BLUEWATER POWER DISTRIBUTION CORPORATION

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February 2, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2701
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: <u>EB-2008-0221 Bluewater Power 2009 Rate Application</u>
<u>Update to Application</u>

In Accordance with Procedural Order No. 4, Bluewater Power has attached an update to its pre-filed evidence to address the pending closure of two material customers.

The update to the pre-filed evidence has been labeled Exhibit 1, Tab 1, Schedule 3.1

We have also attached two additional documents:

- An updated 'Application' (Exhibit 1, Tab 1, Schedule 2); and
- An updated 'List of Orders Sought' (Exhibit 1, Tab 1, Schedule 8)

Two hard copies will follow via courier.

Should there be any questions please contact me at the number below.

L. Dugas

Leslie Dugas
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Bluewater Power Distribution Corporation
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cc: All Intervenors

Bluewater Power Distribution Corporation
EB-2008-0221
Update to 2009 Electricity Distribution Rate Application

Executive Summary

Since the filing of Bluewater Power Distribution Corporation's ("Bluewater Power") 2009 EDR application in September of 2008, two of its customers have announced that they will be closing in 2009. The impact of these closures on the 2009 Test Year distribution revenue forecast is uncertain since the closure dates are unknown. Nevertheless, it is clear that unless Bluewater Power's 2009 distribution rates, which serve as the base for the Incentive Rate Mechanism ("IRM") period, contemplate the closure of these customers, Bluewater Power will experience incremental gross revenue shortfalls that could total $1.5 million over the term of the IRM (i.e., 2010, 2011 and 2012), which is very material to Bluewater Power. Such incremental shortfalls could significantly harm Bluewater Power's financial position, particularly in light of the general deterioration in economic conditions in the Bluewater Power service area.

Accordingly, Bluewater Power proposes to update its 2009 EDR application such that the proposed distribution rates are premised on the closure of the two customers. By making this adjustment, Bluewater Power's distribution rates going into the IRM period will accurately reflect the revenue impact of the absence of these customers. Because Bluewater Power will recover revenue from these customers from the beginning of 2009 until they close, Bluewater Power requests that it be permitted to use a deferral account to record any 2009 distribution revenues paid by these two customers so that in future, these revenues may be returned to Bluewater Power's customers.

Based on this proposal, Bluewater forecasts the following overall bill increases relative to the rates it originally proposed in its September 2008 filing:

Table 1 - Total Bill % Change Caused by Proposal

Rate Class	Total Bill % Change
Residential	0.2%
GS<50	0.0%
GS 50 to 999 kW	0.4%
GS 1000 to 4999 kW	0.3%
Large	0.8%
USL	0.0%
Sentinel (per connection)	0.2%
Street lighting (per connection)	0.3%

Bluewater Power proposes to mitigate these increases by accelerating the period for returning the credit balances recorded in variance and deferral accounts over a two year period, as opposed to over a three year period as originally proposed in the pre-filed evidence. The net impact of Bluewater Power's updated proposed distribution rates and its proposed mitigation results in overall bill decreases for all of Bluewater Power's customers relative to the rates originally proposed in the pre-filed evidence, as illustrated by the following table:

Table 2 - Total Bill % Change Caused by Proposal Plus Mitigation

Rate Class	Total Bill % Change
Residential	-0.3%
GS<50	-0.5%
GS 50 to 999 kW	-0.3%
GS 1000 to 4999 kW	-0.5%
Large	-0.1%
USL	-0.4%
Sentinel (per connection)	-0.4%
Street lighting (per connection)	-0.1%

In summary, unless the loss of Bluewater Power's two material customers is addressed through updated proposed distribution rates, Bluewater Power's financial position going forward will be harmed.
The methodology proposed in this update will ensure that Bluewater Power's rates are just and reasonable, the rates will provide an acceptable return on equity, and that its customers and shareholders are not negatively impacted.

Introduction

Bluewater Power is filing this updated evidence in support of its application for revised electricity distribution rates that will be implemented May 1, 2009. It was triggered by closure announcements by two of Bluewater Power's customers and by Bluewater Power's understanding of the associated financial impacts to its electricity distribution business. This evidence describes and considers:

- The facts surrounding these two customers and their recently announced closures;
- The impact on Bluewater Power's 2009 Load Forecast;
- The associated financial consequences to Bluewater Power;
- Evaluation of the appropriateness of the distribution rates proposed in the September 2008 filing;
- The available rate making options;
- Bluewater Power's preferred rate making option and the analysis supporting that option;
- Bluewater Power's proposed implementation of its preferred option; and
- The impact to customers of Bluewater Power's updated distribution rates and updated rate riders.

The analysis that follows examines the appropriateness of the original proposed rates for 2009 as base rates for the IRM period until the intended next Bluewater Power full rebasing application (for the 2013 test year). For the years within the IRM period both of the customers that are the subject of this update will be closed; hence, the analysis is based on these full closures.

Bluewater Power recognizes that it will receive revenue from these customers for part of the 2009 test year. It is therefore proposing to set base rates for the IRM period that recognize the closure of these plants and also to record the actual distribution revenues collected from these customers in a deferral account for disposition to customers. This proposal addresses the disconnect between the appropriate level of rates in 2009 for Bluewater Power to recover its 2009 revenue requirement and the appropriate level of rates in 2009 to serve as the base year for Bluewater Power's rates during the upcoming 3GIRM term.

Recent Developments at Royal Polymers and UBE

In April of 2008 Elenchus Research Associates ("ERA") prepared a Load Forecast for Bluewater Power in support of its 2009 EDR application. Since that forecast was prepared Royal Polymers Ltd. ("Royal"), a General Service >50 - Intermediate ("Intermediate") customer, and UBE Automotive North America Sarnia Plant, Inc. ("UBE"), a Large Use customer, have announced their intention to close in 2009.

In 2008 Royal was reclassified from the Large User customer class to the Intermediate customer class because of a material reduction in its consumption of electricity in 2007. In September 2008, as Bluewater Power was finalizing the subject application, Royal was deciding whether to close. Because Bluewater Power did not have definitive evidence of the closure Royal was not removed from the 2009 load forecast. Rather, Royal was included and forecast to consume 50% of their actual 2007 load. Bluewater Power has now been advised that Royal intends to cease operations completely in 2009. A copy of the company's press release is attached as Appendix A.

UBE manufactures aluminum car wheels. On January 12, 2009 Bluewater Power learned that UBE intended to cease all commercial operations within 6 months. A letter from UBE is attached as Appendix B.

Bluewater Power has therefore adjusted its plans in recognition that these two large customers will close no later than the end of 2009.

The Impact on Bluewater Power's Load Forecast

Bluewater Power has revised the 2009 Load Forecast to reflect the closure of these customers. The Original load forecast, Updated load forecast with the two customers removed and the associated variance are displayed in the tables below. These forecasts are reflective of 2009 appropriately adjusted to be fair as the base year for the 3rd Generation IRM Plan ("3GIRM").

Table 3 - Number of Connections

	Original	Updated	Variance	Variance %
Customer Class Name	**2009 Normalized**	**2009 Normalized**	**2009 Normalized**	
Residential	32,006	32,006	0	0%
General Service <50 kW	3,924	3,924	0	0%
General Service 50 to 999 kW	396	396	0	0%
General Service 1,000 to 4,999 kW	16	15	(1)	-6%
Large	4	3	(1)	-25%
Unmetered Scattered Load	266	266	0	0%
Sentinel Lighting	526	526	0	0%
Street Lighting	10,009	10,009	0	0%
TOTAL	**47,147**	**47,145**	(2)	-0.004%

Table 4 – Metered Energy (kWh)

Customer Class Name	Original 2009 Normalized	Updated 200 Normalized	Variance 2009 Normalized	Variance %
Residential	266,434,436	266,434,436	0	0%
General Service <50 kW	120,544,382	120,544,382	0	0%
General Service 50 to 999 kW	216,234,424	216,234,424	0	0%
General Service 1,000 to 4,999 kW	181,109,127	165,546,229	(15,562,898)	-9%
Large	321,942,304	280,461,771	(41,480,533)	-13%
Unmetered Scattered Load	2,188,838	2,188,838	0	0%
Sentinel Lighting	684,138	684,138	0	0%
Street Lighting	8,719,920	8,719,920	0	0%
TOTAL	**1,117,857,569**	**1,060,814,138**	(57,043,431)	-5%

Table 5 – Kilowatts (kW)

Customer Class Name	Original 2009 Normalized	Updated 2009 Normalized	Variance 2009 Normalized	Variance %
Residential				
General Service <50 kW				
General Service 50 to 999 kW	593,516	593,516	0	0%
General Service 1,000 to 4,999 kW	398,767	372,459	(26,308)	-7%
Large	493,510	421,890	(71,620)	-15%
Unmetered Scattered Load			0	
Sentinel Lighting	1,637	1,637	0	0%
Street Lighting	23,562	23,562	0	0%
TOTAL	**1,510,992**	**1,413,064**	(97,928)	-6%

The adjustments to the load forecast were based on the 2007 consumption and demand of these customers, adjusted for the growth factors that were applied in the forecasting methodology provided by ERA (Exhibit 3, Tab 2, Schedule 1, Attachment 1, Table 6). As noted earlier, the forecast for Royal already assumed a 50% reduction over the 2007 actual values, so the adjustments in Tables 2 and 3 removed the remaining 50%.

The Associated Financial Consequences to Bluewater Power

Bluewater Power estimates that the closure of these customers will reduce its 2009 Regulatory Net Income ("Net Income") from $1,974,129 to $1,700,838, a $273,291 reduction. This material reduction in Net Income presents an unacceptable risk to Bluewater Power's financial position if not addressed in setting base rates for the 3GIRM term. Please note that the following discussion is premised on both customers being closed throughout 2009 to appropriately characterize the impacts of the closures on Bluewater Power during the IRM period.

This Net Income reduction reflects the combined impact of the following line items:

1. reduced annual distribution revenues recovered through the rates proposed in the September 9, 2008 submission ("Originally Proposed Rates") of $513,820;
2. $639,687 of stranded distribution assets (net book value of $422,193);
3. reduced Working Cash Allowance by $584,166;
4. Net Income .

Each of these impacts is discussed in greater detail below.

1. Distribution Revenue Impact

Applying Bluewater Power's Originally Proposed Rates to the updated Load Forecast yields reduced annual Large User and Intermediate distribution revenue recovered through fixed and variable charges of $513,820 once the closures are in effect on a full year basis. This is derived in the table below.

Table 6 - Projected One Year Distribution Revenue Shortfall

(UBE and Royal closed full 12 months)

	2009 kW in Forecast	Proposed Variable Rate	Proposed Monthly Charge	Distribution Revenue
Distribution Revenue Impact of Large Use Customer	71,620	1.6337	$ 25,756.94	$ 426,088.87
Distribution Revenue Impact of Intermediate Customer	26,306	1.7345	$ 3,508.63	$ 87,731.32
Total Distribution Revenue Impact				$ 513,820.19

Bluewater Power estimates that over the term of the 3GIRM that the distribution revenue loss attributable to these closures could amount to $1.5 million and if the anticipated impacts of existing economic conditions are included then the associated distribution revenue loss could be as much as $1.9 million.

2. Distribution Property, Plant and Equipment Impact

The closure of these two customers will impact Bluewater Power's distribution Property, Plant and Equipment assets.

When completing the Cost Allocation Informational Filing ("CAIF") Bluewater Power determined that net fixed assets, valued at $1,541,173 in 2004, served UBE only. The 2009 net book value of these assets is $1,208,500. After UBE ceases operations, some of these facilities will be redeployed to serve customer growth occurring close to the UBE plant. These facilities will be utilized by all customer classes in the future. $639,687 of the gross asset value will no longer be used and useful to Bluewater Power in providing service to its customers. This amount and the associated accumulated amortization, being $217,493, will therefore be removed from Bluewater Power's rate base. Bluewater Power will seek to recover $422,193, being the net book value of these stranded assets, from UBE.

Table 7 - Asset Values which were Directly Allocated to the Large Use Class

Directly Allocated Assets	Gross Asset	Accumulated Depreciation	Net Asset Value
Year end 2004 (used in Cost allocation informational filing)	$ 1,774,043	$ 232,871	$ 1,541,173
Amount no longer usable (pertaining to year end 2004)	$ 639,687	$ 89,556	$ 550,130
Remaining Amount in Rate Base at year end 2004	$ 1,134,357	$ 143,315	$ 991,042
Year end 2009 (value of all directly allocated assets)	$ 1,774,043	$ 565,543	$ 1,208,500
Amount no longer usable pertaining to 2009	$ 639,687	$ 217,493	$ 422,193
Remaining Amount in Rate Base at end of 2009	$ 1,134,357	$ 348,050	$ 786,307

3. Working Cash Allowance Impact

Additionally, because overall energy deliveries will be reduced by 57,043,431 kWh there will be a reduction in the Working Cash Allowance. This gives rise to consequential changes to the deemed interest expense and to the deemed PILs expense as well as to the Allowed Return. At an "all in" average cost of 10.24 cents/kWh, this results in a $584,166 reduction in the 2009 Working Cash Allowance.

The table below summarizes the original and updated 2009 rate base.

Table 8 – Working Capital, Net Fixed Assets and Rate Base

	Original	Updated	Variance
Working Capital Allowance	$ 13,613,408	$ 13,029,242	$ (584,166)
Net Fixed Assets Opening Balance	$ 37,944,816	$ 37,944,816	$ -
Net Fixed Assets Closing Balance	$ 41,145,335	$ 40,723,141	$ (422,194)
Net Fixed Assets Average Balance	$ 39,545,075	$ 39,333,978	$ (211,097)
TOTAL RATE BASE	**$ 53,158,483**	**$ 52,363,220**	**$ (795,263)**

4. Net Income

Bluewater Power's Net Income will be materially and negatively impacted by the shutdown of UBE and Royal. Bluewater Power's originally proposed 2009 Return on Deemed Equity was $1,974,129. If rates are not adjusted to mitigate for these known load impacts then Bluewater Power's 2009 achieved Net Income can be expected to be reduced to $1,700,838 once the closures are in effect on a full-year basis. This corresponds to a return on equity of 7.47% and is over 100 basis points lower than the currently authorized return on equity. The derivation of these financial impacts is summarized in the table below.

Table 9 – Estimate of Forecasted Achieved Return on Deemed Equity

	Original Proposal	Updated for known Loss of Load
Regulated Revenue	$21,436,076	$20,922,256
OM&A	$11,656,169	$11,656,169
Depreciation	$4,358,109	$4,332,522
Deemed Interest	$2,124,944	$2,093,154
Earnings Before Taxes	$3,296,854	$2,840,411
PILs Expense (40.12%)	$1,322,725	$1,139,573
Net Income	$1,974,129	$1,700,838
Deemed Equity	$23,033,571	$22,780,452
Achieved Return on Deemed Equity	8.57%	7.47%

Evaluation of the Originally Proposed Rates

The originally proposed rates do not establish base rates for the 3GIRM period that are capable of recovering the ongoing costs incurred to provide distribution service to the customers in Bluewater Power's licensed service area and permitting an opportunity to earn a fair return on invested capital – therefore the originally proposed rates are no longer just and reasonable.

If the originally proposed rates are not adjusted for these known changes in load then the reduced level of both Net Income and achievable Return on Equity will persist for the IRM period, being 2010-2012. The cumulative impairment to Net Income could amount to over $820,000. Further, given the pressures of the economic downturn that have already been observed with energy and demand reductions of other classes, as indicated in response to Board Staff interrogatory 6.1, and the expected persistence of the recessionary economic conditions in Bluewater Power's service territory, Bluewater Power expects these economic conditions to further erode this updated forecast of net income quite significantly.

Clearly, the originally proposed rates are inappropriate for the 2009 Rate Year as the base for the subsequent IRM period of 2010 – 2012.

The Available Rate Making Options

Bluewater identified and evaluated the following rate making options:

1. Do nothing;
2. Apply for a Z-factor in 3rd GIRM;
3. Rebase rates for 2010;
4. Preferred Option:
    a. update the 2009 Rates assuming UBE and Royal are closed
    b. accelerate proposed return of variance and deferral account balances and
    c. record any distribution revenue recovered from Royal or UBE in a deferral account for future disposition to customers.

The "Do Nothing" option was rejected out of concern that a reduction to the 2009 distribution revenues of $513,820 which during the IRM period could amount to a total of $1.5 million - $1.9 million poses an unacceptable risk to Bluewater Power's financial position.

The "3GIRM Z- Factor" option was rejected because of the ambiguity associated with the acceptability to the Board of treating as a Z factor unusual economic conditions that result in revenue losses during the IRM period that are not within the control of the utility management, are material, are not recovered through rates and are prudent. Given the uncertainty associated with this option, Bluewater Power considers it prudent and appropriate to address the concern as part of the process of setting base rates that are sustainable for the subsequent 3GIRM period.

The "2010 Rebasing" option was rejected because rebasing is an expensive and resource intense application. Bluewater Power does not believe that it would be in the interest of its customers or the Board to incur the expense of a second full rebasing application during the intended 3GIRM period. Rebasing in 2010 will also further burden Bluewater Power's staff at a time when they should be preparing for the implementation of other initiatives (eg., Time of Use commodity rates, smart metering, IFRS), further tax intervenors' resources available for reviewing 2010 EDR rebasing applications and add to the OEB's administrative and adjudicative workload. Such an application would likely cost as much as the subject application (approximately $340,000) and those duplicate costs would ultimately be recovered from rate payers. Clearly this is not an attractive alternative.

Bluewater Power's Preferred Rate Making Option and the Analysis Supporting that Option

Bluewater Power's preferred Rate Making option is:

- Update the proposed 2009 distribution rates assuming that Royal and UBE are closed for the entire 2009 year;
- Update the proposed rate riders to return of the balances recorded in the variance and deferral accounts over 2 years; and
- Establish a deferral account that will record any distribution revenues recovered from Royal or UBE in the 2009 test year or subsequent years, for future disposition to customers.

This option is preferred because:

- It results in distribution rates that:
  - are just and reasonable
  - are appropriate for the purposes of the 3GIRM
  - are supported by the best available information
  - are expected to be able to be implemented effective May 1, 2009
- It does not require rebasing distribution rates in 2010 through a comprehensive application that is expected to be as costly and resource intensive as the subject application;
- It adjusts the proposed rates of the Test Period for events that will occur during the Test Period;
- It does not delay incorporating in distribution rates the consequences of events that will occur in the 2009 Test Year;
- It does not risk eroding or impairing Bluewater Power's financial position.
- It allows for the earning of the approved return on equity

Bluewater Power's Proposed Implementation of its Preferred Option

Bluewater Power proposes to:

- Update the load forecast to remove the load embedded for the two above noted customers only;
- Update the net fixed assets to remove the amount of assets that will no longer be used and useful;
- Update the Working Cash Allowance, and all consequential amounts, for the proposed reduction in energy deliveries;
- Update the CAIF for the proposed changes to the Load Forecast and rely on the resulting Revenue:Cost ratios for rate making purposes;
- Update the proposed rate riders to accelerate the return to customers of the balances recorded in the variance and deferral accounts;
- Utilize USoA account 1572 to capture any actual net distribution margin realized by Bluewater Power from either Royal or UBE; and
- Dispose of the balance recorded in the deferral account through a future application.

The distribution revenue, rate base and OM&A impacts of Royal's and UBE's closures were discussed previously. The updated 2009 Revenue Requirement is provided in the table below.

Table 10 – Revenue Requirement

Revenue Requirement	Original	Updated	Variance
OM&A Expenses	$ 11,656,169	$ 11,656,169	$ -
3850-Amortization Expense	$ 4,358,109	$ 4,332,522	$ (25,587)
Total Distribution Expenses	$ 16,014,278	$ 15,988,691	$ (25,587)
Regulated Return On Capital	$ 4,098,944	$ 4,037,623	$ (61,321)
PILs (with gross-up)	$ 1,322,854	$ 1,293,915	$ (28,939)
Service Revenue Requirement	$ 21,436,076	$ 21,320,229	$ (115,847)
Less: Revenue Offsets	$ 728,598	$ 728,598	$ -
Base Revenue Requirement	$ 20,707,479	$ 20,591,632	$ (115,847)

The updated 2009 Gross Revenue Deficiency is provided in the table below.

Table 11 – Revenue Deficiency

	Original	Updated	Variance
Gross Revenue Sufficiency / (Deficiency)	$ (4,843,712)	$ (5,087,340)	$ (243,628)

Updating the Cost Allocation Informational Filing

Exhibit 8, Tab 1, Schedule 1 of Bluewater Power's September 9, 2008 submission provides ERA's evidence of a revision to Bluewater Power's 2006 CAIF. The CAIF has been further updated to reflect the loss of the two noted customers. The updated evidence shows the Revenue:Cost ratios for the Large User and Intermediate classes change materially due to the combined effects of:

- the changes in recoverable revenues from the Large User and Intermediate class;
- the changes in the treatment of the directly allocated costs; and
- the changes to the cost allocators.

The changes to the Revenue:Cost ratios of the other classes are relatively small.

The original and updated 2006 revenue requirement allocation and Revenue:Cost ratios are provided in the updated evidence of ERA (attached as Appendix C) and are reproduced below.

Table 12 -Original Adjusted Cost Allocation Results

	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Revenue Requirement	**$17,808,908**	$9,255,455	$2,839,671	$2,752,110	$664,857	$1,384,016	$694,571	$62,481	$155,747
Revenue to Expense %	**100.00%**	99.21%	107.14%	88.34%	139.77%	129.73%	44.17%	32.83%	64.71%

Table 13 -Updated Cost Allocation Results

	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Adjusted Revenue Requirement	**$17,727,744**	$9,323,095	$2,867,579	$2,814,539	$717,815	$1,093,090	$693,040	$62,361	$156,225
Adjusted Revenue to Expense %	**100.00%**	99.90%	107.63%	87.32%	132.25%	134.79%	44.76%	33.22%	65.45%

Hydro One Networks Inc.'s Load Data Analysis has been adjusted as follows:

- remove UBE and Royal's 2004 hourly load data from the 2004 Large User hourly load data
- inspect the resulting load data for the Large User and General Service > 50 kW customer classes to identify the 1, 4 and 12 Coincident Peaks and the 1, 4 and 12 Non-Coincident Peaks

The CAIF has been adjusted as follows:

- Adjust the data input to worksheet I8 consistent with the changes to HONI's Load Data Analysis
- Adjust worksheet I6 as follows:
    - Estimate Large User customer class kWh, kW and revenue adjustment factors consistent with the closure of UBE and Royal; reduce the number of bills to reflect the closure; and
    - alter the number of customers in the Large User customer class (bulk and primary customer base).
- Adjust worksheet I7.1 as follows:
    - eliminate two meters from the Large User class
- Adjust worksheet I7.2 as follows:
    - Reduce the number of eligible customers in the Intermediate and Large User class

No other changes were made to the CAIF.

These computed Revenue:Cost ratios were input into Bluewater Power's 2009 rates model and further adjusted to achieve Revenue:Cost ratios consistent with the Board's policy. The Revenue:Cost ratios underlying the proposed distribution rates are provided in the table below.

Table 14 – Updated Cost Allocation proposed in Application

	Rate Application			Cost Allocation		Target Range	
Customer Class Name	**Allocated Revenue**	**Allocated Cost**	**Revenue to Cost Ratio**	**Revenue to Cost Ratio**	**Variance**	**Floor**	**Ceiling**
Residential	10,716,541	10,770,393	1.00	1.00	(0.00)	0.85	1.15
General Service <50 kW	3,404,801	3,321,757	1.03	1.08	(0.05)	0.80	1.20
General Service 50 to 999 kW	3,297,265	3,297,265	1.00	0.88	0.12	0.80	1.80
General Service 1,000 to 4,999 kW	1,109,745	847,364	1.31	1.32	(0.01)	0.80	1.80
Large	1,471,948	1,291,182	1.14	1.35	(0.21)	0.85	1.15
Unmetered Scattered Load	121,094	172,991	0.70	0.65	0.05	0.80	1.20
Sentinel Lighting	33,338	73,433	0.45	0.33	0.12	0.70	1.20
Street Lighting	436,900	817,247	0.53	0.45	0.09	0.70	1.20
TOTAL	20,591,632	20,591,632	1.00	1.00			

The updated proposed distribution rates are displayed in the table below.

Table 15 – Updated Rates

Rate Class	**Original Fixed Charge (before smart meters)**	**Updated Fixed Charge (before smart meters)**	**Variance**	**Original Variable Charge**	**Updated Variable Charge**	**Variance**
Residential	17.50	17.58	0.08	0.0150	0.0151	0.0001
GS<50	31.52	31.61	0.09	0.0160	0.0161	0.0001
GS 50 to 999 kW	433.49	446.64	13.15	2.1298	2.1944	0.0646
GS 1000 to 4999 kW	3,507.63	3,684.10	176.47	1.7345	1.8218	0.0873
Large	25,755.94	28,129.78	2,373.84	1.6337	1.7843	0.1506
USL	22.37	22.42	0.05	0.0228	0.0228	-
Sentinel (per connection)	3.11	3.13	0.02	8.2803	8.3456	0.0653
Street lighting (per connection)	2.36	2.38	0.02	6.4356	6.4838	0.0482

A reconciliation of the revenues recovered from each customer class through the application of the proposed rates and each class' responsibility for the total revenue requirement is provided in the table below.

Table 16 – Reconciliation of Revenue Recovered through Updated Distribution Rates and Allocation of the Revenue Requirement

Customer Class Name	Calculated Revenue	Allocated Revenue Requirement	Difference
Residential	10,775,146	10,772,288	2,858
General Service <50 kW	3,429,216	3,427,396	1,821
General Service 50 to 999 kW	3,424,845	3,424,855	(11)
General Service 1,000 to 4,999 kW	1,341,684	1,341,688	(4)
Large User	1,765,450	1,765,450	0
Unmetered Scattered Load	121,470	121,504	(34)
Sentinel Lighting	33,418	33,431	(12)
Street Lighting	438,628	438,203	426
TOTAL	**21,329,858**	**21,324,814**	**5,043**

Proposed Updated Rate Riders

Bluewater Power proposes to update its originally proposed rate riders to mitigate the impact of the increase in distribution rates related to this update.

In its September 9, 2008 pre-filed evidence at Exhibit 5, Tab 1, Schedule 5, Attachment 1, Bluewater Power proposed to return the balances recorded in the variance and deferral accounts, $3,974,344, to customers over a three year period. Bluewater Power proposes to amend that proposal so that these balances are returned over a two year period. This will increase the amount returned in 2009 from $1,324,781 to $1,987,172. The increase in the amount returned to customers through rate riders is $662,391 and exceeds the distribution revenue consequences attributable to the closure of UBE and Royal.

The September 9, 2008 proposed rate riders and the updated proposed rate riders are displayed in the table below.

Table 17 – Original 3 year vs. Alternate 2 year Deferral/Variance account disposition

Rate Classification	**Original 3 year Disposition Rate Rider**	**Proposed 2 year Disposition Rate Rider**	**Per kWh or kW**
Residential	(0.0009)	(0.0014)	kWh
General Service <50 kW	(0.0011)	(0.0018)	kWh
General Service 50 to 999 kW	(0.4555)	(0.7219)	kW
General Service 1,000 to 4,999 kW	(0.6174)	(0.9530)	kW
Large	(0.8909)	(1.4394)	kW
Unmetered Scattered Load	(0.0008)	(0.0013)	kWh
Sentinel Lighting	(0.3737)	(0.6086)	kW
Street Lighting	(0.3256)	(0.5310)	kW
Total amount recovered	$ (1,324,781)	$ (1,987,172)	

Deferral Account

Bluewater Power seeks Board authorization to use USoA account 1572, or in the alternative another account that may be required by the Board, to record the net distribution margin realized by Bluewater Power for power supplied to UBE and Royal, until such time as they cease operations. A draft Accounting Order is provided as Appendix D.

The proposed operation of account 1572 will keep both Bluewater Power and its rate payer's whole over time. It will capture any unforecast distribution revenues recovered from UBE or Royal in 2009 prior to closure. Bluewater Power will apply to dispose of the balance recorded in the account through a future application or as directed by the OEB.

The Impact to Customers of Bluewater Power's Updated Distribution Rates and Updated Rate Riders

Bluewater Power seeks Board authorization to charge amended distribution rates in 2009 that recover the 2009 revenue requirement and are premised on the closure as of January 1, 2009 of Royal and UBE. The originally proposed distribution rates and the updated distribution rates are provided in Table 15. Table 18 illustrates the bill impacts of the updated proposed distribution rates only, without adjusting the proposed rate riders as noted above. They demonstrate that bill impacts ranging from 0.0% to 0.8% are associated with the proposed changes to distribution rates. Bluewater Power observes that these impacts are not material.

Table 18 – Bill Impacts of proposals with 3 Year deferral/variance account disposition retained

Original Proposal Bill Impacts (Typical customer)

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000		$6.35	6.0%
GS<50	2,000		$9.99	4.7%
GS 50 to 999 kW	52,000	135	$79.94	1.6%
GS 1000 to 4999 kW	1,700,000	3,532	($1,935.72)	-1.4%
Large	4,446,000	6,900	$4,974.14	1.4%
USL	1,000		$ 18.34	17.9%
Sentinel (per connection)	176	0.46	$2.63	15.6%
Street lighting (per connection)	99	0.21	$1.44	15.6%

Updated Bill Impacts with Closures of Royal and UBE

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000	0	$6.53	6.2%
GS<50	2,000	0	$10.08	4.7%
GS 50 to 999 kW	52,000	135	$98.32	2.0%
GS 1000 to 4999 kW	1,700,000	3,532	($1,515.19)	-1.1%
Large	4,446,000	6,900	$7,912.40	2.2%
USL	1,000	0	$ 18.29	17.8%
Sentinel (per connection)	176	0.46	$2.66	15.8%
Street lighting (per connection)	99	0.21	$1.47	15.9%

Variance of Updated vs. Original Proposals

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000	0	$0.18	0.2%
GS<50	2,000	0	$0.09	0.0%
GS 50 to 999 kW	52,000	135	$18.38	0.4%
GS 1000 to 4999 kW	1,700,000	3,532	$420.53	0.3%
Large	4,446,000	6,900	$2,938.26	0.8%
USL	1,000	0	($0.05)	0.0%
Sentinel (per connection)	176	0.46	$0.03	0.2%
Street lighting (per connection)	99	0.21	$0.03	0.3%

The bill impacts of the updated proposed distribution rates and the updated proposed rate riders are provided in the tables below. Please note that all customer classes experience a favourable bill impact of -0.1% to -0.5% when compared to Bluewater Power's original submission of September 9, 2008.

Table 19 – Bill Impacts assuming a two year deferral/variance account disposition

Original Filing

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000		$6.35	6.0%
GS<50	2,000		$9.99	4.7%
GS 50 to 999 kW	52,000	135	$79.94	1.6%
GS 1000 to 4999 kW	1,700,000	3,532	($1,935.72)	-1.4%
Large	4,446,000	6,900	$4,974.14	1.4%
USL	1,000		$ 18.34	17.9%
Sentinel (per connection)	176	0.46	$2.63	15.6%
Street lighting (per connection)	99	0.21	$1.44	15.6%

Bill Impacts with Loss of Royal and UBE and two year deferral account disposition

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000	0	$6.03	5.7%
GS<50	2,000	0	$8.88	4.2%
GS 50 to 999 kW	52,000	135	$65.84	1.3%
GS 1000 to 4999 kW	1,700,000	3,532	($2,637.66)	-1.9%
Large	4,446,000	6,900	$4,601.78	1.3%
USL	1,000	0	$ 17.89	17.4%
Sentinel (per connection)	176	0.46	$2.57	15.3%
Street lighting (per connection)	99	0.21	$1.43	15.5%

Variance

Rate Class	kWh	kW	Total Bill $ Change	Total Bill % Change
Residential	1,000	0	($0.32)	-0.3%
GS<50	2,000	0	($1.11)	-0.5%
GS 50 to 999 kW	52,000	135	($14.10)	-0.3%
GS 1000 to 4999 kW	1,700,000	3,532	($701.94)	-0.5%
Large	4,446,000	6,900	($372.36)	-0.1%
USL	1,000	0	($0.45)	-0.4%
Sentinel (per connection)	176	0.46	($0.06)	-0.4%
Street lighting (per connection)	99	0.21	($0.01)	-0.1%

Conclusion

Bluewater Power has proposed changes to its 2009 distribution rates that are just and reasonable, are appropriate for the purposes of the IRM, avoid the need for a rebasing application for 2010, allow for earning the approved return on equity, and are consistent with the closure of Royal and UBE. To mitigate the rate and bill impacts Bluewater Power has updated its proposed Rate Riders to return an additional $662,391 to customers in 2009. To ensure that both its customers and the utility are kept whole, Bluewater Power also proposes to establish a deferral account that will track any unforecast revenues recovered from UBE and Royal and will be disposed of through a future proceeding.

Attachments

Appendix A - Letter from Royal (parent company Georgia Gulf)
Appendix B - Letter from UBE
Appendix C - Updated ERA Cost Allocation Report
Appendix D - Sample accounting treatment

Appendix A

Georgia Gulf

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Georgia Gulf Announces Closure of Sarnia PVC Resin Plant

ATLANTA--(BUSINESS WIRE)--Dec. 8, 2008--Georgia Gulf Corporation (NYSE: GGC) announced today it is permanently closing its Sarnia, Ontario (Canada) PVC resin plant. The plant had operated only periodically in 2008 due to decreased demand in the housing and construction markets. In response to continued weakening in the markets, Georgia Gulf has made the decision to permanently close the facility, which had the capacity to produce 450 million pounds of PVC resin annually.

"We operated the Sarnia facility as a swing plant with the intention of re-starting production as soon as the markets recovered and demand improved. In light of prevailing market conditions, we have made the difficult decision to permanently close this facility in an effort to better match our supply with the realities of the marketplace," stated Paul Carrico, President and CEO of Georgia Gulf Corporation.

As a result of the Sarnia PVC resin plant closure, the Company expects to record a non-cash charge of about $50 million in the 4th quarter of 2008. The Company expects the cash costs related to the Sarnia plant closure and other cash restructuring costs incurred in the third and fourth quarters of 2008 to be approximately $12 million. Under the terms of the last credit facility amendment, these charges can be excluded from EBITDA for purposes of Georgia Gulf's covenant calculations.

About Georgia Gulf

Georgia Gulf Corporation is a leading, integrated North American manufacturer of two chemical lines, chlorovinyls and aromatics, and manufactures vinyl-based building and home improvement products. The Company's vinyl-based building and home improvement products, marketed under Royal Group brands, include window and door profiles, mouldings, siding, pipe and pipe fittings, and deck, fence and rail products. Georgia Gulf, headquartered in Atlanta, Georgia, has manufacturing facilities located throughout North America to provide industry-leading service to customers.

Safe Harbor

This news release contains forward-looking statements subject to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements are based on management's assumptions regarding business conditions, and actual results may be materially different. Risks and uncertainties inherent in these assumptions include, but are not limited to continued compliance with covenants in our credit facility and availability of funds thereunder, future global economic conditions, economic conditions in the industries to which our products are sold, uncertainties regarding competitive conditions, industry production capacity, raw materials and energy costs, uncertainties relating to Royal Group's business and other factors discussed in the Securities and Exchange Commission filings of Georgia Gulf Corporation, including our annual report on Form 10-K for the year ended December 31, 2007.

CONTACT: Georgia Gulf
Media
Ashley Mendoza, 225-685-2507
or
Investor Relations
Martin Jarosick, 770-395-4524

Source: Georgia Gulf Corporation

Appendix B

UBE Automotive North America Sarnia Plant, Inc.
21 UBE Drive, Sarnia, ON, Canada N7W 1B6
Phone: (519) 542-8262 Facsimile: (519) 542-3666

January 28th, 2009

Bluewater Power Distribution Corporation
P. O. Box 2140
855 Confederation Street
Sarnia, ON N7T 7L6

Attention: Mr. Alex Palimaka

Dear Sir:

<u>RE: UBE Sarnia Plant Shut-Down</u>

Please be advised that the UBE Sarnia Wheel Plant will cease operation and be shut down between July and December 2009. As we complete negotiations with our customers as to their requirements we will be able to provide a more definitive timeframe.

We appreciate the continued support of Bluewater Power during this extremely difficult time.

Yours truly,

Robert McPherson
Plant Head Coach

Appendix C

Update of Bluewater Power's 2006 Cost Allocation Study

A Report Prepared by John Todd, President Elenchus Research Associates Inc.

On Behalf of Bluewater Power

February 2009

elenchus
Research Associates

Table of Contents

1 INTRODUCTION

Bluewater Power Distribution Corporation ("Bluewater" or "BP") has prepared its 2009 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the OEB's November 14, 2006 document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements"). Section 2.9 of this document sets out the expectations of the Ontario Energy Board ("OEB") with respect to Exhibit 8: Cost Allocation of cost of service applications. The Filing Requirements state:

> *A completed Board approved cost allocation must be filed whether the utility proposes to use it or not.* (p. 20)

Bluewater asked me[1] to advise it on the steps that it should take in order to comply with the Filing Requirements as they pertain to Exhibit 8: Cost Allocation and to assist it in providing an appropriate cost allocation. In addressing this issue, ERA was guided by the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors" (p. 1).

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report. The Board also recognizes however, that cost allocation is, by its very nature, a matter that calls for the exercise of some judgment, both in terms of the cost allocation methodology itself and in terms of how and where cost allocation principles fit within the broader spectrum of rate setting principles that apply to – and the objectives sought to be achieved in – the setting of utility rates. The existence of the influencing factors does not outweigh the merit in moving forward on cost allocation. Rather, the Board considers that it is both important and appropriate to implement cost allocation policies at this time, and believes that the policies set out in this Report are directionally sound. With better quality data, greater experience with cost allocation modeling and further*

[1] This evidence has been prepared by John D Todd, President, Elenchus Research Associates Inc.

developments in relation to other rate design issues, the policies will be refined as required.

The "influencing factors" discussed in 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5) While progress has been made in improving accounting data, the comments of the Board regarding load data remain valid.

> *… load data and load analysis contribute to important cost allocators; namely, the coincident peak and the non-coincident peak. The Board recognizes the significant work done by distributors, and Hydro One Networks Inc. in particular, in obtaining a set of load data as part of the cost allocation informational filings. However, the Board acknowledges that some of the information is based on estimates from a statistical model and may not be completely representative of current loads due to sampling errors and current market characteristics.*
>
> *…*
>
> *With respect to load data and load analysis, the Board anticipates that the installation of smart meters, with their more exact load data, will provide opportunities for better analysis in the future and, as a result, will provide better cost allocators for the cost allocation model. (page 5)*

- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6) With respect to modelling improvements in the future the Board stated:

> *The Board anticipates that, as distributors become more familiar with cost allocation concepts, they will better understand the blending of operating statistics and practice with accounting data, and they will more effectively and consistently use the models in the preparation of their rate applications. The Board also expects distributors to review their allocation factors as better load data become available from smart meters. (page 6)*

- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6) and goes on to state :

> *An initiative is currently under way to examine the rate design for electricity distributors (consultation process EB-2007-003) (the "Rate Review"). The Rate Review covers both customer classification and rate structure issues, and its results could affect the way in which rates are set in the future. (p. 6)*

- **Managing the movement of rates closer to allocated costs:** The report states that:

> *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (page 6)*
>
> *…*
>
> *The Board expects to address these concerns as and when they arise in the context of individual rate applications. Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one. (page 7)*

These comments pertain not only to the 2006 Cost Allocation Information Filings ("2006 CA Filing") of the distributors, but also to any other cost allocation studies that can be prepared by distributors at this time.

BP filed its 2006 CA Filing in January 2007. This filing relied on the Ontario Energy Board's ("OEB") 2006 Cost Allocation Model ("2006 CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

Producing a fully updated cost allocation model at this time would be a significant undertaking for any distributor as it would entail:

- Reviewing the methodology used to classify and functionalize all costs, as directed in the Filing Requirements worksheet E1: Categorization in the 2006 CA Model) to ensure that the methodology is given the specific circumstances of Bluewater;

- Repopulating the 2006 CA Model with current trial balance, asset, expense, revenue, customer and load information;
- Collecting updated information on electrical space heating, water heating and air conditioning saturation information for the residential class;
- Re-estimating the weather sensitive and non-weather sensitive loads for other rate classes and weather-normalizing actual demand for an historical year;
- Developing updated hourly load shapes by class and the derivation of updated demand allocators (1-CP; 4-CP; 12 CP; 1-NCP; 4-NCP and 12-NCP) for use in the model based on the information resulting from the two preceding bullet points; and
- Reviewing and updating, as appropriate, all other allocators.

In weighing the cost and benefits of LDCs updating their cost allocation models for use in their 2009 rate rebasing filings, I concluded that it would be prudent to consider the need for an update on a case-by-case basis. At the heart of my reasoning is the concern that, in general, fully updating an LDC's cost allocation filing at this time would provide little, if any, improvement in the information available for determining the extent to which rates need to be rebalanced among classes. Far better cost allocation studies will be available within a couple of years. Consequently, current cost allocation results should be used only as an indicator of significant directional changes that are required. This cautious approach is a clear message in the OEB's CA Application Report. Since the "new, improved" cost allocation studies are still a couple of years away, it is my view that it would be a poor use of ratepayer funds to update the 2006 CA Filing at this time unless there is evidence that the results of the 2006 CA Filing would be misleading in the absence of an update.

In the case of Bluewater Power, there are two customers that were in the Large User class in 2006 that have announced planned closures during the test year. The resulting reduction in demand will have an impact on allocated costs that is too significant to be ignored. The remainder of the evidence explains the analysis behind this conclusion and the adjustments made to reflect this major reduction in Large User class load.

2 ASSESSING BLUEWATER'S 2006 CA MODEL

The first step in responding to Bluewater's request for advice on the cost allocation information to include in its 2009 EDR Application was an assessment of the merit of undertaking a full update of the Bluewater 2006 CA Model to produce a 2009 Test Year Model. My advice on this matter was based on an assessment of the overall value to the regulatory process of having a fully updated cost allocation study as part of the 2009 EDR Application in light of the costs of producing such a study in terms of the regulatory process and the financial costs that would ultimately be visited on ratepayers.

Recognizing the requirements for a full update of their 2006 CA Model, which are listed above, it was my recommendation to Bluewater (and all of ERA's clients preparing cost of service filings for their 2009 EDR Applications) that there would be little value in preparing a fully updated CA Model at this time. The reasons are as follows.

1. Significant in-house resources would be required to complete an updated cost allocation study. Based on the experience of the distributors that filed cost of service rate applications for 2008, it was evident from the outset that the LDCs filing cost of service applications for 2009 would be challenged to complete their applications by August 15, 2008, even without the added demands of preparing fully updated CA model. The added workload associated with fully updating its CA Model for an LDC that was completing its first-ever cost of service application would risk compromising both the timeliness and the quality of its cost of service application.

2. In addition to the increased demands on internal resources, any distributor that chose to update its CA Model fully would face the prospect of significant incremental regulatory costs associated with external consulting support and the costs associated with a more complex and extensive public process. While these costs, which would ultimately be borne by ratepayers, were clearly not prohibitive, they should, in my view, be considered in the context of the value to the regulatory process of preparing an updated CA Model at this time. For the reasons outlined below, the value of an updated model would be minimal at this time.

3. A fully updated cost of service application would require an updated hourly load profile by rate class. ERA explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as I am aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
4. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have far superior hourly load profile by class data than the estimates that Hydro One is able to provide. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when far superior hourly load profile information will be available in the next few years at minimal incremental cost.
5. The OEB's Rate Design Review is progressing well and is expected to result in a Board Report in the coming year. Given the rate design possibilities that will arise as a result of the widespread rollout of smart meters, it is conceivable, if not likely, that new class definitions and new approaches will result from this process. As a consequence, a current cost allocation is likely to be of little, if any, relevance within a couple of years. Unless there are serious anomalies, investing in an updated cost allocation study at this time does not appear to be a wise use of ratepayer funds.
6. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter demand and, as a result, some key allocators used in cost allocation studies. A fully updated cost allocation study prepared at this time cannot be expected to produce reliable indicators of the changes in relative rates that will be required to ensure that the resulting rate design recovers costs from customers in a manner that improves inter-class and intra-class equity. At best, a current study will provide an indicator of serious anomalies or inequities that justify immediate

rectification. If the 2006 CA Model is a reasonable proxy for a 2009 cost allocation study, an updated study is unlikely to provide better guidance for rate changes.

7. As noted above, a fully updated cost allocation study should include a careful review of the methodology in the context of the specific distributors conducting the study. The 2006 Cost Allocation Model was a generic model that was completed by distributors for information purposes. These models have never been subjected to the rigorous review of a public hearing process. A new LDC-specific cost allocation study that is filed as part of a 2009 EDR Application would be open to being fully reviewed and tested by all stakeholders. Since the methodology will not be robust, for the reasons discussed above, it would not be an efficient use of ratepayer funds to engage in a detailed review of a cost allocation methodology that will be outdated with a year or two.

8. To the extent that (i) the hourly load shapes by class (ii) categorization of costs (rate base and expenses) in relative terms, and (iii) customer data are fairly stable, the results (revenue-to-cost ratios and relative cost responsibility by class) would not change appreciably. The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time. An update at this time would produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs at this time. The 2006 CA Model results can be expected to provide appropriate guidance for purposes of adjusting rates for classes so as to achieve a more equitable basis for recovering the revenue requirement.

9. In general, cost allocation studies are quite robust and stable in the absence of significant changes in a distributor's cost structures or loads. Small increases in rate base and operating expenses that cut across the various cost categories will have little impact on the relative cost responsibilities of customer classes or their relative revenue-to-cost ratios. Similarly, small changes in the relative loads of customer classes will result in small changes to the allocators. The resulting small change in revenue cost ratios will not affect the distributor's rate design where the existing revenue-to-ratios are significantly above or below the ranges endorsed by the OEB

in the CA Application Report or where they are comfortably within the ranges. A small change will only affect customer rates if the revenue-to-cost ratios are close to either the upper or lower limits of the ranges.

Having concluded that there is little value in imposing the costs of preparing a fully updated CA study on ratepayers as a matter of course, the next step in providing my advice was to determine whether there are any circumstances specific to Bluewater that would justify either a partial or full update to the cost allocation model. Of particular concern in this regard was the possibility that an update would produce a significant change in the proportion of the distributor's total revenue requirement that is appropriate to recover from each class.

For example, a problem will arise in the event that one class experiences a significant decline in volume throughput while other classes do not in the years after 2004, which was the basis for the 2006 CA Model. In this case, if the CA Model is not updated, the proportion of costs allocated to each class would be based on the outdated throughput data, while class revenues would be based on the current forecast. A 50% decline in key cost drivers (kW, kWh and customer count) in a class, for example, would result in a similar decline in forecast revenue, but in the absence of an update to the CA Model there would be no reduction in the proportion of costs allocated to the class. The calculated revenue to cost ratio for the test year would therefore be artificially low – in this example, roughly 50% below the "true" value. The "true" revenue-to-cost ratios would not be significantly affected by changes in the relative throughput for different classes assuming the loss of load does not significantly alter the load profile of the classes and directly allocated cost are not a major factor in the cost allocation study. Subject to these caveats, changes in allocated costs and changes in revenues will be similar and the resulting revenue-to-cost ratios will be fairly stable even if there are significant changes in the throughput of one or more classes.

The implication of the foregoing concern is that an analysis of the stability of the relative throughput of the various customer classes is required in order to determine whether the 2006 CA Model results can be viewed as a good proxy for a fully updated cost allocation study. The issue of the stability of these parameters can be addressed by examining the stability of Bluewater's infrastructure, operations, customer count and class shares of billed kWh and kW.

2.1 ASSESSING THE STABILITY OF BLUEWATER'S RATE BASE

The information on Bluewater's rate base in Exhibit 2 of its 2009 EDR Application Filing shows that the underlying infrastructure has been fairly stable since the 2006 EDR which was used as the basis for the 2006 CA Model and Application.

Table 1 below summarizes the 2006 EDR approved and 2009 forecast net book values by asset account of the assets included in Bluewater's rate base. The values in Table 1 correspond to the values set out n Exhibit 2, Tab 2, Schedule 1, Attachment 1 of the Bluewater Application. The proportions of the total rate base as well as the net book values are shown for each asset account.

Table 1: Net Book Values of Assets, 2006 EDR vs. 2009

	2006 EDR Approved		**2009 Balance**	
	$	%	$	%
1805-Land	445,817	1.3%	445,817	1.1%
1806-Land Rights	61,541	0.2%	5,101	0.0%
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,169,269	6.2%	2,841,482	7.0%
1830-Poles, Towers and Fixtures		0.0%	1,808,826	4.5%
1835-Overhead Conductors and Devices	11,781,847	33.6%	11,514,740	28.5%
1840-Underground Conduit		0.0%	229,035	0.6%
1845-Underground Conductors and Devices	9,364,980	26.7%	8,618,545	21.3%
1850-Line Transformers	5,435,158	15.5%	5,855,493	14.5%
1855-Services		0.0%	419,918	1.0%
1860-Meters	2,413,137	6.9%	3,282,258	8.1%
1908-Buildings and Fixtures	2,310,999	6.6%	3,921,754	9.7%
1915-Office Furniture and Equipment	66,818	0.2%	102,053	0.3%
1920-Computer Equipment - Hardware	574,734	1.6%	825,753	2.0%
1925-Computer Software	1,356,398	3.9%	3,023,262	7.5%
1930-Transportation Equipment	306,534	0.9%	656,707	1.6%
1935-Stores Equipment	11,422	0.0%	-22,773	-0.1%
1940-Tools, Shop and Garage Equipment	99,377	0.3%	213,175	0.5%
1945-Measurement and Testing Equipment	8,380	0.0%	18,785	0.0%
1955-Communication Equipment	32,653	0.1%	14,875	0.0%
1960-Miscellaneous Equipment	40,653	0.1%	174,678	0.4%
1970-Load Management Controls - Customer Premises	39,157	0.1%	-2,526	0.0%

1975-Load Management Controls - Utility Premises	545,836	1.6%		0.0%
1980-System Supervisory Equipment		0.0%	509,267	1.3%
1995-Contributions and Grants - Credit	-2,049,843	-5.9%	-4,029,509	-10.0%
TOTAL	35,014,869	100.0%	40,426,717	100.0%

The assets can be grouped together into groups that are categorized in the same way in the 2006 CA Model. The proportions of the rate base attributable to each grouping are shown in Table 2.

Table 2: Distribution of Assets by Classification Group, 2006 EDR vs. 2009

		2006 EDR	**2009 Balance**
Group		%	%
A	1805/1806/1820	7.6	8.1
B	1830/1835/1840/1845	60.4	54.8
C	1850	15.5	14.5
D	1855/1860	6.9	9.2
E	1908/1915/1920/1925/1930/1935/1940/1945/1955/1960/1970/1975/1980	15.4	23.3
F	1995	-5.9	-10.0

Given the modest differences in the allocators used to allocate these costs to rate classes and the stability of the costs, relative to the revenue-to-cost ranges contained in the CA Application Report, it can be concluded that the shift in the relative proportions of rate base from poles and wires accounts (Group B) to the administrative and maintenance accounts (Group E) will not have a large impact on the overall allocation of costs. Given the inherent lack of precision in the CA studies of Ontario electricity LDCs at this time, it is reasonable to conclude that Bluewater's 2006 CA Model does not need to be adjusted to account for changes in the structure of its rate base.

2.2 ASSESSING THE STABILITY OF BLUEWATER'S OPERATING COSTS

The information on Bluewater's operating and maintenance costs in Exhibit 4 of its 2009 EDR Application Filing shows that the cost by account grouping have changed significantly since 2004. This can be seen from the comparison of 2006 EDR and 2009 that is provided in Table 3 below.

Table 3: Operating Cost by Account Grouping, 2006 EDR vs. 2009

Account Grouping	2006 EDR Approved	2009 Projection
3500-Distribution Expenses – Operation	280,776	3,535,352
3550-Distribution Expenses – Maintenance	256,425	157,640
3650-Billing and Collecting	267,288	1,497,443
3700-Community Relations	189,005	216,871
3800-Administrative and General Expenses	8,187,189	5,951,113
3950-Taxes Other Than Income Taxes	139,687	297,750
TOTAL	**9,320,370**	**11,656,169**

However, as explained in Bluewater's evidence (see Exhibit 4, Tab 2, Schedule 3, pages 22-23 discussing 2006 EDR vs. 2007 Variances), the changes are the result of changes in the accounting treatment of certain costs in 2007 and subsequent years as compared to the 2006 EDR. The shift in payroll costs from the Administration and General Expenses account group to other account groupings is not reflective of a change in the allocation of costs, since Bluewater's 2006 CA Model classified and allocated salary costs at a sub-account level that appropriately classified and allocated these costs. The underlying operating costs have exhibit stability similar to Bluewater's rate base.

Given the inherent lack of precision in the CA studies of Ontario electricity LDCs at this time, it is reasonable to conclude that Bluewater's 2006 CA Model does not need to be adjusted to account for changes in the structure of its operating costs.

2.3 Assessing the Stability of Bluewater's Customer Base/Demand

Exhibit 3 in Bluewater's 2009 EDR Application shows that the customer count has been stable except for the loss of one of five Large Users. This decline results from the reduction of demand by one of Bluewater's Large User customers leading to the customers being reclassified as a General Service 1,000 – 4,999 kW (Intermediate) customer. As Tales 4 and 5 below show, kWh and kW decline in the Large User class, while Intermediate kWh and kW have increased, but by a smaller amount.

Table 4: kWh Class Shares, 2006 EDR vs. 2009

Customer Class Name	2006 EDR Approved kWh	2006 EDR Approved Share by Class	2009 Normalized kWh	2009 Normalized Share by Class
Residential	269,172,954	23.4%	266,434,436	25.1%
General Service <50 kW	126,666,633	11.0%	120,544,382	11.4%
General Service 50 to 999 kW	219,392,039	19.1%	216,234,424	20.4%
General Service 1,000 to 4,999 kW	170,944,308	14.9%	165,546,229	15.6%
Large	351,679,464	30.6%	280,461,771	26.4%
Unmetered Scattered Load	2,956,878	0.3%	2,188,838	0.2%
Sentinel Lighting	649,471	0.1%	684,138	0.1%
Street Lighting	8,769,187	0.8%	8,719,920	0.8%
TOTAL	1,150,230,934	100.0%	1,060,814,138	100.0%

Table 5: kW Class Shares, 2006 EDR vs. 2009

Customer Class Name	2006 EDR Approved kW	2006 EDR Approved Share by Class	2009 Normalized kW	2009 Normalized Share by Class
General Service 50 to 999 kW	467,580	34.6%	593,516	42.0%
General Service 1,000 to 4,999 kW	294,070	21.8%	372,461	26.4%
Large	563,939	41.8%	421,890	29.9%
Sentinel Lighting	1,558	0.1%	1,637	0.1%
Street Lighting	23,274	1.7%	23,562	1.7%
TOTAL	1,350,421	100.0%	1,413,066	100.0%

It is evident that the loss of the two Large Users reduces the kWh of the class by about 20% and the kW (and revenue) of the class by about 25%. In the absence of an adjustment to the 2006 CA Model, the proportion of costs allocated to this class will not decline correspondingly and as a result, the calculated revenue-to-cost ratio will be understated by about %, subject to the offsetting effects of the change to the treatment of the directly allocated costs associated with these customers. The magnitude of this change and its estimated impact on the revenue-to-cost ratio for the class suggests that using the share of total costs allocated to rate classes as determined by the 2006 CA Model could significantly over-allocate cost to the Large User class and under-allocate cost to the other classes.

In addition, in Bluewater's 2006 CA Model $1.5 million of net fixed assets associated with one of the customers that is shutting down are directly allocated to the Large User class. Approximately $573,700 of these directly allocated net fixed assets will be stranded when the plant is shut down and the remaining assets will be used to reinforce the distribution system in serving increased general service and residential demand related to customer growth in the area. The stranded assets are being removed from Bluewater's rate base and the remaining assets are allocated to all customer classes.

Although there is reason to believe that it would be prudent to update the 2006 CA Model with respect to the energy and demand allocators, Bluewater's infrastructure and operations are sufficiently stable relative to the acceptable revenue-to-cost ratio ranges recommended by the Board in *Application of Cost Allocation for Electricity Distributors, Report of the Board* (EB-2007-0667) that it can be expected that completing a full cost allocation study for the 2009 test year is not necessary because:

- the proportions of kWh and kW attributable to the intermediate and large users classes are changes that could result in a significant error in the revenue-to-cost ratio calculation for the 2009 test year if the cost allocation study is not adjusted to reflect the reduction in the demand of one former large user;
- Bluewater's capital and operating cost do not exhibit significant discontinuities;
- the revenue-to-cost ratios for all classes are within the Board-approved ranges except lighting (USL, Sentinel, Streetlighting (which is being increased as shown in the table below); hence, small changes in the calculated revenue-to-cost ratios would not require changes in the proposed rates;

Rate Class	Original Cost Allocation Filing Results (Revenue to Cost Ratio's)	Scenario - moving 1/3 toward Floor	OEB Target - Floor Revenue to Cost Ratio	OEB Target - Ceiling Revenue to Cost Ratio
USL	0.65	0.70	0.80	1.20
Sentinel	0.33	0.45	0.70	1.20
Streetlighting	0.44	0.53	0.70	1.20

- Bluewater will be implementing smart meters in the near future, which will provide a significantly improved basis (e.g., a direct measure of the hourly demand of each rate class) for quantifying the allocators used in the cost allocation study than the Hydro One estimates that must be relied on at this time;

hence, it is prudent to defer updating Bluewater's cost allocation study until this information is available;

- it is expected that the Board's current Rate Design Review will result in changes to rate classes necessitating new cost allocation studies; hence, an updated cost allocation study will be required in the near-future in any case.

2.4 UPDATING THE 2006 CA MODEL

As an alternative to completing a fully updated 2009 CA Model, which would involve the steps outlined at page 4 above, an updated 2006 CA Model can be produced. An updated 2006 CA Model would be identical to the 2006 Cost Allocation Information filing in that the rate base and expenses are unchanged. In addition, customer load information is unchanged except for extraordinary changes in customer demand. Put simply, the case of Bluewater's movement of one customer from the Large User class to the Intermediate class, the updated 2006 CA Model would be adjusted to reflect a scenario where this customer's load shift had occurred prior to the 2004 fiscal year which was used as the basis for the 2006 CA Model.

This approach was taken to updating Bluewater's 2006 CA Model. The methodology and results are described in the next section.

3 METHODOLOGY

This section documents ERA's methodology for updating Bluewater Power's ("BP") 2006 Cost Allocation Information Filing to reflect the impact of the reduction in power consumption by former Large User Customers ID 15 and 18 to zero.

3.1 ANALYSIS OF BLUEWATER LARGE USER CLASS

BP provided the hourly load data for each of its 5 Large Users for the period October 1, 2002 through April 30, 2006. The hourly load data for 2004 was used as the basis for modifying the load data provided by HONI (step 2 below) as input to the 2006 Cost Allocation Model (step 3 below). The following data were derived from these data.

- Total kWh for each hour of the year (8784 hours in 2004 since 2004 was a leap year)
- Total kWh with uplift (uplift factor = 0.45%).
- An Adjustment Factor, being the ratio, by hour, with and without Customers ID15 & 18.

Hourly Adjustment Factor = (kWh without ID15/18) / (kWh with ID15/18)

The ratios for each hour in 2004 were used to adjust the HONI load data file (step 2 below).

3.2 REVISE LOAD DATA PROVIDED BY HONI, RUN 2

For Bluewater's 2006 CA Filing, HONI provided a load data file (Load Data from HONI, RUN 2) with three worksheets.

- Data summary: actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- Hourly load shape by class: GWh by class for each hour in 2004.

- Input to Cost Allocation Model (1CP; 4CP; 12CP; 1NCP; 4NCP; 12NCP) derived from the hourly load shape.

A modified file was created (2006 Adjusted Load Data from HONI, RUN 2) as follows.

1. The hourly load shape by class was modified by adjusting each hour in the year to calculate the revised load shape by class for each hour and for each scenario.
   - Multiply the Large User load by the Hourly Adjustment Factor (remove ID15/18) to derive the Revised Large User hourly load
   - Calculate the revised total load by adding the loads for each class using the revised Large User load
2. On the Hourly Load Shape by Rate Class worksheet, the 12 monthly coincident and non-coincident peaks were identified for each rate class. The hours in which the total peak occurred are required in order to derive the coincident peak demand.
   - The peaks for each month were identified for each class (base case and revised) and for the total demand for the base case and revised case.
     - The monthly peaks for the revised case occurred in the same hours as in the base case in all months except January and March.
   - The 12 NCP values for each class were calculated by adding the 12 monthly peaks for each class (base case and revised).
   - The total 12 NCP values are the total of the class 12 NCP values. The Revised Large User 12 NCP value was used.
   - The 12 CP values for each class were derived by adding the hourly demands for the 12 hours during which the monthly system peaks occurred. As noted above, the monthly peaks occurred in different hours for two months in the revised case as compared to the base case.
   - The calculation methodology was verified since the derived base case values matched the HONI results.

3. On the Hourly Load Shape by Rate Class worksheet, the 4 CP and 4 NCP values were determined for each rate class (base case and revised) and for the total base demand (base case and revised). The hours in which the total 4 CPs (base case and revised) occurred are used to derive the 4 CP value.
   - The four highest monthly peaks were identified for each class (including the revised Large User class). The 4 NCP values are the sum of the four highest monthly peaks for each rate class. The total 4 NCP is the sum across the rate classes for the base case and revised case;
   - The four highest monthly peaks were used to determine the 4 CP for total demand (base case and revised). The hours in which the four peaks occurred were then used to determine the 4 CP values for each rate class.
4. On the Hourly Load Shape by Rate Class worksheet, the 1 CP and 1 NCP values were determined for each rate class (base case and revised) and for the total base demand (base case and revised). The hours in which the total 1 CPs (base case and revised) occurred were used to derive the 1 CP values for each rate class.
   - The single highest monthly peak was identified for each class (including the revised Large User classes). The 1 NCP values are the highest monthly peak for each rate class. The total 1 NCP is the sum across the relevant rate classes for the base case and revised,
   - The single highest monthly peak was the 1 CP value for total demand (base case and revised). The hour in which the total 1 CP occurred was then used to determine the 1 CP values for each rate class.
5. The relevant CP and NCP values were then copied onto tables on the Input to CA Model worksheet.
6. The revised 30-year weather normalized amounts by rate class were also added into the tables on the Input to CA Model worksheet. The values used were the summations of the hourly data by class, including the revised amounts for the Large User class.

3.3 REVISED COST ALLOCATION MODEL

On sheet I8 Demand Data, the revised values from the HONI Load Data RUN 2 were entered on rows 40 (rows 38 and 39 match), 45 (rows 43 and 44 match), 50 (rows 48 and 49 match), 55 (row 56 updates), 61 (row 62 updates) and 67 (row 68 updates). This revises the demand data in the CA Model.

1. On sheet I6 Customer Data:
   - Row 56 was updated with the revised kWh – 30 year normalized amount from the HONI Load Data RUN 2
   - Rows 10 and 21 were revised to reflect the revised Large User load (kWhs)
   - Rows 13, 22 and 23 were revised to reflect the revised Large User load (kWs)
   - Row 29 was revised by making adjustments to the revenue that were proportional to the change in Large User energy (kWhs) and demand (kWs).
   - Rows 38 and 40 were updated to reflect the reduction in Large Users from 5 to 3.
2. On Sheet O1 Revenue and Cost/RR:
   - The class revenue to cost ratios were adjusted by scaling up the calculated ratios for each class proportionately so that the total revenue to cost ratio equals 100%. In effect, rates are assumed to be scaled up through an across the board increase to offset the revenue loss due to the reduced demand of customers ID15 & !D18. See row 77.
3. On Sheet I3, TB Data:
   - The Approved Target Net Income, Approved PILS and Approved Interest (cells F11, F12 and F13) were each adjusted to reflect the removal of the stranded assets from rate base. This change reduces the revenue requirement appropriately at Sheet O1, row 35.

4 IMPACT ON CLASS REVENUE REQUIREMENTS

The class revenues and the class revenue-to-cost ratios as determined in the original Bluewater cost allocation model are shown in the table below.

	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Revenue Requirement	$17,808,908	$9,255,455	$2,839,671	$2,752,110	$664,857	$1,384,016	$694,571	$62,481	$155,747
Revenue to Expense %	100.00%	99.21%	107.14%	88.34%	139.77%	129.73%	44.17%	32.83%	64.71%

The revised class revenues and revenue-to-cost ratios are shown in the following table.

	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Adjusted Revenue Requirement	$17,727,744	$9,323,095	$2,867,579	$2,814,539	$717,815	$1,093,090	$693,040	$62,361	$156,225
Adjusted Revenue to Expense %	100.00%	99.90%	107.63%	87.82%	132.25%	134.79%	44.76%	33.22%	65.45%

The revised revenue-to-cost ratios have been used by Bluewater as the reference ratios in its cost of service filing.

Appendix D

Appendix D

Outline of Bluewater Power's Proposed Application of Account 1572

Account 1572 – Extraordinary Event Costs

Purpose: to record unforecast revenues recovered from Royal Polymers or UBE and the associated carrying charges.

Proposed Accounting Entries

To record unforecast distribution revenues and unforecast revenues recovered through Specific Service Charges paid by Royal Polymers and UBE:

Debit Account 1005/1100 – Cash/Accounts Receivable

Credit Account 1572 – Extraordinary Event Costs (sub-accounts 1 to 4)

Sub-accounts of 1572 will be used to distinguish Royal Polymers and UBE as well as to distinguish distribution revenues from service charges.

To record carrying charges on the amounts recorded in Account 1572 (sub-account 5):

Debit Account 4405 – Interest and Dividend Income

Credit Account 1572 – Extraordinary Event Costs – carrying charges (sub-account 5)

Carrying charges shall be calculated using simple interest, with a rate approved by the Board, applied to the monthly opening balances in the account (exclusive of accumulated carrying charges) and will be recorded in a separate sub-account of 1572.

Records shall be maintained at an appropriate level to permit Board review and verification of amounts recorded therein.

Disposition of the balance will be established through a future application.