FORTISBC

Preliminary 2011 Revenue Requirements

Tab 6

Power Purchase and Wheeling

FortisBC Inc.

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6.0 Introduction

This section includes an estimate of 2010 power purchase expense based on FortisBC's actual results to July 31, 2010, with an estimate for August through December, and a complete forecast of power purchase expense for 2011 (see Tables 6.2 and 6.3 at the end of this Tab).

As shown in Table 6.0 below, the 2011 Power Purchase Expense is forecast at $81.2 million compared to $75.2 million currently estimated for 2010. The increase is primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement, and the BC Hydro rate increase, which is partially offset by reduced market requirements and a reduction in the Brilliant Base rate. Balancing Pool adjustments account for the difference between energy entitlements under the Canal Plant Agreement ("CPA ") and actual usage.

Table 6.0: Total Power Purchase Expense

		Forecast 2010	**Forecast 2011**	**Difference**
			($000s)	
1	Surplus Revenues	(1,011)	(814)	197
2	Brilliant	33,217	32,282	(935)
3	BC Hydro	38,293	47,189	8,896
4	Market Spot Purchase & Capacity Purchases	4,525	2,940	(1,585)
5	Independent Power Producers	709	155	(554)
6	Capital Projects	(289)	(371)	(82)
7	Special and Accounting Adjustments	539	-	(539)
8	Balancing Pool	(766)	(136)	630
9	**TOTAL**	**75,217**	**81,245**	**6,028**

6.1 Review of 2010

The winter of 2009/10 saw below average snow packs but normal run-off patterns due to above average precipitation in the spring. Power prices remained moderate to low through the winter and the rest of the year with no changes expected in the coming winter.

The unseasonable wet weather this spring, combined with on-going moderate natural gas prices and a growing base of variable and unpredictable wind generation in the Pacific Northwest provided significant opportunities to obtain market energy at rates below those of the BC Hydro Power Purchase Agreement.

Loads are currently expected to be about 120 GWh below approved 2010 levels over the year. Approximately half of the lower load is due to weather. Costs are expected to be $5.2 million below approved 2010 power purchase expense of $80.4 million (Order G-127-10). As shown in Table 6.1 below $5.1 million of the variance occurs as a result of:

- A decrease of $0.3 million due to higher surplus sales resulting from market activities;
- A combined increase of $1.3 million in market and Independent Power Producers (“IPP”) purchases;
- A decrease in the balancing pool adjustment of $0.6 million; and
- Lower BC Hydro costs, net of accounting adjustments, of $6.0 million, due primarily to a reduced BC Hydro purchase volume of 145 GWh as a result of increased market purchases and decreased load; and
- The $0.5 million negotiated settlement rate reduction;.

BC Hydro costs and associated accounting adjustments, which represent the expected impact of the Commission’s decision setting final BC Hydro rates for the period April 1, 2010 through March 31, 2011, are reflected in the Company’s Financial Statements to July 31, 2010 and will be updated on or before November 1, 2010.

During 2010 there was a normal program of annual generator maintenance on the FortisBC generating units. The South Slocan Unit 1 Life Extension and Upgrade Project was completed in the beginning of 2010. The Corra Linn Unit 1 ULE is expected to be completed in January 2011, which required a planned outage beginning in 2010. The ULE for Corra Linn Unit 2 is expected to begin in the fall of 2011. The increased power purchase costs as a result of these projects are offset by charges to the capital cost of the project and therefore do not impact the power purchase expense (see Table 6.2 at end of Tab 6).

Table 6.1: Total Power Purchase Expense

		Approved 2010[1]	**Forecast 2010**	**Difference**
			($000s)	
1	Surplus Revenues	(695)	(1,011)	(316)
2	Brilliant	33,217	33,217	(0)
3	BC Hydro	44,835	38,293	(6,542)
4	Market Spot Purchase & Capacity Purchases	3,547	4,525	978
5	Independent Power Producers	405	709	304
6	Capital Projects	(265)	(289)	(24)
7	Special and Accounting Adjustments	-	539	539
8	Balancing Pool	(136)	(766)	(630)
9	BCUC Negotiated Rate Reduction	(500)	-	500
10	**TOTAL**	**80,408**	**75,217**	**(5,191)**

1. Approved 2010 as per FortisBC's Application for Approval of Interim Rate Relief Order G-127-10.

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 continues to rely on a strategy of short term purchases from the market to meet the shortfall for 2011. An advance purchase of winter capacity blocks from Powerex has been obtained to meet peak winter loads till the WAX CAPA power is available as discussed in section 6.2.2 of this Tab.

The Company expects to file a Resource Plan Update in Second Quarter 2011 to review appropriate long term resource options to meet the Company’s energy requirements. It is expected that any potential changes resulting from the 2011 Resource Plan Update will impact resource acquisition after 2011.

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 2011 are included in Table 6.3 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 – CPA Entitlements

		Forecast 2010	Forecast 2011
1	Energy (GWh)	1,591	1,604
2	Change (%)		0.8
3	Capacity at winter peak (MW)	223	225
4	Change (%)		0.9

The expected increased Canal Plant Agreement entitlements are the result of the ULE program.

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 Independent Power Producer 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.

The price for the Brilliant Power Purchase Second Amendment Agreement is as follows: for the unregulated-flow component of the upgrade power, price 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 2011.

The Company also purchases approximately 5 MW of capacity under the Brilliant Tailrace Agreement, also approved by the Commission. The estimated 2011 rate is just under 70 percent of the BC Hydro capacity rate.

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

Table 6.2.3 – Brilliant Purchases

	Energy	**Forecast 2010**	**Forecast 2011**
	Base Volume (GWh)	859	859
1	Base ($/MWh)	36.45	35.31
2	Change (%)		(3.1)
3	Upgrade Volume (GWh)	65	65
4	Upgrade - unregulated ($/MWh)	26.55	27.19
5	Change (%)		2.4
6	Tailrace (MW-Months)	42	42
7	Tailrace ($)	164,098	166,921
8	Change (%)		1.7

The Base component for 2011 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 through to the customer. For 2011 the adjustment amounts to a decrease in costs of $2.1 million, based on the difference between forecast and actual costs for 2008 and 2009.

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 – BC Hydro 3808 Purchases

	Energy	**Forecast 2010**	**Forecast 2011**
1			
2	Volume (GWh)	835	1010
3	$/MWh	32.78	34.02
4	Change (%)		3.8
5	**Capacity**		
6	$/MW/Month	5,489	5,804
7	Change (%)		5.7

The Company has used BC Hydro's currently approved rates, including the deferral account rate rider, for 2011 forward. Estimates include a small adjustment for expected excess energy costs.

The Company requests approval to implement any changes to 2011 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 574 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 forecast power purchase expense for these IPPs 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 2010 than planned and at a much lower cost than anticipated.

With the new Zellstoff Celgar generator coming online in the fall of 2010, it is expected that FortisBC purchases from Celgar will be reduced substantially as the power will be sold to BC Hydro. As Celgar is the largest IPP in the FortisBC service territory, it is anticipated that the IPP purchases for 2011 will fall below previous levels.

Table 6.2.5 – IPP Purchases

	Energy	Forecast 2010	Forecast 2011
1	Volume (GWh)	33.4	4.6
2	Change (%)		(86.2)
3	$/MWh	21.3	34.02
4	Change (%)		60.1

D. Market Purchases

The Company's expected 2011 peak load capacity shortfall is approximately 7 MW (see Table 6.3, line 30) due to the Powerex capacity contracts. Any remaining requirements will be purchased on the spot market.

The Company expects to file a Resource Plan Update in Second Quarter 2011 to review appropriate long term resource options to meet the Company's energy requirements. It is expected that any potential changes resulting from the 2011 Resource Plan Update will impact resource acquisition after 2011. For 2011 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 sale of 1/3 of the Waneta plant to BC Hydro, capacity purchases for the winter months are no longer available from Teck. As a result of this transaction, FortisBC entered into a 5 year deal with Powerex to provide winter capacity blocks to replace what was previously available from Teck, commencing November 2010. Table 6.2.6 below is a summary of capacity purchases from Powerex and CPC that have been made for 2010 forward. The price for these blocks is not dependent on market prices as it is a fixed price contract.

Table 6.2.6 – Capacity Block Purchases

	Month	Amount (MW)	Cost ($)	$/MW
1	November-10	50	287,450	5,749
2	December	125	718,625	5,749
3	December (CPC)	25	207,500	8,300
4	January-11	150	862,350	5,749
5	February	75	431,175	5,749
6	November	50	299,850	5,997
7	December	125	749,625	5,997
8	January-12	150	899,550	5,997
9	February	75	449,775	5,997
10	November	50	337,350	6,747
11	December	125	843,375	6,747
12	January-13	150	1,012,050	6,747
13	February	75	506,025	6,747
14	November	50	352,700	7,054
15	December	125	881,750	7,054
16	January-14	150	1,058,100	7,054
17	February	75	529,050	7,054
18	November	50	365,550	7,311
19	December	125	913,875	7,311
20	January-15	150	1,096,650	7,311
21	February	75	548,325	7,311
22	November	50	369,250	7,385
23	December	125	923,125	7,385
24	January-16	150	1,107,750	7,385
25	February	75	553,875	7,385

The 25 MW capacity block (December 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 that expires in 2010.

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- Spot Market Purchases

		Forecast 2010	Forecast 2011
1	**Peak Energy**		
2	Volume (GWh)	15.6	5.9
3	Change (%)		(62.2)
4	$/MWh	35.89	47.15
5	Change (%)		31.4

The forecast market prices are taken from a July 27, 2010 Argus Media Publication titled "Argus US Electricity". The lower rate in 2010 as compared to 2011 is related to attractive prices for 2010 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 2010 BC Hydro capacity charges, but increased market volume to meet peak load to 16 GWh.

Spot market purchases to meet peak requirements are expected to be approximately $0.28 million in 2011 compared to $0.56 million in 2010. Overall the total cost of purchases from the market (Market Purchases Made in Advance plus Spot Market) is expected to be approximately $2.9 million in 2011 compared to approximately $4.5 million in 2010. $1.9 million of the 2010 market costs were for market energy (93.2 GWh) to fill the storage accounts rather than to meet peak loads. Of this amount 4.2 GWh was purchased at rates above the BCH PPA rate due to concerns that storage account levels were too low to maintain reliable cost-effective supply. It is anticipated that 7 GWh of non-PPA power (market energy) will be required to be purchased in 2011 in order to maintain appropriate energy reserves.

6.3 Summer Surplus

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 and higher than normal rainfall, 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.

As a result of the 1/3 sale of the Waneta Dam to BC Hydro, FortisBC entered into a 5 year contract with Powerex to sell its summer surplus energy. This contract was executed in July 2010, and resulted in sales of 29.52 GWH to Powerex, which was the maximum allowed under that deal. In addition, sales were made to Morgan-Stanley, Teck and Powerex. Despite these sales, 16 GWh of energy could not be stored for later use and was therefore spilled. This will reduce the 2011 water fee rental payments.

Table 6.3.1- Summer Surplus Sales

	Energy	**Forecast 2010**	**Forecast 2011**
1	Volume (GWh)	51	30
2	Change (%)		(41)
3	$/MWh	19.82	27.14
4	Change (%)		37

Overall the revenue from summer surplus sales is expected to decrease from approximately $1.0 million in 2010 to approximately $0.8 million in 2011 due to lower volumes.

6.4 Wheeling Expense

The Wheeling Expense forecast includes an estimate of 2010 expense based on actuals through July and an estimate of the remaining expense. The expense includes wheeling service provided by BC Hydro Transmission under the GWA made in 1986 and also wheeling provided by BC Hydro Transmission under its Open Access Transmission Tariff, as needed to supply the Company's loads in the Okanagan from Vernon and the interconnection at Vaseux Lake (which together are termed the Okanagan Point of Interconnection), and at Creston and Princeton. Also included are charges paid to Teck Cominco for the use of their 71 Line.

Rates under the GWA are specified in BC Hydro Transmission filed Rate Schedule 21. In 2011, GWA costs are forecast to account for all the wheeling expense except for $0.024 million of OATT and Teck Cominco wheeling expense.

Wheeling Expense is forecast to decrease from $4.0 million in 2010 to $3.34 million in 2011 due to higher wheeling nominations ($0.1 million) and the annual estimated rate increase of 0.5 percent ($0.04 million), which is offset by wheeling revenue from the Duck Lake Interconnection with BCTC ($0.8 million). Calculation of 2011 Wheeling Expense is shown in Table 6.4 below.

Table 6.2 – 2010 Estimated Power Purchase Expense

2010	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Forecast	Forecast	Forecast	Forecast	Forecast	
Energy (GWh)													
Fortis BC Resources	115.925	140.924	155.737	140.518	102.502	92.513	197.9	123	108	117	109	162	**1,564**
Brilliant Base Plant	81.944	63.071	57.161	81.457	79.191	72.127	79.3	86	66	62	63	65	**857**
Brilliant Upgrade	0.702	-0.642	-0.443	9.792	13.896	12.938	13.9	13	1	1	0	0	**65**
Total BCH 3808 Energy	132.565	73.840	63.826	14.398	9.938	5.933	33.4	47	60	101	144	149	**835**
Small Misc IPP	4.241	4.755	4.632	2.268	3.664	6.881	3.5	1	1	1	1	1	**33**
Market Energy	4.038	0.000	0.000	2.710	36.299	42.466	0.0	0	0	0	5	3	**93**
Market Capacity - Energy	0.000	0.000	0.701	0.000	0.000	0.000	14.4	0	0	0	1	0	**16**
Operating Reserve	0.000	0.000	0.000	0.000	0.014	0.014	0.0	0	0	0	0	0	**0**
FBC DSM	0.000	0.000	0.000	0.000	0.000	0.000	0.0	2	2	2	3	3	**13**
City of Nelson Special Adjustment	0.000	0.000	0.000	0.000	0.000	-2.224	0.0	0	0	0	0	0	**(2)**
WEPAS Adjustments	0.000	-0.292	-0.713	0.040	-0.072	-0.140	0.0	0	0	0	0	0	**(1)**
IPP Export	-0.357	-1.394	-0.660	-0.337	0.000	0.000	0.0	0	0	0	0	0	**(3)**
FBC Surplus Sales	0.000	0.000	0.000	0.000	0.000	0.000	-51.0	0	0	0	0	0	**(51)**
FBC Exchange Account Spill							-16.2						**(16)**
													-
Total Gross Load (GWh)	**339.058**	**280.262**	**280.241**	**250.846**	**245.432**	**230.508**	**275.2**	**271**	**238**	**283**	**325**	**383**	**3,402**
Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity (MW)													**Peak**
Fortis BC Resources	194	186	199	196	183	178	188	203	207	208	214	213	214
Brilliant Base Plant	123	123	123	117	106	100	117	106	100	106	115	119	123
Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	20
Brilliant Tailrace	4.4	3	1	2.5	6	6	5.7	3.6	0.9	0.9	3.4	4.8	6
BCH Billing Capacity	188	173	145	145	145	145	145	191	143	171	200	200	200
BCH Utilized Capacity	148	118	103	142	74	109	113	191	107	171	200	200	200
BCH Excess Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Cominco Capacity Blocks	150	75	0	0	0	0	0	0	0	0	0	0	150
Powerex Capacity Blocks	0	0	0	0	0	0	0	0	0	0	50	125	125
CPC Capacity Blocks	0	0	0	0	0	0	0	0	0	0	0	25	25
Real Time Market Purchases	0	0	50	0	0	0	110	0	0	0	0	0	110
FBC DSM	0	0	0	0	0	0	0	2	3	3	3	4	4
FBC Peak Gross Load	639	525	496	478	465	423	554	525	437	509	603	654	654
Energy Rates ($/MWh)													
Brilliant Base Plant	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	36.45	
Brilliant Upgrade	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	26.55	
BCH 3808	31.14	31.14	31.14	31.14	31.14	31.14	31.14	31.14	34.02	34.02	34.02	34.02	
IPP Rate	31.02	32.34	30.30	30.64	23.58	7.37	23.58	23.58	23.58	23.58	23.58	23.58	
Market Energy	41.53			24.76	23.33	12.64		25.39	31.00	36.50	36.50	36.50	
Market Capacity - Energy			48.34				35.14	40.00	39.00	37.00	40.00	41.75	
Operating Reserve					24.36	10.44							
Surplus Rate							19.82	19.85	24.90	29.85	29.85	29.85	
Capacity Rates ($/MW/month)													
BRD Tailrace Capacity Rate	3,897	3,897	3,897	3,897	3,897	3,897	3,897	3,897	3,897	3,897	3,897	3,897	
BCH 3808 Capacity Rate	5,313	5,313	5,313	5,313	5,313	5,313	5,313	5,313	5,804	5,804	5,804	5,804	
Cominco Capacity Rate	3,839	3,186											
Powerex Capacity Rate											5,749	5,749	
CPC Capacity Rate												8,300	
Exchange Rate	1.044	1.056	1.025	1.005	1.043	1.040	1.043	1	1	1	1	1	
Energy Expense ($000)													
Brilliant Base Plant	2,986.859	2,298.938	2,150.040	2,982.922	2,890.995	2,633.622	2,892.1	3,140	2,410	2,270	2,296	2,373	**31,324**
Brilliant Upgrade	18.638	(17.045)	(11.762)	259.978	368.939	343.504	368.8	339	26	16	8	9	**1,728**
BCH 3808	4,127.849	2,299.252	1,987.433	448.329	309.452	184.744	1,041.1	1,454	2,051	3,440	4,899	5,062	**27,304**
BCH 3808 Excess/Unallocated costs	-	-	0.448	4.334	17.156	17.062	26.7	-	-	-	-	-	**66**
IPP Costs	120.498	108.695	120.351	59.167	86.406	50.731	83.3	14	17	12	19	19	**709**
Market Energy	167.713	-	-	67.090	846.740	536.596	-	-	-	-	170	112	**1,899**
Market Capacity - Energy			33.883	-	-	-	505.3	-	-	-	20	-	**559**
Operating Reserve	-	-	-	-	0.341	0.146	-	-	-	-	-	-	
Total Energy Expense ($000)	**7,421.557**	**4,689.840**	**4,280.394**	**3,821.821**	**4,520.030**	**3,766.405**	**4,917.5**	**4,946**	**4,503**	**5,739**	**7,411**	**7,574**	**63,591**
Capacity Expense ($000)													
BRD Tailrace Capacity	17.145	11.690	3.897	9.742	23.050	23.362	22.2	14	4	4	13	19	**164**
BCH 3808 Capacity	998.769	916.424	768.999	768.999	768.999	768.999	769.0	1,015	832	995	1,161	1,161	**10,924**
Cominco Capacity	600.824	252.276	-	-	-	-	-	-	-	-	-	-	**853**
Powerex Capacity	-	-	-	-	-	-	-	-	-	-	287	719	**1,006**
CPC Capacity	-	-	-	-	-	-	-	-	-	-	-	208	**208**
Total Capacity Expense ($000)	**1,616.738**	**1,180.389**	**772.896**	**778.740**	**792.049**	**792.361**	**791**	**1,029**	**835**	**998**	**1,462**	**2,106**	**13,154**
Other Expenses ($000)													
Surplus Revenue	-	-	-	-	-	-	(1,011.1)	-	-	-	-	-	**(1,011)**
Capital Project Recovery	(87.112)	(17.202)	-	(11.022)	(21.944)	(28.358)	-	-	-	-	(92)	(32)	**(289)**
Special & Accounting Adjustments	(90.000)		(4.975)	(10.447)		(12.791)	52.2	61	154	154	154	154	**610**
WEPAS Adjustment	(22.503)		(36.140)	6.120	(18.437)								**(71)**
Balancing Pool Adjustments	(1,008.320)	523.497	1,210.968	103.535	(1,048.489)	(406.625)	1,280.0	(778)	(812)	(340)	(510)	1,021	**(766)**
Total Other Expense ($000)	(1,207.936)	506.295	1,169.854	88.186	(1,088.870)	(447.8)	321.1	(717)	(659)	(187)	(448)	1,143	**(1,528)**
Total Power Purchase Expense	**7,830.359**	**6,376.524**	**6,223.143**	**4,688.748**	**4,223.209**	**4,110.992**	**6,029.8**	**5,258**	**4,680**	**6,551**	**8,424**	**10,822**	**75,217**

Table 6.3 - 2011 Forecasted Power Purchase Expense

	2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1–2		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
3	**Energy (GWh)**													
4	Fortis BC Resources	150	143	131	125	117	102	177	122	109	117	114	163	**1,568**
5	Turbine Upgrades	1	1	1	1	1	1	1	1	1	1	1	1	**13**
6	Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	**857**
7	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**
8	Total BCH 3808 Energy	140	113	110	37	38	55	40	47	57	93	134	146	**1,010**
9	Small Misc IPP	0	0	0	0	0	0	1	0	0	0	0	0	**5**
10	Market Energy	0	0	0	0	0	0	0	0	0	0	0	7	**7**
11	Market Capacity - Energy	0	0	3	0	0	0	2	0	0	0	0	0	**6**
12	FBC DSM	4	4	3	3	3	3	3	3	3	3	4	4	**40**
13	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	**-**
14	WEPAS Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
15	FBC Surplus Sales	0	0	0	0	0	0	-30	0	0	0	0	0	**(30)**
16														**-**
17	**Total Gross Load (GWh)**	**378**	**323**	**306**	**257**	**253**	**246**	**287**	**272**	**238**	**277**	**316**	**387**	**3,540**
18	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
19														
20	**Capacity (MW)**													**Peak**
21	Fortis BC Resources	197	195	202	194	189	180	190	205	209	210	200	200	210
22	Brilliant Base Plant	123	123	124	117	106	100	106	115	119	119	123	123	124
23	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	20
24	Brilliant Tailrace	4.4	3	1	2.5	6	6	5.7	3.6	0.9	0.9	3.4	4.8	6
25	BCH Billing Capacity	200	191	200	162	150	192	200	194	150	171	200	200	200
26	BCH Peak Usage	200	191	200	162	137	192	200	194	105	171	200	200	200
27	BCH Excess Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125	150
29	CPC Capacity Blocks	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Real Time Market Purchases	7	0	53	0	0	0	40	0	0	0	18	5	53
31	FBC DSM	5	4	3	3	3	3	3	2	3	3	3	4	5
32														
33	FBC Peak Gross Load	706	610	566	499	460	500	564	540	455	523	618	681	706
34														
35	**Energy Rates (CDN$/GWh)**													
36	Brilliant Base Plant	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	
37	Brilliant Upgrade	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	
38	BCH 3808	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	
39	IPP Rate	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.02	
40	Market Energy	36.93	34.19	31.46	19.86	17.15	17.15	30.27	30.27	30.27	34.98	37.69	40.40	
41	Market Capacity - Energy	51.67	47.62	43.57	35.36	33.10	35.36	52.20	51.20	50.19	47.89	51.91	55.92	
42	Surplus Rate	33.41	30.71	28.01	16.79	14.09	14.09	27.14	27.14	27.14	31.87	34.57	37.27	
43														
44	**Capacity Rates (CDN$/MW/month)**													
45	BRD Tailrace Capacity Rate	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	
46	BCH 3808 Capacity Rate	5,804	5,804	5,804	5,804	5,804	5,804	5,804	5,804	5,804	5,804	5,804	5,804	
47	Powerex Capacity Rate	5,825	5,825									6,015	6,015	
48	CPC Capacity Rate													
49														
50	Exchange Rate	1.01	1.01	1.01	1.00	1.00	1.00	1.00	1.00	1.00	1.003	1.003	1.003	1.01
51														
52	**Energy Expense ($000)**													
53	Brilliant Base Plant	2,893	2,227	2,083	2,890	2,801	2,551	2,802	3,041	2,335	2,199	2,224	2,299	**30,345**
54	Brilliant Upgrade	19	(17)	(12)	266	378	352	378	347	26	17	8	9	**1,770**
55	BCH 3808	4,773	3,851	3,750	1,260	1,282	1,864	1,356	1,587	1,955	3,168	4,553	4,961	**34,361**
56	BCH 3808 Excess/Unallocated costs	-	-	-	-	-	-	-	-	-	-	-	-	**-**
57	IPP Costs	9	13	17	7	15	14	20	8	16	14	15	7	**155**
58	Market Energy	-	-	-	-	-	-	-	-	-	-	-	299	**299**
59	Market Capacity - Energy	2	-	150	0	-	0	115	-	-	-	12	-	**279**
60														
61	**Total Energy Expense ($000)**	**7,696**	**6,073**	**5,987**	**4,423**	**4,476**	**4,782**	**4,671**	**4,983**	**4,332**	**5,398**	**6,813**	**7,575**	**67,209**
62														
63	**Capacity Expense ($000)**													
64	BRD Tailrace Capacity	17	12	4	10	24	24	23	14	4	4	13	19	**167**
65	BCH 3808 Capacity	1,161	1,109	1,161	942	871	1,116	1,161	1,125	871	991	1,161	1,161	**12,828**
66	BCH 3808 Excess Capacity	-	-	-	-	-	-	-	-	-	-	-	-	**-**
67	Powerex Capacity	874	437	-	-	-	-	-	-	-	-	301	752	**2,363**
68														
69	**Total Capacity Expense ($000)**	**2,052**	**1,557**	**1,165**	**952.3**	**894**	**1,140**	**1,183**	**1,139**	**874**	**994**	**1,475**	**1,932**	**15,358**
70														
71	**Other Expenses ($000)**													
72	Surplus Revenue	-	-	-	-	-	-	(814)	-	-	-	-	-	**(814)**
73	Capital Project Recovery	(90)	(83)									(100)	(99)	**(371)**
74	Special & Accounting Adjustments													**-**
75	WEPAS Adjustment													**-**
76	Balancing Pool Adjustments	102	680	524	(388)	(612)	(782)	1,395	(850)	(748)	(272)	(272)	1,089	**(136)**
77														
78	**Total Other Expense ($000)**	12	597	524	(388)	(612)	(782)	581	(850)	(748)	(272)	(372)	990	**(1,322)**
79														
80	**Total Power Purchase Expense**	**9,760**	**8,228**	**7,676**	**4,987**	**4,758**	**5,139**	**6,435**	**5,271**	**4,457**	**6,120**	**7,916**	**10,497**	**81,245**

Table 6.4: 2011 Forecast Wheeling Expense

Analysis of Forecast Wheeling Expense for Year Ending December 31, 2011

	2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2	**Nomination (MW)**													
3	Vernon	180	180	180	180	180	180	180	180	180	200	200	200	**2,220**
4	Lambert	35	35	35	35	35	35	35	35	35	35	35	35	**420**
5	Princetion	0	0	0	0	0	0	0	0	0	0	0	0	-
6														
7	**Rate ($/kW/month)**													
8	Vernon	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,668	1,668	1,668	
9	Lambert	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,087	1,087	1,087	
10	Princetion	-	-	-	-	-	-	-	-	-	-	-	-	
11														
12	**Cost ($000)**													
13	Vernon	296	296	296	296	296	296	296	296	296	334	334	334	**3,663**
14	Lambert	37	37	37	37	37	37	37	37	37	38	38	38	**451**
15	Princetion	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16														
17	**Excess Wheeling Costs ($000)**													
18	Cominco Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	**12**
19	OATT and Emerg. Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	**12**
20	Duck Lake Wheeling Revenue	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	**(800)**
21														
22	**Total Wheeling Costs ($000)**	**269**	**269**	**269**	**269**	**269**	**269**	**269**	**269**	**269**	**307**	**307**	**307**	**3,338**