values
  - Voltage Records
  - Load information
  - Customer information
- ☐General Route Location
  - Start and finish locations
  - Different routes in the same general area
- ☐Options
  - Route options
  - Structure types
- ☐FortisBC Equipment Standards
  - Identify any non-standard equipment
- ☐Schedule
  - 1, 2 or 3 or more Years
- ☐Class 5 Estimate
  - Produced from FortisBC Designer Workbook
- ☐Risks
  - Identify risks associated with the project not moving ahead
- ☐Assumptions
  - List of assumptions used in estimate that effects cost of project.
- ☐Statistics
  - Pertinent Statistics if available
- ☐Operational Problems
  - From SCC outage reports
- ☐Planning sign-off

- ☐Engineering sign-off

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 4 classification.

Class 4 (Evaluate)

Required Documentation

- ☐Planning Preliminary Scope Issued
  - Issued by Planning to Engineering
- ☐Preliminary Construction Plan
  - Starting quarter and ending quarter identified
- ☐Preliminary SLD
  - Major equipment Identified
- ☐Preliminary Material List
  - Major long term delivery equipment identified
- ☐Preliminary Route Plan
  - Legal Plan acquired, R/W boundaries determined
  - Surveys and Geotechnical studies (if required) approved
  - Potential lands/environmental issues identified
- ☐Preliminary Structure Locations
  - Preliminary Structure types determined
- ☐Preliminary Profile
  - Based on Government terrain models
- ☐Class 4 Estimate
  - Produced from FortisBC Designer Workbook
- ☐Preliminary Survey Data
  - In progress
- ☐Preliminary Geotechnical Data
  - In progress
- ☐Preliminary Schedule
  - Engineering, Construction, and Commissioning schedules are determined
- ☐Planning sign-off

- ☐Engineering sign-off

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 3 classification.

Class 3 (Define)

Required Documentation

- ☐Approved Planning Scope
  - Operations signoff
  - SCC sign-off
- ☐Approved Construction Plan
  - Signoff by PMO
  - Signoff by Project Engineer
  - Signoff by SCC
- ☐Approved SLD
  - Signoff by Project Engineer, SCC, Planning
- ☐Material list complete
  - Signoff by Project Engineer
- ☐Approved Route Plan
  - Lands issues resolution in progress
  - Signoff by Project Engineer
- ☐Approved Schedule
  - Signoff by PMO
  - Signoff by Project Engineer
  - Signoff by SCC
  - Signoff by Operations
- ☐Finalized Structure Locations
- ☐Finalized Profile
- ☐Survey Data Complete
  - Incorporated into the project design
- ☐Geotechnical Data Complete
  - Incorporated into the project design
- ☐Preliminary Budget Set
- ☐Class 3 Estimate
  - Produced from FortisBC Designer Workbook
- ☐Business case started
- ☐System Studies
  - Completed
- ☐Load Studies
  - Completed

Once sign-offs are complete, the project can proceed to the Class 2 classification.

Class 2 (Execute)

Part of Project Management Process and therefore not defined in this document

Class 1 (Operate)

Part of Project Management Process and therefore not defined in this document

APPENDIX E - Distribution ‘Checklist’

Distribution Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

Distribution

Project class definitions and documentation required.

Class 5 (Identify)

Required Documentation

- ☐Planning Problem or Opportunity
  - Explanation of problem/opportunity.
  - Capital Planning Initiation Document (CPID) document initiated
- ☐Planning Project Definition
  - From problem /opportunity project definition developed (progress into scope document)
  - Identify distribution feeder, voltage and conductor ampacity
- ☐Planning Sketches – SLD
  - Line routes, switching (Isolation points), taps, and major equipment only
- ☐Planning Sketches – Maps
  - Route maps
- ☐Planning System Documentation
  - Load Flow Values
  - Voltage Records
  - Load information
  - Customer information
- ☐General Route Location
  - Different site routes in the same general area
- ☐Options
  - Route options
  - Structure types
- ☐FortisBC Equipment Standards
  - Identify any non-standard equipment
- ☐Schedule
  - 1, 2 or 3 or more Years
- ☐Class 5 Estimate
  - Produced from FortisBC Designer Workbook
- ☐Risks
  - Identify risks associated with the project not moving ahead.
- ☐Assumptions
  - List of assumptions used in estimate that effects cost of project.
- ☐Statistics
  - Pertinent Statistics if available
- ☐Operational Problems
  - From SCC outage reports
  - From operations or regional engineer
- ☐Planning sign-off

- ☐Engineering sign-off

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 4 classification.

Class 4 (Evaluate)

Required Documentation

☐Planning Preliminary Scope Issued
  - Issued by Planning to Engineering

☐Preliminary Construction Plan
  - Starting quarter and ending quarter identified

☐Preliminary SLD
  - Line routes, isolation points, taps, and major equipment identified

☐Preliminary Material List
  - Major long term delivery equipment identified

☐Preliminary Route Plan
  - Legal Plan acquired, R/W boundaries determined
  - Surveys and Geotechnical studies (if required) budgeted and approved
  - Identify land issues

☐Preliminary Structure Locations
  - Preliminary Structure locations & types determined
  - Preliminary anchor locations determined

☐Preliminary Profile
  - Based on Government terrain models
  - Selection of structure locations

☐Class 4 Estimate
  - Produced from FortisBC Designer Workbook

☐Preliminary Schedule
  - Engineering, Construction, and Commissioning schedules are determined

☐Planning sign-off

☐Engineering sign-off

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 3 classification.

Class 3 (Define)

Required Documentation

☐Approved Planning Scope
  - Operations signoff
  - SCC sign-off

☐Approved Construction Plan
  - Signoff by PMO
  - Signoff by Engineering
  - Signoff by SCC

☐Approved SLD
  - Signoff by Regional Engineer
  - Sign off by Operations

☐Materials
  - Long lead materials finalized

☐Approved Schedule
  - Signoff by PMO
  - Signoff by Engineering
  - Signoff by SCC
  - Signoff by Operations

☐Preliminary Budget Set

☐Class 3 Estimate
  - Produced from FortisBC Designer Workbook

☐Business case started

☐System Studies
  - Completed

☐Load Studies
  - Completed

☐R/W requirements identified (budget costs set)

If Required
- Land rights (private land, crown land)
- First Nations approval
- Ministry of Environment approval
- Municipal or Regional permitting
- Railways approval

Once sign-offs are complete, the project can proceed to the Class 2 classification.

Class 2 (Control)

Part of Project Management Process and therefore not defined in this document

Class 1 (Operate)

Part of Project Management Process and therefore not defined in this document

APPENDIX F - Generation ‘Checklist’

Generation Project Cost Classification System

(Based on the AACE International Recommend Practice No. 18R-97)

Generation

Project class definitions and documentation required.

Class 5 (Identify)

Required Documentation

- ❒Planning Initiation Document (CPID)
    - Explanation of problem/opportunity
    - Initiated for every project
- ❒Options Review
    - Produced from Generation Preliminary Planning Approval Templates
    - Risks Identified
    - Major equipment
    - Operation problems identified
- ❒Scope document
    - Produced from Generation Scope Template
    - Based on preferred option
    - Site location
    - Contracting out requirement.
    - Plant or Unit Outage requirement
    - Project Battery Limits
- ❒Project Rating – Generation Internal
    - Produced from Generation Rating Template
    - Safety, Environment, and Operational risks
    - Used to determines approximate year in which project will be installed
    - Used to determine estimate class requirement at this time
- ❒Class 5 Estimate
    - Produced from Generation Estimate Templates
    - Based on preferred option
    - Assumptions
    - Engineering discipline requirements
    - Preliminary schedule
    - Preliminary Cash Flow
    - SAP historical cost information
- ❒Operations sign-off of complete Class 5 package

- ❒Planning sign-off of complete Class 5 package

- ❒Engineering sign-off of complete Class 5 package

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 4 classification.

Class 4 (Evaluate)

Required Documentation

☐Options Approval
- Produced from Generation Preliminary Planning Approval Templates
- Option costs
- Pros and Cons of selected option clearly stated
- Operations, engineering discipline sign off

☐Planning Scope Issued
- Issued by Planning to Engineering
- Based on selected option

☐Sketches and Preliminary Lists
- Documentation will vary depending on project type, and Engineering discipline.
- Document to be signed as reviewed by Engineering discipline

Minimum sketch requirement is:
- Equipment layout.
- Equipment lists, material quantities, long term delivery items identified
- Equipment sizing, single line drawing

☐Class 4 Estimate
- Produced from Generation Estimate Sheet
- SAP Historical Cost Information
- Budgetary Vendor Quotes
- WBS (Work Breakdown Structure) as part of estimate.
- EPCM (Engineering, Procurement, Construction Management) costs and man-hours estimated
- Cost of Removal estimated
- FortisBC labor man-hours identified
- Preliminary Schedule based on WBS, will indicate as a minimum engineering, construction and commissioning schedules

☐Preliminary Work Plan
- Starting quarter and ending quarter identified
- Identify construction constraints including weather, remote location, crane requirements, access, facilities etc.

☐Business case started
- For Management/Directors approvals

☐Planning sign-off of complete Class 4 package

☐Engineering sign-off of complete Class 4 package

Once Planning and Engineering sign-offs are complete, the project can proceed to the Class 3 classification.

Class 3 (Define)

Required Documentation

☐Approved Planning Scope
  - Operations signoff
  - SCC sign-off (as required)

☐Approved Work Plan
  - Work Plan to be signed as reviewed by Operations, Engineering and SCC (if required)
  - Site access
  - Crane requirements and access
  - On site facilities
  - Management and labour resources
  - Security

☐Drawings and Lists
  - Documentation will vary depending on project type, and engineering discipline.
  - Document to be signed as approved by engineering discipline.

  Minimum Drawing Requirement:
  - Equipment layout. Site Plan
  - Equipment lists, material quantities, long term delivery items identified
  - Equipment sizing, Single Line Drawing

☐Preliminary Specifications
  - Operations signoff
  - Engineering signoff

☐Approved Schedule
  - Completed using MS Project
  - Signoff by PMO
  - Signoff by Project Engineer
  - Signoff by SCC
  - Signoff by Operations

☐Class 3 Estimate
  - Produced from Generation Estimate Sheet
  - SAP Historical Cost Information, inflation review
  - Written Vendor quotes based on preliminary specification
  - Confirmation of Contracting Out status

☐Preliminary Budget Set

☐Business case completed

Once sign-offs are complete, the project can proceed to the Class 2 classification.

Class 2 (Execute)

Part of Project Management Process and therefore not defined in this document

Class 1 (Operate)

Part of Project Management Process and therefore not defined in this document

APPENDIX G - BCUC Order G-50-10

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-50-10

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and
2010 Certificates of Public Convenience and Necessity Application Guidelines

BEFORE: L.F. Kelsey, Commissioner
D.A. Cote, Commissioner March 18, 2010

ORDER

WHEREAS:

A. The *Utilities Commission Act* (the Act) states in section 46(1) that an applicant for a Certificate of Public Convenience and Necessity (CPCN) must file with the British Columbia Utilities Commission (the Commission) information, material, evidence and documents that the Commission prescribes; and

B. On March 31, 2004 the Commission, by Order G-28-04, issued its “Guidelines for CPCN Applications” which established the required procedure and information for CPCN applications under the Act; and

C. On September 16, 2009, the Commission issued draft 2009 CPCN Application Guidelines for a 60-day comment period from regulated utilities and the public; and

D. Comments were received from British Columbia Hydro and Power Authority , British Columbia Transmission Corporation, FortisBC Inc., Pacific Northern Gas Ltd., Skeetchestn Indian Band and Terasen Utilities; and

E. The Commission has reviewed the comments and considers that the establishment of the 2010 CPCN Application Guidelines is warranted.

NOW THEREFORE the Commission orders as follows:

1. Commission Order G-28-04 is cancelled.

2. An application for a CPCN pursuant to sections 45 and 46 of the Act is to be made in a form that satisfies the requirements outlined in Appendix A to this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of March 2010.

BY ORDER

Original signed by:

D.A. Cote
Commissioner

Attachment

APPENDIX A
to Order G-50-10

British Columbia Utilities Commission

2010 Certificates of Public Convenience and Necessity Application Guidelines

TABLE OF CONTENTS

PURPOSE AND SCOPE OF GUIDELINES

The purpose of these guidelines is to assist public utilities and other parties wishing to construct or operate utility facilities in preparing their applications for a Certificate of Public Convenience and Necessity (CPCN) so the review of these applications by the British Columbia Utilities Commission (Commission) can proceed as efficiently as possible. The Commission expects CPCN applications will generally be prepared in accordance with the guidelines.

Section 45(1) of the Utilities Commission Act (UCA) requires that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the Commission a CPCN approving the construction or operation. Section 46(1) of the UCA requires an application for a CPCN be filed with Commission.

A copy of the UCA can be found at http://www.qp.gov.bc.ca/statreg/stat/U/96473_01.htm

The guidelines do not alter the fundamental regulatory relationship between utilities and the Commission. They provide general guidance regarding the Commission's expectations of the information that should be included in CPCN applications while providing the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project, and the issues that it raises. An applicant is expected to apply the guidelines in a flexible and reasonable manner. The Commission may issue further directions relating to the information to be included in specific CPCN applications and may require applicants to provide further information to supplement material in filed applications.

CPCN applications may be supported by long-term resource plans filed under section 44.1 of the UCA. These long-term resource plans may deal with significant aspects of project justification, particularly the need for the project and the assessment of the overall costs and benefits of the project and alternatives to the project. Under section 44.1(9) of the UCA, in approving a long-term resource plan, the Commission may order that a proposed utility plant or system, or an extension of either, is exempt from the requirements of section 45(1) of the UCA.

Public utilities and other project proponents are encouraged to initiate discussions with appropriate government agencies and consult with the public and potentially affected First Nations as early as possible in the planning and design phase of a project in order to gain an understanding of the issues to be addressed prior to the filing of an application.

DEEMED CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Sections 45(2), 45(5) and 45(6) of the UCA state:

> (2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it:
>
>> (a) to operate the plant or system; and
>> (b) subject to subsection (5), to construct and operate extensions to the plant or system.
>
> (5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.
>
> (6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.

In order to evaluate whether a public utility should apply for a CPCN for a specific extension to a utility plant or system and therefore whether to make an order pursuant to section 45(5), the Commission needs to be aware of planned extensions that are significant. This information is provided in the statement of planned extensions that a public utility is required to file at least once a year. The statement should be filed in a timely fashion and should identify each discrete extension to a utility plant or system that may have a material impact on customer rates or raise some other significant issue. The statement should include all extensions that the utility is likely to initiate over the period until the filing of the next statement on extensions, and should use a definition of extension that is as broad and inclusive as possible. A utility should inform the Commission in the event it plans to initiate a significant extension that was not identified in its most recent statement on extensions.

A long-term resource plan filed pursuant to section 44.1 of the UCA or a capital expenditure schedule filed pursuant to section 44.2(1)(b) may meet the requirements of section 45(6) provided it is filed prior to the start of the construction of the extensions. Also, section 45(4) provides that the Commission may, by regulation, exclude utility plant or categories of utility plant from the operation of section 45(1). Under this provision, the Commission may establish project thresholds relating to size, production capacity, type and absence of local impacts that will determine projects that would generally not require a CPCN application.

PROCEDURAL CONSIDERATIONS

An application for a CPCN pursuant to sections 45 and 46 of the UCA will be made to the Secretary of the Commission. Applications are to be filed in accordance with the Commission's document filing protocols. A text recognizable and bookmarked electronic copy with working spreadsheets and 12 hard copies of the completed and signed CPCN application should be submitted. Applications are typically made public, except where special circumstances require confidentiality.

The filed application is initially reviewed by the Commission for possible deficiencies and any additional information is requested through an information request which is responded to by the applicant. Once the response to the information request is received, the application is reviewed by the Commission to understand the application, identify any additional deficiencies, and make a preliminary determination as to whether a hearing is required, and if required, the nature of the proceeding. Pursuant to section 46(2), the Commission may establish an oral or written hearing and regulatory timetable if further review of the application is required.

The Commission makes a determination on disposition of the CPCN application as follows:

(a) Grant a CPCN without further input from the applicant or other interested parties.
(b) Require further information from the applicant.
(c) Set down an oral or written public hearing.
(d) Deny the application.

Approval of a CPCN application results in the Commission issuing an order to the applicant granting the CPCN. The order may include terms and conditions which the Commission believes the public convenience or necessity require.

For further information, contact:

Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Telephone: (604) 660-4700
Toll Free: 1-800-663-1385
Facsimile: (604) 660-1102
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

APPLICATION REQUIREMENTS

An application under sections 45 and 46 of the UCA should contain the following information:

1. <u>Applicant</u>
   - (i) Name, address and description of the nature of the applicant's business and all other persons having a direct interest in project ownership or management;
   - (ii) Evidence of the financial and technical capacity of the applicant and other persons involved, if any, to undertake and operate the project;
   - (iii) Name, title and address of the person with whom communication should be made respecting the application;
   - (iv) Name and address of legal counsel for the applicant, if any;
   - (v) Organizational chart of the project team, including the names of the Project Manager and Executive Sponsor for the project; and
   - (vi) Outline of the regulatory process the applicant recommends for the Commission's review of the application, including how persons who were consulted about the project can raise outstanding application-related concerns with the Commission.

2. <u>Project Need, Alternatives and Justification</u>
   - (i) Studies or summary statements identifying the need for the project and confirming the technical, economic and financial feasibility of the project, identifying assumptions, sources of data, and feasible alternatives considered. The applicant should identify alternatives that it deemed to be not feasible at an early screening stage, and provide the reason(s) why it did not consider them further;

(ii) A comparison of the costs, benefits and associated risks of the project and feasible alternatives, including estimates of the value of all of the costs and benefits of each option or, where these costs and benefits are not quantifiable, identification of the cost or benefit that cannot be quantified. Cost estimates used in the economic comparison should have, at a minimum, a Class 4[1] degree of accuracy as defined in the Advancement of Cost Engineering ("AACE International") Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009);

(iii) A schedule calculating the revenue requirements of the project and feasible alternatives, and the resulting impacts on customer rates;

(iv) A schedule calculating the net present values of the incremental cost and benefit cash flows of the project and feasible alternatives, and justification of the length of the term and discount rate used for the calculation;

(v) A schedule and supporting discussion comparing the project and feasible alternatives in terms of social and environmental factors, and the applicant's assessment regarding the overall social and environmental impact of the project relative to the overall impact of the feasible alternatives; and

(vi) Information relating the project to the applicant's approved long-term resource plan filed pursuant to section 44.1 of the UCA, including the extent to which the project was considered in the plan, and, if applicable, a discussion explaining how the plan provides support and justification for the need for the project.

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[1] Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval.

3. Consultation

First Nations Consultation

Note: Crown utilities are required to provide the information requirements set out in the British Columbia Utilities Commission 2010 First Nations Information Filing Guidelines for Crown Utilities, which replace and supersede the application requirements in this First Nations Consultation section of the CPCN Application Guidelines.

If an applicant is of the view that the application does not require consultation with First Nations, reasons supporting its conclusion should be provided to the Commission. Unless otherwise justified, the following information should be filed:

(i) Identification of the First Nations potentially affected by the application or filing, including the feasible project alternatives; and the information considered to identify these First Nations.

For each potentially affected First Nation, summarize the consultation to date, including:

(ii) Identification of any group, body, specific band or specific person(s) that have been consulting on behalf of the First Nation in connection with the application. Identify the specific member bands represented by any group or body;

(iii) A chronology of meetings, other communications and actions;

(iv) Any relevant, non-confidential written documentation regarding consultation, such as notes or minutes of meetings or phone calls, or letters received from or sent to the First Nation;

(v) Identification of specific issues or concerns raised by the First Nation;

(vi) Description of how the specific issues or concerns raised by the First Nation were avoided, mitigated or otherwise accommodated; or explain why no further action is required to address an issue or concern;

(vii) Copies of any documents which confirm that the First Nation is satisfied with the consultation to date;

(viii) Evidence that the First Nation has been notified of the filing of the application with the Commission and has been informed on how to raise outstanding concerns with the Commission; and

(ix) The applicant's overall view as to the sufficiency of the consultation process with the First Nation to date, in the context of the decision which is being sought from the Commission.

Public Consultation

(i) Overview of the community, social and environmental setting in which the project and its feasible alternatives will be constructed and operated, and of the public who may be directly impacted by the project and its feasible alternatives;

(ii) Description of the information and consultation programs with the public, including the organizations, agencies and individuals consulted, the information provided to these parties, and a chronology of meetings and other communications with members of the public and their representatives. This includes consultation with both the public who may be directly impacted by the project and the public that may experience impacts on their rates and service;

(iii) Description of the issues and concerns raised during consultations, the measures taken or planned to address issues or concerns, or an explanation of why no further action is required to address an issue or concern;

(iv) Identification of any outstanding issues or concerns; and

(v) Applicant's overall assessment as to the sufficiency of the public consultation process with respect to the project, in the context of the decision which is being sought from the Commission.

4. Project Description

(i) Description of the project, its purpose and cost, including engineering design, capacity, location options and preference, safety and reliability considerations, and all ancillary or related facilities that are proposed to be constructed, owned or operated by the applicant;

(ii) Outline of the anticipated construction and operation schedule, including critical dates of key events, a chart of major activities showing the critical path (e.g., GANTT[2] chart), and the timing of approvals required from other agencies to ensure continued economic viability;

(iii) Description of any new or expanded public works, undertakings or infrastructure that will result from or be required by the project, and an estimate of the costs and necessary completion dates;

(iv) Human capital resources required to undertake the project;

(v) Risk analysis identifying all significant risks to successful completion of the project, including an assessment of the probability of each risk occurring, and the consequences and the cost to mitigate the risk;

(vi) Identification and preliminary assessment of potential effects of the project on the physical, biological and social environments or on potentially affected First Nations and the public, proposals for reducing potentially negative effects and maximizing benefits from positive effects, and the cost to the project of implementing the proposals;

(vii) Identification of the customers to be served by the project and, where the project would expand the area served by the applicant, a geographical description of the expanded service area;

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[2] GANTT chart is a bar chart which illustrates a project schedule.

(viii) List of all required federal, provincial and municipal approvals, permits, licenses or authorizations; and

(ix) Summary of the material conditions that are anticipated in federal, provincial and municipal approvals and confirmation that the costs of complying with these conditions are included in the cost estimate in the application.

5. Project Cost Estimate

(i) Project cost estimate, including a description of the method of estimating used, the percentage of engineering completed at the time of the estimate, and identification and justification of all assumptions, exclusions, inflation and discount factors, and sources of benchmarks and other data;

(ii) The cost estimate should be stated in nominal as well as real dollars, identify an expected accuracy range and have, at a minimum, a Class 3[3] degree of accuracy as defined in AACE International Recommended Practice No. 10S-90, Cost Engineering Terminology (May 20, 2009);

(iii) The cost estimate should provide:

- (a) Any funds spent in prior years attributable to the project;
- (b) A list of all project direct and indirect costs using a work breakdown structure by year until completion;
- (c) Escalation (including inflation) amounts;
- (d) Contingency amount;
- (e) Interest during construction or allowance for funds used during construction and corporate overhead;
- (f) Identification and explanation of any management or other reserves;

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[3] Class 3 estimates are typically prepared to support full project funding requests, and become the first project phase “control estimate” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates.

(g) Any legal, regulatory and other non-project costs, including costs associated with First Nations and public consultation and accommodation.

(iv) Identification of any cost items not included in the estimate, including transportation costs, and the reason for the exclusion; and

(v) If a Monte Carlo[4] analysis was used to model and back-up the amount of project contingency included in the cost estimate, the base estimate, P50 expected value estimate, P90 estimate, histogram and cumulative curves, and tornado graphs.

6. Provincial Government Energy Objectives and Policy Considerations

(i) Discuss how the project is consistent with and will advance the government's energy objectives as set out in the UCA. If the nature of the project precludes a direct link to the energy objectives, the application should discuss how the project does not hamper other projects or initiatives undertaken by the applicant or others, from advancing these energy objectives;

(ii) Discuss how the project relates to and supports the Province's electricity self-sufficiency goals as set out in 64.01 of the UCA or as set out in Special Direction No. 10 to the Commission, if applicable; and

(iii) Where the applicant is BC Hydro or a prescribed public utility, discuss how the project relates to and supports the Province's clean and renewable electricity goal as set out in 64.02 of the UCA, if applicable.

7. New Service Areas

(i) Telephone number or other means by which customers will be able to contact the utility, particularly regarding an emergency;

(ii) Description of facilities and trained personnel that will provide emergency response;

---

[4] Monte Carlo analysis involves using random numbers and probability to solve problems.

(iii) Tariff including terms and conditions of service, rate schedules and initial rates the applicant proposes for customers in the new service area; and

(iv) Information confirming the proposed rates will be competitive with other service options that are available to customers in the new service area.

Capital Plan Project Cost and Resource Summary Sheet

Project Name :

Planning Number : PLN11-

	Base	Dollars ($) Contingency	Total
Planning & Preapproval costs			**$ -**
Distribution	$ -	$ -	**$ -**
Transmission	$ -	$ -	**$ -**
Station	$ -	$ -	**$ -**
Generation	$ -	$ -	**$ -**
Overall Project Management			**$ -**
Land/ROW			**$ -**
Environment			**$ -**
Public Consultation			**$ -**
Regulatory			**$ -**
Other	$ -		**$ -**
Project Contingency			**$ -**
Subtotal of Capital	**$ -**	**$ -**	**$ -**
Cost Of Removal - Distribution	*$ -*		***$ -***
Cost Of Removal - Transmission	*$ -*		***$ -***
Cost Of Removal - Station	*$ -*		***$ -***
Cost Of Removal - Generation	*$ -*		***$ -***
Cost Of Removal - Other			***$ -***
Subtotal of Cost of Removal	***$ -***	***$ -***	***$ -***
Total Project Costs Unloaded	**$ -**	**$ -**	**$ -**

NOTE : Total Project Cost to be entered in AFUDC Sheet

Identified Risks (not part of estimate)

Total	***$ -***
Description	Dollars($)

Capital Plan Cost and Resource Summary Project Sheet

Project Name : 0

Planning Number : PLN11- 0

Other Costs Description	**Dollars ($)**
Total	$ -

Capital Plan Cost and Resource Summary Project Sheet

Project Name : 0

Estimate Filename :

Planning Number : PLN11- 0

Pre-Budget Submission	**Dollars ($)**
Planning & Preapproval costs	$ -

Station Estimate	**Dollars ($)**
Engineering	
Construction	
Material	
Commissioning	
Project Management/Other	
Land/ROW	
Contingency	
Subtotal of Capital	$ -
Cost Of Removal	$ -
Total	$ -

Manpower Requirements	**Manhours**	
Construction		
Mechanical		
Control Release (Gen)		
PLT		
C&M (Electrical)		Subtotal
CPC Techs		0
Engineering		
Design		
Drafting		
Engineering		
Engineering Support		
Construction Support		Subtotal
Settings		0
Commissioning		
Engineering		
C&M/CPC		Subtotal
PLT		0

Description	Qty	Unit Cost	Total Cost
			$ -
Engineering			$ -
Construction			$ -
Material			$ -
Commissioning			$ -
PMO			$ -
Miscellaneous			$ -
			$ -
			$ -
			$ -
			$ -
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			$ -
Equipment Removal Total	Qty	Unit Cost	**$ -**
			$ -
			$ -
			$ -
			$ -
			$ -
			$ -

Capital Plan Cost and Resource Summary Project Sheet

Project Name : 0

Estimate Filename :

Planning Number : PLN11- 0

Pre-Budget Submission	**Dollars ($)**
Planning & Preapproval costs	$ -

Transmission Line Estimate	**Dollars ($)**
Engineering	
Construction	
Material	
Commissioning	
Project Management/Other	
Land/ROW	
Contingency	
Subtotal of Capital	$ -
Cost Of Removal	$ -
Total	$ -

Manpower Requirements	**Manhours**	
Construction		
Mechanical		
Control Release (Gen)		
PLT		
C&M (Electrical)		Subtotal
CPC Techs		0
Engineering		
Design		
Drafting		
Engineering		
Engineering Support		
Construction Support		Subtotal
Settings		0
Commissioning		
Engineering		
C&M/CPC		Subtotal
PLT		0

Description	Qty	Unit Cost	Total Cost
			$ -
Engineering			$ -
Construction			$ -
Material			$ -
Commissioning			$ -
PMO			$ -
Miscellaneous			$ -
			$ -
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Equipment Removal Total	Qty	Unit Cost	**$ -**
			$ -
			$ -
			$ -
			$ -
			$ -
			$ -

Capital Plan Cost and Resource Summary Project Sheet

Project Name : 0

Estimate Filename :

Planning Number : PLN11- 0

Pre-Budget Submission	**Dollars ($)**
Planning & Preapproval costs	$ -

Distribution Line Estimate	**Dollars ($)**
Engineering	
Construction	
Material	
Commissioning	
Project Management/Other	
Land/ROW	
Contingency	
Subtotal of Capital	$ -
Cost Of Removal	$ -
Total	$ -

Manpower Requirements	**Manhours**	
Construction		
Mechanical		
Control Release (Gen)		
PLT		
C&M (Electrical)		Subtotal
CPC Techs		0
Engineering		
Design		
Drafting		
Engineering		
Engineering Support		
Construction Support		Subtotal
Settings		0
Commissioning		
Engineering		
C&M/CPC		Subtotal
PLT		0

Description	Qty	Unit Cost	Total Cost
			$ -
Engineering			$ -
Construction			$ -
Material			$ -
Commissioning			$ -
PMO			$ -
Miscellaneous			$ -
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Equipment Removal Total	Qty	Unit Cost	**$ -**
			$ -
			$ -
			$ -
			$ -
			$ -
			$ -

Capital Plan Cost and Resource Summary Project Sheet

Project Name : 0

Estimate Filename :

Planning Number : PLN11- 0

Pre-Budget Submission	**Dollars ($)**
Planning & Preapproval costs	$ -

Generation Estimate	**Dollars ($)**
Engineering	
Construction	
Material	
Commissioning	
Project Management/Other	
Land/ROW	
Contingency	
Subtotal of Capital	$ -
Cost Of Removal	$ -
Total Project Unloaded	$ -

Manpower Requirements	**Manhours**	
Construction		
Mechanical		
Control Release (Gen)		
PLT		
C&M (Electrical)		Subtotal
CPC Techs		0
Engineering		
Design		
Drafting		
Engineering		
Engineering Support		
Construction Support		Subtotal
Settings		0
Commissioning		
Engineering		
C&M/CPC		Subtotal
PLT		0

Description	Qty	Unit Cost	Total Cost
			$ -
Engineering			$ -
Construction			$ -
Material			$ -
Commissioning			$ -
PMO			$ -
Miscellaneous			$ -
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			$ -
			$ -
Equipment Removal			$ -

FORTISBC

Property Insurance Recommendations

prepared for

FORTIS INC.
"FortisBC Inc."

South Slocan, British Columbia
Canada

conferred with

D'Arcy Pommier, Superintendent
Gary Petit, Electrical Superintendent
Blaine Whiteside, Supervisor-Substations

prepared by

Darren W. Marsh, P.Eng.
Aon Risk Control Services, Halifax, NS

Survey Date: November 2010

Risk Control Report

AON

Limiting Conditions

All Aon Reed Stenhouse Inc. site visits, reports and recommendations are purely advisory and are provided for the purpose of assisting Clients and Insurers in risk control and safety procedures. The observations and recommendations expressed in this report are the result of practices and conditions observed at the time of the visit and reflect Aon Reed Stenhouse Inc.'s best judgement based on those observations and the information available to it at the time of preparation. Unless expressly noted, the observations and recommendations do not purport to refer to, or guarantee compliance with, any or all regulations which may be applicable to such practices and conditions. This report should not be considered a definitive listing of all existing hazards nor an absolute solution to all indicated hazards. It is not intended to imply that no other risks exist or that no other precautions need be taken. No responsibility for the implementation, management and operation of risk control and safety procedures is assumed by Aon Reed Stenhouse Inc., and Aon Reed Stenhouse Inc. assumes no responsibility for loss or damage of any kind or nature resulting from reliance upon the statements and information contained in this report.

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Purpose & Objective

The objective of this report is to outline relevant recommendations to facilitate the process of Property Insurance placement.

Based on a Site Survey dated November 1st to 4th, 2010 and Interviews of relevant Site Personnel, our recommendations reflect suggested improvements to help minimize the potential for Property Insurance related losses.

Implementing the recommendations will minimize the potential for Physical Asset Risk Exposure and assist in obtaining Preferred Property Insurance terms and conditions.

General Comments

Insurance coverage changed during the 2007 year with several Insurance Carriers now providing coverage. Due to the number of Insurance Carriers, Aon Reed Stenhouse Inc. will be conducting Risk Control Activities and the new Insurance Carriers will visit the sites as required for coverage. Only a Single Loss Prevention Report will be generated by Aon Reed Stenhouse Inc.

During this visit, two Insurance Carriers [AEGIS and GCAN] visited the Hydro Sites with this Consultant. Dayle Francis, Fortis Risk Analyst, also attended the tour.

The visit included detailed discussions with Operations and Management Personnel regarding Maintenance and Loss Prevention Activities. Discussions were held with D'Arcy Pommier, Superintendent Mechanical Maintenance Generation and Blaine Whiteside, Supervisor-Substations.

It should be noted that the Transmission & Distribution as well as the Generation Group continue to have very good maintenance programs and a high level of interest in loss prevention/risk management.

The following Sites were visited during the week:

Corra Lynn Hydro
Upper Bonnington Hydro
Lower Bonnington Hydro
South Slocan Hydro
Lambert Terminal
Mawdsley Terminal
Ruckles Substation
Grand Forks Terminal
Kettle Valley Substation
Osoyoos Substation
Pine Street Substation
Westminster Substation
RG Anderson Terminal
Glenmore Substation

Recommendations Completed

Aon 08-1
IN PART

Install Fire Walls between Transformers

Fire Walls have been provided between Transformers located at the following locations:

- Corra Linn (several walls installed)
- South Slocan

Aon-8-4
IN PART

Improve Fire Pump Testing

The Fire Pump Testing has improved and many of the past irregularities have been addressed. This Consultant will visit the Sites during the annual test in 2011 to resolve any remaining Fire Pump Test results irregularities.

Aon 09-1

Replace Lead Acid Batteries

The set of Lead Acid Batteries in the Recreational Substation was replaced in early 2010.

Aon 09-3

Improve Battery Maintenance

The water level in the Lead Acid Battery set located at the following Substations were topped up to proper levels:

- OK Mission
- Lambert Terminal

Station Batteries are on a quarterly inspection (every 3- 4 months), where voltages, water levels and general condition are documented. Cascade (CMMS) manages and documents the Inspection Process.

Aon 09-6

Inspect Runner

A Routine Inspection Schedule is completed on all the ULE units with the Voith Runner.

Aon 09-7

Forward Risk Assessment

Units 1 through 4 at Upper Bonnington "Summary of Report Mechanical Inspections" all indicate significant erosion, with the worst being Unit #1 Upper and Lower Runners with comments that there is significant erosion including Blade perforations and possible signs of metal failure (cracking). The Outage Reports are very general, not including a lot of detail about the Inspections. This does not seem to be a new condition and is not unexpected.

Mr. Pommier provided the following by email in December: UBO Units 1-4 have 3 Runners per Unit. The Runners are small and do not allow for easy inspection. During our Unit Inspections, we visually inspect the 3 Runners looking for any cracks, broken blades etc. We also note how thin or worn the Trailing Edge of each Blade is. We are underway with an Old Plant Repowering Project (UBO Units 1-4) that will address the Runner condition. This portion of the project is awaiting approval from BCUC and is planned for 2012-2014 if approved.

Recommendations

Aon 08-1
UPDATED

Install Fire Walls between Transformers

Fire Walls should be provided between all Transformers located at the following locations:

- Corra Linn – One Wall remaining
- Huth Substation – Between each Transformer would be ideal but due to space may not be practical; serious consideration should be given between Banks of Single Phase Transformers and Large 3 Phase Transformers.
- (NEW) Mawdsley Terminal – between T1 and T2; 30 ft. apart; >5000 Gallons of Oil each
- (NEW) Westminster Substation – Between T1 and T2; 12 ft. apart; >500 Gallons each

Comment: The noted Transformers are too close for the relative size and volume of Oil contained within them. A fire and/or explosion in a single Unit would take out multiple Units.

Barrier Walls are recommended when Transformers do not achieve the following adequate distances between Buildings or other Transformers:

Oil (Gallons)	Distance (ft.)
< 500	5
500 to 5000	25
> 5000	50

Typically Fire Wall Installations are constructed of Concrete Block or Reinforced Concrete Walls. An option to this type of construction is the use of a product called Durabarrier. Details of this product have been forwarded previously.

This recommendation was submitted by AIG, GCAN, AEGIS and AON.

FortisBC is in the process of constructing Fire Walls within the scope of the Upgrade and Life extension (ULE)P program on a Unit by Unit basis at the Hydro Plants. The ULE Program is scheduled to be complete by 2011. The ULE Program Team will review the “Durabarrier” for its suitability, cost effectiveness and availability as an alternate to the Concrete Block construction.

A Single Wall remains to be completed at Corra Linn and was under construction during the visit.

Response: (Feb. 2011 by Patrick Audet) Corra Linn is being dealt with through the ULE Program.

Huth – 3 Single Phase Units will be salvaged in the next upgrade, the other 3 in service will be replaced when the Load Growth reaches the TX's capacity and possibly a Voltage Conversion may occur. Planning will be involved. Space has limited the option on these Units.

Aon 08-2

Install Automatic Sprinkler Protection

Automatic Sprinkler Protection should be installed throughout the following buildings at Warfield (in order of importance):

1. Control Centre
2. District Complex Building/Warehouse
3. Fleet Maintenance Building

Comment: The Control Centre is the main control for all of FortisBC. The building is constructed of Concrete Block with a Wood Roof and only has protection in the Server and Electrical Room (gas suppression – single shot). Loss of this Site, although would not affect power production, it would limit the possibility of optimum control of the Facilities.

Response: (D'Arcy Pommier) FortisBC will not be installing Sprinkler Protection at this time.

Aon 08-3

Install CCTV Camera System at all Hydro Sites

A remotely operated CCTV Camera System should be provided at the Unmanned Sites. The Cameras should be provided to monitor Site Access as well as critical areas inside and outside of the Facilities.

The Cameras should be monitored by the Operations Department at Warfield.

Comment: The Hydro Stations are typically unmanned. Providing Cameras will enable Operators at Warfield to monitor the Sites 24 hours per day.

Response: (D'Arcy Pommier) FortisBC is still reviewing corporate security. The application of CCTV Camera Systems will be considered in the review.

Aon-8-4
UPDATED

Improve Fire Pump Testing

The Fire Pump Testing should be witnessed by this Consultant during the Annual Test in 2011 to resolve any remaining Fire Pump Test Results irregularities.

Comment: Review of the past Testing Results of the Fire Pumps at the four Hydro Stations has shown some irregularities. Most of these have been addressed with the remaining issues to be addressed during the annual visit which will be scheduled for the end of June or the first part of July 2011.

Response: (D'Arcy Pommier) Aon Consultant should witness the test; planned for the Summer of 2011.

Aon 08-7

Install Fire Detection

Fire Detection should be installed in the detached Switch House Building at Lower Bonnington.

Comment: Early detection of a fire will enable a quick response.

Response: (D'Arcy Pommier) A project to install Fire Detection in the Switch House Building at Lower Bonnington will be created in our Capital Plan for evaluation and possible inclusion in the 2011/12 Capital Plan with a completion date of 2017 for all Plants.

Aon 09-2

Repair Hydran Alarm

The Hydran Alarm on GSU Unit #5 should be repaired in order to notify Operators of potential increasing gassing issues.

Comment: The Hydran alarm is in a constant state of alarm (failed low) and this transformer is on a watch list for gassing units.

This recommendation was submitted by Aon and BI&I.

Response: (Feb. 2011 by Patrick Audet) An independent company was brought in to investigate misc. Hydran Alarms in late 2010. GSU Unit #5 I suspect is referring to Upper Bonnington, and this Unit was looked at, and waiting on report to determine next steps.

Aon 09-4

Improve Oil/Grease Storage

The Oil/Grease Storage located in the Oliver Substation Office Building should be improved with the use of Flammable Liquids Cabinets.

Comment: During the tour over twenty 5 Gallon Pails were noted to be stacked around the Varsol Cleaner with no containment. This Building has no Sprinkler Protection and basic storage conditions for these products should be in an approved Flammable Liquids Cabinet.

Response: No update.

Aon 09-5

Improve Generation Sprinkler Deluge Systems

Serious consideration should be given to replacing the Ordinary Control Valves with Listed Deluge Valves featuring approved Pneumatic or Electric Releases.

To improve system reliability and to prevent accidental discharge, Cross Link Activation by both the Linear Heat Sensor and a Generator Fault should be considered.

Comment: Currently the Deluge Sprinkler Systems protecting the Generator Enclosures are controlled by Ordinary Control Valves and Pneumatic Actuators.

This was submitted by Commonwealth Insurance.

Response: (D'Arcy Pommier) A project to install Fire Detection and update Fire Protection on the Hydro Units will be created in the Capital Plan for evaluation and possible inclusion in the 2011/12 Capital Plan with a completion date of 2017.

Aon 09-8

Provide Sprinkler Protection

For future upgrades of the older Hydro Units #1 to #4 at Upper Bonnington, consideration should be given to providing Sprinkler Protection for the Hydraulic/Governor Oil Systems and Generator Enclosures.

Comment: This was submitted by Commonwealth Insurance. Aon agrees with this recommendation.

Response: (D'Arcy Pommier) FortisBC will be evaluating protection as part of the Old Plant Repowering Project that is currently under way.

Aon 09-9

Provide Testing Confirmation

The following should be confirmed:

1. The Bell Substation Yard Security System (light beams) should be tested at least annually.
2. The Lee Terminal Fire Detection System should be tested at least annually.

Comment: All Security and Fire Detection Systems should be fully tested at least annually and records kept for review. Confirmation of the testing could not be confirmed during the visit.

Response: (Feb. 2011 by Patrick Audet) Bell Station Yard Perimeter Security is not tested annually at this point, however Alarms to SCC if a Zone is violated or a diagnostic of the system detects a component failure. Lee Terminal fire Detection was tested in 2010. The system components are a Control Module, Heat and Smoke Detectors. These tasks will be included in the CMMS. The District Electrician will be assigned to accompany an Inspector annually.

Aon 10-1
NEW

Install Hydran on Transformers

Hydran On-Line Gas Monitoring should be installed on the Large Transformers located in the RG Anderson Substation.

Comment: Neither of the Large Transformers in the Substation have On-Line Hydran Systems which would permit on-line gas build up detection. These Transformers are rated at 120/160/200 MVA and 90/120/150 MVA and have extremely long lead times for replacement.

Aon 10-2
NEW

Improve Conditions at Substation

The Ruckles Substation should have the Water Drainage improved.

In addition, T2 Transformer has Oil leaking and should be repaired as soon as possible.

Comment: This Substation is routinely inundated with water due to the current land conditions. A Sump Pump is installed inside the Switch Building and all water collected is pumped to a Holding Area within the Substation.

Aon 10-3
NEW

Install Fire Detection

Fire Detection should be installed in the following Buildings at the Substations:

- Osoyoos
- Pine Street
- RG Anderson
- Glenmore

Comment: Fire Detection will permit an early response in the event of a fire. The above noted Buildings do not have Fire Detection.

Aon 10-4
NEW

Install Fire Barrier

A UL/FM approved Fire Barrier should be installed over the Exposed Combustible Insulation inside the Buildings at the Pine Street Substation.

Comment: Combustible Insulation such as Sprayed on Paper or Expanded Plastic should not be exposed in Substation Buildings. A Fire Barrier will limit combustion, reduce smoke and retard fire spread in the event of a fire.

Aon 10-5
NEW

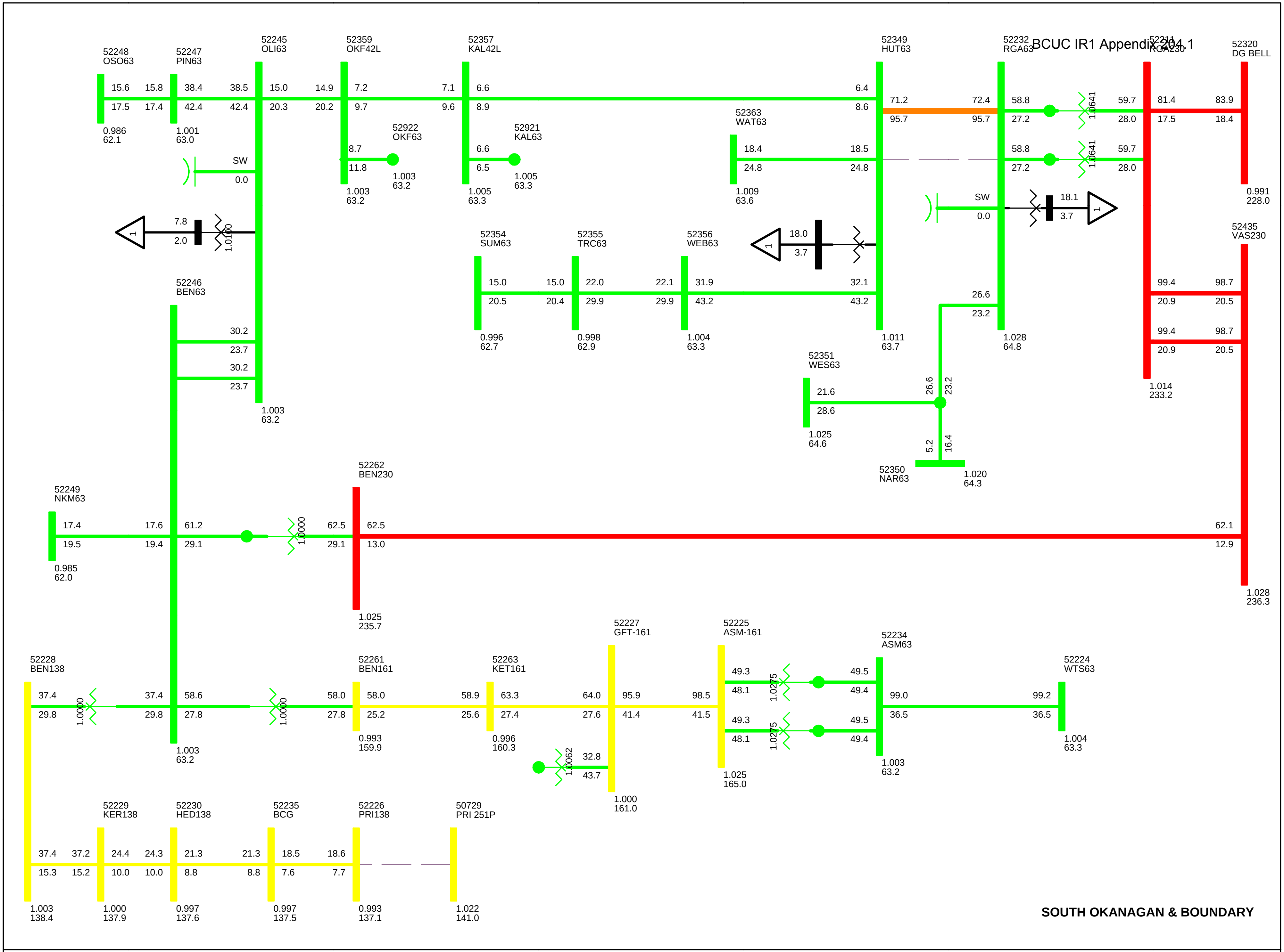
Remove Cover Over Fire Detection

The Temporary Plastic Cover over the Fire Detection device in the Building at Kettle Valley Substation should be removed.

Comment: The Orange Plastic cover which must have been utilized during some operational work remains in place and essentially limits the ability of the Fire Detector.

Document History

Revision #	Survey Date	Prepared By
0	May 2008	Darren W. Marsh
1	November 2009	Darren W. Marsh
2	November 2010	Darren W. Marsh



SOUTH OKANAGAN & BOUNDARY

CREATED FROM 20HS1AP.SAV.FBC 778MW,TC 220MW
GEN 864MW,LOSSES 28MW,IMPORT 162MW
WED, AUG 31 2011 9:30

2020 SUMMER PEAK

LOAD (MW): PENTICTON 127, OLIVER 100, BOU 37

ATTACHMENT BCUC IR1 Q204.1

Bus - VOLTAGE (KV/PU)
Branch - MVA/% OF RATE B
Equipment - MW/MVAR

90.0%RATEB

KV: <=30.000 <=63.000 <=161.000 <=230.000 >230.000

MIDGARD

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MEMORANDUM

To: Ian Dyck, FortisBC

From: Midgard Consulting

Date: February 7, 2011

Subject: Costs to Procure Planning Reserve Margin Shortages – 2011 to 2020

This memorandum outlines the estimated cost to FortisBC of procuring market-based capacity from 2011 through to 2020. FortisBC would rely on this purchased capacity in order to fill its anticipated capacity shortages between 2011 and 2020, as outlined in Table 2. The monthly estimated cost of these capacity puchases is detailed in Table 5.

FortisBC will be faced with capacity gaps largely because of the addition of planning reserve margin ("**PRM**")[1] to its historical capacity requirement calculations. PRM will be fully phased in to 2016 levels in 2012 and will remain constant until 2016. It is important to note that the 2016 levels of PRM do not entirely cover the PRM requirements prior to the commissioning of the Waneta Expansion Facility in 2015 (a major source of FortisBC capacity). From 2017 through to 2020, PRM acquisitions will be increased in parallel with the growing size of the PRM requirement. Table 1 lists the estimated cost to procure the PRM each year between 2011 and 2020. Note that there may be physical capacity deficits prior to the commissioning of the Waneta Expansion Facility in 2015. This memo only addresses the associated PRM gaps. After the commissioning of the Waneta Expansion Facility in 2015, FortisBC does not have physical load-based capacity gaps again until 2021.

Table 1 – PRM Cost to Procure: 2011 to 2020

Year	Total Cost (2010$)
2011	$0
2012	$2,238,000
2013	$2,238,000
2014	$2,238,000
2015	$2,238,000
2016	$2,238,000
2017	$2,506,000
2018	$2,769,000
2019	$3,030,000

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[1] The monthly PRM requirement is calculated based upon the loss of FortisBC's single largest generating unit (Brilliant Hydro or WAX CAPA, depending on the month) plus 5% of monthly load responsibility.

2020	$3,302,000

Capacity Gap

The capacity gaps are derived using the expected load forecast (as per the 2011 Resource Plan) less a 50% DSM target. The monthly PRM gaps are displayed in tabular form in Table 2 (Note: this represents PRM deficits only and not any physical deficits that may occur).

Table 2 - Actual Planning Reserve Margin Capacity Gaps (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	46.8	41.9	39.6	9.4	0.0	36.2	39.5	38.2	0.0	28.3	42.3	45.6
2012	47.6	42.6	40.3	17.3	0.0	36.8	40.2	38.9	0.0	36.8	43.0	46.3
2013	48.4	43.2	40.9	24.6	0.0	37.3	40.8	39.4	0.0	38.6	43.7	47.1
2014	49.1	43.8	41.4	31.5	3.6	37.8	41.3	40.0	0.0	39.1	44.3	47.8
2015	82.0	70.3	108.8	0.0	0.0	19.8	17.8	0.0	0.0	0.0	0.0	50.8
2016	97.0	9.8	0.0	0.0	0.0	24.5	23.0	0.0	0.0	0.0	0.0	57.1
2017	103.2	15.1	0.0	0.0	0.0	28.9	28.0	0.0	0.0	0.0	0.0	63.1
2018	109.3	20.4	0.0	0.0	0.0	33.2	32.8	0.0	0.0	0.0	0.0	68.9
2019	115.3	25.6	0.0	0.0	0.0	37.5	37.7	0.0	0.0	0.0	0.0	74.8
2020	121.3	30.8	0.0	0.0	0.0	40.6	42.5	0.0	0.0	0.0	2.0	80.6

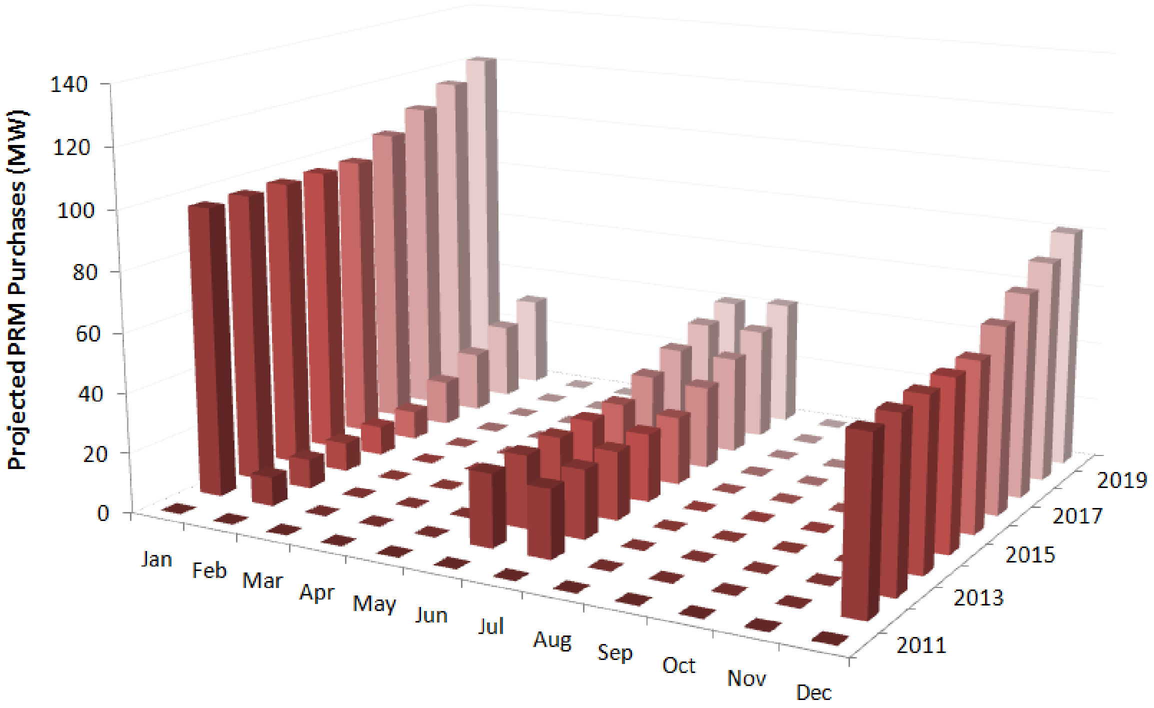
Projected PRM Purchases

Table 3 displays the monthly projected PRM purchases. These purchases are also represented visually in Figure 1.

Table 3 – Projected Planning Reserve Margin Capacity Purchases (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	97.0	9.8	0.0	0.0	0.0	24.5	23.0	0.0	0.0	0.0	0.0	57.1
2013	97.0	9.8	0.0	0.0	0.0	24.5	23.0	0.0	0.0	0.0	0.0	57.1
2014	97.0	9.8	0.0	0.0	0.0	24.5	23.0	0.0	0.0	0.0	0.0	57.1
2015	97.0	9.8	0.0	0.0	0.0	24.5	23.0	0.0	0.0	0.0	0.0	57.1
2016	97.0	9.8	0.0	0.0	0.0	24.5	23.0	0.0	0.0	0.0	0.0	57.1
2017	103.2	15.1	0.0	0.0	0.0	28.9	28.0	0.0	0.0	0.0	0.0	63.1
2018	109.3	20.4	0.0	0.0	0.0	33.2	32.8	0.0	0.0	0.0	0.0	68.9
2019	115.3	25.6	0.0	0.0	0.0	37.5	37.7	0.0	0.0	0.0	0.0	74.8
2020	121.3	30.8	0.0	0.0	0.0	40.6	42.5	0.0	0.0	0.0	2.0	80.6

Figure 1 – Projected Planning Reserve Margin Capacity Purchases (MW)



Estimated Cost of Capacity

The estimated cost of procuring capacity by month is detailed in Table 5 below. These cost estimates are based upon the following assumptions:

- All prices are in 2010 dollars
- The cost of procuring capacity is based on 80% of the UCC price estimate for the lowest cost UCC resource – a simple cycle gas turbine @ $10,163 per MW-Mo, as per the FortisBC 2010 Resource Option Report by Midgard Consulting Inc. The discount is applied because this capacity product is expected to be supplied from existing and operating facilities.
- The cost of capacity is expected to vary by month based upon the availability of surplus regional market supply. This variability is approximated using the BC Hydro monthly super-peak delivery factor table from the 2008 Clean Power Call (shown in Table 4).
- The capacity price will not vary by year due to the assumption that the capacity is linked to BC based resources, and therefore transmission constraints between BC and neighbouring jurisdictions will not materially impact the price.

Table 4 – BC Hydro Super-Peak Time-of-Delivery Factors[2]

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
141%	124%	124%	104%	90%	87%	105%	110%	116%	127%	129%	142%

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[2] Taken from BC Hydro's "Specimen Electricity Purchase Agreement", Schedule A, Part I (revised on October 21, 2008)

Table 5 – Estimated Cost of Capacity per Month (‘000s, $2010)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2012	$1,112	$98	$0	$0	$0	$173	$196	$0	$0	$0	$0	$659
2013	$1,112	$98	$0	$0	$0	$173	$196	$0	$0	$0	$0	$659
2014	$1,112	$98	$0	$0	$0	$173	$196	$0	$0	$0	$0	$659
2015	$1,112	$98	$0	$0	$0	$173	$196	$0	$0	$0	$0	$659
2016	$1,112	$98	$0	$0	$0	$173	$196	$0	$0	$0	$0	$659
2017	$1,183	$153	$0	$0	$0	$204	$239	$0	$0	$0	$0	$728
2018	$1,253	$206	$0	$0	$0	$235	$280	$0	$0	$0	$0	$796
2019	$1,322	$258	$0	$0	$0	$265	$322	$0	$0	$0	$0	$863
2020	$1,391	$311	$0	$0	$0	$287	$363	$0	$0	$0	$21	$930