BRANT COUNTY POWER INC.
2011 RATES REBASING CASE
EB-2010-0125

ENERGY PROBE RESEARCH FOUNDATION
INTERROGATORIES

Interrogatory # 1

Ref: Exhibit 1, Tab 1, Schedule 8

a) **Please provide a copy of the loan agreement between BCP and BCPS. There is formal agreement in place.**

b) **What is the expected average loan balance for 2011?**

c) **What is the current market rate on this loan?**

d) **How have the rates charged by BCP for time spent on BCPS activities been calculated?**

e) **Are the separate billing systems in place?**

f) **How were the costs of the separate billing systems split between BCP and BCPS? Please explain the rationale for this allocation of costs.**

g) **Does BCPS have its own Board of Directors?**

h) **Please confirm that there is no cost associated with the BCPS Board of Directors in the BCP revenue requirement.**

Response:

a) The loans and related terms were approved by the board of directors in both companies via minutes, no formal agreements in place.

b) The average expected loan balance for 2011 is $495,270.

c) The interest rate is P + 1.75% or currently 4.75%.

d) See answer to Part F below.

e) Historically, the billings systems were intertwined for water heaters and softeners in Brant County's service territory. We have since been working to separate these billing systems, which has been completed. The first separate bills were issued late January 2011.

f) The costs of the separate billing systems are split based on actual costs borne by each entity. Previously an estimate for time spent by staff was allocated to BCP's revenue (as a reduction of admin expenses). The company has moved to a time sheet system whereby actual costs (based on time spent) will be recorded. This will be effective January 1, 2011.

g) YES

h) Yes – that's correct.

Interrogatory # 2

Ref: Exhibit 1, Tab 2, Schedule 1

a) **The evidence on page 1 indicates that there is a revenue deficiency from changes in OM&A, amortization, rate of return and PILS and states that with rates currently in effect, BCP estimates that its revenues for 2011 would not be sufficient to provide a reasonable return. Please reconcile these statements with the first sentence in this exhibit that indicates that there is a revenue sufficiency of $300,388.**

b) **Please indicate how many months of actual data have been included in the 2010 bridge year forecast.**

Response:

a) The second reference is a typo. Brant County confirms that we filed rates that incorporate a revenue sufficiency of $300,388.

b) BCP used the 2010 approved budget in the bridge year forecast as the actual results through to the filing date closely aligned with budget and did not warrant further adjustments.

Interrogatory # 3

Ref: Exhibit 1, Tab 2, Schedule 5

a) **Please provide a hard copy of the Revenue Requirement Work Form.**

b) **Please provide a live Excel version of the Revenue Requirement Work Form.**

Response:

a) See attached

b) See attached

Interrogatory # 4,

Ref: Exhibit 2, Tab 1, Schedule 3, page 6

a) **Please update the 2010 bridge year continuity schedule to reflect actual additions in 2010. If actual figures are not yet available for 2010, please update using the most recent year-to-date actuals available, along with a projection for the remainder of the year.**

b) **Please explain the $1,461,350 shown for account 1860 Meters. Does this include spending on smart meters?**

Response:

a) see attached.

b) Yes - this includes approximately $1,275,000 on the smart meter initiative.

Interrogatory # 5

Ref: Exhibit 2, Tab 2, Schedule 1 & Exhibit 2, Tab 1, Schedule 3, pages 6 & 7

There are a number of accounts shown in the table of Exhibit 2, Tab 2, Schedule 1 for 2010 and 2011 that do not match the corresponding figures on pages 6 & 7 of Exhibit 2, Tab 1, Schedule 3. In particular, there is a mismatch for accounts 1805 & 1905, accounts 1830 & 1845, and accounts 1920 & 1925. In each case, the total of the two accounts is correct, but there is a different allocation of the additions between the different set of schedules. Please indicate which set of tables reflects the correction allocation of the capital additions to the accounts.

Response:

Exhibit 2, Tab 2, Schedule 1 is the correct file. Note, this will have a $0 impact on Rate Base, Rate or Return or Distribution Rates.

Interrogatory # 6

Ref: Exhibit 2, Tab 4, Schedule 1, page 3

a) **Please update the 2011 cost of power to reflect the October 18, 2010 Regulated Price Plan Price Report.**

b) **Please confirm that BCP has not estimated the cost of power based on the split between RPP and non-RPP volumes for each of the rate classes shown.**

c) **Please provide an estimate of the RPP and non-RPP volumes for the 2011 test year and indicate how this estimate has been calculated.**

d) **Please provide the actual 2010 (or most recent year-to-date 2010, if complete 2010 data is not available) split between RPP and non-RPP volumes for each rate class shown.**

e) **Please confirm that based on the October 18, 2010 Regulated Price Plan Price Report, the weighted average Ontario Electricity Market Price Forecast for the May, 2011 through April, 2012 period is $62.50 per MWh calculated as follows based on the figures provided in Table 1 of the Price Report, along with the Global Adjustment shown in Table ES-1:**

	Months	Price
May-Jul	3	35.20
Aug-Oct	3	37.57
Nov-Jan	3	37.87
Feb-Apr	3	33.85
Weighted Average		36.12
Global Adjustment		26.38
Non-RPP Price		62.50

f) Please confirm that based on the October 18, 2010 Regulated Price Plan Price Report, the Average Supply Cost for RPP Customers for the May, 2011 through April, 2012 period is $65.04 per MWh calculated as follows based on the figures provided in Table ES-1 of the Price Report, along with the weighted average Ontario Electricity Market Price Forecast calculated in (e) above:

Load Weighted Price for RPP Consumers	**42.16**
Forecast Wholesale Electricity Price	**39.23**
Ratio	**1.074688**
May-Apr Weighted Average	**36.12**
May-Apr Load Weighted Price for RPP Consumers	**38.82**
Global Adjustment	**26.38**
Adjustment to Address Bias	**1.00**
Adjustment to Clear Existing Variance	**-1.16**
RPP Price	**65.04**

g) Please update the 2011 cost of power to reflect a Non-RPP price of $62.50 and an RPP price of $65.04 (as calculated in (e) and (f) above).

Response:

Brant County Power used the Cost of Power, Transmission, Low Voltage and Wholesale Market rates as a place holder and fully intends to implement the most recent rates for all above charges, to estimate working capital allowance provisions, upon approval of our rate process**.**

a) Brant County will not be processing a new rate model and distribution rates for this IR response, as we intend to use mandated / most recent rates upon approval of our application. The impact from the requested change is calculated below.

	Billing Determent	Original Rates		Update Rates			Rate Base Impact (15%)
	RPP	Rate	Cost	RPP Rate	Cost	Difference	
Residential	80,122,583	0.0694	5,560,507	0.06404	5,131,050	- 429,457	
GS < 50 kW	39,095,551	0.0694	2,713,231	0.06404	2,503,679	- 209,552	
GS 50 to 4,999 kW	151,750,742	0.0694	10,531,501	0.06404	9,718,118	- 813,384	
Unmetered Load	493,370	0.0694	34,240	0.06404	31,595	- 2,644	
Sentinel Lights	215,167	0.0694	14,933	0.06404	13,779	- 1,153	
Street Lights	1,707,054	0.0694	118,470	0.06404	109,320	- 9,150	
Total			18,972,882		17,507,541	- 1,465,341	- 219,801
RPP Rate for 2011	0.06250						
Non-RPP Rate for 2011	0.06504						
Utilized Blended Rate	0.06404						
	RPP Sales		AQEW	RPP %			
2010 June	9,008,004		23,496,388	38.3%			
May	8,245,637		22,592,407	36.5%			
Apr	6,915,714		20,729,870	33.4%			
Mar	8,768,878		23,603,010	37.2%			
Feb	13,674,385		23,530,384	58.1%			
Jan	10,500,455		26,612,098	39.5%			
2009 Dec	8,067,470		22,792,716	35.4%			
Nov	8,775,853		22,835,440	38.4%			
Oct	8,370,424		22,776,634	36.8%			
Sept	8,198,694		25,483,724	32.2%			
Aug	10,273,858		22,710,666	45.2%			
July	8,720,665		22,075,594	39.5%			
June	8,631,525		20,713,714	41.7%			
Annual	118,151,561		299,952,646	39.4%			

b) BCP did not use a RPP / Non-RPP split to determine the working capital portion of rate base. Although the analysis uses 39.4% RPP and 60.6% Non-RPP to generate the blended COP rate of $.06404 in part a) above.

c) Brant County has not performed this work. Please see historical results above (which would be used as a proxy).

d) BCP does not have this data available. Please see RPP sales vs. total AQEW for reference in a) above.

BCP agrees and has used this value for response a) above.

e) BCP agrees and has used this value for response a) above.

f) BCP agrees and has used this value for response a) above.

g) See response a) above.

Interrogatory # 7

Ref: Exhibit 2, Tab 5, Schedule 1, page 5

a) **Please update the 2010 bridge year table to show the actual expenditures for 2010, or if not yet available, the estimate of the actual expenditures based on the most recent actual data available, along with projections of what was spent for the remainder of 2010.**

b) **For each of the projects shown for the 2010 bridge year, please indicate if the project has been completed and placed into service by the end of 2010. For any project not completed and not placed into service, please indicate if the project will be completed and placed into service in 2011.**

Response:

a) The year end numbers are not available – this schedule is our best estimate to year end.

b) All of the projects listed on this schedule were completed in 2010.

Interrogatory # 8

Ref: Exhibit 2, Tab 5, Schedule 1

a) **Please explain why the capital expenditures for 2010 and 2011 both include amounts related to smart meters. Have these smart meter expenditures been included in the rate base calculations for 2010 and 2011? Why is the revenue requirement associated with these capital expenditures not included in the smart meter variance account?**

b) **Please provide a description of each of the 2010 and 2011 capital expenditure projects in the same format as shown for 2006 through 2009 projects at pages 9 through 16.**

Response:

a) OEB IR # 8 asked a similar question. BCP is proposing to remove any Smart Meter capital expenses from our 2011 CoS rate base and will continue to utilize the variance accounts and Smart Meter rate rider until implementation is completed and a prudency review can be undertaken. BCP will include Smart Meter capital in our next CoS application.

b) See attached file.

Interrogatory # 9

Ref: Exhibit 2, Tab 6, Schedule 1 &
Exhibit 2, Tab 1, Schedule 3, page 7

a) **What is the date of the Asset Management Plan?**

b) **Was this Asset Management Plan approved by the Board of Directors? If yes, please provide the date of this approval.**

c) **If a more recent Asset Management Plan is available, please provide a copy. Please also indicate if the Board of Directors has approved this more recent Plan.**

d) **Please reconcile the 2011 figure of $2,694,003 shown on page 11 of Exhibit 2, Tab 6, Schedule 1 with the figure of $2,893,154 shown on page 7 of Exhibit 2, Tab 1, Schedule 3.**

e) **Please explain the $1,461,350 shown for retail meters in 2010 on page 12 of Exhibit 2, Tab 6, Schedule 1.**

f) **Please reconcile the $130,000 for transportation equipment shown on page 7 of Exhibit 2, Tab 1, Schedule 3 for 2011 with the estimate cost of $30,000 for each of two vehicles show as 2011 replacements in the vehicle replacement schedule on page 48 of Exhibit 2, Tab 6, Schedule 1.**

Response:

a) See also OEB IR # 9. The plan was completed in October 2010 and will be reviewed by management annually.

b) The Asset Management plan was not formally approved by the board of directors, but was reviewed during a board meeting for their comments.

c) A more recent one is not available.

d) Please see schedule included as part of the response to VECC IR 24, which details the correction. The correct number is $2,893,154.

e) Of this amount $1.275 million is related to the smart meter initiative.

f) Planned vehicle replacements in 2011 are the 2 vehicles $30,000 each as noted. In addition, we have put into the budget 1 SUV at $40,000 and 1 vehicle at $30,000 for our renewable energy division.

Interrogatory # 10

Ref: Exhibit 3, Tab 1, Schedule 1 & Schedule 2

Schedule 1 indicates that distribution revenues have been calculated using the most recently approved rates with delivery rates based on the Rate Order EB-2009-0258 dated April 1, 2010.

a) **Please confirm that the 2011 test year revenues shown in Schedule 2 have been calculated using the RB-2009-0258 rates. If this cannot be confirmed, please calculate the 2011 distribution revenues shown in Schedule 2 by rate class based on the current rates in place.**

b) **Is the revenue generated from the provision of services to BCPS included in Other Distribution Revenue? If yes, please indicate where it has been included. If no, please explain how these revenues are reflected in the revenue requirement.**

c) **Please provide a table showing the revenues and associated costs in each of 2006 through 2011 associated with the provision of services to BCPS.**

Response:

a) Schedule 2, 2011 test year revenue is not based on EB-2009-0258 rates, but rather on the applied for rates. Please see attachment also used in VECC IR # 7e.

2011 Test - existing rates							
	Customers	Consumption	Fixed Charge	Variable Charge	Fixed Revenue	Variable Revenue	Distribution Revenues
	(Year-End)	(kWh / KW)					($)
Residential	8,290	80,122,583	11.02	0.0225	1,096,270	1,802,758	2,899,028
GS<50	1,315	39,095,551	16.54	0.0194	261,001	758,454	1,019,455
GS>50 to 499 kW	106	388,493	29.47	5.6124	37,486	2,180,378	2,217,864
Unmetered Scattered Load	51	493,370	8.27	0.0194	5,061	9,571	14,633
Sentinel Lighting	218	574	2.53	8.5088	6,618	4,884	11,503
Street Lighting	2,630	4,783	0.81	4.4208	25,564	21,145	46,708
TOTAL					1,432,000	4,777,190	6,209,190

b) This question was answered in OEB IR # 3, please see copy below (note replies are highlighted in yellow)

(a) How has Brant County reflected the revenues for services to BCPS in its 2011 forecast? Brant County has reflect these revenue as offsets to admin expense. In the 2011 forecast, there was $48,400 was recorded as an offset.

(b) How did Brant County estimate the 2011 revenues for these executive services to BCPS if there have not been time sheets kept in the past? In the past, these amounts were estimated, based on our best estimate of executive management time spent on BCPS activity.

(c) Please show the details of the determination of the revenues for 2011. See attached pdf file for support of the $48,400 as outlined in part (a) above.

(d) Does Brant County expect the same level of revenues for these services to BCPS over the IRM term commencing in 2012? Yes – that's correct.

(e) Are these services provided in accordance with the Affiliate Relationship Code? In the past, we believe that we were not 100% compliant with the ARC. We have taken corrective action by implementing a time sheet function (effective January 1, 2011) for senior management as well taking steps to separate the billing functions of BCP and BCPS activity. This separation was completed in late January 2011.

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c) This question was answered in VECC IR 21b, please see attachment.

Interrogatory # 11

Ref: Exhibit 3, Tab 1, Schedule 3

a) **Please explain the increase in Other Revenue of $135,000 relating to the Green Energy Act initiatives.**

b) **Please provide the cost associated with generating the $135,000 related to the Green Energy Act initiatives. Where have these costs been included in the revenue requirement?**

Response:

a) This question was answered in OEB IR # 12, please see copy below (note replies are highlighted in yellow)

b) This question was answered in OEB IR # 12, please see copy below (note replies are highlighted in yellow)

IR 12

Ref: Exhibit 3 Tab 1 Schedule 3 Exhibit 3 Tab 3 Schedule 1

Issue: Other Utility Operating Income

On Exhibit 3 Tab 1 Schedule 3, Brant County states that there is an increase to other revenue of $135,000 relating to Green Energy Act initiatives. On Exhibit 3 Tab 3 Schedule 1, Brant County shows for the test year Other Utility Operating Income of $135,000.

(a) Is the $135,000 in Other Utility Operating Income Exhibit 3 Tab 3 Schedule 1 for the Green Energy Act initiatives? If not please explain what the $135,000 shown on the exhibit is and where the Green Energy Act initiatives are recorded. Yes

(b) Please state what the initiatives are and show the determination of the $135,000.

Brant County opened up a renewable division – Brant Renewable Energy, which focuses on promoting, educating and facilitating renewable energy projects. It has hired an employee to lead the division and the $135,000 is the expected net margin the company expects to receive before admin expenses. All other expenses of this division are included in the admin expense section of the forecast.

Interrogatory # 12

Ref: Exhibit 3, Tab 2, Schedule 1

a) **Please confirm that the customer figures shown are year-end figures.**

b) **Please explain what is meant by "normalized" average consumption. Please show how the "normalized" figures are calculated. Specifically, please show the calculation of the normalized figure of 79,540,610 kWh for the residential class in 2009.**

c) **Please provide the actual normalized consumption figures (for kWh and kW) for 2010 as shown in the table on page 1.**

d) **Please provide the actual kWh purchases for 2010.**

Response:

a) The customer figures are year end values.

b) The term normalized was used internally and does not have any relevance to the load forecasts submitted. All load and demand projections were done by an independent third party and their report was submitted.

c) The values provided on Exhibit 3, Tab 2, Schedule 1, Page 1 for 2010 are projections provided by our consultants, as referenced above in b) their report was submitted as part of our original submission.

d) The 2010 unbilled analysis has not yet been completed and the requested data is not yet available. Similar data was requested for VECC IR # 4o, please see excerpt from this response below.

2010 Actual Purchases by Class

Year	Month	Residential	GS < 50 kW	GS>50kW (50 to 4,999 kW)		Street Lighting		Sentinel Lighting		Unmetered Scattered Load (USL)
		kWh	kWh	kWh	kW	kWh	kW	kWh	kW	kWh
2010	Jan	7,256,748	3,311,680	13,790,950	30,818	190,765	401	14,705	41	42,412
	Feb	8,326,173	3,677,446	13,954,782	30,003	189,687	401	15,266	40	42,412
	Mar	7,111,749	3,330,317	12,924,353	29,507	156,832	401	15,316	41	42,412
	Apr	6,542,937	3,218,070	13,531,422	26,623	158,431	401	15,188	40	42,412
	May	5,902,349	2,964,516	12,095,217	25,956	134,580	401	15,188	40	41,984
	June	5,568,955	2,646,414	12,869,919	29,389	123,941	400	15,175	40	40,578
	July	6,721,166	2,871,728	13,321,409	28,160	110,590	400	15,016	40	40,578
	Aug	8,179,720	3,151,451	14,384,786	28,800	117,474	401	15,059	40	38,977
	Sep	8,098,259	3,613,813	15,177,097	28,096	131,485	401	14,785	39	38,977
	Oct	6,655,912	3,667,446	14,194,855	28,093	145,010	401	14,884	39	38,977
	Nov	5,566,885	2,941,900	12,964,790	27,000	156,275	401	14,899	39	38,977
	Dec	5,854,951	2,921,833	13,661,932	27,790	178,388	401	14,798	39	38,977

Interrogatory # 13

Ref: Exhibit 3, Tab 2, Schedule 1

a) **Please provide the estimated coefficients for the purchased kWh prediction model equation.**

b) **Please provide all the data used to estimate the equation in a live Excel spreadsheet.**

c) **Please explain why data over only a 5 year period, 2005 through 2009 was used to estimate the equation. Was data prior to 2004 not available?**

d) **Where any other equations estimated and rejected in favour of the one chosen? If yes, please provide the other equations that were estimated, along with the regression coefficients and statistics and data used to estimate them (if they involved data other than that provided in the live Excel spreadsheet requested in (b) above), along with an explanation as to why the equation was rejected.**

e) **Over what period has BCP calculated the average for heating and cooling degree days?**

f) **Please provide the sensitivity analysis that was done showing the impact of using 10 year and 20 year weather trend data.**

g) **What period did Toronto Hydro Electric System Ltd. use for its heating and cooling degree days in EB-2007-0680)?**

h) **How has BCP forecast the increase in Ontario Real GDP? Please provide the forecast increase for each of 2010 and 2011.**

i) **What was the forecast change for Ontario Real GDP for 2009? If this is different than -3.6%, please update the Ontario Real GDP to reflect a -3.6% in for 2009.**

j) Please update the forecast to reflect the average increase calculated below based on the most recent provincial economic forecasts available from the 5 major banks in Canada. Please show the impact on the predicted kWh purchases and the billed kWh (total and by rate class) and the revenue sufficiency of using this updated information.

	Forecast Date	2010	2011
CIBC	Sept. 30, 2010	3.4	1.7
TD	Dec. 17, 2010	3.0	2.4
BMO	Dec. 23, 2010	3.3	2.6
Scotiabank	Dec. 7, 2010	3.2	2.1
RBC	Dec., 2010	3.3	3.1
Average		3.24	2.38

k) How has the BCP target 2011-2014 net cumulative energy savings target of 9.850 GWh (EB-2010-0215/EB-2010-0216 Decision and Order dated November 12, 2010) been reflected in the forecast? In particular, what CDM savings have been reflected in 2009, 2010 and 2011?

l) Please provide all the data and calculations used to calculate the rate class billed energy (kWh) based on the forecast of customer numbers and historical usage patterns per customer.

m) Please provide all the data and calculations used to estimate the billed energy forecast for classes that are weather sensitive that ensures that the total billed energy forecast by class correlates to the total weather normalized billed energy forecast.

n) Please confirm that the "constant" noted on page 3 of the Burman Energy report is a dummy variable used for 2006.

Response:

a)

	Coefficients
Intercept	-14859932.85
Heating Degree Days	6014.761825
Cooling Degree Days	43198.63816
GS>50kW Flag for 2006	5461949.591
Number of Days in Month	391961.5878
Ontario Real GDP Monthly %	145506.6749
CDM Activity Variable	-5.258390622

$$
\begin{aligned}
Purchased\ kWh_{Predicted} &= \left(HDD_{coefficient} * HDD\right) + \left(CDD_{coefficient} * CDD\right) + \left(GS > 50kW\ Flag_{Coef.}\right. \\
&\quad * 'Constant'\big) + \left(Number\ of\ Days\ in\ a\ Month_{Coefficient}\right. \\
&\quad * Number\ of\ days\ in\ a\ month\big) + \left(Ontario\ real\ GDP_{Coefficient} * GDP\right) \\
&\quad + \left(CDM\ Activity_{coefficient} * CDM\ activity\right) + \ Intercept
\end{aligned}
$$

b) Please see attachment

c) No Data prior to 2005 was available.

d) Yes, other equations estimated have been rejected because of the statistical analysis results which did not satisfy criterion in order for the load forecast model to be useful. Although, the R-Squared value and Adjusted-R Squared value exceeded 0.85, the T-STAT from the statistical analysis does not satisfy an accurate load forecasting model using the aforementioned variables in VECC Responses Question 4.b) above.

Please see attachment.

e) The average Heating and Cooling Degree Days were obtained from Environment Canada Weather Online Database, the range of the Data was from 1990 to July 2010. The load forecast model uses an average Heating and Cooling Degree Days (HDD, CDD) for a seven-year period (2003 to 2009).

Sensitivity Analysis:

7 Year HDD CDD Weather Trend							
Month	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days/Month	GS>50kW Flag for 2006	CDM Activity Variable	Predicted kWh
Jan	741.59	0.00	139.04	31	1	204,844	26,367,263
Feb	667.16	0.00	139.40	28	1	220,630	24,713,874
Mar	559.87	0.00	139.77	31	1	236,416	25,214,766
Apr	331.77	0.00	140.14	30	1	252,202	23,421,283
May	179.17	8.81	140.51	31	1	267,988	23,246,743
June	37.40	56.39	140.88	30	1	283,774	24,027,808
July	5.24	89.51	141.25	31	1	299,560	25,628,330
Aug	12.11	71.80	141.62	31	1	315,346	24,875,436
Sep	63.37	18.70	141.99	30	1	331,131	22,469,078
Oct	261.30	2.73	142.36	31	1	346,917	23,332,883
Nov	413.47	0.00	142.74	30	1	362,703	23,709,763
Dec	626.73	0.00	143.11	31	1	378,489	25,355,996
						SUM	292,363,223

10 Year HDD CDD Weather Trend							
Month	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days/Month	GS>50kW Flag for 2006	CDM Activity Variable	Predicted kWh
Jan	725.86	0.00	139.04	31	1	204,844	26,272,676
Feb	643.36	0.00	139.40	28	1	220,630	24,570,739
Mar	547.61	0.00	139.77	31	1	236,416	25,141,034
Apr	327.53	0.79	140.14	30	1	252,202	23,429,899
May	171.52	9.50	140.51	31	1	267,988	23,230,343
June	38.01	57.40	140.88	30	1	283,774	24,075,293
July	5.53	92.07	141.25	31	1	299,560	25,740,503
Aug	10.44	78.57	141.62	31	1	315,346	25,157,821
Sep	67.09	21.82	141.99	30	1	331,131	22,626,225
Oct	262.47	2.61	142.36	31	1	346,917	23,334,799
Nov	414.18	0.00	142.74	30	1	362,703	23,714,025
Dec	640.85	0.00	143.11	31	1	378,489	25,440,933
						SUM	292,734,290

20 Year HDD CDD Weather Trend							
Month	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days/Month	GS>50kW Flag for 2006	CDM Activity Variable	Predicted kWh
Jan	738.27	0.00	139.04	31	1	204,844	26,347,342
Feb	651.13	0.00	139.40	28	1	220,630	24,617,482
Mar	551.64	0.07	139.77	31	1	236,416	25,168,177
Apr	325.27	-1.10	140.14	30	1	252,202	23,334,870
May	176.32	6.26	140.51	31	1	267,988	23,119,390
June	39.12	65.61	140.88	30	1	283,774	24,436,633
July	5.03	94.88	141.25	31	1	299,560	25,859,061
Aug	10.63	78.79	141.62	31	1	315,346	25,168,634
Sep	45.90	21.55	141.99	30	1	331,131	22,487,020
Oct	256.59	3.67	142.36	31	1	346,917	23,345,321
Nov	418.23	0.00	142.74	30	1	362,703	23,738,367
Dec	640.65	0.00	143.11	31	1	378,489	25,439,749
						SUM	293,062,046

g) According to Burlington Hydro 2010 Electricity Distribution Rate Application (EB-2009-0259), Reference is made for a weather normalization forecast method approved by the Board and used by Toronto Hydro Electric System Ltd. The Heating and Cooling Degree Days are taken from 1996 to 2008 in the Burlington Hydro Application. A similar method is used by Burman Energy Consultants for Brant County Power weather normalization load forecast.

20 Year HDD CDD Weather Trend							
Month	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days/Month	GS>50kW Flag for 2006	CDM Activity Variable	Predicted kWh
h) Jan	738.27	0.00	139.04	31	1	204,844	26,347,342
Feb	651.13	0.00	139.40	28	1	220,630	24,617,482
Mar	551.64	0.07	139.77	31	1	236,416	25,168,177
Apr	325.27	-1.10	140.14	30	1	252,202	23,334,870
May	176.32	6.26	140.51	31	1	267,988	23,119,390
June	39.12	65.61	140.88	30	1	283,774	24,436,633
July	5.03	94.88	141.25	31	1	299,560	25,859,061
Aug	10.63	78.79	141.62	31	1	315,346	25,168,634
Sep	45.90	21.55	141.99	30	1	331,131	22,487,020
Oct	256.59	3.67	142.36	31	1	346,917	23,345,321
Nov	418.23	0.00	142.74	30	1	362,703	23,738,367
Dec	640.65	0.00	143.11	31	1	378,489	25,439,749
						SUM	293,062,046

h) Sources:

a. 1988 to 2006: 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance

b. 2007 to 2011: 2010 Ontario Budget March 25, 2010, Ontario Ministry of Finance

Year	Real Ontario GDP (chained $1997)	Growth Rate	Real Ontario GDP (chained $1997 with Base 100 in 1997)	Check Growth Rate
1988	312.0		86.8	
1989	322.5	3.4%	89.7	3.4%
1990	316.9	-1.7%	88.2	-1.7%
1991	304.5	-3.9%	84.7	-3.9%
1992	307.2	0.9%	85.5	0.9%
1993	310.2	1.0%	86.3	1.0%
1994	328.5	5.9%	91.4	5.9%
1995	340.1	3.5%	94.6	3.5%
1996	343.8	1.1%	95.7	1.1%
1997	**359.4**	**4.5%**	**100.0**	**4.5%**
1998	376.7	4.8%	104.8	4.8%
1999	405.0	7.5%	112.7	7.5%
2000	427.9	5.7%	119.1	5.7%
2001	435.4	1.8%	121.1	1.8%
2002	451.1	3.6%	125.5	3.6%
2003	457.4	1.4%	127.3	1.4%
2004	468.9	2.5%	130.5	2.5%
2005	481.5	2.7%	134.0	2.7%
2006	493.5	2.5%	137.3	2.5%
2007	504.9	2.3%	140.5	2.3%
2008	502.4	-0.5%	139.8	-0.5%
2009	485.3	-3.4%	135.0	-3.4%
2010	498.4	2.7%	138.7	2.7%
2011	514.3	3.2%	143.1	3.2%
2012	530.8	3.2%	147.7	3.2%

i) Question 4.h) above, shows a forecast change for Ontario Real GDP for 2009 to be-3.4%. The proposed change of -3.6% Ontario Real GDP for 2009 is used and the updated forecast is shown below.

Year	Real Ontario GDP (chained $1997)	Growth Rate	Real Ontario GDP (chained $1997 with Base 100 in 1997)	Check Growth Rate
1988	312.0		86.81	
1989	322.5	3.4%	89.73	3.4%
1990	316.9	-1.7%	88.17	-1.7%
1991	304.5	-3.9%	84.72	-3.9%
1992	307.2	0.9%	85.48	0.9%
1993	310.2	1.0%	86.31	1.0%
1994	328.5	5.9%	91.40	5.9%
1995	340.1	3.5%	94.63	3.5%
1996	343.8	1.1%	95.66	1.1%
1997	**359.4**	**4.5%**	**100.00**	**4.5%**
1998	376.7	4.8%	104.81	4.8%
1999	405.0	7.5%	112.69	7.5%
2000	427.9	5.7%	119.06	5.7%
2001	435.4	1.8%	121.15	1.8%
2002	451.1	3.6%	125.51	3.6%
2003	457.4	1.4%	127.27	1.4%
2004	468.9	2.5%	130.45	2.5%
2005	481.5	2.7%	133.98	2.7%
2006	493.5	2.5%	137.33	2.5%
2007	504.9	2.3%	140.48	2.3%
2008	502.4	-0.5%	139.78	-0.5%
2009	**484.3**	**-3.6%**	**134.75**	**-3.6%**
2010	**500.0**	**3.24%**	**139.12**	**3.24%**
2011	**511.9**	**2.38%**	**142.43**	**2.38%**
2012	528.3	3.2%	146.98	3.2%

	Forecast Date	2010	2011
CIBC	Sept. 30, 2010	3.4	1.7
TD	Dec. 17, 2010	3	2.4
BMO	Dec. 23, 2010	3.3	2.6
Scotiabank	Dec. 7, 2010	3.2	2.1
RBC	Dec., 2010	3.3	3.1
	Average	3.24	2.38

Predicted Purchase kWh (New GDP Growth Rate used)								
Year	Month	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days/Month	GS>50kW Flag for 2006	CDM Activity Variable	Predicted Purchase kWh
2010	Jan	741.59	0.00	135.33	31.00	1.00	132,925.95	26,205,586.17
	Feb	667.16	0.00	135.63	28.00	1.00	138,028.89	24,598,964.38
	Mar	559.87	0.00	135.93	31.00	1.00	143,131.83	25,146,581.51
	Apr	331.77	0.00	136.23	30.00	1.00	148,234.77	23,399,780.62
	May	179.17	8.81	136.54	31.00	1.00	153,337.72	23,271,880.28
	June	37.40	56.39	136.84	30.00	1.00	158,440.66	24,099,541.75
	July	5.24	89.51	137.14	31.00	1.00	163,543.60	25,746,616.61
	Aug	12.11	71.80	137.45	31.00	1.00	168,646.54	25,040,233.61
	Sep	63.37	18.70	137.75	30.00	1.00	173,749.48	22,680,342.44
	Oct	261.30	2.73	138.06	31.00	1.00	178,852.42	23,590,570.68
	Nov	413.47	0.00	138.37	30.00	1.00	183,955.36	24,013,829.84
	Dec	626.73	0.00	138.67	31.00	1.00	189,058.31	25,706,398.00
2011	Jan	741.59	0.00	139.04	31.00	1.00	204,844.21	26,367,262.75
	Feb	667.16	0.00	139.40	28.00	1.00	220,630.11	24,713,873.64
	Mar	559.87	0.00	139.77	31.00	1.00	236,416.01	25,214,765.92
	Apr	331.77	0.00	140.14	30.00	1.00	252,201.91	23,421,282.83
	May	179.17	8.81	140.51	31.00	1.00	267,987.81	23,246,743.06
	June	37.40	56.39	140.88	30.00	1.00	283,773.72	24,027,808.05
	July	5.24	89.51	141.25	31.00	1.00	299,559.62	25,628,329.52
	Aug	12.11	71.80	141.62	31.00	1.00	315,345.52	24,875,436.37
	Sep	63.37	18.70	141.99	30.00	1.00	331,131.42	22,469,078.45
	Oct	261.30	2.73	142.36	31.00	1.00	346,917.32	23,332,883.49
	Nov	413.47	0.00	142.74	30.00	1.00	362,703.22	23,709,763.15
	Dec	626.73	0.00	143.11	31.00	1.00	378,489.13	25,355,995.69

Rate Class Energy Model (With New Economic Rate)										
Year	kWh Purchases	Modeled kWh Purchases	Loss Factor	Total Billed	Residential	GS < 50 kW	GS > 50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)
2005	236,756,080	237,105,183	1.0707	221,115,207	81,427,289	36,179,422	101,120,635	1,645,693	210,113	532,055
2006	242,722,450	241,529,155	1.0957	221,518,681	79,560,842	34,406,201	105,111,506	1,707,240	208,256	524,636
2007	306,747,610	303,227,205	1.0658	287,802,804	80,124,626	33,769,287	171,480,226	1,712,240	196,420	520,005
2008	297,492,850	298,065,175	1.0570	281,438,922	79,456,965	35,036,376	164,540,705	1,714,986	187,414	502,476
2009	285,044,124	288,836,397	1.0506	271,310,355	79,540,610	36,124,082	153,259,553	1,709,467	180,387	496,256
2010		293,687,170	1.0482	280,182,380	79,960,664	38,563,460	159,226,689	1,711,505	220,581	499,482
2011		297,531,381		283,849,820	84,556,802	41,259,213	155,618,215	1,707,054	215,167	493,370

The table above shows a weather corrected kWh for each class type for 2010 and 2011.

k) The CDM target savings in 2009, 2010, 2011 is that set by the “Directive”, dated March 31,2010 to the Ontario Energy Board (the “Board”) with regard to electricity conservation and demand management (“CDM”) Targets to be met by licensed electricity distributors. At the time the load forecast was conducted the CDM targets for the years in question considers 14 GWh and not the revised 9.85 GWh target.

l) Note: Refer to Question 4.L) in the VECC Response for the Average Customer Number table 1.

Usage Per Customer						
Year	Residential	GS < 50 kW	GS>50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)
2005						
2006	10,348	27,602	922,031	645	1,093	9,052
2007	10,243	28,141	1,551,857	646	1,388	9,204
2008	10,032	29,136	1,523,525	650	1,353	9,220
2009	9,902	28,934	1,478,982	648	1,007	9,475
2010	9,803	29,392	1,456,798	648	997	9,537
2011	9,705	29,857	1,434,946	649	987	9,599

Usage Per Customer = Class Type kWh / Average Customer Number (by Class Type)

Example : 2006 Residential Usage Per Customer Calculation

Usage Per Customer = Residential kWh / Residential Customer Number

Usage Per Customer = 79,560,842 / 7,689 = 10,348

Year	Residential	GS < 50 kW	GS>50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)
2005						
2006						
2007	0.99	1.02	1.68	1.00	1.27	1.02
2008	0.98	1.04	0.98	1.01	0.97	1.00
2009	0.99	0.99	0.97	1.00	0.74	1.03
Geometric Mean	0.99	1.02	0.99	1.00	0.99	1.01

Ratio Between the Years:

To obtain a Geometric Mean in order to calculate Usage Per Customer for 2010, 2011

Rate Class Energy Model										
Year	kWh Purchases	Modeled kWh Purchases	Loss Factor	Total Billed	Residential	GS < 50 kW	GS > 50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)
2005	236,756,080	237,105,183	1.0707	221,115,207	81,427,289	36,179,422	101,120,635	1,645,693	210,113	532,055
2006	242,722,450	241,529,155	1.0957	221,518,681	79,560,842	34,406,201	105,111,506	1,707,240	208,256	524,636
2007	306,747,610	303,227,205	1.0658	287,802,804	80,124,626	33,769,287	171,480,226	1,712,240	196,420	520,005
2008	297,492,850	298,065,175	1.0570	281,438,922	79,456,965	35,036,376	164,540,705	1,714,986	187,414	502,476
2009	285,044,124	288,836,397	1.0506	271,310,355	79,540,610	36,124,082	153,259,553	1,709,467	180,387	496,256
2010		293,500,326		274,447,754						
2011		292,363,223		273,384,466						

Loss Factor = 1 + (kWh Purchases - Total Billed) / (Total Billed)

The numbers in the table above are tabulated in order to forecast the Usage Per Customer for 2010 and 2011 for the different classes. For example, the Residential Class ratio for 2007 is obtained by taking the 2007 Residential Usage Per Customer (= 10,243) divided by 2006 Residential Usage Per Customer (=10,348).

Therefore, 2007 Residential ratio is = 10,243 / 10,348 = 0.98985 = 0.99. A similar calculation is done for the other classes.

Non-Weather Corrected Forecast							
Year	Residential	GS < 50 kW	GS>50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)	Total Billed
2010	80,090,431	38,626,044	159,345,849	1,711,505	220,581	499,482	280,493,891
2011	80,456,513	39,258,491	152,041,991	1,707,054	215,167	493,370	274,172,586

For the Non-Weather Correct Forecast the following is done, the Usage Per Customer multiplied-by Average Customer Number. Fore Example, to obtain 2010 Residential Non-Weather Corrected Forecast we have:

2010 Residential Customer Number = 8,170
2010 Residential Usage Per Customer = 9,803
2010 Residential Non-Weather Corrected Forecast = 8,170 * 9,803 = 80,090,431

% Weather Sensitive								
Year	65%	65%	30%	0%	0%	0%		
	Residential	GS < 50 kW	GS>50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)	TOTAL	Adjustment
2010	52,058,780	25,106,929	47,803,755	0	0	0	124,969,463	-6,046,137
2011	52,296,734	25,518,019	45,612,597	0	0	0	123,427,350	-788,120

Using Hydro One RUN Files, Burman Energy Consultants obtained the Percentage weather sensitivity of each class. For example, the Residential class sensitivity is obtained by taking the Non-Weather Corrected forecast and multiply-by 65%. Calculation: 80,090,431 * 65% = 52,058,780

The Adjustment Factor in the % Weather Sensitive table is obtained by taking the total billed kWh from the Rate Energy Model Table above and subtracting it from the Non-Weather Corrected total kWh.

For example, 2010 Adjustment is calculated by:

274,447,754 – 280,493,891 = -6,046,137

Allocation Weather Sensitive Amount							
Year	Residential	GS < 50 kW	GS>50kW (50 to 4,999 kW)	Street Lighting	Sentinel Lighting	Unmetered Scattered Load (USL)	Total
2010	-2,518,651	-1,214,696	-2,312,789	0	0	0	-6,046,137
2011	-333,930	-162,940	-291,250	0	0	0	-788,120

The allocation of weather sensitive amounts in the table above is calculated by:

Taking the % Weather Sensitive amount for the particular class and then dividing-by the Total % weather Sensitive amount and then multiply by the Adjustment Factor. For example, 2010 Residential Allocation Weather Sensitive Amount is (52,058,780 / 124,969,463) * (-6,046,137) = -2,518,651

m) Refer to Question L) above.

n) The Constant '1' noted on page 3 is a dummy variable used from November 2006 to December 2011. This is done due to the increase in kWh consumption for the GS>50kW class.

Interrogatory # 14

Ref: Exhibit 3, Tab 2, Schedule 1 &
Exhibit 8, Tab 1, Schedule 5

a) **Please explain the difference in the loss factors between that shown on page 4 of the Burman Energy report and those shown in Exhibit 8, Tab 1, Schedule 5.**

b) **Please update the loss factors in Exhibit 8, Tab 1, Schedule 5 to include data for 2005.**

c) **Please update the billed kWh forecast for 2011 using the average loss factor for 2005 through 2009 from Exhibit 8, Tab 1, Schedule 5.**

Response:

a) The reason for the discrepancy in Loss Factor between the data shown on Exhibit 8, Tab1, Schedule 5 and the Burman Energy Report is due to variance between wholesale kWh in and billed kWh for 2006. Also, a variance between Billed kWh in 2007, 2008, and 2009 in the Burman Energy report and Exhibit 8, Tab1, Schedule 5.

b) BCP does not have confidence in the 2005 historical data and therefore suggest it is of little value and will not be providing the requested data. If the desire is to use a 5-year loss factor average, BCP suggests using a 2006 – 2010 period. 2010 loss factor data can be provided when available.

c) BCP has made significant improvements/investment in its infrastructure to improve the line losses. As a result, we believe that the 2010 and 2011 estimate is more accurately represented based on data from 2009 and not the 5 year average from 2005 – 2009.

Interrogatory # 15

Ref: Exhibit 3, Tab 2, Schedule 2

a) **Please update the number of year-end customers shown in the table on page 2 to reflect the actual data for 2010. If 2010 year-end figures are not yet available, please provide a table that shows the number of customers at the end of November, 2010 and November, 2009, along with the difference between these two figures.**

b) **Please provide the actual 2010 kWh consumption data (if available) in the same level of detail as shown in the table on page 2.**

c) **Please provide the actual 2010 kW consumption data (if available) in the same level of detail as shown in the table on page 3. If complete 2010 data is not yet available, please provide the actual year-to-date figures through November 2010, along with the corresponding figures for the same period in 2009.**

Response:

a) Please see attached.

b) Please see attached.

c) Please see attached.

Interrogatory # 16

Ref: Exhibit 3, Tab 3, Schedule 1

a) **Please update the Other Operating Revenue table to reflect actual figures for 2010. If actual figures for 2010 are not available, please provide a table in the same level of detail as shown for the other operating revenue that shows the most recent year-to-date actual figures for 2010, along with the year-to-date figures for the corresponding period in 2009.**

b) **Please explain the reduction between 2009 and 2010 for Specific Service Charges, Misc. Service Revenues and for Misc. Non-Operating Income.**

c) **Are all of the revenues and expenses shown in accounts 4375 and 4380 related to CDM? If not, please provide a breakdown of accounts 4375 and 4380 between CDM related figures and non-CDM related figures for each of 2006 through 2011.**

d) **Please explain why there are no gains from disposition of utility and other plant (account 4355) for 2011. In particular, where does BCP account for the proceeds of disposition of the vehicles forecast to be replaced in 2011?**

Response:

a) Please see attached – note the 2010 numbers are preliminary and subject to yearend adjustments and auditor review.

b) Misc. Service charges – amounts has increased (no reduction) due to increased activity with respect to connections/disconnections. The trend in this area has eased off after the new customer service rules which came into effect in Oct 2010.

   Late Payment charges – amount has increased reflecting increased collection efforts and 3 day "grace period" before a penalty is applied.

   Misc. Non-operating income. – The nominal decrease is not material.

c) The amounts in accounts 4375 and 4380 are all CDM related.

d) The two vehicles that are expected to be replaced in 2011 are the two GMC pickups. We expect the proceeds (if any) to be very small and not material.

Interrogatory # 17

Ref: Exhibit 3, Tab 3, Schedule 2

a) **Please split the $135,000 noted under other utility operating income between the new energy generation project and the revenue from MicroFit generators.**

b) **How many MicroFit generators does BCP currently have? How many are expected by the end of 2011?**

Response:

a) The $135,000 is all from the new energy generation project. We do not expect the income from MicroFit generators to be material, and accordingly have not included this for purposes of this rate case.

b) We currently have 7 connections.

Interrogatory # 18

Ref: Exhibit 4, Tab 1, Schedule 1

With respect to the 2010 additional staff additions:

a) **Please confirm that both of these positions were filled in 2010.**

b) **What is the total cost (including benefits) associated with each of these positions in the 2011 test year?**

c) **Please explain the relationship between the $135,000 in other revenue to the CDM/Green Energy Coordinator (or to the Smart Meter Data Analyst as it is not clear which position is related to this other revenue).**

Response:

a) Yes – these positions were both filled in 2010.

b) The total cost including benefits is approximately $120,000 in 2011.

c) The $135,000 in revenue is related to the Sales Manager (in 2011) related to the renewable energy division. The expected revenue will more than offset the expected cost. See also OEB IR 12.

Interrogatory # 19

Ref: Exhibit 4, Tab 1, Schedule 1

With respect to the 2011 additional staff additions:

a) **Please provide the total cost (including benefits) associated with each of these positions that is included in the test year revenue requirement.**

b) **Please provide the projected hiring date for each of the positions.**

Response:

a)

- Sales Manager – total costs including benefits $75,181 – hired Nov 10
- Office Manager - total costs including benefits $62,475 – hired Jan 11
- GIS/GPS Manager - total costs including benefits $80,000 – estimated hire Mar 11 -
- Engineering Manager - total costs including benefits $110,000 – estimated hire Apr 11.
- Jr. Collector - total costs including benefits $51,000 – estimated hire Mar 11

b) see answer to part a.

Interrogatory # 20

Ref: Exhibit 4, Tab 1, Schedule 1

With respect to the Sales Manager position please provide the following:

a) **Please describe the renewable energy division business. Why is this business included in the regulated utility?**

b) **Where is the offsetting revenue shown that is anticipated to offset this cost?**

Response:

a) This is allowed by the Green Energy Act. The company will assess over the next several years as to whether it will remained “housed” within the realm of the LDC.

b) This is the aforementioned $135,000 as described in IR 18 above.

Interrogatory # 21

Ref: Exhibit 4, Tab 1, Schedule 1

a) **Please provide more specific details as to the need for an Office Manager.**

b) **Will the Engineering Manager replace both the Operations Manager and Operations Superintendent over the next 2 to 3 years when the current employees in these positions retire? If not, what are the succession plans for these positions?**

c) **Please provide the total cost (including benefits) associated with each of the Operations Manager and the Operations Superintendent in the 2011 test year.**

d) **What is the expected annual cost (including benefits) associated with the Engineering Manager?**

e) **Please provide the reduction in collection costs included in the 2011 revenue requirement as a result of the Jr. Collection position.**

f) **Please confirm that BCP is requesting an increase of $2,800 associated with LEAP from what is currently included in the OM&A expense.**

g) **Please reconcile the addition of 3 new staff members noted on page 4 with the 5 additions shown on pages 1 and 2.**

h) **Is the Office Manager role noted on page 4 the same Office Manager role noted on page 1?**

Response:

a) The office manager, or more correctly newly titled Team Leader, is a position which BCP previously had in place however chooses not to fill when the individual resigned in 2007. During 2009 a need was identified to revisit this decision, an opportunity to enhance the customer experience was required, process management/ simplifications were necessary, the need for the development and implementation of individual measures and with that accountability was required. Further the clerical team was separated into 3 distinct groups supervised by staff from operations, finance as well as the executive assistant with resultant mixed management styles, messages and differing priorities. The need to address these issues, introduce cross training and to focus on the new accountabilities driven by the provincial smart meter initiative caused the decision to reinstate this position. Additionally the accountability for implementation and management of the newly legislated collections processes have been assigned to this person as has the repatriation of this work from a third party to better serve our customers.

b) The Engineering Manager will not replace both of these positions upon retirement, however it is expected that if successful the individual will be a candidate for the operations manager's position upon retirement. With two senior staff expected to retire, BCP believed it to be prudent to strengthen the knowledge base of the senior team, thereby ultimately reducing our outsourcing requirements while introducing an individual who has appropriate certifications and skills to potentially step into the operations manager role in the future. This individual would also be expected to have a strong understanding of GIS mapping thereby ensuring local knowledge is appropriately transferred to a digital database for future use. With respect to the operations superintendent role we hope to fill this role internally through a natural training and coaching progression process.

c)

- Operations Manager - $135,524
- Operations Superintendent - $118,035

d) See 19a above.

e) The Jr. Collector position will result in a reduction of approximately $30,000.

f) Yes – that is correct – necessary in order to meet 0.12% of our revenue requirement.

g) The additions in 2011 are 5 new staff members. There are cost reductions and revenue increase which off-set two of these positions. Renewable Energy Co-ordinator (originally entitled Sales Manager in the application) is off-set by revenue increases included in the CoS and the Jr. Collector position is off-set by a reduction in outsourced collection costs.

h) Yes

Interrogatory # 22

Ref: Exhibit 4, Tab 2, Schedule 1

a) **Pease provide further details related to account 5645 and the decrease in costs in 2010 and 2011 as compared to the level recorded in 2009.**

b) **With respect to the $856,850 in account 5645 for 2009 the evidence indicates that this amount reflects the total amount of the expense and that there is a revenue offset recorded in the revenue section of the filing. Please indicate where in the evidence this revenue offset is shown and identified.**

Response:

The 2009 expense reported in the RRR Trial Balance Filing for USOA 5645 of $856,850 reflects the gross costs of employee pension and benefit costs.

The 2009 RRR Trial Balance filing includes a revenue offset in USOA 5695 OM&A Contra of $677,529 which was not included in the 2009 COS filing under the General and Administrative Costs classification. This results in an over statement of costs for 2009.

The revenue offset does not exactly equal the gross costs primarily due to under recovery of V&E and Stores costs.

The 2010 and 2011 costs are shown as zero as a result of the budgeting process. Overhead burden rates were established and these costs are directly contained in the gross costs of the individual USOA accounts.

Interrogatory # 23

Ref: Exhibit 4, Tab 7, Schedule 1

a) **How were the depreciation/amortization costs calculated in the 2006 rates proceeding? In particular, were they based on 2004 actual costs? If yes, please explain whether the 2004 costs reflected application of a full year of depreciation on assets added during 2004 or did the costs reflect the application of depreciation in the month following the in-service date of the application?**

b) **Please illustrate how the depreciation expense was calculated in 2006 through 2010 in light of the following examples for 2010:**
   i) **account 1860 appears to have depreciation calculated based on the total for depreciation ($2,851,714) at 4% (i.e. full year depreciation calculated on the 2010 additions);**
   ii) **account 1855 appears to be underestimated since 4% of the net for depreciation ($2,275,749) is more than the depreciation shown, and does not account for the additions in 2010; and**
   iii) **account 1850 appears to be underestimated since 4% of the net for depreciation ($3,744,312) is more than the depreciation shown, and does not account for the addition in 2010.**

c) **Please provide a live Excel spreadsheet that shows the calculation of the depreciation expense for each of 2009, 2010 and 2011.**

d) **Please provide a version of Appendix 2-M for the 2011 test year that explicitly includes only one-half of the 2011 capital additions in the calculation of the depreciation expense.**

Response:

a) The depreciation costs in 2006 rates were based on 2004 actual costs and the 2004 additions were depreciated using the half year rule.

b – d)
BCP has populated Appendix 2-M based on actual costs. BCP has fully utilized the ½ year rule on both capital expenditures and amortization costs in the rate base determination (please see Exhibit 2, Tab 1, Schedule 2, Page 1)

Interrogatory # 24

Ref: Exhibit 4, Tab 8, Schedule 1

a) **Please explain the derivation of the 2011 tax rate of 28.50%. Please explain why the 2011 tax rate should not be 28.25% reflecting a federal tax rate of 16.50% and a provincial tax rate of 11.75%.**

b) **Please confirm that the Ontario surtax claw-back on the first $500,000 of taxable income was eliminated effective July 1, 2010 and that the provincial income tax rate on the first $500,000 of taxable income was reduced to 4.50%.**

c) **Has BCP included a tax reduction of $36,250 related to the Ontario small business tax rate on the first $500,000 in taxable income (calculated as $500,000 times the difference between 11.75% and 4.50%)? If not, why not?**

d) **Is BCP aware that the Ontario capital tax was eliminated effective July 1, 2010?**

e) **Will BCP have any positions eligible for the Ontario apprenticeship training tax credit, cooperative education tax credit and/or the federal apprenticeship job creation tax credit? If yes, please identify the number of positions eligible for each of the credits in 2011.**

Response:

a) BCP has recalculated the PILS provision utilizing the tax table set out in Board Staff Interrogatory 20. The recalculation excludes any capital taxes. See the response to this interrogatory.

b) Please see OEB IR 20. – excerpt below

c) Please see OEB IR 20 – excerpt below

d) Please see OEB IR 20 – excerpt below

IR 20

Ref: Exhibit 4 Tab 8 Schedule 1 page 2

Issue: Income Taxes

BCP has used an incorrect income tax rate to calculate its PILs. In addition, an amount of $24,718 is included as Ontario Capital Tax as part of the PILs determination. (Note: The Ontario Capital Tax was repealed effective July 1, 2010.)

(a) Please recalculate the PILs amount using the correct income tax rate from the Table below, and excluding the Ontario Capital Tax.

	January to June 30th	July 1st to December 31st	January to June 30th	July 1st to December 31st	January to June 30th	July 1st to December 31st
Income Range	**$0 to $500,000**	**$0 to $500,000**	**$500,0001 to $1,500,000**	**$500,0001 to $1,500,000**	**> $1,500,000**	**> $1,500,000**
Federal Rate	11.00%	11.00%	16.50%	16.50%	16.50%	16.50%
Ontario Rate**	4.50	4.50	4.50	4.50	12.00%	11.50%
Income Tax Rate	15.50%	15.50%	21.00%	21.00%	28.50%	28.50%
Blended Rate	15.50%		21.00%		28.25%	
Capital Tax Rate 1	Repealed					
Surtax 2	Repealed					
Ontario Capital Tax Exemption	Repealed					

See revised PILS determination below

Brant County Power
PILS Determination - Response to Board Staff IR #20

	2011 Test
Determination of Taxable Income	
Regulatory Net Income (after tax ROE)	$888,212
Book to Tax Adjustments	
Additions to Accounting Income:	
Depreciation and amortization	$896,214
Other Additions	
Total Additions	$896,214
Deductions from Accounting Income:	
Capital Cost Allowance	$1,496,414
Cumulative eligible capital deductions (see table below)	$96,345
Other Deductions	
Total Deductions	$1,592,759
Regulatory Taxable Income	$191,667
Corporate Income Tax Rate	15.50%
Regulatory Income Tax	$29,708
Calculation of Utility Income Taxes	
Income Taxes (prior to gross-up)	$29,708
Ontario Capital Tax	$0
Large Corporation Tax	$0
Total Taxes	$29,708
Gross UP factor (1-tax rate)	84.50%
Taxes after Gross-up	
Income Taxes (15.5% gross-up)	$35,158
Ontario Capital Tax	$0
Large Corporation Tax	$0
Total taxes with Gross up	$35,158

Note: Utilizing tax table set out in Board Staff IR 20
blended tax rate for taxable income up to $500,000 is 15.5%

Brant County Power	
Cumulative Eligible Capital Deduction	
Balance December 31, 2009 per tax return	1,479,958
2010 Deduction - 7%	-103,597
Balance December 31, 2010	1,376,361
2011 Deduction - 7%	-96,345
Balance December 31, 2011	1,280,016

e) No.

Interrogatory # 25

Ref: Exhibit 4, Tab 8, Schedule 1 &
Exhibit 6, Tab 1, Schedule 1

Please explain the difference in the regulatory net income (before tax) of $888,212 shown in Exhibit 4, Tab 8, Schedule 1 on page 2 with utility income before taxes of $989,329 shown in Exhibit 6, Tab 1, Schedule 1, along with a figure of $88,2312 shown as the utility income after taxes in the same schedule.

Response:

The Exhibit 4, Tab 8, Schedule 1 reference to “Regulatory Net Income (Before Tax)” of $888,212 is incorrectly labelled. This value represents the after tax rate of return based on the applied for rate base, deemed capital structure and rates of return. This value is consistent throughout the application.

Interrogatory # 26

Ref: Exhibit 4, Tab 8, Schedule 1

Please explain the lower opening balance in the 2010 CCA schedule shown on page 67 than the UCC shown at the end of 2009 on Schedule 8 of the 2009 income tax return.

Response:

Please see revised CCA schedule for 2010 that reconciles to 2009 Tax return.

The changes result in a 2011 CCA difference of approximately $8,000 which will have an impact on 2011 tax projections. This change will be included in the final rate determinations after OEB approval.

2010					
T2S(8)	Opening	Additions	Rate	CCA	Ending
Class 1	9,005,855		4%	360,234	8,645,621
Class 1	127,488	10,000	6%	7,949	129,539
Class 8	137,221	28,500	20%	30,294	135,427
Class 10	535,115	325,000	30%	209,285	650,831
Class 12	-		100%	-	-
Class 17	23,699		8%	1,896	21,803
Class 45	8,543		45%	3,844	4,699
Class 47	6,490,746	2,660,770	8%	625,690	8,525,826
Class 50	22,159	162,300	55%	56,820	127,639
	$16,350,827	$3,186,570		$ 1,296,013	$18,241,384

2011					
T2S(8)	Opening	Additions	Rate	CCA	Ending
Class 1	8,645,621		4%	345,825	8,299,796
Class 1	129,539	60,000	6%	9,572	179,966
Class 8	135,427	10,500	20%	28,135	117,791
Class 10	650,831	130,000	30%	214,749	566,081
Class 12	-		100%	-	-
Class 17	21,803		8%	1,744	20,059
Class 45	4,699		45%	2,114	2,584
Class 47	8,525,826	2,512,654	8%	782,572	10,255,907
Class 50	127,639	180,000	55%	119,701	187,938
	$18,241,384	$2,893,154		$1,504,414	$ 19,630,124

Interrogatory # 27

Ref: Exhibit 6, Tab 1, Schedule 1

Please show how a reduction in utility income before income taxes of $300,388 results in a reduction in income taxes (grossed up) of $266,452.

Response:

The existing rates column, in the referenced exhibit, was a straight proxy calculated using a 28.5% tax rate estimation and not based on the submitted detailed PILS determination in Exhibit # 4.

The $266,452 difference is comparing a proxy 2011 PILS value based on existing rates ($367,569) to the detailed PILS determination ($101,117) which can be found in Exhibit 4.

Interrogatory # 28

Ref: Exhibit 7, Tab 1, Schedule 1

Please explain why Brantford Power with a delivery point demand of 1,067 kW is considered a GS < 50 kW customer rather than a GS > 50 kW customer.

Response:

This question was asked by Board Staff IR # 23 a. See response below.

Board Staff Interrogatories

Brant County Power Inc.
2011 Electricity Distribution Rates Application
EB-2010-0125

IR 23

Ref: Exhibit 7 Tab 1 Schedule 1 p.2

Issue: Embedded Service to Brantford

Board staff notes that Brant County has included Brantford Power Distribution Inc. ("Brantford") as a GS<50 customer.

(a) Please state why, with a demand of 1,067 kW, Brant County has included them in a class for customers with less than 50 kW demand?

Response:

a) The Brantford load references of 1,067 kW is an annual demand value. The monthly average value calculates to less than 22 kW per month.

The descriptions of GS < 50 and GS >50 use the average monthly peak demand of 50 kW has the threshold for customer class assignment. As applied for Brantford is a GS < 50 kW customer.

Interrogatory # 29

Ref: Exhibit 7, Tab 3, Schedule 1 &
Exhibit 8, Tab 1, Schedule 7

a) **Please provide the Board approved ranges for the revenue to cost ratios for each rate class shown.**

b) **Please assume that the revenue-to-cost ratios are adjusted as follows: street light and sentinel light are adjusted as proposed by BCP, unmetered scattered load is reduced to 120%, GS < 50 kW remains at 94% and residential is increased from 81% to 85%. What is the resulting revenue-to-cost ratio for the GS > 50 kW class?**

c) **Based on the revenue-to-cost ratios identified in (b) above, please provided a revised Table 8a from Exhibit 8, Tab 1, Schedule 7 showing the customer impacts.**

Response:

a) BCP is not aware of the actual Board Approved ranges for revenue to cost ratios. Board Staff provided targets or guidelines for revenue to cost ratios and BCP believes they are as follows:

	Residential	GS < 50	GS 50 - 4,999	Street Light	Setinel Lights	Unmetered
Board Staff Min RC%	85.00%	80.00%	80.00%	70.00%	70.00%	80.00%
Board Staff Max RC%	115.00%	120.00%	180.00%	120.00%	120.00%	120.00%

b) Below would be the specific customer classes RC% under the requested assumptions.

	Residential	GS < 50	GS 50 - 4,999	Street Light	Setinel Lights	Unmetered
Class Specific DRR %	85%	94%	111%	70%	70%	120%

c) See requested table below.

Rate Classification	Minimum Change %	Minimum Change $	Maximum Change %	Maximum Change $
Residential	1.65%	$0.45	2.84%	$8.04
GS<50kW	0.01%	$0.25	2.99%	$4.48
GS - 50kW to 4,999kW	-3.42%	-$106.79	-4.19%	-$1,253.93
Unmetered	n/a	n/a	2.74%	$3.13
Sentinel	n/a	n/a	44.98%	$13.71
Streetlighting	n/a	n/a	227.36%	$46.58
MicroFit Generator	No Change			

Interrogatory # 30

Ref: Exhibit 8, Tab 1, Schedule 1

Is BCP aware of other distributors that have the proposed wording in their definitions referring to the monthly average demand as proposed by BCP? If yes, please provide examples. If no, how do other distributors define the GS < 50 and GS > 50 kW classes?

Response:

BCP is not aware of other distributors that have proposed the specific wording provided by BCP. BCP has provided certain examples below which highlight the fact there are slightly different wordings which may cause confusion or result in different approaches. Further, where averages are taken the description of the period of time may be different depending upon the distributor. (e.g. a 12month period, a 12 months calendar period or some longer period). BCP would note that the Distribution System Code permits a re-classification with 5 consecutive months of out of class demands.

Burlington Hydro EB-2009-0259

GS<50kW

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose **monthly average peak demand** during a calendar year is less than, or forecast by BHI to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

GS>50kW and less than 4,999kW

This classification applies to general service customers with a **monthly average peak demand** during a calendar year equal to or greater than, or is forecast by BHI to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Brantford EB-2009-0214

G.S. 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose **average monthly maximum demand** used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Cambridge and North Dumphries EB-2009-0260

G.S. 50 to 999 kW SERVICE CLASSIFICATION

General Service refers to the supply of electrical energy to business customers, to bulk-metered residential buildings and to combined residential and business or residential and agricultural buildings. Apartment buildings that are bulk metered will be billed at the appropriate General Service rate. This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Lakefront Utilities EB-2009-02333

G.S. 50 to 2,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose **monthly average peak demand** is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Hydro One Networks EB-2009-0096 (Village of Arkona PUC)

General Service

This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are
demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.
Hydro One establishes billing determinants for demand customers at the greater of 100 per cent
of kW and 90 per cent of kVA where kVA metering is installed. When a Customer's power factor
is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be
used for measuring and billing.

Sioux Lookout EB-2009-0249

GS 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered
General Service >1,000 to 4,999 kW interval metered.

Further servicing details are available in the distributor's Conditions of Service.

Oshawa PUC EB-2009-0240

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. Note that for statistical purposes the following sub-classifications apply:

General Service 50 to 200 kW

General Service over 200 kW

Further servicing details are available in the distributor’s Conditions of Service.

Interrogatory # 31

Ref: Exhibit 8, Tab 1, Schedule 1 &
Exhibit 2, Tab 4, Schedule 1 &
Exhibit 1, Tab 1, Schedule 6

a) Please reconcile the statement of the annual current cost of approximately $375,000 now charged for distribution by Brantford Power Inc. with the figure shown in the working capital allowance calculation in Exhibit 2, Tab 4, Schedule 1.

b) If the difference is related to amounts paid to Hydro One, please indicate why BCP is not shown as embedded via Hydro One in Exhibit 1, Tab 1, Schedule 6.

Response:

a) Brant County has included the Brantford Distribution Charges in the LV expense line USoA 4750. Brant County also pays Hydro 1 LV charges as well. The total LV expense of $682,065 is comprised of Brantford charges of $375,000 and Hydro One charges of $307,065 .

b) Brant County Power is embedded in Hydro 1 distribution system. This was an omission on BCP part.

Interrogatory # 32

Ref: Exhibit 8, Tab 1, Schedule 5

Please update the table shown on page 2 to include actual data for 2010. If complete 2010 data is not yet available, please update the table to reflect the most recent year-to-date information for 2010 that is currently available.

Response:

BCP has yet finalized our 2010 audit process and any loss factor determination would be premature as unbilled calculations have not been finished.

Interrogatory # 33

Ref: Exhibit 9, Tab 1, Schedule 2

The evidence indicates that BCP will re-file the variance account section of its application using December 31, 2010 audited balances. When does BCP expect to file this information?

Response:

BCP expects to file these variance accounts on or before March 31, 2011.

Interrogatory # 34

Ref: Exhibit 9, Tab 1, Schedule 2 &
Exhibit 10, Tab 1, Schedule 1

Please explain why BCP proposes to rebate balances in the deferral accounts to customers over a two year period, but collect the LRAM/SSM balances over only one year.

Response:

This was proposed to avoid rate shock to customers. The deferral / variance account rate credit is much larger than the LRAM / SSM recovery. BCP is not opposed to spreading the LRAM / SSM rate over the same period.

Energy Probe IR # 3a Attachment

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Brant County Power	(1)
File Number:		
Rate Year:	2011	Version: 2.11

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) Pale yellow cells represent drop=down lists

(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

		Data Input			(1)
		Initial Application		(7)	Per Board Decision	
1	**Rate Base**					
	Gross Fixed Assets (average)	$28,545,689		$ 28,545,689	$28,545,689	
	Accumulated Depreciation (average)	($10,036,965)	(5)	-$ 10,036,965	($10,036,965)	
	Allowance for Working Capital:					
	Controllable Expenses	$3,531,485		$ 3,531,485	$3,531,485	
	Cost of Power	$23,366,671		$ 23,366,671	$23,366,671	
	Working Capital Rate (%)	15.00%		15.00%	15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$6,209,190				
	Distribution Revenue at Proposed Rates	$5,908,802				
	Other Revenue:					
	Specific Service Charges	$117,920				
	Late Payment Charges	$97,000				
	Other Distribution Revenue	$291,406				
	Other Income and Deductions	$51,000				
	Operating Expenses:					
	OM+A Expenses	$3,839,038		$ 3,839,038	$3,839,038	
	Depreciation/Amortization	$896,214		$ 896,214	$896,214	
	Property taxes	$6,000		$ 6,000	$6,000	
	Capital taxes	$24,718				
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($696,545)	(3)			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$54,625				
	Income taxes (grossed up)	$76,399				
	Capital Taxes	$24,718	(6)	(6)		(6)
	Federal tax (%)	16.50%				
	Provincial tax (%)	12.00%				
	Income Tax Credits					
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(2)	(2)		(2)
	Common Equity Capitalization Ratio (%)	40.0%				
	Prefered Shares Capitalization Ratio (%)					
		100.0%				
	Cost of Capital					
	Long-term debt Cost Rate (%)	5.68%				
	Short-term debt Cost Rate (%)	2.07%				
	Common Equity Cost Rate (%)	9.85%				
	Prefered Shares Cost Rate (%)					

Notes:

Data inputs are required on on this Sheet A. Data Input Sheet, and on Sheets 7A and 7B, for Bill IMpacts. Data on this input sheet complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6) Not applicable as of July 1, 2010
(7) Select option from drop-down list by clicking on cell M10. This columnallows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outsome of any Settlement Process can be reflected.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$28,545,689	$ -	$28,545,689	$ -	$28,545,689
2	Accumulated Depreciation (average)	(3)	($10,036,965)	$ -	($10,036,965)	$ -	($10,036,965)
3	Net Fixed Assets (average)	(3)	$18,508,724	$ -	$18,508,724	$ -	$18,508,724
4	Allowance for Working Capital	(1)	$4,034,723	$ -	$4,034,723	$ -	$4,034,723
5	**Total Rate Base**		$22,543,447	$ -	$22,543,447	$ -	$22,543,447

	(1) **Allowance for Working Capital - Derivation**						
6	Controllable Expenses		$3,531,485	$ -	$3,531,485	$ -	$3,531,485
7	Cost of Power		$23,366,671	$ -	$23,366,671	$ -	$23,366,671
8	Working Capital Base		$26,898,156	$ -	$26,898,156	$ -	$26,898,156
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$4,034,723	$ -	$4,034,723	$ -	$4,034,723

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Utility income

Line No.	Particulars	Initial Application				Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$5,908,802	($5,908,802)	$ -	$ -	$ -
2	Other Revenue (1)	$557,326	($557,326)	$ -	$ -	$ -
3	Total Operating Revenues	$6,466,128	($6,466,128)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$3,839,038	$ -	$3,839,038	$ -	$3,839,038
5	Depreciation/Amortization	$896,214	$ -	$896,214	$ -	$896,214
6	Property taxes	$6,000	$ -	$6,000	$ -	$6,000
7	Capital taxes	$24,718	$ -	$24,718	$ -	$24,718
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$4,765,970	$ -	$4,765,970	$ -	$4,765,970
10	Deemed Interest Expense	$735,548	($735,548)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$5,501,518	($735,548)	$4,765,970	$ -	$4,765,970
12	**Utility income before income taxes**	$964,610	($5,730,581)	($4,765,970)	$ -	($4,765,970)
13	Income taxes (grossed-up)	$76,399	$ -	$76,399	$ -	$76,399
14	**Utility net income**	$888,212	($5,730,581)	($4,842,369)	$ -	($4,842,369)

Notes

(1) **Other Revenues / Revenue Offsets**

Specific Service Charges	$117,920		$ -		$ -
Late Payment Charges	$97,000		$ -		$ -
Other Distribution Revenue	$291,406		$ -		$ -
Other Income and Deductions	$51,000		$ -		$ -
Total Revenue Offsets	$557,326	$ -	$ -	$ -	$ -

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Taxes/PILs

Line No.	Particulars	Application				Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$888,212		$ -		$ -	
2	Adjustments required to arrive at taxable utility income	($696,545)		$ -		($696,545)	
3	Taxable income	$191,666		$ -		($696,545)	
	Calculation of Utility income Taxes						
4	Income taxes	$54,625		$54,625		$54,625	
5	Capital taxes	$24,718	(1)	$24,718	(1)	$24,718	(1)
6	Total taxes	$79,343		$79,343		$79,343	
7	Gross-up of Income Taxes	$21,774		$21,774		$21,774	
8	Grossed-up Income Taxes	$76,399		$76,399		$76,399	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$101,117		$101,117		$101,117	
10	Other tax Credits	$ -		$ -		$ -	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	12.00%		12.00%		12.00%	
13	Total tax rate (%)	28.50%		28.50%		28.50%	

Notes

(1) Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$12,624,330	5.68%	$716,882
2	Short-term Debt	4.00%	$901,738	2.07%	$18,666
3	**Total Debt**	60.00%	$13,526,068	5.44%	$735,548
	Equity				
4	Common Equity	40.00%	$9,017,379	9.85%	$888,212
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,017,379	9.85%	$888,212
7	**Total**	100.00%	$22,543,447	7.20%	$1,623,759

Line No.	Particulars				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$22,543,447	0.00%	$ -

Line No.	Particulars	**Per Board Decision**			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	5.68%	$ -
9	Short-term Debt	0.00%	$ -	2.07%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.85%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$22,543,447	0.00%	$ -

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		($300,388)		($1,720,864)		$4,765,970
2	Distribution Revenue	$6,209,190	$6,209,190	$6,209,190	$7,629,666	$ -	($4,765,970)
3	Other Operating Revenue Offsets - net	$557,326	$557,326	$ -	$ -	$ -	$ -
4	**Total Revenue**	$6,766,516	$6,466,128	$6,209,190	$5,908,802	$ -	$ -
5	Operating Expenses	$4,765,970	$4,765,970	$4,765,970	$4,765,970	$4,765,970	$4,765,970
6	Deemed Interest Expense	$735,548	$735,548	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$5,501,518	$5,501,518	$4,765,970	$4,765,970	$4,765,970	$4,765,970
7	**Utility Income Before Income Taxes**	$1,264,998	$964,610	$1,443,220	$1,142,832	($4,765,970)	($4,765,970)
8	Tax Adjustments to Accounting Income per 2009 PILs	($696,545)	($696,545)	($696,545)	($696,545)	$ -	$ -
9	**Taxable Income**	$568,453	$268,065	$746,674	$446,287	($4,765,970)	($4,765,970)
10	Income Tax Rate	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%
11	**Income Tax on Taxable Income**	$162,009	$76,399	$212,802	$127,192	($1,358,302)	($1,358,302)
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$1,102,989	$888,212	$1,230,417	($4,842,369)	($3,407,669)	($4,842,369)
14	**Utility Rate Base**	$22,543,447	$22,543,447	$22,543,447	$22,543,447	$22,543,447	$22,543,447
	Deemed Equity Portion of Rate Base	$9,017,379	$9,017,379	$ -	$ -	$ -	$ -
15	Income/Equity Rate Base (%)	12.23%	9.85%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.85%	9.85%	0.00%	0.00%	0.00%	0.00%
17	Sufficiency/Deficiency in Return on Equity	2.38%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	8.16%	7.20%	5.46%	0.00%	-15.12%	0.00%
19	Requested Rate of Return on Rate Base	7.20%	7.20%	0.00%	0.00%	0.00%	0.00%
20	Sufficiency/Deficiency in Rate of Return	0.95%	0.00%	5.46%	0.00%	-15.12%	0.00%
21	Target Return on Equity	$888,212	$888,212	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	($214,777)	$ -	($1,230,417)	$ -	$3,407,669	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	($300,388) **(1)**		($1,720,864) **(1)**		$4,765,970 **(1)**	

Notes:
(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$3,839,038		$3,839,038		$3,839,038	
2	Amortization/Depreciation	$896,214		$896,214		$896,214	
3	Property Taxes	$6,000		$6,000		$6,000	
4	Capital Taxes	$24,718		$24,718		$24,718	
5	Income Taxes (Grossed up)	$76,399		$76,399		$76,399	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$735,548		$ -		$ -	
	Return on Deemed Equity	$888,212		$ -		$ -	
8	Distribution Revenue Requirement before Revenues	$6,466,128		$4,842,369		$4,842,369	
9	Distribution revenue	$5,908,802		$ -		$ -	
10	Other revenue	$557,326		$ -		$ -	
11	**Total revenue**	$6,466,128		$ -		$ -	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	($4,842,369)	**(1)**	($4,842,369)	**(1)**

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

Residential

Consumption 800 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
4	Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
5	Distribution Volumetric Rate	per kwh	$ 0.0216	800	$ 17.28	$ 0.0303	800	$ 24.23	$ 6.95	40.24%
6	Low Voltage Rate Adder	per kwh	$ 0.0008	800	$ 0.64	$ 0.0023	800	$ 1.84	$ 1.20	187.50%
7	Volumetric Rate Adder(s)		$ -	800	$ -	$ -	800	$ -	$ -	
8	Volumetric Rate Rider(s)		$ -	800	$ -	$ -	800	$ -	$ -	
9	Smart Meter Disposition Rider		$ -	800	$ -	$ -	800	$ -	$ -	
10	LRAM & SSM Rate Rider		$ -	800	$ -	$ 0.0025	800	$ 2.00	$ 2.00	
11	Deferral/Variance Account Disposition Rate Rider		$ -	800	$ -	-$ 0.0057	800	-$ 4.57	-$ 4.57	
12			$ -		$ -	$ -		$ -	$ -	
13			$ -		$ -	$ -		$ -	$ -	
14			$ -		$ -	$ -		$ -	$ -	
15			$ -		$ -	$ -		$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 29.87**			**$ 35.51**	**$ 5.64**	**18.87%**
17	RTSR - Network	per kwh	$ 0.0052	839.6	$ 4.37	$ 0.0052	838.56	$ 4.36	-$ 0.01	-0.12%
18	RTSR - Line and Transformation Connection	per kwh	$ 0.0039	839.6	$ 3.27	$ 0.0039	838.56	$ 3.27	-$ 0.00	-0.12%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 37.51**			**$ 43.14**	**$ 5.63**	**15.00%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	839.6	$ 4.37	$ 0.0052	838.56	$ 4.36	-$ 0.01	-0.12%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	839.6	$ 1.09	$ 0.0013	838.56	$ 1.09	-$ 0.00	-0.12%
22	Special Purpose Charge		$ -	839.6	$ -	$ 0.0004	838.56	$ 0.34	$ 0.34	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	839.6	$ 5.88	$ 0.0070	838.56	$ 5.87	-$ 0.01	-0.12%
25	Energy	per kWh	$ 0.0694	839.6	$ 58.27	$ 0.0694	838.56	$ 58.20	-$ 0.07	-0.12%
26					$ -	$ -		$ -	$ -	
27					$ -	$ -		$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 107.36**			**$ 113.24**	**$ 5.88**	**5.48%**
29	HST		13%		$ 13.96	13%		$ 14.72	$ 0.76	5.48%
30	**Total Bill (including Sub-total B)**				**$ 121.32**			**$ 127.97**	**$ 6.65**	**5.48%**
31	**Loss Factor (%)**	**Note 1**	4.95%			4.82%				

Notes:
Note 1: Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Brant County Power
File Number:
Rate Year: 2011

General Service < 50 kW

Consumption 2000 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge		$ 16.5100	1	$ 16.51	$ 17.0000	1	$ 17.00	$ 0.49	2.97%
2	Smart Meter Rate Adder		$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
4	Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
5	Distribution Volumetric Rate		$ 0.0186	2000	$ 37.20	$ 0.0205	2000	$ 40.91	$ 3.71	9.98%
6	Low Voltage Rate Adder		$ 0.0007	2000	$ 1.40	$ 0.0023	2000	$ 4.60	$ 3.20	228.57%
7	Volumetric Rate Adder(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
8	Volumetric Rate Rider(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
9	Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
10	LRAM & SSM Rider		$ -	2000	$ -	$ 0.0016	2000	$ 3.20	$ 3.20	
11	Deferral/Variance Account Disposition Rate Rider		$ -	2000	$ -	-$ 0.0059	2000	-$ 11.85	-$ 11.85	
12			$ -		$ -	$ 0.0035		$ -	$ -	
13			$ -		$ -	$ -		$ -	$ -	
14			$ -		$ -	$ -		$ -	$ -	
15			$ -		$ -	$ -		$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 56.11**			**$ 54.87**	**-$ 1.24**	**-2.21%**
17	RTSR - Network		$ 0.0048	2099	$ 10.08	$ 0.0048	2096.4	$ 10.06	-$ 0.01	-0.12%
18	RTSR - Line and Transformation Connection		$ 0.0034	2099	$ 7.14	$ 0.0034	2096.4	$ 7.13	-$ 0.01	-0.12%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 73.32**			**$ 72.06**	**-$ 1.26**	**-1.72%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	2099	$ 10.91	$ 0.0052	2096.4	$ 10.90	-$ 0.01	-0.12%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	2099	$ 2.73	$ 0.0013	2096.4	$ 2.73	-$ 0.00	-0.12%
22	Special Purpose Charge		$ -	2099	$ -	$ 0.0004	2096.4	$ 0.85	$ 0.85	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	2099	$ 14.69	$ 0.0070	2096.4	$ 14.67	-$ 0.02	-0.12%
25	Energy		$ 0.0694	2099	$ 145.67	$ 0.0694	2096.4	$ 145.49	-$ 0.18	-0.12%
26			$ -		$ -	$ -		$ -	$ -	
27			$ -		$ -	$ -		$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 247.58**			**$ 246.95**	**-$ 0.63**	**-0.25%**
29	HST		13%		$ 32.19	13%		$ 32.10	-$ 0.08	-0.25%
30	**Total Bill (including Sub-total B)**				**$ 279.76**			**$ 279.05**	**-$ 0.71**	**-0.25%**
31	**Loss Factor**	**Note 1**	4.95%			4.82%				

Notes:

Note 1: See Note 1 from Sheet 1A. Bill Impacts - Residential

Energy Probe IR # 4a Attachment

Brant County Power Inc.
Capital Expenditure Summary

	91.6% of 2010	2010 Nov. YTD	Estimate to Year End	2010 BUDGET
Distribution	**Distribution Plant**			
1805	Land	$ -	$ -	$ -
1808	Service Building	8,500	8,500	-
1820	Distribution Station Equipment	-	-	-
1815	Transformer station	-	-	-
1830	Poles, Towers, and Fixtures	238,762	386,757	425,616
1835	Overhead Conductors & Devices	315,807	368,960	368,960
1840	Underground Conduit	25,749	63,598	63,598
1845	Underground Conductors and Devices	96,487	96,487	71,158
1850	Line Transformers	113,226	195,428	195,428
1855/1856	Services	32,022	84,660	84,660
1860	Meters	1,973	5,000	186,350
		$ 832,526	**$ 1,209,390**	**$ 1,395,770**
Acct #	**General Plant**			
1905	Land	$ 2,936	$ 2,936	$ -
1908	Office Building	899	2,000	10,000
1915	Office Equipment and Furniture	45,277	80,000	500
1920/1925	Computer Hardware/Software	46,340	97,014	162,300
1930	Rolling Stock	331,248	365,000	325,000
1935	Stores Equipment	2,580	2,580	-
1940	Tools Shop and Garage	11,493	13,000	13,000
1945	Measurement and Testing Equipment	3,559	15,000	15,000
1950	Power Operated Equipment	-	-	-
1955	Communication Equipment	-	-	-
1960	Miscellaneous Equipment	90,421	90,421	-
2010	Miscellaneous Equipment	-	-	-
		$ 534,753	**$ 667,951**	**$ 525,800**
TOTAL CAPITAL EXPENDITURES BEFORE CAPITAL CONTRIBUTIONS		**$ 1,367,279**	**$ 1,877,341**	**$ 1,921,570**
1995	Capital Contributions	(27,918)	(27,918)	(10,000)
CAPITAL EXPENDITURES (Cash Flow)		**$ 1,339,361**	**$ 1,849,423**	**$ 1,911,570**
1555	**Smart Meter Capital**	1,088,840	1,275,000	1,275,000
CAPITAL EXPENDITURES (Total)		**$ 2,428,201**	**$ 3,124,423**	**$ 3,186,570**

Energy Probe IR # 8b Attachment

2010 Capital projects

Padmount Transformers and Pads in Paris and St George

We found a number of padmount transformer pads were crumbling in older underground fed areas of our system. These were dangerous for our employees to work on and as dirt kept washing in it was creating a hazard to the public as well. New transformer pads were installed as well as new wet well transformers were purchased as these are safer to operate than the old dry well type. Work was done in July and August, 2010.

Mile Hill Conversion

Mile Hill was converted from 8320 to 27.6 kV to increase line capacity and improve line loss. This project was done in February and March of 2010.

Rest Acres Road – Line Construction

The PM4 feeder was extended from the town of Paris to Powerline Road. This line will be a part of our Smart Grid and feeds the new twin pad arena.

Mt Pleasant Road – Line Construction

Approximately 2 km of 27.6 feeder was built to permit a new subdivision to be fed from our system. Previously the subdivision was fed from our 8 kV system which was at capacity. This was the final phase for this project.

Re-pole a Section of Line on Powerline Rd

New poles were installed on Powerline Road from Oak Park Road to the Grand River in preparation for reconductoring the feeder.

Rotted Pole Replacements

Continuation of project.

Miscellaneous Small Projects

Small Capital Projects occur at various times throughout the year.

2011 Capital Projects

Paris Conversions

Several small conversions are planned for the North end of Paris. This will eliminate a step down transformer, reduce our line loss and improve system reliability,

Rest Acres Road Conversions

The remaining services which are fed from our 8 kV system on Rest Acres Road will be converted to the 27.6 kV system.

New PM6 Feeder

The PM6 feeder will be built from Powerline MTS to Powerline Road.

River Crossing

The new double circuit river crossing will be installed in 2011.

Smart Grid Development

The first two Scada-Mate switches are planned to be installed in the Paris area. This will allow the industrial area in North Paris to be switched automatically between feeders in the event that one feeder fails. An S&C Vista Switch is being installed to allow the downtown Paris area to be switched between feeders to allow for the system to be restored quickly if a feeder fails.

Energy Probe IR # 15 Attachment

Brant County Power Inc.
Statistics - 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Unbilled Rev Adj	Total
KWH														
Res	7,162,468	8,230,609	7,028,747	6,460,107	5,837,282	5,500,475	6,647,056	8,095,912	8,015,922	6,589,977	5,504,664	5,781,304		80,854,523
Res LTLT	94,280	95,564	83,002	82,830	65,067	68,480	74,110	83,808	82,337	65,935	62,221	73,647		931,280
Gen <50	3,296,981	3,661,962	3,317,752	3,202,369	2,931,960	2,611,525	2,879,475	3,135,484	3,597,655	3,653,531	2,929,872	2,908,006		38,126,573
Gen <50 LTLT	14,699	15,484	12,565	15,701	32,556	34,889	(7,747)	15,967	16,158	13,915	12,028	13,827		190,041
Gen >50	13,790,950	13,954,782	12,924,353	13,531,422	12,095,217	12,869,919	13,321,409	14,384,786	15,177,097	14,194,855	12,964,790	13,661,932		162,871,512
Gen >50 LTLT														
Interval <1000														0
Interval >1000														0
Large	0	0	0	0	0	0	0	0	0	0	0	0		0
Streetlt	189,695	188,617	155,762	157,361	133,510	122,871	109,520	116,404	130,415	143,940	155,205	177,318		1,780,618
Streetlt LTLT	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070		12,846
Sentlt	14,705	15,266	15,316	15,188	15,188	15,175	15,016	15,059	14,785	14,884	14,899	14,798		180,280
Scattered	42,412	42,412	42,412	42,412	41,984	40,578	40,578	38,977	38,977	38,977	38,977	38,977		487,676
Short Term LT														0
Total Billed/Accrued	24,607,261	26,205,767	23,580,980	23,508,461	21,153,834	21,264,981	23,080,488	25,887,468	27,074,417	24,717,085	21,683,727	22,670,880	0	285,435,349
IMO Billed	26,612,098	23,530,384	23,603,010	20,729,870	22,592,407	23,496,388	27,083,186	27,734,973	24,073,743	22,590,141	23,573,944	25,812,916		291,433,060
kwh Loss	2,004,837	(2,675,383)	22,030	(2,778,591)	1,438,573	2,231,407	4,002,698	1,847,505	(3,000,674)	(2,126,944)	1,890,217	3,142,036	0	5,997,711
	7.53%	-11.37%	0.09%	-13.40%	6.37%	9.50%	14.78%	6.66%	-12.46%	-9.42%	8.02%	12.17%		2.06%
KW														
Gen >50	30,818	30,003	29,507	26,623	25,956	29,389	28,160	28,800	28,096	28,093	27,000	27,790		340,236
Gen >50 LTLT														
Interval <1000														-
Interval >1000														-
Large														-
Streetlt	398	398	398	398	398	398	398	398	398	398	398	398		4,770
Streetlt LTLT	3	3	3	3	3	2	2	3	3	3	3	3		31
Sentlt	41	40	41	40	40	40	40	40	39	39	39	39		479
Short Term LT														-
Total Billed/Accrued	31,259	30,444	29,947	27,064	26,396	29,829	28,600	29,240	28,535	28,533	27,440	28,230	0	345,516
Residential														
Customers	8,145	8,180	8,175	8,189	8,184	8,170	8,202	8,194	8,193	8,219	8,213	8,215		
Avg kwh	879	1,006	860	789	713	673	810	988	978	802	670	704		
G<50														
Customers	1,288	1,291	1,290	1,287	1,287	1,314	1,344	1,348	1,342	1,345	1,337	1,337		
Avg kwh	2,560	2,837	2,573	2,488	2,278	1,988	2,143	2,326	2,681	2,716	2,192	2,175		
G>50														
Customers	107	105	106	106	106	109	110	111	111	113	115	115		
Avg kwh	128,731	132,903	121,435	127,415	114,095	117,753	120,875	129,878	136,357	125,582	112,950	118,807		

Energy Probe IR # 16a Attachment

Appendix 2-C
Other Operating Revenue

USoA	Description	2006	2007	2008	2009	2010 (Draft)
4235	Misc. Service Revenues	101,564	129,254	138,484	108,459	152,694
4225	Late Payment Charges	69,205	78,169	86,045	96,584	69,198
4082	Retail Services Revenue					
4084	Service Transaction Requests Revenues					
4090	Electric Service Incidental to Energy Sales					
4205	Interdepartmenal Rents					
4210	Rent from Electric Property	32,884	43,162	37,315	34,748	39,237
4215	Other Utility Operating Income					
4220	Other Electric Revenues	255,884	167,768	159,858	165,162	163,142
4240	Provision for Rate Refunds					
4245	Government Assistance Directly Credit to Income					
Total Other Distribution Revenues		**288,768**	**210,930**	**197,173**	**199,910**	**202,379**
4305	Regulatory Debits					
4310	Regulatory Credits					
4315	Revenues from Electric Plant Leased to Others					
4320	Expenses of Electric Plant Leased to Others					
4325	Revenues from Merchandise, Jobbing, Etc.			2,000		
4330	Costs and Expenses of Merchandising, Jobbing, Etc					
4335	Profits and Losses from Financial Instruments Hedges					
4340	Profits and Losses form Financial Instrument Investments					
4345	Gains from Disposition of Future Use Utility Plant					
4350	Losses from Disposition of Future Use Utility Plant					
4355	Gains from Disposition Utility and Other Plant		44,822	- 9,578		
4360	Losses from Disposition of Utility and Other Plant					
4365	Gains from Disposition of Allowance for Emission					
4370	Losses from Disposition of Allowance for Emission					
4375	Revenues from Non-Utility Operations	24,385	39,622	26,477	41,311	
4380	Expenses of Non-Utility Operations	- 21,163	- 20,360	- 23,911	- 40,286	
4385	Non-Utility Rental Income					
4390	Misc. Non-Operating Income	17,041	21,951	23,839	10,973	8,786
4395	Rate-Payer Benefit Including Interest					
4398	Foreign Exchange Gains and Losses, Inc. Amortization					
4405	Interest and Dividend Income	36,241	75,583	49,023	25,651	42,995
4415	Equity in Earnings of Subsidiary Companies					
Total Other Distribution Expenses		**56,504**	**161,618**	**67,850**	**37,649**	**51,781**
Specific Service Charges		101,564	129,254	138,484	108,459	152,694
Late Payment Charges		69,205	78,169	86,045	96,584	69,198
Other Distribution Revenues		288,768	210,930	197,173	199,910	202,379
Other Income and Expenses		56,504	161,618	67,850	37,649	51,781
Total		**516,041**	**579,971**	**489,552**	**442,602**	**476,052**

Energy Probe IR # 21c Attachment

BRANT COUNTY POWER INC.
Admin Expenses

		General Admin	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Budget	
	5625	*Administrative Expense Transferred - Credit -BCPSI*							
M1		Billing costs			$ (9,672)	$ (9,672)	$ (9,600)	$ (9,600)	800 per month for billing
M2		Administration	(32,798)	(46,817)	(53,572)	(27,867)	(25,000)	(25,000)	Other admin costs
M3		Executive and Management Services Fee	(10,038)	(3,476)	(4,016)	(4,637)	(5,000)	(5,000)	CEO/CFO
M4		Accounting & Bookkeeping Services Fee	(4,717)	(11,020)	(10,200)	(9,016)	(8,800)	(8,800)	Accounting dept
			$ (47,553)	$ (61,313)	$ (77,460)	$ (51,192)	$ (48,400)	$ (48,400)	