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BY E-MAIL

February 22, 2013

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Bluewater Power Distribution Corporation
Application for Rates
Board File Number EB-2012-0107

In accordance with the process documented in Procedural Order No. 3, please find attached Board staff's supplemental interrogatories in the above proceeding with respect to Bluewater Power Distribution Corporation's application for 2013 rates.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications & Regulatory Audit

Attach

Board Staff Supplemental Interrogatories
2013 Electricity Distribution Cost of Service
Bluewater Power Distribution Corporation
("Bluewater Power")
EB-2012-0107
February 22, 2013

General

1-Staff-58s

Ref: 2.1-1-Staff-1

Bluewater Power has not responded directly to the author of the letter of comment filed in this proceeding. It is Bluewater Power's interpretation that the author's concerns with commodity price increases and the debt of the former Ontario Hydro are beyond the control of management of Bluewater Power.

Please confirm that Bluewater Power is of the view that it has no responsibility as an LDC to assist its customers in clarifying or explaining electricity related matters that are beyond the control of Bluewater Power. If confirmed, please provide Bluewater Power's view as to how this approach is consistent with the LDC's customer service objectives.

1-Staff-59s

Ref: 3.2-1-EP-2

In its response to Energy Probe's IR, Bluewater Power indicated that it will be adopting IFRS as of January 1, 2014.

In February 2013, the Accounting Standards Board ("AcSB") decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2015.

Please confirm that Bluewater Power will still be adopting IFRS as of January 1, 2014, notwithstanding the recent decision of the AcSB.

1-Staff-60s

Ref: 3.2-1-EP-2

In its response to Energy Probe's IR, Bluewater Power stated that, "The 2013 Test Year will remain on an MIFRS basis, even though the 2013 reporting year will be based on CGAAP."

Bluewater Power also indicated that it has adjusted the employee future benefit expense from $478,667 on an IFRS basis to $577,399 on a CGAAP basis. Board staff noted that the revenue requirement was increased by $98,732, which reflects the increase in employee future benefits.

a) Given that the 2013 test year will “remain on an MIFRS basis” as stated by Bluewater Power, please explain why the employee future benefit expense was adjusted from an IFRS basis to a CGAAP basis.
b) Please specify any other areas in the application that are based on CGAAP rather than IFRS. If any, please provide the quantification and the impacts to revenue requirement of the changes.

1-Staff-61s

Ref: 3.2-1-EP-2

In its response to Energy Probe’s IR, Bluewater Power stated that although it will be under CGAAP for 2012, Bluewater Power has made the decision to make the following changes under CGAAP effective January 1, 2013:

- Indirect overhead will no longer be capitalized (same as MIFRS)
- The useful lives of capital assets for depreciation purpose will be changed to the same basis as filed in the 2013 Test Year (same as MIFRS)
- The useful lives for the amortization of contributed capital will be changed as the same basis as filed in the 2013 Test year (same as MIFRS)

With respect to each area of PP&E listed below, please identify the accounting policy choices (still under CGAAP, or aligned with IFRS) for 2013 Test Year under MIFRS:

#	Area of PP&E policy in 2013 Test Year in the Rate Application	Still Under CGAAP or Aligned with IFRS	External Auditor agreement with the policy? (Y/N)[1]	Impact of the change, if any, to the revenue requirement of 2013
1.	Asset Useful Lives			
2.	Componentization of Assets			
3.	Capitalization of Overheads			
4.	De-recognition of PP&E (including asset retirement)			
5.	Asset impairment			
6.	Asset contribution			
7.	Others – please specify			

Note 1: Please provide the reasons if the answer is “No” in the table. Please provide the plan for consultation with its auditor if Bluewater Power has not obtained the agreement with its external auditor.

Exhibit 2 – Rate Base

2-Staff-62s
Ref: 4.8-2-Staff-7
Bluewater Power has provided preliminary 2012 actual capital expenditures on a MIFRS basis. The preliminary actual expenditure of $8,211,489 is lower than the expenditure of $9,132,166 forecast in the application filed on October 22, 2012. Bluewater Power states that the actual results are subject to review through the audit process, and that the impact of 2012 actuals has not been reflected in rate base. Please provide the status of the audit process and advise when the 2012 actual capital expenditure will be reflected in rate base.

2-Staff-63s
Ref: 4.17-2-Staff -10
Project UT39 is a $223,211 capital expense "on implementing upgrade improvements to SAP and connected Operations software to improve workflow efficiencies in Maintenance, Asset Management, Dispatch and Supply Chain." Part (b) of Staff IR #10 sought the measures that Bluewater Power will use to measure the improvements in workflow efficiencies. The response stated:

> The implementation phase above mentioned process will focus heavily on ensuring that all changes to the planning/scheduling/work execution implementation process are sustainable. It will require staff job description changes as well to ensure sustainability.

The scope and expected results of this project are unclear. What specific measures will Bluewater Power use to measure the improvements in workflow efficiencies?

2-Staff-64s
Ref: 4.21-2-Staff-14
Bluewater Power indicated that it has no formal IT Asset Management Strategy, but provided a summary of the practices it follows for management of IT assets. How do these practices manage the 21 IT capital projects, so that common requirements, such as system testing, are co-ordinated where possible?

2-Staff-65s
Ref: 4.25-2-Staff-16
Bluewater Power states that the annual cost of the CN lease has not been removed from the 2013 forecast as the lump sum payment to CN is not expected to be paid until the end of 2013. What is Bluewater Power's proposal for the CN lease during the IRM period?

2-Staff-66s
Ref: 4.28-2-AMPCO-6
Ref: 4.26-2-Staff-17
Staff IR 17 queried Bluewater Power reliability performance and specifically questioned what additional measures were put in place following the incident related to the failed arrestor. Bluewater Power replied that arrestor failure is impossible to predict without performing destructive testing. AMPCO IR 6 queried the reliability programs that Bluewater Power has in place to address reliability issues faced by the Large User class. Bluewater Power replied that in some cases, arrestors have been replaced proactively. Please reconcile these two positions.

Exhibit 3 - Revenue

3-Staff-67s
Ref: 5.16-3-Staff-24
Ref: 5.18-3-VECC-21
Bluewater Power provided the derivation of its proposed adjustment to account for the impacts of CDM in response to Staff IR 24. Bluewater Power also provided the final 2006-2010 CDM Impacts and 2011 CDM Impact Reports as reported by the OPA in response to VECC IR 21.

Board staff observes that the adjustment for historical CDM takes the annual cumulative results as reported by the OPA for each year from 2006 to 2011 and then averages these. However, the results reported by the OPA are annualized, i.e. assume that the program is in place for the full year. For example, the 2006 'net' CDM impacts on 2006 are reported as 2,450,277 kWh. This estimate would only be true if the 2006 CDM programs were fully in place at the stroke of midnight on January 1, 2006. Clearly, they are not. In the absence of detailed information of when the programs took place, when results started to show, and seasonal patterns of CDM impacts, a half-year rule might be a better approach for estimating the actual impact in the first year of a CDM program. The persistence into subsequent years should be on the full-year "annualized" basis.

In using the annualized results, the average annual impact of 2006-2011 CDM programs is likely overstated. Why does Bluewater Power believe that average annual impact based on annualized CDM impacts is appropriate for their adjustment to account for historical CDM on the base forecast?

3-Staff-68s
Ref: 5.16-3-Staff-24
Ref: 5.18-3-VECC-21
Bluewater Power has proposed to use a CDM target of 30% as the CDM adjustment for the 2013 load forecast amount to take into account the persistence of 2011 and 2012 CDM programs, and the impact of 2013 CDM programs on 2013 demand (consumption, measured in kWh).

An alternative approach is to take into account the 2011 results and their persistence, as measured and reported by the OPA for Bluewater Power, and then to assume an equal increment for each of 2012, 2013, and 2014 so as to achieve Bluewater Power's CDM target of 53,730,000 kWh. Board staff views that this approach is preferable as there are results on what the utility has achieved to date, and hence what more will be needed to achieve the cumulative four-year target. In using the measured and reported results from the 2011 programs, including the persistence into 2013, Board staff views that an improved estimate of the CDM impact of 2011-2013 programs on the LRAMVA threshold for 2013 (and 2014) would result, along with the corresponding adjustment to the 2013 test year load forecast.

Based on the final 2011 OPA results provided in response to VECC IR 21, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:

Load Forecast CDM Adjustment Work Form (2013)

Bluewater Power Inc.	***EB-2012-0107***

4 Year (2011-2014) kWh Target:					
53,730,000					
	2011	2012	2013	2014	Total
%					
2011 CDM Programs	9.89%	9.67%	9.67%	9.61%	38.85%
2012 CDM Programs		10.19%	10.19%	10.19%	30.58%
2013 CDM Programs			10.19%	10.19%	20.38%
2014 CDM Programs				10.19%	10.19%
Total in Year	**9.89%**	**19.87%**	**30.06%**	**40.19%**	**100.00%**
kWh					
2011 CDM Programs	5,313,187	5,198,072	5,198,072	5,162,989	20,872,319
2012 CDM Programs		5,476,280	5,476,280	5,476,280	16,428,840
2013 CDM Programs			5,476,280	5,476,280	10,952,560
2014 CDM Programs				5,476,280	5,476,280
Total in Year	**5,313,187**	**10,674,352**	**16,150,632**	**21,591,829**	**53,730,000**
				Check	53,730,000

	Net-to-Gross Conversion "Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ('g')
2006 to 2011 OPA CDM programs: Persistence to 2013	1	1	0	0.00%

	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	5,198,072	5,476,280	5,476,280		16,150,632
Manual Adjustment for 2013 Load Forecast	5,198,072	5,476,280	2,738,140		13,412,492
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

The methodology for this is as follows:

For the first table

- The 2011-2014 CDM target is input into cell B4;
- Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C13 to F13;

Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

The second table is to calculate the conversion from "net" to "gross" results. While the LRAMVA is based on the "net" OPA-reported results, the load forecast is impacted also by CDM savings of "free riders" and "free drivers". While Board staff has input values of "1" in each of cells D24 and E24, in the absence of information, these should be populated with the measured "gross" and "net" CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports.

For the last table, two numbers are calculated:

- The "Amount used for CDM threshold for LRAMVA" is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and
- "Manual Adjustment for 2013 Load Forecast" represents the amount to be reflected in the 2013 load forecast. This amount uses the "gross" impact, which is calculated by multiplying each year's CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 "actual" consumption is divided by 2 to reflect a "half year" rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the "annualized" results reported in the OPA report will overstate the "actual" impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a "half-year" rule may proxy the impact.

a) Please input the "gross" and "net" cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D24 and E24.
b) Please verify the inputs and results of the model.
c) Please derive the class CDM kWh and kW savings that would correspond with the "net" CDM savings above.
d) Please provide Bluewater Power's comments on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What refinements to this approach should be considered? For example, since the 2011 actual results are impacted by 2011 CDM programs, should some adjustment (e.g. a half-year rule) be used to account for the fact that 2011 CDM programs would have impacted the 2011 actual results and, in a stochastic manner the resulting regression models and base forecast? Also provide Bluewater Power's views on whether this approach integrates with the adjustment to account for historical CDM impacts as discussed in Staff IR 24.

Exhibit 4 – Operating Costs

4-Staff-69s

Ref: Exh 4-2-9
<u>Ref: 6.10-4-VECC-27</u>
At Exh 4-2-9, it states that "Bluewater Power has not included any amounts for charitable donations in its 2013 OM&A, and therefore nothing is included in revenue requirement." In response to VECC IR #27, it states that account 5410 "Sundry"

captures amounts Bluewater Power provides to various agencies such as the Inn of the Good Shepherd. Bluewater Power states that the account increased in 2011 by $24,000 related to LEAP funding. Please confirm whether Bluewater Power has included any amounts for charitable donations in its 2013 OM&A.

4-Staff-70s
Ref: 6.36-4-Staff-33
Ref: 6.38-4-VECC-36
Ref: Exh 3-1-2 Attachment 1
Bluewater Power states that the 75th percentile for compensation for Executive and Management was selected for the purposes of retention and recruitment. In response to VECC IR #36, Bluewater Power notes competition from the Chemical Valley for staff.

a) What is average staff turnover in per cent for the period 2009 to 2012?
b) Bluewater Power's load forecast utilized full-time employment for the Windsor-Sarnia area as reported in Statistics Canada's Monthly Labour Force Survey. Please provide the Windsor-Sarnia unemployment rate from that survey and how that rate compares with other regions in Ontario, as reported by Statistics Canada.

4-Staff-71s
Ref: 6.45-4-Staff-34
Board staff provided a blank table for retirement data. Bluewater Power has populated the table, however, one item is missing. Please provide the prior period balance cumulative.

4-Staff-72s
Ref: 6.51-4-Staff-38
Ref: Exh 4-8-3, Attachment 1 – 2013 PILs model
In its response to part (d) of Board staff IR 38 with respect to adjusting the PILs provision to spread out the tax savings related to smart meter software, Bluewater Power stated that this treatment is no different than certain one-time costs that are spread evenly over the IRM period.

Please provide any regulatory precedent specifically for the one-time tax saving over the IRM period.

4-Staff-73s
Ref: 6.51-4-Staff-38
Ref: Exh 4-8-3, Attachment 1 – 2013 PILs model
In its response to part (b) of Board staff IR 38, Bluewater Power clarified that the capital expenditure of $770,255 for smart meter software was incurred in 2012 and allocated to Class 12 in 2012. In addition, Bluewater Power stated that the first 50% forms part of the total CCA deduction in 2012, and the remaining forms part of the total CCA deduction in 2013.

In the 2013 PILs model schedule 8 CCA for bridge year (2012), a total addition of $3,060,259 is included for Class 12 computer software. In the 2013 PILs model schedule 8 CCA for test year (2013), a total addition of $993,695 is included for Class 12 computer software and the UCC Test year opening balance for class 12 computer software is $1,530,130.

a) Please confirm that the smart meter computer software of $770,255 is included in the total addition of $3,060,259 in 2012 bridge year schedule 8 CCA.
b) Please confirm that the UCC Test year opening balance for class 12 of $1,530,130 includes the second half of the $770,255 smart meter software expenditure.
c) Please confirm that the 2013 addition of $993,695 for class 12 computer software on schedule 8 does not include the $770,255 smart meter software.
d) If the answer to c) is yes, please explain Bluewater Power's justification of the proposed adjustment to spread the one-time tax saving of the smart meter computer software where there is no adjustment to spread the addition of $993,695 class 12 computer software in 2013.

4-Staff-74s
Ref: 6.69-4-VECC-49
In its response to VECC IR 49, Bluewater Power notes that it still does about 430 meter reads monthly for GS > 50 kW demand metered customer through its affiliate at a cost of about $6.78 per meter read.

Board staff calculates this annual expense to be: $6.78 x 430 reads x 12 months = $34,984.80.

a) Where is this cost documented in Bluewater Power's OM&A?
b) What were the costs for these meter reads for each year from 2009 to 2012?

Exhibit 5 – Capital Structure and Cost of Capital

5-Staff-75s
Ref: 7.5-5-VECC-53
Ref: 7.4-5-VECC-52
In its response to VECC IR 53, Bluewater Power states that the unfunded debt portion should be based on the Board's deemed debt rate. Board staff observes that the "unfunded debt" that Bluewater Power refers to results from its actual equity thickness of 49%, as documented in the response to VECC IR 52, which is higher than the deemed equity thickness of 40%. This is a decision of Bluewater Power and its shareholder on the capital structure adopted for financing purposes.

Board staff notes that the Board's policy and practice for the treatment of notional debt has been well established in Board decisions relating to both the December 20, 2006 *Report of the Board on the Cost of Capital and 2nd Generation Incentive Regulation for*

Ontario's Electricity Distributors and the current *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084), issued December 11, 2009.[1]

Please provide further reasons why Bluewater Power believes that the deemed long-term debt rate should apply to its notional debt rate rather than the average weighted cost of long-term debt based on the company's actual and forecasted debt instruments in the 2013 test year.

5-Staff-76s
Ref: Exh 5-1-1
On February 14, 2013, the Board issued a letter which set out the cost of capital parameters updates for cost of service applications effective May 1, 2013. Please update Appendix 2-OA, the RRWF and bill impacts (Residential 800 kWh and GS<50 kW 2,000 kWh) accordingly.

Exhibit 7 – Cost Allocation

7-Staff-77s
Ref: 9.2-7-Staff-42
The objective of the interrogatory was to examine the weighting factor for services for non-residential customers. However, the response provided information related to residential customers. Please provide the response for non-residential customers.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-78s
Ref: 4.2-2-Staff-5
Ref: 11.3-9-Staff 51
In response to Staff IR 5, Bluewater Power provided 2012 NBV of stranded meters. Please explain why the NBV differs from that used to determine the SMRR in the response to Staff IR 51.

[1] Decision and Order EB-2008-0235 (London Hydro Inc.), August 21, 2009, page 37 and Decision with Reasons EB-2010-0008 (Ontario Power Generation Inc.), March 10, 2011, page 125