Board Staff Supplemental Interrogatories
2009 Electricity Distribution Rates
West Coast Huron Energy Inc. ("West Coast Huron")
EB-2008-0248
As per Procedural Order #3 dated January 21, 2009.

Load Forecast

1. Ref: Exh3/Tab2/Sch1/pp 1 to 13 ***(Revised January 16, 2009)***
Please provide a detailed description of the methodology the Applicant employed in developing its 2008 and 2009 load forecasts including identification (and rationale for the identification) of the weather sensitive and non-weather sensitive classes, differentiating any differences in the approach(es) used for weather sensitive and non-weather sensitive classes, the process for the separate development of the kWh vs. kW forecasts, description of the checks employed to ensure the correct kWh vs. kW relationship has been maintained, etc.

- ***2008 & 2009 load forecast are based on projected customer counts and historical weather adjusted consumption profiles. 2002 – 2007 consumptions by customer class have been adjusted by the IESO weather correction factors (as found in quarterly IESO reports). The weather adjusted customer class usage statistics are then averaged using a weighted approach to calculate an average (2002 – 2007) consumption by customer class. This weighted average customer consumption is then applied to the 2008 / 2009 customer projections to derive a weather adjusted LDC wide load profile.***
- ***The identification of weather sensitive classes was applied consistent to the Hydro One analysis provided with the cost allocation filing and is applied to Residential, GS<50 kW, and GS>50 to 499 kW classes.***
- ***For the non-weather sensitive classes the same forecasting approach for kWh was applied as the weather sensitive class without the application of the IESO annual weather normalization factor.***
- ***The same methodology was utilized for kW as that for kWh in all classes except for the Large Use class.***
- ***Given the expansion plans proposed and identified to WCHE by Sifto, the kW demand for this account was forecast based upon its current demand which is an increase over historical months. If the same process was utilized for the Large Use class as all others then Sifto's projected demand would have been significantly understated.***

2. Ref: Exh3/Tab2/Sch1/p 2 *(Revised January 16, 2009)*
On page 2, the Applicant states that "The annual trend growth is used to project customer growth into 2008 and 2009." Please:

a) Explain how the Applicant's forecasting methodology is differentiated from a "rear view mirror" approach that relies solely (or substantially) on the future being an extrapolation of the past and ignores both broader economic effects that would impact the Province as a whole and energy consumption changes as a result of CDM.
   - ***WCHE's forecasting methodology is a "rear view mirror" approach and did not consider broader economic effects nor the impact of CDM.***
   - ***Attempting to forecast these economic and conservation impacts would have been an extremely subjective process that would be difficult to substantiate.***
   - ***Had WCHE utilized changes based on these effects the resulting impact on variable rates for the customer would have been an increase as both of these variable could have reduced the amount of kWh's and kW's forecast.***

b) Compare the economic assumptions made in the application with economic forecasts prepared by national economic forecasting institutions (e.g. Canadian chartered banks) and regional equivalents (e.g. Boards of Trade or regional councils).
   - ***WCHE is a small utility with minimal growth. The forecast customer numbers by rate class are within the range of the utilities past growth as detailed in its customer count forecast. WCHE has forecast growth of 38 customers which is not a significant increase for a utility this size. WCHE is uncertain as to the materiality any such analysis would create.***

3. Ref: Exh3/Tab2/Sch1/pp 1 to 13, Exh3/Tab2/Sch4/p1 and Exh3/Tab3/Sch4/p 2 *(Revised January 16, 2009)*
At Tab 2, Schedule 1, page 2, in discussing Residential and GS<50 customer classes, the Applicant states that "The annual trend growth is used to project customer growth into 2008 and 2009." Also on Tab 2, Schedule 1, page 2, in discussing the GS>500 to 4999 customer classes, the Applicant states that "…an annual growth rate of 0% was assumed for 2007 and 2008 and Volvo was removed from the customer forecast as a result of its impending closure."

On Tab 2, Schedule 1, pages 4 and 5; on Tab 2, Schedule 4, page 1; and on Tab 3, Schedule 4, page 2; the Applicant displays tables containing customer count for the various customer classes. The data in the various tables are not consistent. (For example, on Tab 2, Schedule 1, page 4, the 2008 GS<50 customer count is 517 and the 2009 GS>50 to 499 customer count is 51; the corresponding values on page 5 are 521 and 49 respectively. Discrepancies also exist among the other tables referenced.) Please:

a) Verify that in the first unnumbered table in Exhibit 3/ Tab 2/ Schedule 1/ page 4, the Residential class customer count growth from 3,166 in 2002 to 3,290 in 2007 corresponds to an approximate 0.8% p.a. growth whereas the 2007 to 2008 growth

(3,290 to 3,323) and 2008 to 2009 growth (3,323 to 3,356) each correspond to an approximate 1.0% p.a. growth.

- ***Verified.***

b) Reconcile the percentage increases in a) above with the statement: "The annual trend growth is used to project customer growth into 2008 and 2009."

- ***Given the relatively low number of customers in WCHE's service territory the growth rate was rounded up from 0.8% to 1.0% in the calculation of the forecasted customer numbers.***
- ***However, upon further analysis this rounding produces approximately 13 more customers in 2009 than would have been forecast had the original growth percentage been used as an actual figure at 0.8%.***

c) Clarify if the statement "…an annual growth rate of 0% was assumed for 2007 and 2008…" is meant to also refer to 2008 to 2009 growth.

- ***The statement should in fact be 2008 and 2009 growth.***

d) Explain why on page 4, the four Volvo accounts are added back in to the 2009 forecasts giving the appearance that the 2009 customer count continues to include the Volvo customer and, also, why the sum of the accounts in the GS>500 to 4999 customer classes for 2007 is 49 (i.e. 46+3), for 2008 is 51 (i.e. 48+3) and for 2009 is 56 (i.e. 51+4) while the statement was made for those classes on page 2 that "…an annual growth rate of 0% was assumed for 2007 and 2008 and Volvo was removed from the customer forecast as a result of its impending closure."

- ***While the statement made refers to growth rate, the actual change in the number of customers made was for the expected change in customers, not utilizing a growth rate for the change in the customer class. Therefore, the change in customer numbers is as anticipated and should remain as filed.***
- ***The 2009 forecast that is listed on page 4 with the Volvo accounts added back should read 2009 original forecast. The actual customer forecast used to calculate consumption and load is the column 2009 W/O Volvo and can be viewed in its liver version in Schedule # 4 D included in this response.***

e) Re-file the four referenced tables with consistent data based on consistent assumptions.

- ***See Schedule # 3 E and Below.***

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Actual
Residential	3,214	3,257	1.34%	3,257	3290	1.01%	3290	3316	0.80%	3316.3	3343	0.80%
GS<50	496	508	2.42%	508	512	0.79%	512	517	0.98%	517	521	0.77%
GS>50 to 499 kW	43	41	-4.65%	41	46	12.20%	46	48	4.35%	48	49	2.08%
GS>500 kW to 4999 kW	4	3	-25.00%	3	3	0.00%	3	3	0.00%	3	3	0.00%
Large Use	1	1	0.00%	1	1	0.00%	1	1	0.00%	1	1	0.00%
Unmetered Scattered Load	9	9	0.00%	9	9	0.00%	9	9	0.00%	9	9	0.00%
Sentinel Lighting	13	13	0.00%	13	13	0.00%	13	13	0.00%	13	13	0.00%
Street Lighting	1,334	1,333	-0.07%	1,333	1333	0.00%	1333	1333	0.00%	1333	1333	0.00%
	5,114	**5,165**		**5,165**	**5207**		**5,207**	**5,240**		**5,240**	**5,272**	

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Actual
Residential	3,214	3,257	43	3,257	3290	33	3290	3316	26	3316.3	3343	27
GS<50	496	508	12	508	512	4	512	517	5	517	521	4
GS>50 to 499 kW	43	41	- 2	41	46	5	46	48	2	48	49	1
GS>500 kW to 4999 kW	4	3	- 1	3	3	-	3	3	-	3	3	-
Large Use	1	1	-	1	1	-	1	1	-	1	1	-
Unmetered Scattered Load	9	9	-	9	9	-	9	9	-	9	9	-
Sentinel Lighting	13	13	-	13	13	-	13	13	-	13	13	-
Street Lighting	1,334	1,333	- 1	1,333	1333	-	1333	1333	-	1333	1333	-
	5,114	**5,165**	**51**	**5,165**	**5207**	**42**	**5,207**	**5,240**	**33**	**5,240**	**5,272**	**32**

Counts

	2002	2003	2004	2005	2006	2007	2008	2009 W/O Volvo	Volvo Accts	2009 Forecast
RESIDENTIAL	3,166	3,197	3,214	3,226	3,257	3,290	3,316	3,343		3,356
Less than 50 kW	487	488	496	500	508	512	517	521	1	522
Greater than 50 to 499 kW	37	42	43	42	41	46	48	49	2	51
Greater than 500 to 4,999 kW	2	2	3	3	3	3	3	3	1	4
Large Use	1	1	1	1	1	1	1	1		1
Unmetered Scattered Load	9	9	9	9	9	9	9	9		9
Sentinel Lighting	12	13	13	13	13	13	13	13		13
Street Lighting	1,295	1,328	1,334	1,328	1,333	1,333	1,333	1,333		1,333
	5,009	5,080	5,113	5,122	5,165	5,207	5,240	5,272	4	5,289

West Coast Huron Energy		Board Approved	Historical Actual	Historical Normalized	Historical Actual	Historical Normalized	Bridge Year Estimate	Bridge Year Normalized	Test Year Normalized
Year		2004	2006	2006	2007	2007	2008	2008	2009
Customer Class									
Residential	#	3,214	3,257	3,257	3,290	3,290	3,316	3,316	3,343
	kWh	27,302,454	27,222,139	27,427,407	26,672,783	26,532,896	27,161,746	27,741,627	27,963,560
GS<50 kW	#	496	508	508	512	512	521	521	521
	kWh	15,808,273	15,638,855	15,756,780	15,487,130	15,405,907	15,700,610	16,172,585	16,297,712
GS>50 to499 kW	#	43	41	41	46	46	48	48	49
	kWh	22,642,985	20,866,610	21,023,954	20,645,650	20,537,372	20,827,212	23,719,459	24,213,614
	kW	79,207	69,316	69,839	71,037	70,664	73,907	73,907	78,630
GS> 500 to 4999	#	4	3	3	3	3	3	3	3
	kWh	17,730,678	12,348,682	12,348,682	12,145,375	12,145,375	9,804,028	11,029,532	11,029,532
	kW	40,273	25,002	25,002	25,619	25,619	24,757	24,757	25,095
Large Use >5000 kW	#	1	1	1	1	1	1	1	1
	kWh	63,184,213	62,522,031	62,522,031	62,029,064	62,029,064	63,440,389	63,440,389	63,440,389
	kW	126,126	133,199	133,199	137,861	137,861	152,653	152,653	155,172
Unmetered Scattered Load	#	9	9	9	9	9	9	9	9
	kWh	156,531	179,382	179,382	177,482	177,482	166,487	166,487	166,487
Sentinel Lighting	#	13	13	13	13	13	13	13	13
	kWh	20,456	24,313	24,313	23,275	23,275	21,860	22,144	22,144
	kW	66	64	64	64	64	65	65	64
Street Lighting	#	1,334	1,333	1,333	1,333	1,333	1,333	1,333	1,333
	kWh	901,277	1,078,742	1,078,742	1,057,613	1,057,613	980,351	1,064,486	1,064,486
	kW	2,944	2,916	2,916	2,842	2,842	2,843	2,843	2,896

4. Ref: Exh3/Tab2/Sch1/pp 3 to 5 *(Revised January 16, 2009)*

On page 3, the Applicant provides the non-normalized consumption history and forecast. Assuming that the values have been derived using the normalized average consumption method, Board staff is able to reproduce some of the forecast values but not others. Also, there is some uncertainty if the values in pages 3 to 5 are billing (retail) data or wholesale data. In addition, the application does not appear to contain a clear indication as to which of the tables of values in the application the Applicant is relying on for the development of its distribution rates. Please:

a) Verify that the values in the table on page 5, form the forecast on which the Applicant is relying for the development of its distribution rates.
   - ***Verified.***

b) Explain the role the values on page 3 play in the development of the Applicant's forecast given that the values on page 3 are not weather corrected whereas the values in the forecast on page 5 are weather corrected.
   - ***Page 3 values are the starting point of actual data utilized in the weather correction process.***
   - ***Further tables should have been included in this section to detail the weather correction process.***
   - ***The full live spreadsheet can be viewed at Schedule # 4 D included with this response.***

c) Verify that the data on pages 3 to 5 are billing (retail) data.
   - ***Verified.***

d) Provide a live Excel spreadsheet (i.e. one where the formulae are visible) showing the development of the 2008 and 2009 values – both kWh and kW – that are presented in *page **3***.
   - ***Please see attached schedule # 4 D.***
   - ***This schedule also includes continued tables to the one included on page 3 that reconcile to the data on page 5 and are weather normalized.***

e) Provide a live Excel spreadsheet (i.e. one where the formulae are visible) showing the development of the 2008 and 2009 values – both kWh and kW – that are presented in *page **5***.
   - ***Please see attached schedule # 4 E.***
   - ***This worksheet simply references schedule # 4 D in the working copy of the rate model.***

5. Ref: Exhibit 3*(Revised January 16, 2009)*
Some of the Applicant's evidence may require to be adjusted in light of responses to the preceding customer count, load and revenue forecasting interrogatories. Please re-file any Exhibit 3 tables that require to be updated as a result of changes in the Applicant's evidence as a result of these interrogatories.

- ***There are no substantive changes resulting from changes to the applicant's evidence or these interrogatories.***
- ***The number of customers in the residential class is potentially overstated by 13 customers, however, since applying this change would further increase this classes fixed and variable rates WCHE is not proposing to change its evidence in this regard.***

OM&A

6. Ref: Exh4/Tab2/Sch7 (*Revised January 16, 2009)*

The number of full time equivalents reported on this schedule has changed from the original application.

a) Please explain why the historical count has changed.

- ***The historical count remained constant for a number of years prior to the market opening. As a result of the industry changes, along came the need to have staff with the required skills and to operate within desired levels of expenditure. The utility has a very small staff. In the years 2006 and 2007, there were retirements of two full time personnel. The LIne Superintendent in March of 2006 and the Executive Secretary in September 2007. The LIne Superintendent was not replaced and the services of Erie Thames was contracted to provide Asset Management and Operational supervision. The Executive Secretary was not replaced. The President and Treasurer were part time employees until the end of 2007. In 2008, the costs previously recorded as wages is now paid as a Management Fee. An Apprentice was hired the end of November 2007 and resigned in March 2008. An Apprentice was hired in May 2008 and remains employed.***

b) What is the effect of this change on the forecast year?

- ***The forecast year reflects the reduction of the Executive Secretary and the savings achieved as a result of the retirement of the line superintendent less the cost (plus CPI) to Erie Thames for the contract.***

c) If staff has been reduced, have Purchased services increased?

- ***Yes.***

d) If purchased services have increased, please provide detailed cost impacts.

- ***The contract price to Erie Thames for Asset Management and Operational supervision is $ 60,000.00. The cost of wages plus benefits for the now retired LIne Superintendent was in excess of $ 100,000.00.***

7. Ref: Board Staff Interrogatory Schedule #6

This schedule provided by West Coast Huron is in response to Board staff's request for a table identifying one time and on-going regulatory costs.

a) The response indicates some costs are on-going, but is silent on costs not classified as on-going. Are the unclassified costs one time costs?
   - ***The unclassified costs are not one time costs.***
   - ***OEB annual assessment and ESA fees are ongoing.***
   - ***For the most part legal costs are ongoing; however they are estimated to be higher in 2009 due to rate rebasing.***

b) Please explain the costs that comprise the $105,000 of on-going costs itemized as Rate applications.
   - ***Costs for annual rate applications are on going and have been in the range of $20,000 to $30,000 depending upon the process. The incremental amount for 2009 due to the Cost of Service rate rebasing process would be considered one time.***

8. Ref: Board Staff Interrogatory #7 a)

Please explain the $150,000 one time post retirement benefit charge that is disclosed in this interrogatory response. How was it determined and why was it not included in the original evidence?

- ***The $150,000 is management's estimate of the liability of the post retirement non pension benefit plan which includes for eligible retirees: lifetime post retirement life insurance, extended health care coverage, vision and dental until age 65.***
- ***The amount was included in the original evidence, however it was not detailed or highlighted since it was embedded as part of the operating budget numbers.***

9. Ref: Board Staff Interrogatory #7 d)

In West Coast Huron's response, it stated that there are no forecast costs in 2009 for International Financial Reporting Standards conversion.

a) Does West Coast Huron have an estimate for the costs for International Financial Reporting Standards conversion?
   - ***WCHE is in the process of assessing the requirements and the impact of converting to IFRS and as yet has no estimate of the costs to do so.***

b) What year would this expense occur?
   - ***This expense would occur in 2009, 2010 and 2011.***

c) If over more than one year, please provide yearly expenses.
   - ***Yearly expenses are not known at this time.***

Rate Base/Capital Expenditures

10. Ref: Board Staff Interrogatory # 17
Please provide greater detail (including rationale and costs) for the projects listed below:

a) Upgrade of poles and conductors on M3 6 spans: How many poles will be replaced as part of this projects and what is the average cost of each pole?

- ***As part of the 31M3 enhancements to help relieve constraints on the south loop there is a requirement to upgrade a section of the 31M3 line that connects directly with the Goderich Transmission Station. The scope of this project requires 7 double circuit poles to be replaced which are joint use with Hydro One. The poles have been identified as having extensive rot damage requiring them to be replaced. As well this section of line requires the 336 aluminum conductor to be upgraded to 556 aluminum. The project deals with poles both inside and outside of the transmission station fence and requires make ready work by Hydro One. The average cost of the pole upgrades is $8000 to $10,000 per pole based one equipment transfers. Also included in the cost of the project is Hydro One make ready costs.***

b) Purchase truck ($33,000) – type of truck, is it a replacement or a new purchase?

- ***$33,000 was the budgeted cost to purchase a new Toyota Tacoma pickup truck which replaced a 2000 Chevy S10 pickup.***

c) Transformer purchases for inventory – number of transformers being purchased, cost of each transformer

- ***Over the last several years WCHE through the capital plan has been converting load from 4.16kv to 27.6kv. As more loads get directly connected to the 27.6kv distribution system there is a need to increase the inventory levels for emergency stock of transformers. In 2008 WCHE purchased a 300kva 27.6-120/208volt padmount transformer at a cost of $15000. In 2009 WCHE plans on purchasing 5 single phase polemount transformers at an average cost of $4000/transformer.***

d) Cost of connecting new customers – bridge and test year – will the utility be receiving any contributions or grants? If "yes", please provide details

- ***New residential customers requiring a basic connection are not required to provide a capital contribution for the connection. WCHE's conditions of service dictate the cost for a residential basic connection is built into rates. General Service connections typically require a capital contribution from the customer. Budget***

costs for new connections are net costs (total cost to connect – capital contribution received = budget amount).

e) Replace danger poles within distribution system (bridge and test year) – number of poles being replaced, average costs, methodology for identifying poles for replacement

- ***Methodology for identify pole replacements is a process performed by a third party contractor. The contractor first performs a visual inspection than sounds the pole utilizing a hammer around the base of the pole. The final inspection of the pole involves a drill bore 6"-12" below grade at the base of the pole determining the extent of rot and life expectancy of each pole. Chemicals are added in the bore holes to poles that are showing the beginning stages of rot to prolong the life expectancy of the asset. Rotten poles that are found through the inspection process are noted and tagged with a requirement for immediate action or action within the near future (3 year max). Replacement poles then go into the capital plan and are prioritized based on the level of risk they present to the utility. In WCHE 2008 bridge year 14 poles have been targeted for replacement at an average cost of $7000/pole. WCHE's test year represents 10 poles at an average cost of $6000/pole. The average cost per pole replacement is higher in the bridge year based on the size, number of circuits and equipment on the poles which in return has put them at a higher priority list for replacement.***

f) 27 kV conversion and feeder operating enhancements and relieve 31M3 27.6 kV constraints on South Loop – rationale for both projects, alternatives considered, date of completion, costs of projects included in rate base of bridge and test year.

- ***Rational and alternatives considered have been detailed in the "Distribution System Feeder Assessment which was included in the original application. Also included in the original application was a summary of this engineering study and a capital additions explanation under project id 1124, 1132, 1134. Cost filed in rate base for 2008 bridge year are $175,000 for project 1124 and $95,000 for project 1132. In 2009 test year costs filed are $315,000 for project 1134. The feeder enhancement project is a multiyear project which will require approximately $300,000-$350,000 per year over the next 5 years. Expected completion of the entire south loop feeder enhancement is 2013.***

Cost of Debt

11. Ref: Board Staff Interrogatory #26
West Coast Huron has submitted a copy of the original Promissory Note in response to Board Staff Interrogatory # 26. The original Promissory Note signed in December 2000 for the sum of approximately $2.6 million carrying a fixed rate of 7.25% per annum, refers to retaining the Note for a period of four years and then making it subject to review after this period.

The Note was then revised/renegotiated in November 2002 and a balance of $974,454 was fixed at a rate of 7.25% per annum under the original and current conditions.

Please answer the following questions with respect to the Promissory Note:

a) The original conditions of the Note indicated a period of four years and a review of the Note at the end of this period. These conditions were not changed or amended in the November 2002 Note. Was the Note reviewed in 2004 or 2006? If not, please provide reasons for not reviewing the Note.
   - ***The note was not reviewed in 2004. Both the Shareholder and the Board were satisfied with the terms as the rate was set at what was historically the OEB's prescribed rate for debt 7.25%.***
   - ***The details of the Promissory Note were discussed by the Shareholder and the utility during its annual Shareholders meeting on April 25th, 2006***

b) Did West Coast Huron obtain a market quote on a similar debt when it amended the Note in November 2002? Please provide details.
   - ***No market quote was obtained in November of 2002.***

c) Has the Ontario Energy Board reviewed the original Note or the Revised Note in a prior proceeding?
   - ***The note and interest have both been part of all prior rate applications.***

Income Tax

12. Ref: Exh6/Tab1/Sch1
In Exhibit 6/Tab1/Schedule1, West Coast Huron requested Board approval of a deemed capital structure of 53.33% debt and 46.67% equity. Please confirm whether West Coast Huron is seeking the above or the deemed structure stated below:

Common Equity Ratio – 43.33%
Short term debt Ratio – 4.00%
Long term debt Ratio – 52.67%

Please clearly restate the deemed capital structure that West Coast Huron is requesting.

- ***WCHE is seeking the deemed structure stated here of :***

- ***Common Equity Ratio – 43.33%***
- ***Short term debt Ratio – 4.00%***
- ***Long term debt Ratio – 52.67%***

13. Ref: Schedule 22 responding to Board Staff Interrogatory # 22

a) Please confirm the total PILs amount for Rate Purposes that West Coast Huron is requesting.

- ***West Coast Huron Energy is requesting $44,728 in PILS for rate purposes which grossed up for rate purposes is $51,294.***

c) What equity ratio has West Cost Huron used in its PILs calculation? If West Cost Huron has not used the deemed equity ratio in its calculation, please provide reasons for not doing so.

- ***WCHE used 46.67% equity in this calculation.***
- ***WCHE is requesting its deemed debt equity structure to be 46.67% debt and 43.33% equity as a result of supplemental interrogatory # 12 above and will be required to update its calculation of PILS to reflect this deemed amount in its finalized rates.***

d) Please provide the income tax rates that have been used in the PILs calculation. If West Coast Huron has used a Corporate Income Tax Rate other than 16.5%, please provide reasons for doing so.

- ***The income tax rates used in the PILS calculation are Federal Tax of 12.8%, Ontario tax of 14.00%, Provincial Small Business rate of 5.50% and the Provincial Tax Claw back Rate of 4.25%.***
- ***These rates were referenced from the CRA website and were used to calculate the taxes for WCHE's application and result in a weighted average rate of 18.30%.***

Smart Meters

14. Ref: Board Staff Interrogatory # 20

In Response to the Board Staff Interrogatory, West Coast Huron has indicated that it is planning to deploy smart meters in 2009 and is requesting a rate adder of $1.00 per month. West Coast intends to install approximately 1,678 meters in the 2009 Test Year. Please complete the following table:

Total number of metered customers	3,874
Total number of smart meters to be installed (2009 and beyond)	3,817
Total capital cost of the Smart Meter Program	$515,295
Total installed cost per smart meter	$135
Approximate completion date of installing all smart meters	December 2010
Total expenditures incurred to-date	$0.00
Total balances in smart meter related deferral accounts (by account type)	$30,449
Annual estimated OM&A costs (once all smart meters are installed)	$28,000

Retail Transmission Service Rates

15. Ref: Board staff Interrogatory # 46

West Coast Huron submitted Schedule# 46 A and B in response to Board Staff Interrogatory #46a), including sub-totals highlighted for the period June-November 2008. West Coast Huron provided an analysis of monthly over- and under-collections over a twenty-two month period in response to # 46b). In response to # 46c), West Coast Huron undertook to file a revised proposal for RTSRs. However, the Revision Document notes that "WCHE was not confident that the results [of its analysis] meet the intent of the question", and the revised application in fact proposes no change from the existing approved rates for all classes.

a) Please confirm that the wholesale cost of Network service from June to November 2008 was $285,176, that the applicable rate at that time was $2.31 per kW, and that the cost would have been approximately $320,000 if the rate had been $2.57 per kW (as recently approved in Board Order EB-2008-0113).
   - ***Confirmed.***

b) Please confirm that the revenue from Network retail rates from June to November 2008 was $294,911, and that the revenue would have been approximately $320,000 if the West Coast Huron's Retail Transmission Service Rates for Network had been 7.6% higher than West Coast Huron's currently approved rates.
   - ***Confirmed.***

c) Please confirm that the wholesale cost of Connection service from June to October 2008 was $257,761, that the applicable rate at that time was $2.20 per kW, and that the cost would have been approximately $270,000 if the rate had been $2.32 per kW (as recently approved in Board Order EB-2008-0113).
   - ***Confirmed.***

d) Please confirm that the revenue from Network retail rates from June to November 2008 was $244,668, and that the revenue would have been approximately $270,000 if the West Coast Huron's Retail Transmission Service Rates for Network had been 11.1% higher than West Coast Huron's currently approved rates.
   - ***Confirmed.***

e) Please provide Retail Transmission Service Rates that would differ from the currently approved rates by the amounts suggested in parts b) and d), or alternatively provide other rates with a rationale for not making the adjustment suggested in parts b) and d). Note that such a rationale might involve allowing for the partial year used in those calculations or for West Coast Huron's revised load forecast.

West Coast Huron Energy
Retail Transmission Rates Adjustment Model

Network

Retail Rates

	Current Rate	Adjustment Factor	Proposed 2009 Rate
Residential	0.0039	7.60%	0.0042
GS < 50 kW	0.0036	7.60%	0.0039
GS > 50 to 499 kW	1.4585	7.60%	1.5693
GS > 500 to 4999 kW	1.5491	7.60%	1.6668
Large Use	1.7153	7.60%	1.8457
Unmetered Load	0.0036	7.60%	0.0039
Sentinel Lights	1.1056	7.60%	1.1896
Street Light	1.1000	7.60%	1.1836

Connection

Retail Rates

	Current Rate	Adjustment Factor	Proposed 2009 Rate
Residential	0.0041	11.10%	0.0046
GS < 50 kW	0.0037	11.10%	0.0041
GS > 50 to 499 kW	1.4725	11.10%	1.6359
GS > 500 to 4999 kW	1.6142	11.10%	1.7934
Large Use	1.8459	11.10%	2.0508
Unmetered Load	0.0037	11.10%	0.0041
Sentinel Lights	1.1621	11.10%	1.2911
Street Light	1.1621	11.10%	1.2911

Deferral and Variance Accounts

16. Ref: Board Interrogatories # 37 and 47

West Coast Huron provided the continuity schedule of Deferral and Variance accounts as requested. However, Board staff requests further information concerning the data in the continuity schedule:

a) With respect to the third sub-account in account 1508 'Other Regulatory Assets', please describe the transfer of $563,349 made in 2006 from account 1588 to 1508, and subsequent reduction of $153,827 in 2006 and $283,753 during 2007. Please include an explanation of why the balance of $125,769 is described as "Recovery – court order" in note 7 to the 2007 Financial Statements.
- ***The segregation of the amount ordered by OEB EB-2004-0513 from other accumulated variances, the balance was allocated to account 1508 and revenue collected via the rate rider effective May 1st, 2006 was also recorded in this account. The reductions noted as $153,827 in 2006 and $283,753 in 2007 are the revenue collected from all rate payers of the utility via this rate rider.***
- ***It was described as "recovery Court Order" in the financial statements merely to note its difference from other Regulatory assets/liabilities.***

b) Please provide a reference to guidance in the Accounting Procedures Handbook or other Board direction which West Coast Huron has relied on to record and dispose of a balance in this sub-account of 1508.
- ***The Board direction is EB-2004-0513 and the recovery was a specific component of the rate rider effective May 1st, 2006.***

c) Please explain which of the amounts recorded in account 1508 (described in part a above) in fiscal 2006 may have already been recovered as part of the amount $563,169 that is a component in the rate riders approved in the 2006 EDR Regulatory Asset Recovery model (part of December 31, 2004 balances).
- ***The amount $563,549 recorded in 1508 represented the component of the rate rider approved in 2006 EDR regulatory asset recovery model.***

d) Board staff provided a continuity schedule with blank cells as a framework with its Interrogatories to West Coast Huron. In November 2006, utilities were advised by the Board to reallocate the 2006 EDR approved regulatory asset balances from their account of origin to the 1590 recovery accounts effective May 1, 2006.

Please update the continuity schedule to reflect, and reconcile with, the amounts that were approved by the Board as part of West Coast Huron's 2006 EDR Decision (EB-2005-0431).

As an example, the Board approved the transfer of $563,169 from Account 1508 in 2006; however the amount presented in the continuity schedule attached with the response to Board Staff Interrogatory # 47 states a sum of

principal and interest of $0 transferred to account 1590. The numbers included in the column “Transfer of Board-approved amounts to 1590 as per 2006 EDR” are either incorrect, or the entries are missing entirely from the continuity schedule filed by West Coast Huron.

	Transfer Variance	**Transfer Interest**	**Total**
RSVA - Wholesale Market - 1580	(166,285.00)	(41,358.00)	(207,643.00)
RSVA - Network Charge - 1584	191,050.00	35,278.00	226,328.00
RSVA - Connection Charge - 1586	137,538.00	25,887.00	163,425.00
Misc deferred debits - 1525	(17,001.00)		(17,001.00)
Qualifying Transition costs - 1570	(225,480.00)	-	(225,480.00)
			-
RSVA - Power - 1588	(388,887.00)	(68,746.00)	(457,633.00)
	(469,065.00)	(48,939.00)	(518,004.00)
the above variance amounts were moved to 1590 as approved			
Transferred to 1590	469,065.00	48,939.00	518,004.00
Transferred to 1508 from 1588 - same amount as discussed in part (a) on 2006 continuity schedule under adjustments "other"			563,169.00
EDR Decision			1,081,173.00