FORTISBC

Preliminary 2010 Revenue Requirements

Tab 6

Power Purchase and Wheeling

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6.0 Introduction

This section includes a forecast of 2009 power purchase expense based on FortisBC's actual results to July 31, 2009, with an estimate for August through December, and a forecast of power purchase expense for 2010 (see Tables 6.2 and 6.3 at the end of this Tab).

As shown in Table 6.0 below, the 2010 Power Purchase Expense is forecast at $77.2 million compared to $70.2 million currently forecast for 2009. The increase is primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement, and BC Hydro and Brilliant Plant rate increases partially offset by reduced market requirements. Balancing Pool adjustments account for the difference between energy entitlements under the Canal Plant Agreement ("CPA") and actual usage due to storage.

Table 6.0: Total Power Purchase Expense

		Forecast 2009	Forecast 2010	Difference
		($000s)		
1	Surplus Revenues	(765)	(670)	95
2	Brilliant	31,090	33,217	2,127
3	BC Hydro	35,433	41,945	6,512
4	Market Spot Purchase & Capacity Purchases	4,927	2,452	(2,475)
5	Independent Power Producers	592	405	(187)
6	Capital Projects	(205)	0	205
7	Special and Accounting Adjustments	(39)	0	39
8	Export Sales Wheeling Adjustment	13	0	(13)
9	Balancing Pool	(845)	(125)	720
10	**TOTAL**	70,201	77,224	7,023

6.1 Review of 2009

The winter of 2008/09 saw below average snow packs but normal run-off patterns and reduced regional demand due to economic circumstances. Power prices remained moderate to low through the winter and the rest of the year with no changes expected in the coming winter.

The Company's summer surplus sales were relatively weak compared to previous years. However, the Company was able to take advantage of these lower prices to displace significant amounts of BC Hydro Power Purchase Agreement power.

Due to weather, gross loads are currently expected to be about 35 GWh (20 GWh after DSM) above approved 2009 over the year despite the general economic downturn. Costs are expected to be $0.75 million below approved 2009, as shown in Table 6.1 below as a result of:

- An increase of $0.2 million due to lower surplus sales;
- A combined increase of $1.7 million in market and Independent Power Producers ("IPP") purchases;
- A balancing pool adjustment of $(0.6) million; and
- Lower BC Hydro costs, net of accounting adjustments, of $2.0 million, due primarily to a reduced BC Hydro purchase volume of 53 GWh as a result of increased market purchases.

BC Hydro costs and associated accounting adjustments, which represent the expected impact of the Commission's decision setting final BC rates for the period April 1, 2008 through March 31, 2010, are reflected in the Company's Financial Statements to July 31, 2009 and will be updated on or before November 2, 2009. The net change to Power Purchase Expense is expected to be relatively small.

There was a normal program of annual generator maintenance on the FortisBC generating units. The South Slocan Unit 1 ULE Project is expected to be completed in February 2010, which required a planned outage beginning in 2009. The increased power purchase cost as a result of this project is charged to the capital cost of the project and therefore does not impact the power purchase expense (see Table 6.2 at end of Tab 6).

Table 6.1: Total Power Purchase Expense

		Approved 2009	Forecast 2009	Difference
		($000s)		
1	Surplus Revenues	(969)	(765)	204
2	Brilliant	31,083	31,090	7
3	BC Hydro	38,443	35,433	(3,010)
4	Market Spot Purchase & Capacity Purchases	3,427	4,927	1,500
5	Independent Power Producers	386	592	206
6	Capital Projects	(208)	(205)	3
7	Special and Accounting Adjustments	(1,009)	(39)	970
8	Export Sales Wheeling Adjustment	-	13	13
9	Balancing Pool	(209)	(845)	(636)
10	**TOTAL**	70,944	70,201	(743)

6.2 Power Purchases

The goal of the Company's resource acquisition policy is to meet customer load requirements at low cost with minimal environmental impacts, while recognizing ongoing resource uncertainties as outlined below.

6.2.1 Power Purchase/ Resource Uncertainty

The Company has long-term, firm resources from which it can supply over 98 percent of the annual energy requirements. The small shortfall is due to system capacity constraints during peak load days.

Due to the uncertainty associated with loads, and because the amounts of energy required to supply the peak are relatively small, the Company continues to rely on a strategy of short term purchases from the market to meet the shortfall for 2010. Advance purchases of winter capacity or energy block purchases are generally made to minimize or reduce real-time purchases from the market and have been assumed in this forecast (as discussed in section 6.2.2 of this Tab).

The Company filed a Resource Plan in May 2009 to review appropriate long term resource options. It is expected that any potential changes resulting from the 2009 Resource Plan will impact resource acquisition after 2010.

The generation ULE Program, which may include turbine upgrades in some cases, is planned to continue until 2012 and may further increase FortisBC's entitlements.

6.2.2 Power Purchase Costs

Power Purchase costs for 2010 are included in Table 6.2 at the end of Tab 6. Where applicable, forecast power purchase costs have been determined using contract prices plus a forecast of future market prices.

Existing Resource Base and Long Term Purchases

Company-owned generation entitlements under the CPA before any allowances for outages or entitlement shaping in the energy, or allowance for outages and reserves in the capacity, are forecast as follows:

Table 6.2.2

		Forecast 2009	Forecast 2010
1	Energy (GWh)	1,591	1,591
2	Change (%)		0
3	Capacity at winter peak (MW)	223	223
4	Change (%)		0

The Company has firm supply including:

A. The Brilliant Power Purchase Agreement ("BPPA") (a 125 MW contract terminating in 2056), and an amendment to the BPPA which reflects the purchase of the Brilliant Upgrade power (20 MW) and the Brilliant Tailrace Capacity agreement (5 MW);

B. A contract with BC Hydro (200 MW) under BC Hydro Rate Schedule 3808 that terminates September 30, 2013;

C. A number of small IPP contracts, and;

D. A number of market purchase arrangements described below.

A. Brilliant Power Purchase Agreement and Tailrace Agreement

The Company purchases power under the BPPA and under the Brilliant Power Purchase Second Amendment Agreement, both of which have been approved by the Commission.

The prices paid under the BPPA are based on forecasts of the annual operating and maintenance costs and capital charges for the plant.

For the unregulated-flow component of the upgrade power, the price for the Brilliant Power Purchase Second Amendment Agreement is based on a forecast of the all-in capital cost of the upgrades. The regulated flow component was recalled by the owner in late 2005 and no regulated upgrade energy is expected to be available for purchase in 2010.

The Company also purchases approximately 5 MW of capacity under the Brilliant Tailrace Agreement, also approved by the Commission. The estimated 2010 rate is just under 75 percent of the BC Hydro capacity rate.

A forecast of the prices for these various categories of supply from the Brilliant Plant is as follows:

Table 6.2.3

	Energy	Forecast 2009	Forecast 2010
	Base Volume (GWh)	858	857
1	Base ($/MWh)	34.03	36.45
2	Change (%)		7.1
3	Upgrade Volume (GWh)	65	65
4	Upgrade - unregulated ($/MWh)	25.90	26.55
5	Change (%)		2.5
6	Tailrace (MW-Months)	42	42
7	Tailrace ($)	159,500	164,100
8	Change (%)		2.9

The Base component for 2010 includes a “true-up” adjustment for prior years, which is the difference between the forecast and actual costs as allowed under the Agreements. In the past, the Company has consistently flowed through any difference between forecast and actual costs to the customer. For 2010 the adjustment amounts to a decrease in costs of $0.4 million, based on the difference between forecast and actual costs for 2008. The Company proposes that this "true-up" treatment continues in the future.

B. BC Hydro

The rates under FortisBC's Power Purchase Agreement with BC Hydro (under Rate Schedule 3808) are shown in Table 6.2.4 below:

Table 6.2.4

		Forecast 2009	Forecast 2010
1	**Energy**		
2	Volume (GWh)	855	973
3	$/MWh	29.66	31.25
4	Change (%)		5.4
5	**Capacity**		
6	$/MW/Month	4,992	5,313
7	Change (%)		6.4

The Company has used BC Hydro's currently approved rates, including the deferral account rate rider, for 2010 forward. Estimates include a small adjustment for expected excess energy costs. An adjustment in respect of the Commission's decision setting final BC Hydro rates for the period April 1, 2008 through March 31, 2010, will be included in the November 2, 2009 Revenue Requirements update. Final BC Hydro rates decreased for the period April 1, 2008 to March 31, 2009 and increased for the period April 1, 2009 to March 31, 2010. The net impact of these rate changes is expected to be relatively small.

The Company requests approval to implement any changes to 2010 Power Purchase Expense arising from future BC Hydro rate increases by way of a flow-through adjustment at the time of a Commission decision on BC Hydro's Application. This flow-through treatment of BC Hydro rate increases would be consistent with prior years.

The existing resource base and long-term power purchase arrangements described above provide access to a maximum capacity of 572 MW, before allowances for unit outages and operating reserves.

C. Independent Power Producers

The Company has eight small power purchase contracts with Independent Power Producers. The rate used to calculate power purchase expense for these IPP's is the BC Hydro rate.

Due to poor market opportunities during the freshet to independently market their surplus, Zellstoff Celgar exports to the Company were significantly higher in 2009 than planned and at a much lower cost than anticipated.

Table 6.2.5

	Energy	Forecast 2009	Forecast 2010
1	Volume (GWh)	22.7	13.0
2	Change (%)		(43)
3	$/MWh	26.1	31.14
4	Change (%)		19.3

D. Market Purchases

The Company's expected 2010 peak load capacity shortfall is approximately 154 MW (see Table 6.3, lines 54 and 59). While this is a significant capacity shortfall, only small amounts of energy are required to be purchased from the market for peak load days due to this capacity shortfall.

The Company's strategy is generally to purchase the majority of these market requirements several months in advance of the winter peak to avoid over-purchasing, and leave the remainder to the spot market. The Company filed a Resource Plan in May 2009 to review appropriate long term resource options but this does not impact forecast expenses for 2010. The Company uses (i) Market Purchases Made in Advance and (ii) Spot Market Purchases described below.

i) Market Purchases Made in Advance

For the last few years, cost-effective capacity block purchases from Teck Metals Ltd. have been available. With the completion of the Brilliant Expansion project, a 25 MW December capacity block multi-year contract was also entered into with the Columbia Power Corporation (“CPC”) extending through December 2010. For the January 2010 to February 2010 period no contract with Teck has been reached due to the pending BC Hydro Waneta Transaction which would result in the acquisition of the Teck surplus from the Waneta plant by BC Hydro. The Company is currently in discussions with Powerex to replace this product on terms similar to the previous year. The Company expects the price will be dependent on the average monthly spread between the Heavy Load Hour and Light Load Hour daily prices. While this does not provide a fixed price, the expected price of the block (the magnitude of the spread) is less volatile than relying on real-time purchases and also provides the required reliability of supply. The Company expects to be able to purchase capacity blocks for the November 2010 forward winter months as well. The price for the 25 MW block from CPC for December 2010 was negotiated as part of the multi-year agreement.

The standard capacity block purchases are included in the 2010 forecast at an estimated price based on forecast market prices.

The forecast market prices are taken from an August 10, 2009 Economic Insight Publication titled “Energy Market Report” with quotations from Coral Energy. Forecast market prices will be updated as part of the information filed with the Commission as part of the September actuals.

Table 6.2.6 below is a summary of capacity purchases from Teck and CPC that have been made or planned for 2008 forward. The supplier of the January 2010 forward blocks is not known at this time.

Table 6.2.6

	Month	Amount (MW)	Cost ($)	$/MW
1	January 2008	150	820,000	5,467
2	February	75	277,000	3,693
3	November	50	177,000	3,540
4	December	125	973,000	7,784
5	December (CPC)	25	182,500	7,300
6	January 2009	150	566,000	3,773
7	February	75	236,000	3,147
8	November (estimate)	50	249,000	4,980
9	December (estimate)	125	762,000	6,096
10	December (CPC)	25	195,000	7,800
11	January 2010 (estimate)	150	703,000	4,687
12	February (estimate)	75	283,000	3,773
13	November (estimate)	50	257,000	5,140
14	December (estimate)	125	728,000	5,824
15	December (CPC)	25	208,000	8,320

The 25 MW capacity block (December 2008, 2009 and 2010) was purchased from CPC. While it is generally at a higher price than other capacity blocks, it is part of a multi-year contract for December through to 2010. It also adds significant value compared to other block purchases as it includes Light Load Hour capacity and the opportunity for an additional entitlement storage account position.

ii) Spot Market Purchases

Any remaining peak requirements will be purchased on a day-ahead or real-time basis with the forecast rates as follows:

Table 6.2.7

		Forecast 2009	Forecast 2010
1	**Peak Energy**		
2	Volume (GWh)	16.2	3.8
3	Change (%)		(77)
4	$/MWh	59.5	71.8
5	Change (%)		21

The 2010 rates are based on the energy block rates forecast in the "Energy Market Report" as well as quotations from Coral Energy with an adjustment to account for the fact that these purchases are made for the most valuable hours in the energy block. The lower rate in 2009 as compared to 2010 is related to attractive prices for 2009 in general as well as buying market energy to meet load in additional hours beyond the very peak hours to displace BC Hydro capacity. This decreased the 2009 BC Hydro capacity charges, but increased market volume to meet peak load to 16 GWh.

Spot purchases to meet peak requirements are expected to be approximately $0.27 million in 2010 compared to $0.96 million in 2009. Overall the total cost of purchases from the market (Market Purchases Made in Advance plus Spot Market) is expected to be approximately $2.5 million in 2010 compared to approximately $4.9 million in 2009. $2.0 million of the 2009 market costs were for market energy (97.4 GWh) that was obtained below the BC Hydro energy rate.

6.3 Surplus Sales

The Company has small amounts of surplus available in the months of May, June and July because its firm resources, including the entitlements under the CPA, exceed the load requirements in that period.

The Pacific Northwest Region experienced a marked decline in power requirements over the surplus sales period. Weak demand for power combined with normal timing for the start of the freshet, led to extremely weak surplus power prices with very low, even negative prices observed. Much of the American Columbia Basin hydro generation must run for environmental reasons and the hydro generation can exceed the readily available load to receive it for certain hours at night. In addition, the continuing development of wind generation is creating a real problem with unexpected system generation. This can be particularly pronounced during the freshet period since it is much harder to back down hydro generation to accommodate the wind generation. While these factors led to a relatively weak year for surplus sales, the Company was able to take advantage of these low prices during the day to meet load as discussed above. In addition, storage account flexibility allowed about 15 GWh of low cost May/June energy to be purchased for later sale when prices were higher. For 2010, prices are expected to be higher than 2009 based on the current market conditions.

Table 6.3.1

	Energy	**Forecast 2009**	**Forecast 2010**
1	Volume (GWh)	37.7	23.1
2	Change (%)		(39)
3	Mills/kWh	20.3	29.0
4	Change (%)		(43)

Overall the revenue from summer surplus sales is expected to decrease from approximately $0.8 million in 2009 to approximately $0.7 million in 2010 due to lower volumes.

6.4 Wheeling Expense

The Wheeling Expense forecast includes an estimate of 2009 expense based on actuals through July and an estimate of the remaining expense. The expense includes wheeling service provided by the BCTC under the GWA made in 1986 and also wheeling provided by BCTC under its OATT, as needed to supply the Company's loads in the Okanagan from the interconnections at Vernon and at Vaseux Lake (which together are termed the Okanagan Point of Interconnection), as well as the interconnections at Creston and at Princeton. Also included are charges paid to Teck for the use of its 71 Line.

Rates under the GWA are specified in BCTC's filed Rate Schedule 21. In 2010, GWA costs are forecast to account for all the wheeling expense except for $0.024 million of OATT and Teck wheeling expense.

Wheeling Expense is forecast to increase from $4.0 million in 2009 to $4.15 million in 2010 due to higher wheeling nominations ($0.09 million) and the annual estimated rate increase of 1.6 percent ($0.06 million). Calculation of 2010 Wheeling Expense is shown in Table 6.4.

Table 6.2

1							ANALYSIS OF FORECAST POWER PURCHASE EXPENSE							
2							FOR THE YEAR ENDING DECEMBER 31,		2009					
3		2	3	4	5	6	7	8	9	10	11	12	13	
4		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
5	**ENERGY GW.h**	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Forecast	Forecast	Forecast	Forecast	Forecast	
6	FortisBC	147.227	122.446	136.928	108.590	130.995	107	161	118	123	126	118	152	1552.291
7	Brilliant Base Plant	81.944	63.071	57.693	81.797	79.313	72.241	79	86	66	62	63	65	858.036
8	Brilliant Upgrade	0.702	-0.642	-0.443	9.792	13.896	12.938	14	13	1	1	0	0	65.093
9	Brilliant Regulated	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0.000
10	Teck	0.000	0.000	0.000	0.050	0.000	0.000	0	0	0	0	0	0	0.050
11	Small Misc IPP Resource	2.324	2.914	3.582	2.357	2.788	2.972	2	1	1	1	1	1	22.718
12														
13	Turbine Upgrades	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0.000
14		0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0.000
15	CPC Loss, Wheeling & PPA Adjustments	0.812	0.770	0.416	0.301	0.886	1.201	1	0	0	0	0	0	5.286
16	DSM	0.000	0.000	0.000	0.000	0.000	0.000	0	2	2	2	2	2	10.524
17	City of Nelson Special Adjustment	0.000	0.000	0.000	0.000	0.280	2.153	0	0	0	0	0	0	2.433
18	Market Capacity - ENERGY	0.055	0.185	11.000	0.000	0.000	0.470	4.197	0.000	0.000	0.000	0.301	0.000	16.208
19	Market Energy Purchase	5.686	6.327	6.219	34.480	12.101	25.904	6.731	0.000	0.000	0.000	0.000	0.000	97.448
20	BCH Purchase	135.496	117.600	99.252	12.905	7.222	18.305	42.8750	41.957	38.9817	79.9410	117.5308	142.5584	854.624
21		----	----	----	----	----	----	----	----	----	----	----	----	----
22	Gross Load	374.246	312.671	314.647	250.272	241.620	243.421	279.852	261.300	231	272	302	364	3447.0290
23	Surplus	0.000	0.000	0.000	0.000	5.861	0.005	31.816	0	0	0	0	0	37.682
24	**RATE (Mills/kW.h)**												Pwr Pur =	1914.177
25	Surplus Rate					10.39	28.18	22.14	20.15	21.16	34.48	42.56	54.46	
26	Brilliant Base Plant	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
27	Brilliant Upgrade	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	
28	Brilliant Regulated	28.25	28.25	28.25	28.25	28.25	28.25	28.25	28.25	31.14	31.14	31.14	31.14	
29														
30	Market Capacity - ENERGY	72.04	47.30	61.82	122.46		40.46	54.54	59.67	45.99	45.15	59.77	75.63	
31	Market Energy Purchase	36.33	37.14	26.07	17.63	17.54	14.46	23.12	20.15	21.16	34.48	42.56	54.46	
32	BCH : Purchase	28.254	28.254	28.254	28.254	28.254	28.254	28.254	28.254	31.138	31.138	31.138	31.138	
33	IPP Rate	29.96	29.19	29.95	30.49	15.08	17.92	28.25	28.25	28.25	28.25	28.25	28.25	
34	**ENERGY EXPENSE ($000)**													
35	Surplus Revenue	$0.000	$0.000	$0.000	$0.000	($60.898)	($0.141)	($705)	$0	$0	$0	$0	$0	(765.601)
36	Brilliant Base Plant	$2,788.554	$2,146.306	$2,007.294	$2,784.845	$2,699.021	$2,458.770	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	29,244.667
37	Brilliant Upgrade	$18.182	($16.628)	($11.474)	$253.613	$359.906	$335.094	$360	$330	$25	$16	$8	$9	1,685.909
38	Brilliant Regulated	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0	$0	$0	$0	$0	$0	0.000
39		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0	$0	$0	$0	$0	$0	0.000
40														
41	IPP Costs	$69.631	$85.070	$107.270	$71.857	$42.047	$53.255	$67	$17	$20	$14	$23	$23	592.467
42	BCH Purchase	$3,828.304	$3,322.670	$2,804.266	$364.618	$204.050	$517.189	$1,211	$1,185	$1,214	$2,489	$3,660	$4,439	25,239.731
43	Market Capacity - ENERGY	$3.962	$8.751	$680.008	$6.123	$0.000	$19.014	$229	$0	$0	$0	$18	$0	964.732
44	Market Energy Purchase	$206.585	$234.971	$162.147	$607.767	$212.236	$374.570	$156	$0	$0	$0	$0	$0	1,953.878
45		----	----	----	----	----	----	----	----	----	----	----	---- ----	
46		$6,915.218	$5,781.141	$5,749.512	$4,088.822	$3,456.363	$3,757.752	$4,019	$4,464	$3,509	$4,639	$5,852	$6,685	58,915.783
47														
48	**CAPACITY (MW)**													
49	FortisBC	194	186	184	161	187	174	188	203	200	194	193	208	2272.709
50	Brilliant Base Plant	123	123	101	117	106	100	106	115	119	119	123	123	1372.894
51	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238.000
52	Brilliant Tailrace Capacity	4	3	1	3	6	6	6	4	1	1	3	5	42.200
53	Teck	22	0	0	75	16	0	60	0	0	0	0	0	173.000
54	Market Capacity	20	0	190	0	90	140	35	0	0	0	14	0	488.840
55		0	0	0	0	0	0	0	0	0	0	0	0	0.000
56	FortisBC DSM	0	0	0	0	0	0	0	3	4	4	4	5	18.600
57		0	0	0	0	0	0	0	0	0	0	0	0	0.000
58	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
59	Cominco Market Capacity	150	75	0	0	0	0	0	0	0	0	50	125	400.000
60	CPC Market Capacity	0	0	0	0	0	0	0	0	0	0	0	25	25.000
61	BCH : Billing Capacity	197	184	154	147.75	147.75	147.75	158	181	144	169	190	200	2020.822
62	BCH : Used for Load	182	175	140	111	16	42	147	181	100	169	190	202	1656.050
63	BCH : Excess Purch	0	0	0	0	0	0	0	0	0	0	0	0	0.000
64		----	----	----	----	----	----	----	----	----	----	----	----	----
65	Gross FortisBC Monthly Peak	714	580	626	487	440	462	561	525	443	507	598	650	6592.400
66														
67	Capacity Planning Load	714	580	626	487	440	462	561	525	443	507	598	650	6592.400
68	**RATE ($/MW-month) / EXPENSE ($000)**													
69	BCH 3808 Rate	4820.52	4820.52	4820.52	4820.52	4820.520	4820.520	4820.52	4820.52	5312.60	5312.60	5312.60	5312.60	
70	BCH 3808 Capacity Charge	$949.642	$886.976	$742.360	$712.232	712.232	712.232	$762	$875	$764	$900	$1,009	$1,063	10,087.422
71	BRD Tailrace Capacity Charge	$16.836	$11.479	$3.826	$7.926	22.958	22.958	$21	$13	$4	$4	$14	$19	159.451
72	Market Capacity Charge													0.000
73	Teck Capacity Charge	$566.497	$235.690	$0.000	$0.000	0.000	0.000	$0	$0	$0	$0	$249	$762	1,813.253
74	CPC Capacity Charge												$195	195.000
75	Total Capacity EXPENSE($000)	$1,532.976	$1,134.145	$746.186	$720.158	735.190	735.190	$782	$888	$767	$903	$1,272	$2,039	12,255.126
76														
77	**TOTAL POWER PURCH EXPENSE($000)**													
78	Surplus Revenues	$0.000	$0.000	$0.000	$0.000	($60.898)	($0.141)	($704.562)	$0.000	$0.000	$0.000	$0.000	$0.000	(765.601)
79	Export Wheeling Costs	$0.000	$0.000	$0.000	$0.000	$13.755	$0.000	$0	$0	$0	$0	$0	$0	13.755
80	Brilliant	$2,823.572	$2,141.157	$1,999.646	$3,046.384	$3,081.886	$2,816.822	$3,081	$3,274	$2,279	$2,139	$2,165	$2,243	31,090.027
81														
82	BCH	$4,777.946	$4,209.646	$3,546.626	$1,076.850	$916.282	$1,229.421	$1,973	$2,060	$1,978	$3,389	$4,669	$5,502	35,327.153
83	BCH Excess/Unallocated Costs	$0.000	$0.000	$0.136	$13.719	$30.608	$26.976	$24.174	$7	$3	$0	$0	$0	105.890
84		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0	$0	$0	$0	$0	$0	0.000
85	Market Spot Purchase & Com Capacity	$777.044	$479.412	$842.156	$613.890	$212.236	$393.585	$385	$0	$0	$0	$267	$957	4,926.864
86	IPP	$69.631	$85.070	$107.270	$71.857	$42.047	$53.255	$67	$17	$20	$14	$23	$23	592.467
87														
88	Capital Projects	($59.559)	($17.910)	$0.000	$0.000	($28.895)	$0.000					($74)	($25)	(205.341)
89	Special & Accounting Adjustments						($67)			($8)	($8)	($8)	$53	(38.908)
90	Balancing Pool Adjustments	($25.146)	($44.500)	$569.318	($797.356)	($77.727)	($288.274)	$533	($848)	($311)	$0	($174)	$618	(845.241)
91		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
92	**TOTAL**	$8,363.489	$6,852.876	$7,065.152	$4,025.343	$4,129.295	$4,164.562	$5,358	$4,511	$3,960	$5,534	$6,867	$9,370	70,201.063

Table 6.3

1	ANALYSIS OF FORECAST POWER PURCHASE EXPENSE													
2	FOR THE YEAR ENDING DECEMBER 31, 2010													
3		2	3	4	5	6	7	8	9	10	11	12	13	
4		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
5	**ENERGY GW.h**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
6	FortisBC	156	151	140	123	133	118	140	118	123	111	118	162	1,592.692
7	Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857.415
8	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	65.093
9														
10	Teck	0	0	0	0	0	0	0	0	0	0	0	0	0.000
11	Small Misc IPP Resource	1	0	1	1	3	2	3	1	1	1	1	1	13.000
12														
13	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
14		0	0	0	0	0	0	0	0	0	0	0	0	0.000
15	CPC Loss, Wheeling & PPA Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0.000
16	DSM	3	3	3	2	2	2	2	2	2	2	3	3	29.947
17	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0.000
18	Market Capacity - ENERGY	0	0	1	0	0	0	2	0	0	0	0	0	3.839
19	Market Energy Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0.000
20	BCH Purchase	131	124	102	46	20	34	43	42	53	96	136	145	973.052
21		----	----	----	----	----	----	----	----	----	----	----	----	----
22	Gross Load	373	341	303	263	245	242	267	261	246	273	321	377	3,511.927
23	Surplus	0	0	0	0	6	0	17	0	0	0	0	0	23.111
24	**RATE (Mills/kW.h)**												Pwr Pur =	1,912.399
25	Surplus Rate	46.08	43.45	40.12	23.14	22.04	17.75	31.39	32.05	31.45	47.51	52.52	60.39	
26	Brilliant Base Plant	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	
27	Brilliant Upgrade	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	
28														
29														
30	Market Capacity - ENERGY	64.27	60.77	51.86	47.55	43.17	44.86	82.67	88.61	67.02	60.90	72.85	83.35	
31	Market Energy Purchase	46.08	43.45	40.12	23.14	22.04	17.75	31.39	32.05	31.45	47.51	52.52	60.39	
32	BCH : Purchase	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	
33	IPP Rate	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	
34	**ENERGY EXPENSE ($000)**													
35	Surplus Revenue	$0	$0	$0	$0	($131)	$0	($539)	$0	$0	$0	$0	$0	(669.771)
36	Brilliant Base Plant	$2,987	$2,299	$2,150	$2,983	$2,891	$2,634	$2,892	$3,140	$2,410	$2,270	$2,296	$2,373	31,324.365
37	Brilliant Upgrade	$19	($17)	($12)	$260	$369	$344	$369	$339	$26	$16	$8	$9	1,728.219
38														
39														
40														
41	IPP Costs	$16	$12	$22	$19	$78	$69	$84	$19	$22	$16	$25	$25	404.798
42	BCH Purchase	$4,064	$3,874	$3,179	$1,425	$623	$1,073	$1,351	$1,303	$1,659	$2,983	$4,239	$4,525	30,299.190
43	Market Capacity - ENERGY	$22	$0	$61	$0	$0	$0	$176	$0	$0	$0	$15	$0	272.905
44	Market Energy Purchase	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
45		----	----	----	----	----	----	----	----	----	----	----	----	----
46		$7,107	$6,168	$5,400	$4,687	$3,829	$4,118	$4,334	$4,800	$4,117	$5,285	$6,583	$6,932	63,359.706
47														
48	**CAPACITY (MW)**													
49	FortisBC	193	183	193	188	187	178	188	203	203	181	189	208	2,292.287
50	Brilliant Base Plant	123	123	87	117	106	100	106	115	119	119	123	123	1,359.238
51	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238.000
52	Brilliant Tailrace Capacity	4.4	3.0	1.0	2.5	6.0	6.0	5.7	3.6	0.9	0.9	3.4	4.8	42.200
53	Teck	0	0	0	0	0	0	0	0	0	0	0	0	0.000
54	Market Capacity	4	0	34	0	0	0	38	0	0	0	10	0	85.540
55		0	0	0	0	0	0	0	0	0	0	0	0	0.000
56	FortisBC DSM	4	4	3	3	3	3	2	2	3	3	3	4	36.400
57		0	0	0	0	0	0	0	0	0	0	0	0	0.000
58	Turbine Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0.000
59	Teck Market Capacity	150	75	0	0	0	0	0	0	0	0	50	125	400.000
60	CPC Market Capacity	0	0	0	0	0	0	0	0	0	0	0	25	25.000
61	BCH : Billing Capacity	200	185	200	152	150	180	200	178	150	182	200	195	2,171.854
62	BCH : Used for Load	200	185	200	152	125	180	200	178	89	182	200	195	2,085.343
63	BCH : Excess Purch	0	0	0	0	0	0	0	0	0	0	0	0	0.000
64		----	----	----	----	----	----	----	----	----	----	----	----	----
65	Gross FortisBC Monthly Peak	697	589	538	483	446	486	560	522	434	505	598	649	6,506.000
66														
67	Capacity Planning Load	697	589	538	483	446	486	560	522	434	505	598	649	6,506.000
68	**RATE ($/MW-month) / EXPENSE ($000)**													
69	BCH 3808 Rate	5313	5313	5313	5313	5313	5313	5313	5313	5313	5313	5313	5313	
70	BCH 3808 Capacity Charge	$1,063	$983	$1,063	$805	$797	$956	$1,063	$946	$797	$966	$1,063	$1,038	11,538.192
71	BRD Tailrace Capacity Charge	$17.105	$11.663	$3.888	$9.719	$23.325	$23.325	$22.159	$13.995	$3.499	$3.499	$13.218	$18.660	164.055
72														0.000
73	Cominco Capacity Charge	$703	$283	$0	$0	$0	$0	$0	$0	$0	$0	$257	$728	1,971.282
74	CPC Capacity Charge												$208	207.500
75	Total Capacity EXPENSE($000)	$1,783	$1,278	$1,066	$815	$820	$979	$1,085	$960	$800	$970	$1,333	$1,992	13,881.029
76														
77	**TOTAL POWER PURCH EXPENSE($000)**													
78	Surplus Revenues	$0	$0	$0	$0	($131)	$0	($539)	$0	$0	$0	$0	$0	(669.771)
79	Export Wheeling Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
80	Brilliant	$3,023	$2,294	$2,142	$3,253	$3,283	$3,000	$3,283	$3,492	$2,439	$2,290	$2,317	$2,400	33,216.639
81														
82	BCH	$5,126	$4,857	$4,242	$2,231	$1,420	$2,029	$2,414	$2,250	$2,456	$3,949	$5,302	$5,563	41,837.382
83	BCH Excess/Unallocated Costs	$0	$0	$0	$14	$31	$27	$25	$7	$3	$0	$0	$0	107.584
84		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.000
85	Market Spot Purchase & Com Capacity	$725	$283	$61	$0	$0	$0	$176	$0	$0	$0	$272	$935	2,451.687
86	IPP	$16	$12	$22	$19	$78	$69	$84	$19	$22	$16	$25	$25	404.798
87														
88	Capital Projects													0.000
89	Special & Accounting Adjustments													0.000
90	Balancing Pool Adjustments	$249	$847	$729	($448)	($93)	($249)	$93	($934)	($311)	($467)	($174)	$635	(124.553)
91		-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
92	**TOTAL**	$9,138	$8,294	$7,196	$5,067	$4,587	$4,876	$5,536	$4,833	$4,609	$5,787	$7,741	$9,559	77,223.766

Table 6.4

		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
1	ANALYSIS OF FORECAST WHEELING EXPENSE													
2	FOR THE YEAR ENDING DECEMBER 31, 2009 BCTC WHEELING SCHEDULE 3817													
3														
4		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
5	NOMINATION (MW)													
6														
7	- Okanagan	175	175	175	175	175	175	175	175	175	180	180	180	
8	- Creston	35	35	35	35	35	35	35	35	35	35	35	35	
9														
10														
11	RATE ($/kW/Month)													
12														
13	- Okanagan	1662	1662	1662	1662	1662	1662	1662	1662	1662	1688	1688	1688	20020.8
14	- Creston	1083	1083	1083	1083	1083	1083	1083	1083	1083	1100	1100	1100	13047.6
15														
16														
17	COST ($000)													
18														
19	- Okanagan	$291	$291	$291	$291	$291	$291	$291	$291	$291	$304	$304	$304	3529.0
20	- Creston	$38	$38	$38	$38	$38	$38	$38	$38	$38	$39	$39	$39	456.7
21														
22	EXCESS WHEELING COSTS ($000)													
23														
24	Teck Wheeling Costs	$1.137	$1.302	$2.987	$6.653	$2.632	$5.094	$1	$1	$1	$1	$1	$1	25.8
25	OATT Wheeling Costs + Emer	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$1	$1	$1	$1	$1	$1	6.0
26	PRINCETON WTS Wheeling													0.0
28														
29	TOTAL WHEELING COSTS ($000)													
30														
31		$329.848	$330.013	$331.698	$335.364	$331	$334	$331	$331	$331	$344	$344	$344	4017.4