ORILLIAPOWER

Energizing Our Community

Telephone: (705) 326-7315
Fax: (705) 326-0800

December 2, 2009

Delivered by Courier and by RESS

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Orillia Power Distribution Corporation - Board File No: EB-2009-0273
2010 Electricity Distribution Rate Application

Please find attached the response to Board staff interrogatories in the above-noted proceeding.

Respectfully submitted,

John F. Mattinson P. Eng.
President & Secretary
Orillia Power Distribution Corporation

Orillia Power Distribution Corporation
2010 Electricity Distribution Rates
EB-2009-0273
Board Staff Interrogatories

Administrative Documents

1. Currently approved Tariff Sheet

Refs: Exhibit 1 /1 /1 /p6
In the Applicant's EB-2008-0239 tariff sheet, Standby Power is shown as "Approved on an Interim Basis". Please explain why the Schedule of Proposed Rates and Charges does not contain this limitation.

OPDC RESPONSE:

The Schedule of Proposed Rates and Charges does not contain this limitation due to an oversight by OPDC when preparing the schedule. The heading for this category should read "Standby Power – APPROVED ON AN INTERIM BASIS" in the rate schedule. OPDC has adjusted it's rate schedule accordingly.

2. Need of Application

Refs: Exhibit 1 /2 /2

a) On page 5 the Applicant states: "OPDC must make a significant dollar investment in capital projects into (1) currently unserviced areas and (2) distribution system upgrades needed in existing areas." Please provide further background regarding the currently unserviced areas including their location, area, number of potential customers, etc.

b) In Table 1-6 the SAIDI and SAIFI statistics for "Service Quality for All Interruptions excluding loss of supply" appear to be increasing. Does the Applicant have any specific plan to address this situation?

c) On page 8 the Applicant tables its recent system reliability history. On page 9 the Applicant states: "OPDC intends to maintain or enhance the standards achieved to date in all areas of customer service and reliability." Please explain with reference to the already-filed evidence, the investments the Applicant plans to make in the Test Year to enhance reliability and the quantitative improvements in reliability identified in any business case the Applicant may have that justified these investments.

OPDC RESPONSE:

Response to (a):
There are three main areas within OPDC's service territory that are identified as currently un-serviced areas– Westridge, Couchiching Point and Line 15 North.

- Westridge, in the west section of Orillia is expected to be the primary growth area of the city in both the short and long term. Building on the substantial residential and retail / commercial growth in this area over the past 5-10 years, development over the next 15 years is expected to result in as many as 3,000 new customers for OPDC. In addition, construction of a new campus of Lakehead University in this area (scheduled for completion in 2011) will be a catalyst for significant growth.
- Couchiching Point, in the east section of the city, has seen residential growth over the past five years and we anticipate further growth over the next five years with several subdivision and building projects planned for the area. OPDC's five year plan incorporates construction of a new substation in the Couchiching Point area to accommodate the additional load growth. At this stage, the expectation is that there is potential for as many as 500 new customers in this area.
- The Line 15 North project is driven by Section 6.5.4 of the DSC (revised July 24, 2008) requiring geographic distributors to eliminate their Long Term Load Transfer arrangements before January 31, 2009. OPDC's license was amended to grant an exemption from the requirements of section 6.5.4 of the DSC until January 31, 2011. Capital plans to connect its LTLT customers to its distribution

system were already approved before the most recent revision to the DSC June 16, 2009 extending the deadline for elimination of LTLT arrangements to June 30, 2014. The immediate impact of the transfer is to pick up four additional customers, however, the long term growth prospects for the area serviced by this line are for potentially another 50 to 100 customers.

Response to (b):

The four years displayed in the chart (2005 – 2008) indicate SAIDI results of 0.71, 0.81, 1.50 and 0.80 respectively. The one anomaly in these results, 2007, was driven by a significant ice storm that hit the area on December 3, 2007 and took down numerous trees and power lines. The SAIFI results, which trended above the four year average in both 2007 and 2008, were impacted by the 2007 ice storm noted above as well as a major wind storm in the area on December 28, 2008. In order to improve these statistics, we continue to perform extensive forestry management practices (tree trimming). Furthermore, rigorous pole line inspections highlight areas of potential system weakness and opportunities for equipment upgrades or improvements that will reduce the customer impact of future weather events by reducing outages.

Response to (c):

The investments the Applicant plans to make in the Test Year to enhance reliability are included in Exhibit 2, Tab 4, Schedule 1. Although we have not identified the specific quantitative improvements in reliability in a written business case, the investments / projects were planned as a result of existing reliability issues that were directly affecting customer service and / or equipment that had surpassed its expected useful life. Through extensive inspection programs and implementation of OPDC's Asset Management Plan, we strive to pro-actively manage our assets to prevent a decline in reliability. The specific investments are summarized in point form below. To review the rationale, supporting each of these reliability enhancing investments, please refer to Exhibit 2, Tab 4, Schedule 1.

- Pole Replacement - 44 kV lines
- Load Break Switches
- Pole Replacement – Overhead
- Patrick Street Re-build – Nottawasaga to Brant
- Reconstruct Rear of BDO Dunwoody

3. Customer Bill Impacts from Rebasing in 2010

Refs: Exhibit 1 /2 /3 /p1 and Exhibit 1, Appendix 1-H

In Exhibit 1 /2 /3 /p1 the Applicant states: "OPDE has attempted to lower total bill impact for all classes by repaying certain deferral and variance accounts over the shortest possible time period being one year." In Appendix 1-H the Applicant shows its capital plans for the period 2010 to 2015 and, in particular, shows the total capital increasing from $1.714 million in 2010 to $2.561 million in 2011. Please recalculate the percentage changes in the Residential class rates (at 800 kWh) and General Service <50kW (at 2,000 kWh) that would be effective after the one year period has passed if all else were to remain constant.

OPDC RESPONSE:

The table below shows the percentage changes in the Residential class rates (at 800 kWh) and General Service <50kW (at 2,000 kWh) that would be effective after the one year period has passed once the regulatory asset rider is removed assuming all else were to remain constant.

Description	Increase in Total Bill	% Increase in Total Bill
Residential - 800 kWh per month	**$1.02**	**1.1%**
General Service Less Than 50 kW - 2000 kWh per month	**$2.12**	**0.9%**

4. Dividends

Refs: Exhibit 1 /3 /1 /p2

In Table 1-11 the Applicant provides details of dividends. Based on history and the methodology used in the past, what is the anticipated dividend that will likely be paid in 2010 please?

OPDC RESPONSE:

OPDC normally declares dividends once a year subsequent to audited financial results being available for the previous year. The amount of the dividend is normally based on the prior year end results and existing cash needs going forward as is our normal practice.

Dividends paid in 2010 will be determined after 2009 year end results are finalized and approved by OPDC's Board at that time. Having said that, based on 2009 projected net earnings results as evidenced in Appendix 1-N, it is expected that this dividend would be approximately $300,000.

5. Unbilled Revenue

Refs: Exhibit 1 /3 /1 /p3

Table 1-12 summarizes assets and liabilities. The table shows Regulatory Liabilities of $0.408 million, $0.523 million, $0.942 million and $1.401 million for the years 2007, 2008, 2009 and 2010 respectively. Please explain in detail the annual changes resulting in this 243% increase over four years.

OPDC RESPONSE:

OPDC's reconciliation of the changes in regulatory liabilities is attached in the schedule following this explanation. Year over year changes are the result of billings for cost of power pass through accounts exceeding projected costs, collection of the smart meter funding adder, collection of rate riders in 2008 for market opening costs and an error in balance sheet classification (explained below).

It appears that in preparing pro forma balance sheets for 2009 and 2010 regulatory liabilities was overstated by $196,000 as was cash by the same amount.

In 2008 regulatory assets including this amount were netted against regulatory liabilities leaving a net liability amount of $523,000 on the balance sheet. This same amount for other regulatory assets of $196,000 was left out of total regulatory liabilities in the schedules for 2009 and 2010 overstating the regulatory liabilities balance.

Reconciliation of Annual Changes in Regulatory Liabilities

Description	2007 Actual	2008 Actual	2009 Bridge	2010 Test
BREAKDOWN OF REGULATORY ASSETS AS PRESENTED IN TABLE 1-12				
Other reg assets - pension etc.	213,000			
Smart meter funding adder	(55,000)			
Market opening variances (PMOEV / QTC)	(3,000)			
Reclassified from regulatory assets for statement presentation				
	155,000	0	0	0
BREAKDOWN OF REGULATORY LIABILITIES AS PRESENTED IN TABLE 1-12				
Reclassified from regulatory assets for statement presentation purposes				
Other reg assets - pension etc.		(196,000)		
Smart meter funding adder		83,000	187,000	352,000
Market opening variances (PMOEV / QTC)		145,000	145,000	145,000
Settlement variances	408,000	491,000	610,000	904,000
	408,000	523,000	942,000	1,401,000
Change - year over year - including regulatory assets		**270,000**	**419,000**	**459,000**
EXPLANATION OF YEAR OVER YEAR CHANGE				
Reduction in other reg assets		17,000		
Collection of smart meter funding adder		28,000	104,000	165,000
Collection of rider for market opening variances (PMOEV / QTC)		142,000	0	0
Increase in settlement variances		83,000	119,000	294,000
ERROR - Remaining balance of other regulatory assets left off schedule			**196,000**	
Change - year over year - including regulatory assets		**270,000**	**419,000**	**459,000**

6. Shared Services and Affiliate Relationship Code (ARC) Exemptions

Ref: Exhibit 1, Appendix 1-F

In the Appendix, the Decision and Order (RP-2002-0071/EB-2002-0365) is included. Section 2.3.3 of the Decision and Order states in part: “A cost-based price shall reflect the costs of producing the service or product, including a rate of return on invested capital. The return component shall be the higher of the utility’s approved rate of return or the bank prime rate.” For each of the years 2004 to 2009 (to date), please identify:

a) The Applicant’s average approved rate of return,
b) The average bank prime rate, and
c) The return component used by the Applicant in its shared services calculations.

OPDC RESPONSE:

Decision and Order (RP-2002-0071/EB-2002-0365), section 2.3.3 states in part: “A cost-based price shall reflect the costs of producing the service or product, including a rate of return on invested capital. The return component shall be the higher of the utility’s approved rate of return or the bank prime rate.” For each of the years 2004 to 2009 (to date):

Response to (a):
OPDC’s approved rate of return on equity is 9% and its average approved rate of return changed from 8.13% to 8.01%. The numbers are provided in the table below.

Response to (b):
The average bank prime rate is calculated using rates from the TD Canada Trust website from Jan/04 to Oct 31/09. The numbers are provided in the table below.

Response to (c):
The return component used by OPDC in its shared services calculations was not applied in 2004 and 2005 by an oversight. A return component of 9% was applied in 2006 and 2007 to all costs associated with providing service. The decision was made to use the average rate of return of 8% in 2008 and 2009.

	2004	2005	2006	2007	2008	2009
Approved rate of return - equity	9.88%	9.88%	9.00%	9.00%	9.00%	9.00%
Average return on rate base	8.57%	8.57%	8.13%	8.13%	8.07%	8.01%
Average bank prime rate	4.06%	4.35%	5.71%	6.10%	4.96%	2.55%
Return component used			9.00%	9.00%	8.00%	8.00%

7. Customer Base and Growth Rate

Ref: Exhibit 1, Appendix 1-G

On page 2, the total customer base for December 2007 is shown as 12,780, for December 2008 as 12,932, and for December 2009 as 13,065. In Exhibit 1 /1 / 4 / p1, the Applicant notes it has approximately 12,800 customers. Please reconcile the values from the two sources and note any mid-year assumptions.

OPDC RESPONSE:

On page 2, the total customer base for December 2007 is shown as 12,780, for December 2008 as 12,932, and for December 2009 as 13,065. In Exhibit 1 /1 / 4 / p1, OPDC notes it has approximately 12,800 customers based on the actual customer count of 12,815 on December 31, 2008. Exhibit 1, Appendix 1-G page 2 provides customer base and growth rate comparisons. Unmetered scattered load customers (USL) are billed on the number of connections. At the request of a few customers, connections have been aggregated for billing purposes. General Service customer base in this schedule is grossed up by 114 for December 31, 2007 and by 117 for December 31, 2008 through 2013 to the total number of USL connections billed as shown in the following table:

	Dec 31/07	Dec 31/08	Dec 31/09
USL accounts included in year end count	42	37	37
USL connections aggregated for billing purposes	114	117	117
Total USL connections billed	**156**	**154**	**154**

Rate Base

8. The OPDC Distribution System

Ref: Exhibit 2 / 1 /1/ p3

On page 3 the Applicant notes: "The control centre is staffed twelve hours a day, seven days a week and is monitored after-hours through a paging and dial-in system as well as a third party call centre."

a) Please verify that the paging and dial-in system is an automated system requiring no on-site personnel, or describe, and

b) Please provide details of the business arrangements with the third party call centre including the name of the organization, the process used to select the vendor and the approximate annual cost to the Applicant.

OPDC RESPONSE:

Response to (a):
The automated paging system is set up to notify the on call operator of any alarms picked up on the organization's SCADA system (i.e. open switches, sub-station trouble alarms, etc.). In the event the operator receives an alarm page, they would then dial-in on a laptop computer to get further details on the issue and take appropriate action. We verify that the paging system is automated and requires no on-site personnel.

Response to (b):
The third party call centre was established to accept customer outage calls after hours, when a control centre operator is not on duty. This call centre is particularly important from a customer service perspective as some outages, particularly smaller more localized outages that don't involve a system switch or other major system component, may not be picked up by a SCADA system alarm. There were very limited vendor options for this service in the local market and the Orillia Fire Department was selected to provide this service for the following reasons:

- The Fire Department is well versed in handling emergency situations.
- The Fire Department has a high degree of familiarity with the local geography, which is critical when dispatching line staff to the emergency location.
- The Fire Department offered a cost effective solution at only $1,500 per month ($18,000 annually).

9. Gross Fixed Assets

Ref: Exhibit 2 / 2 / 2 / p2

Account 1830 - Poles, Towers and Fixtures for the years 2008 to 2010 has no amounts shown.

a) Please verify that the items that would normally be in this category have been included in a related category.

b) If so, please provide the amount separately for the years 2008 to 2010.

OPDC RESPONSE:

Response to (a):
We verify that items that would normally be in this category have been included in account 1835 – Overhead Conductors and Devices.

Response to (b):
Historically, OPDC has allocated the majority of costs for account 1830 – Poles, Towers and Fixtures together with the costs for account 1835 - Overhead Conductors and Devices into only account 1835. We recognize that the proper allocation requires the appropriate split between these two accounts and OPDC is planning to correct this allocation issue. Given the potential complexity of accurately splitting the historical cost allocation, we expect to undertake and engineering review to calculate the allocation and make the necessary correcting entries.

On a going forward basis, we plan to correct the allocation process. With the forthcoming transition to International Financial Reporting Standards (IFRS), which requires greater detail is asset componentization, we see this as an opportune time to review and correct our allocation process, thereby complying with both the Uniform System of Accounts and IFRS.

Splitting the assets will have no impact on the 2010 revenue requirement.

10. Donations

Ref: Exhibit 2 / 3 / 1 / p3 and Exhibit 4 / 2 / 1 / p11

In Table 2-16 under Other Deductions, the 2009 and 2010 entries for “6205 – Donations” and “Donations not related to customers” are shown as $20,000 and $14,000 respectively. Please:

a) Explain these entries, name the beneficiary/beneficiaries of these donations and explain how the beneficiary/beneficiaries is/are related to the Applicant’s business.

b) For each year, the entry for “Donations not related to customers” is subtracted from the previous line entry “Other Items Total”. Please explain why the donation is subtracted and not added.

c) Reconcile these donations with the statement in Exhibit 4 / 2 / 1 / p11: “OPDC did not include any charitable donations not related to the welfare of Orillia’s distribution customers in our OM&A expenses.”

d) Clarify if any of these donations relate to the Applicant’s Low Income Energy Assistance Program and whether these are existing or new programs.

OPDC RESPONSE:

Response to (a):
The explanation for the methodology behind the entries is outlined in OPDC’s response to (b). Note that only one donation totaling $6,000 to the Salvation Army has been included in the calculation of OPDC’s revenue requirement as will be explained further below.

The rate filing guideline criteria for inclusion of a donation as a distribution expense is as follows: “recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor’s customers in paying their electricity bills and assistance to low income consumers”.

Excluding the Salvation Army donation previously mentioned, OPDC makes various donations throughout the year to groups like Big Brothers/Big Sisters, Sharing Place Food Bank, United Way of Greater Simcoe County and Telecare Orillia Distress Line among others. None of these donations meet the OEB’s rate filing guidelines so they are not included in OPDC’s revenue requirement calculation.

For some time now, OPDC has contributed an amount to the Salvation Army annually in the amount of $6,000 and will continue to do in the coming years. Our understanding with the Salvation Army is that this amount is to be used solely for assisting OPDC customers with the payment of electricity bills. OPDC believes this donation meets the filing guideline requirements. It is also very much within the spirit of the Energy Board's request to continue to provide financial assistance to low income energy consumers for 2009-2010 winter season under existing arrangements

Response to (b):
Certain donations are subtracted and not added because the starting point of total donations included in account 6205 has all donations made by OPDC throughout the year consisting of both eligible and non-eligible donations (2010 - $20,000). The amounts backed out from total donations are donations that **do not** meet the OEB criteria (2010 – $14,000). This leaves only donations that OPDC feels do meet the established criteria (2010 - $6,000) in the total for administration and general expenses (2010 - $1,461,000) factored into the calculation of the working capital allowance as presented in Table 2-2 of Ex. 2.

Response to (c):
The statement made in Exhibit 4 / 2 / 1 / p11 that "OPDC did not include any charitable donations not related to the welfare of Orillia's distribution customers in our OM&A expenses" would have been more informative if it had read "OPDC did not include any charitable donations not related to the welfare of Orillia's distribution customers in our OM&A expenses **that were used to calculate OPDC's revenue requirement. Ineligible donation expenses have been backed out of the calculations**."

OPDC believes the response to part (b) demonstrates this fact.

Response to (d):
OPDC does not currently have a formal Low Income Energy Assistance Program. OPDC is awaiting guidance expected to follow the Minister of Energy's recent announcement in September that it is developing a province - wide program.

For some time now, OPDC has contributed an amount to the Salvation Army annually in the amount of $6,000 and will continue to do in the coming years. Our understanding with the Salvation Army is that this amount is to be used solely for assisting OPDC customers with the payment of electricity bills.

This is the $6,000 referred to in (b) and has been included in our revenue requirement OPDC believes this donation meets the filing guideline requirements. It is also very much within the spirit of the Energy Board's request to continue to provide financial assistance to low income energy consumers for 2009-2010 winter season under existing arrangements.

11. Cost of Power for Working Capital Allowance

Ref: Exhibit 2 / 3 / 2 / p1

The Applicant states: “As a result, Orillia Power Distribution CUSTOMERS continue to benefit, post Bill 35, in the form of lower power costs due to the receipt of various credits to both wholesale market service and transmission costs.”

a) Please state the overall percentage saving in power costs enjoyed by the Applicant’s customers and the monthly dollar savings that fall to Residential customers (at 800 kWh) and General Service <50 kW (at 2,000 kWh).

b) Please describe the nature of the various credits referenced.

OPDC RESPONSE:

Response to (a):
The 2010 cost of power calculation of $23,732,000 shown in Table 2-17 would have been $24,469,000 without the benefit of these credits. This amounts to an annual reduction of $737,000 or an effective 3.0% overall percentage saving in power costs to OPDC customers.

Allocation of $737,000 to each of the 311,571,000 kwh projected to be billed to OPDC customers in 2010 amounts to a savings of $1.89 per month for a Residential customer at 800 kWh and $4.73 per month for a General Service <50 kW at 2,000 kWh.

Response to (b):
When Bill 35 was passed, all power contracts that existed at that time were not normally allowed to continue. The credits to wholesale market service costs and transmission costs were the result of OPDC management working with Government (Minister of Energy) to preserve through statute certain benefits that Orillia customers had always enjoyed due to our ability to provide power at lower cost using our generation. OPDC was able to preserve the benefits for our customers from certain power wheeling arrangements that had been in place with Ontario Hydro for our generation plants.

As a result, OPDC receives a credit from Hydro One each month on the wholesale market service charges for all power produced at the two plants where former wheeling arrangements existed. OPDC also receives reduced transmission charges from Hydro One as peak production at the two plants is used to offset slightly the total demand that would normally be charged to OPDC from power supplied by the Orillia T.S.

The net effect of these credits is a reduction in cost of power for wholesale market service and transmission experienced by OPDC over what would be expected. This lower power cost is ultimately passed on to OPDC customers through settlement variance rate rider credits every few years as balances accumulate in the RSVAs.

12. Capital Expenditures

Ref: Exhibit 2 / 4 / 1 / pp 2,3,17 &19

On pages 2 and 3 the Applicant summarizes its capital expenditures for the 2004 to 2010 period.

a) Please confirm that the 2010 planned capital expenditure of $1.714 million is 1.3% higher than the average capital expenditure over the 2004 to 2009 period.

b) Please explain how the Applicant's strategic objectives will be met by the planned capital expenditure and how performance improvements will be measured.

c) On pages 17 and 19 the Applicant identifies four situations where, through the economic process, dollar payments were made to developers. Please explain the economic process employed.

OPDC RESPONSE:

Response to (a):
OPDC confirms that the 2010 planned capital expenditure of $1.714 million is 1.3% higher than the average capital expenditures over the 2004 to 2009 period.

Response to (b):
Through the implementation of OPDC's Asset Management Plan and through the forward looking process of developing its five-year capital plan, staff spends a significant amount of time analyzing and prioritizing capital projects. When reviewing proposed capital expenditures, both globally and on an individual project basis, there are a number of considerations that may be taken into account, including, but not limited to;

- Improvements in service reliability
- Health and safety impact / improvements for staff and the public
- Environmental impacts and environmental risk management
- Cost effectiveness

Performance improvements as a result of capital expenditures are measured in a variety of ways. The organization regularly monitors and reports on a number of Service Quality Indicators (SQI's). These indicators help to identify areas for improvement and will continue to be closely monitored to ensure that capital investments have the desired impacts.

Given the high organizational priority placed upon both public and staff health and safety, it is often a factor that influences capital expenditures. The fact that the organization is now over seven years without a lost time injury and has a stellar record for public safety, provides strong evidence that our objectives are being achieved in this area. The organization has a similarly impressive record with respect to environmental matters, indicating that the pro-active approach to environmental risk management is paying dividends for the organization and the community as a whole. Measures for public safety, employee health & safety and the environment will continue to monitored closely and now form part of the organization's Employee Performance Plan, to further reinforce their importance.

Response to (c):
OPDC follows a methodology in accordance with section 3 and Appendix B of the Ontario Energy Board's Distribution System Code related to expansions of the electrical system. OPDC performs an economic evaluation based on capital costs, ongoing maintenance costs and future revenues. As described in Article 430 of the USoA, OPDC records the capital cost of the development as property, plant and equipment received in the form of capital assets constructed by the developer. An equal amount is recorded in an asset contra account, Contribution in Aid of Construction.

Under the economic evaluation process, OPDC uses discounted cash flow techniques to determine the net present value of projected revenue for distribution services provided by the facilities with the present value of capital costs and on-going maintenance (operating) costs for the facilities.

The developer is paid the net present value of projected revenue for distribution services less operating costs not to exceed the capital cost of the development. The developer payment is applied to reduce the amount recorded in the asset contra account, Contribution in Aid of Construction.

13. Asset Management Plan

Ref: Exhibit 2, Appendix 2-A

The Applicant includes a Form 3, "Statement of Adherence to the Guideline for Proximity to Distribution Lines dated Jan. 12, 2005" which includes exceptions related to Andrew St. and Colborne St. facilities. In both cases the Action Taken is stated as "to be budgeted for 2010 correction". Please confirm that the current capital expenditures include this corrective work and reference the items in the pre-filed evidence or explain.

OPDC RESPONSE:

The current capital expenditures include this corrective work. The first, item which refers to Andrew Street is in fact underway and will be completed in 2009. The reference for this item is Exhibit 2, Tab 4, Schedule 1, page 10 – under the title 'Proximity Issues – Mississaga & Andrew'. The item for Colborne Street is scheduled for completion in 2010. The reference for this item is Exhibit 2, Tab 4, Schedule 1, page 10 – under the title 'Colborne to Andrew Re-build'.

Operating Revenue

14. Load Forecasting Methodology

Ref: Exhibit 3 / 1 / 1 / pp1-3

On page 1, the Applicant states that its weather normalization forecasting method is similar to the one approved by the Board for Toronto Hydro Electric System Ltd. in its 2008, 2009 and 2010 rate application (EB-2007-0680). It also lists a number of 2009 cost of service applicants that used the same method as Toronto.

a) Please confirm that in the Toronto application – as in this application – the Applicant developed a multivariate model which resulted in a mathematical expression to forecast future loads.

b) Please confirm that in the Toronto application, a GDP forecast for the GTA was applied to the model to develop a forecast of future loads.

c) Please confirm that in the current application, the Applicant does not directly utilize *any* GDP forecast but, rather, reduces the 2008 weather-normalized load by the Province-wide load changes estimated by the IESO.

d) On page 3, the Applicant states that it "believes it is proposing a small improvement" by incorporating information from the IESO 18-month Outlook. Please explain how the use of the IESO load change data which are an estimate for the Province as a whole, which do not take into account local economic conditions and which do not take into account the Applicant's CDM individual plans, provides a better forecast than the approach utilized by Toronto.

e) Please explain why GDP is included in the multifactor regression model when the only utilized output is the 2008 weather normalized load.

f) Please re-estimate 2008 weather normalized load using only weather related variables.

OPDC RESPONSE:

Response to (a):
OPDC developed a multivariate model which resulted in a mathematical expression that was used to predict loads from 1996 to 2008 based on actual weather, economic conditions and other factors consistent with the approach used by Toronto Hydro in their 2008, 2009 and 2010 rate application (EB-2007-0680).

Response to (b):
It is OPDC understanding that in an updated version to the Toronto application, a GDP forecast for the GTA was applied to the model to develop a forecast of future loads.

Response to (c):
In the current application, OPDC did not directly utilize *any* GDP forecast but, rather, reduces the 2008 weather-normalized load by the Province-wide load changes estimated by the IESO.

Response to (d):
During the process of preparing the load forecast for the rate application, OPDC was concerned that the recent economic downturn was not being properly reflected in the load forecast. At the same time, the IESO's 18-month Outlook for the months June 2009 to November 2010 was also released. In the report it stated on Page iii of the Executive Summary

> *"The economic downturn that began last fall has triggered a noteworthy drop in demand for electricity across North America. In Ontario, peak and energy demand have declined in recent months, in part, as wholesale industrial consumers have scaled back on consumption. Over the first three months of the year, wholesale industrial consumption of electricity dropped by approximately 20 per cent compared with the same period in 2008. Other factors affecting demand are the growth in embedded generation and the impacts of conservation. Although the North American economy is expected to recover in 2010, electricity demand is unlikely to recover within the Outlook period. Overall, electricity demand in Ontario is expected to decline by 4.0 per cent in 2009 and 0.3 per cent in 2010"*

It also stated on page v of the Executive Summary of the 18-Month Outlook that

> *"The current recession has significantly reduced electricity demand on the system. Both energy and peak demands are tracking much lower than a year ago. Although the economy is expected to recover in 2010, electricity demand will not due to the structural change in the Ontario economy, higher level of conservation and continuing growth in embedded generation."*

OPDC knew that in OPDC service area, there was a decline in load from the economic downturn, higher level of conservation and continuing growth in embedded generation. However, OPDC was not able to sufficiently quantify these amounts in manner that could be supported in the application. As a result, OPDC believed that a decline of 4.0 per cent in 2009 and 0.3 per cent in 2010 in the overall electricity demand in Ontario was a reasonable estimate on the impact of electricity demand in the OPDC service area. In addition, it is OPDC's view that a multivariable regression analysis could be used to determine the OPDC load forecast but without significant cost this method could never be as sophisticated and accurate as the methodology used to produce the IESO 18-Month Outlook.

Response to (e):
Using a regression analysis, OPDC developed a multivariable formula to predict "actual" purchased kWh's for 1996 to 2008 assuming actual weather conditions. One of the variables used in the regression analysis is GDP. The multivariable formula was used to predict 2008 purchased kWh's with actual weather conditions and 2008 weather normalized kWhs with normal weather conditions. In both cases the 2008 GDP value is used to produce the prediction. As a result, the GDP is used to produce the 2008 weather normalized load.

Response to (f):
The estimated 2008 weather normalized purchased load using only weather related variables is 332.5 GWh compared to 344.8 GWh in the application.

15. Load Forecast Results

Ref: Exhibit 3 / 1 / 3 / pp1-21

To forecast the 2009 and 2010 weather-normalized purchases, the Applicant stated that it has incorporated the IESO 18-Month Outlook for June 2009 to November 2010, dated May 25, 2009. IESO is forecasting a 4.0% decline in the year 2009 and an additional 0.3% decline in the year 2010.

a) Please compare the economic trends expected in the Applicant's local area with the economic trends inherent in the IESO Outlook.

b) Please file the regional data and provide the sources that support the Applicant's position in a) above.

c) Please recalculate the load forecast for the 2009 bridge year and the 2010 test year using the multifactor regression model including economic indicators instead of the IESO adjustment, and compare the outcome to the current load forecast for the 2009 bridge and 2010 test years.

OPDC RESPONSE:

Response to (a):
OPDC does not have any economic trend data available for it's service area which means the requested comparison can not be completed.

Response to (b):
See response to a)

Response to (c):
See response to a)

16. CDM influence in the Load Forecast

Ref: Exhibit 3 / 1 / 3 / pp1-21 and Exhibit 4 / 6 / 1 / p3

The Applicant appears to have made no further adjustments for CDM activities since it incorporated the IESO 18-Month Outlook into its load forecasting model and the Outlook already accounts for CDM energy savings.

a) Please describe the Applicant's CDM initiatives and compare the reduction expected by the Applicant with the CDM assumptions included in the IESO 18-Month outlook.

b) Please describe the Exhibit 4 entry "Turn Key Services OPA CDM Programs - $189k"

OPDC RESPONSE:

OPDC has made no further adjustments for CDM activities since it incorporated the IESO 18-Month Outlook into its load forecasting model.

Response to (a):
OPDC's CDM initiatives are summarized in the following table:

Conservation Program	Results since 2007
OPA Every Kilowatt Counts	
OPA Cool Savings Rebate Program	
OPA Great Refrigerator Roundup Program	1,149 old units taken out of service to date
OPA Energy Retrofit Incentive Program - GS<50kW	10 prescriptive / I custom projects funded to date
OPA Direct Install Incentive Program - GS>50kW	265 retrofit projects funded to date

OPDC has had a very good response to the Energy Retrofit and Direct Install incentive programs for local businesses. OPDC will be continuing these programs and is looking into a similar incentive program that will target residential customers (ie. social housing and other low income consumers). OPDC local CDM activities for 2006 through 2008 have resulted in annual energy savings of 1.5% of forecasted load based on Ontario Power Authority Conservation Results for OPDC in 2008. It is OPDC's view that a similar level of savings will continue in 2009 and 2010.

The IESO 18-Month Outlook, Table 4.3: "Summary of Scenario Assumptions", shows Demand Forecast: Conservation - Incremental growth of 215 MW at the time of peak. This information is the only numerical information that OPDC was able to find in the IESO 18-Month Outlook with regards to the CDM results. The 215 MW is 0.9% of the 2010 summer normal weather peak demand in the IESO 18-Month Outlook (Table 3.1: "Forecast Summary"). By using the IESO results which include CDM savings of 0.9, the

OPDC load forecast may not completely reflect the savings achieved in the OPDC service area. However, please refer to response to VECC IR#11 m) which provides OPDC's view on the appropriateness of using the overall results of IESO 18-Month Outlook to determine the 2010 load forecast for rate setting purposes.

Response to (b):
Details of Exhibit 4 entry "Turn Key Services OPA CDM Programs - $189k" is provided in the following table.

Supplier	Description	Amount
M3&W Inc	2008 Direct Install Incentive Program - management fee	$31,001
M3&W Inc	2008 Direct Install - customer incentive payments for 156 retrofits	$148,161
M3&W Inc	2009 Direct Install Incentive Program - initial management fee	$9,765
	Total	**$188,927**

17. Manual Adjustments to the Predicted kWh load

Ref: Exhibit 3 / 1 / 3 / p7

On page 7 the Applicant shows a graph comparing actual and predicted load from 1996 to 2008.

a) Please describe any manual adjustments that were employed in developing the model.

b) If manual adjustments were incorporated in the model, please recalculate the 2008 kWh load without the manual adjustments.

OPDC RESPONSE:

Response to (a):
No manual adjustments were employed in developing the model.

Response to (b):
Not applicable

18. Period used to define Weather Normal

Ref: Exhibit 3 / 1 / 3 / pp8&9

On page 9 the Applicant notes that it has utilized historical weather from January 1996 to December 2008; i.e. a 13 year period. In Table 3-5 the 2008 predicted value corresponding to this year is 339.5 kWh. However, the following line reads: “2008 Weather Normal – 13 year average: 344.8 kWh”.

a) Please differentiate between the 339.5 and 344.8 kWh values that seem to describe the same 13 year period.

b) Please clarify which value was used as the basis for obtaining the 2009 and 2010 load forecast values.

OPDC RESPONSE:

Response to (a):

The 339.5 GWh value is a prediction of the actual amount for 2008 assuming actual 2008 weather conditions. The 344.8 GWh value is a prediction of the weather normal amount for 2008 assuming normal weather conditions.

Response to (b):

The 344.8 GWh value was used as the basis for obtaining the 2009 and 2010 load forecast values.

19. Customers/Connections

Ref: Exhibit 3 / 1 / 3 / p11

On page 11 the Applicant describes the method it used to obtain customers/connections forecasts and records the resulting values.

Please confirm that the geometric mean approach used is essentially a rear-view mirror approach in that no economic or demographic forecasts are utilized. Please describe the checks made to verify that the projected values are consistent with local economic and demographic expectations.

OPDC RESPONSE:

OPDC confirms that the geometric mean approach used is essentially a rear-view mirror approach in that no economic or demographic forecasts are utilized.

OPDC checked the reasonableness of its projected values with a consultant report prepared for the City of Orillia: “Economic Development Strategy”. Observations made in the executive summary under Summary of Findings:

> *“The City of Orillia has a population of 30,259 residents, an increase of 3.9% since 2001 and 8% since1996. While significant, when consideration is given to the rate of growth being experienced across the region, it is evident that the City is growing at a much slower rate than either the County or the surrounding townships.”*

are consistent with OPDC assumptions used in its forecast.

20. kW/kWh Conversion

Ref: Exhibit 3 / 1 / 3 / pp19-20

In Table 3-17, the Applicant shows the General Service <50 kW kW/kWh ratios from 1996 to 2008 and the average value over this period. Board staff notes the average value (0.2631%) is higher than any value since 2003 due to the downward trend. Please recalculate the 2010 kW forecast for this class (Table 3-18) but now using the trend value evident in Table 3-17 data rather than the average.

OPDC RESPONSE:

The 2010 kW forecast for the General Service <50 kW class by using a value of 0.2547% resulting from the requested trend analysis is 384,515 kW.

21. Distribution and Other Revenues

Ref: Exhibit 1 / 1 / 1 / p6, Exhibit 3 / 1 / 3 / p21, Exhibit 3 / 3 / 1 / p2 and Exhibit 3, Appendix 3-C

In Table 1-1 the Applicant provides a schedule of proposed rates and charges by customer class. In Table 3-19 the 2010 load and customers/connections forecast together with billing determinants by customer class are provided. In Table 3-26 the anticipated 2010 revenues by customer class are provided. Please:

a) By utilizing the data in the first two identified references, compute the expected revenues,

b) Reconcile any overall revenue variance and identify whether Applicant or customers benefit from the variance, and

c) Reconcile any overall revenue variance with the detailed variance calculations in Appendix 3-C.

OPDC RESPONSE:

Response to (a):
The table below shows the expected revenues when the rates identified in Table 1-1 are applied to the billing determinants identified in Table 3-19 in the first column. The differences when compared to Table 3-26 are highlighted in the third column.

	Difference Caused By Rate Rounding		
Class	Fixed Rate Rounded to 2 Decimals and Variable to 4 Decimals	Revenues as Summarized in Table 3-26	Difference
Residential	$3,631,219	$3,628,315	$2,904
GS <50 kW	$1,340,247	$1,341,449	($1,202)
GS>=50 kW	$1,925,293	$1,929,795	($4,502)
Street Light	$183,411	$179,358	$4,053
Sentinel	$17,262	$17,262	$0
Unmetered Scattered Load	$21,142	$20,721	$421
TOTALS	$7,118,574	$7,116,900	$1,674

It appears that slight adjustments to fixed / variable splits for some classes were made subsequent to preparing Table 3-26 were not reflected in that table. This had no affect on total revenue requirement but does account for most of the differences shown in the last four classes as will be illustrated below.

Table 8-16 (Ex. 8 Tab 5 Sch. 2 page 4) calculated expected revenues when proposed rates are applied to billing determinants however does so without rounding the monthly fixed charge to two decimals and the variable charge to 4 as required. Table 3-26 should have reflected the figures in Table 8-16 and had it done so then the calculations requested would have been reflected in the following table.

	Difference Caused By Rate Rounding		
Class	**Fixed Rate Rounded to 2 Decimals and Variable to 4 Decimals**	**Revenues as Summarized in Table 3-26**	**Difference**
Residential	**$3,631,219**	**$3,628,315**	**$2,904**
GS <50 kW	**$1,340,247**	**$1,341,448**	**($1,201)**
GS>=50 kW	**$1,925,293**	**$1,925,281**	**$12**
Street Light	**$183,411**	**$183,411**	**$0**
Sentinel	**$17,262**	**$17,262**	**$0**
Unmetered Scattered Load	**$21,142**	**$21,183**	**($41)**
TOTALS	**$7,118,574**	**$7,116,900**	**$1,674**

Response to (b):
The overall variance resulting from the calculations requested in (a) totals $1,674 in favour of OPDC. This is caused by rounding the monthly fixed charge to two decimals and the variable charge to four decimals as required on rate orders.

Response to (c):
Appendix 3-C did not perform detailed variance calculations for 2010 so a reconciliation cannot be completed.

Operating Costs

22. Drivers of Wage and Related Increases

Ref: Exhibit 4 / 1 / 1 / page 4

On page 4 the Applicant notes that it has been its practice over the years that the Executive/Management group receives the same annual percentage wage increases as per the union contract. Please identify any exceptions in the 2006 to 2010 period to the practice.

OPDC RESPONSE:

OPDC confirms that there have been no exceptions for the 2007, 2008 and 2009 contract years and no exception is projected for 2010. There was a minor exception to this general rule in 2006 as explained below.

For the 2006 contract year, union employees received an increase of 3.25% over the previous year with the exception of line staff who received an effective increase of 4.0%. Management received a 4% increase in that year.

23. OM&A Expenses

Ref: Exhibit 4 / 2 / 1 / page 2

In Table 4-4 the Applicant provides a summary of its OM&A expenses.

a) Please confirm that the 2010 OM&A (including billing and amortization costs) at $4.346 million is 11.8% greater than the 2008 value of $3.8885 million.

b) Please confirm that the 2008 OM&A (including billing and amortization costs) at $3.8885 million is 7.8% greater than the 2006 value of $3.6073 million

c) Please identify the drivers responsible for the increased trend in OM&A expenses (i.e. from 7.8% to 11.8% in successive two-year periods).

OPDC RESPONSE:

Response to (a):
OPDC confirms that the 2010 OM&A expenses shown in Table 4-4 at $4.346 million is 11.8% greater than the 2008 value of $3.8885 million.

Amortization is NOT included in any of the figures in Table 4-4.

Response to (b):
OPDC confirms that the 2008 OM&A expenses shown in Table 4-4 at $3.8885 million is 7.8% greater than the 2006 value of $3.6073 million.

Amortization is NOT included in any of the figures in Table 4-4.

Response to (c):
Please see table below.

COST DRIVER LISTING	2006 to 2008	2008 to 2010
Actual Expenditures - Beginning of Period Year	**3,607,300**	**3,888,500**
# 1 - Labour rate increases	119,000	139,000
# 2 - Inflation	101,000	60,000
# 3 - Regulatory costs	-	47,000
# 4 - Bad debt expense	130,000	75,000
# 5 - Staffing additions / subtractions	95,000	83,000
# 6 - Write off residual value of water heaters	(54,000)	-
# 7 - Reduced over-time following implementation of new billing system	(20,000)	-
# 8 - Employee performance plan payout	38,000	-
# 9 - Reduction in capital taxes and refund for 2007 capital tax	(33,000)	-
# 10 - Renegotiated wholesale settlement services contract	(21,000)	-
# 11 - Reduction in energy conservation expenditures	(28,000)	-
# 12 - Increased preventive air brake maintenance and tree trimming on 44kV	-	38,000
# 13 - Eliminate maintenance cost Matthias line	-	(32,000)
# 14 - IFRS consulting and support	-	30,000
Immaterial unexplained difference	(45,800)	17,500
Actual Expenditures - End of Period Year	**3,888,500**	**4,346,000**

24. Bad Debt Expenses

Ref: Exhibit 4 / 2 / 1 / page 4

In Table 4-5 the Applicant provides a cost driver table for various expenses including bad debt. Please provide a detailed table showing the actual/projected year-by-year expenses (2006 to 2010) for bad debt.

OPDC RESPONSE:

Please see table below.

BAD DEBT EXPENSES	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Bad debt expense - various accounts	114,000	69,500	70,800	65,000	120,000
Large commercial - 2005 write-off recovered	(174,000)				
Large commercial - 2009 write-off due to Ch 11				150,000	
Credit Insurance - commercial accounts		3,200	14,600	20,000	40,000
Total bad debt expense	**($60,000)**	**$72,700**	**$85,400**	**$235,000**	**$160,000**

25. MEARIE Utility Performance Management Survey

Ref: Exhibit 4 / 2 / 1 / page 9

On page 9 the Applicant references the MEARIE Utility Performance Management Survey and notes: “Through this benchmarking process, management can identify areas for potential improvements and thereby realize future cost reductions.” With reference to the most recent survey, please identify the key areas for improvement that management identified and the future cost reductions that should be expected.

OPDC RESPONSE:

With respect to the most recent MEARIE survey, one key area identified for potential improvement, was the cost of billing and collection services. As with many expenses, there continues to be upward pressure on the costs that fall within the billing and collection category. OPDC’s efforts at managing these costs will have the expected impact of 2010 costs (exclusive of bad debts and bad debt / credit insurance) remaining at a level that is consistent with the average cost in this category from the period 2004 through 2009. Without the efforts, costs most certainly would have continued to escalate. OPDC expects to continue to manage costs in this area and is not anticipating any significant increase in this category over the next two to three years.

The other key area that OPDC identified as an area of potential improvement relates to a statistic for Operations and Maintenance Expense per Customer. This is a broad measure that incorporates the full range of O & M expenses and provides an overall benchmark and may indicate that there are expenses within the category that provide an opportunity for cost savings. Having said that, OPDC is aware that this measure can be inconsistently measured across utilities given differing capitalization policies and procedures.

In 2008, the most recent survey year, one factor that resulted in a noticeable O & M cost increase was related to conductor theft at OPDC substations. In fact, these costs and related repairs were $47,000 in 2008. Corrective actions with increased security measures were implemented with the goal of reducing these costs by at least half in 2009. With 2009 coming to a close, our efforts seem to have been successful as we now anticipate costs in this area to be $15,000 or less for the year. On a going forward basis, we expect these costs will not go back to the 2008 level and expect them to be in the range of $20,000 or less.

26. Regulatory Costs

Ref: Exhibit 4 / 2 / 1 / page 10

In Table 4-7 the Applicant breaks down the components of its regulatory costs and identifies “Operating expenses associated with staff resources allocated to regulatory matters (Regulatory Officer and New Engineering Staff.)” as the component responsible for the largest increase; i.e. an increase from $100,299 in 2008 to $198,000 in 2010.

a) Please explain why this component of regulatory cost is expected to effectively double in two years.

b) Please provide a forecast of the regulatory costs during the Applicant’s upcoming incentive regulation term.

OPDC RESPONSE:

Response to (a):
The primary factor influencing the increase in regulatory costs is the need to add a staff member in the engineering department in order to adequately address the increased regulatory requirements and regulatory reporting. In particular, the proposed new engineering technician will be focused on ensuring compliance with Regulation 22/04.

Response to (b):
OPDC’s forecast of the regulatory costs during the Applicant’s upcoming incentive regulation term are as follows:

- 2010 - $330,000
- 2011 - $331,000
- 2012 – $334,000
- 2013 - $332,000

The costs associated with preparing this application have been amortized over 4 years and are included in the above.

27. Administration and General

Ref: Exhibit 4 / 2 / 2 / p3

In Table 4-8 the Applicant breaks down the components of its Administration and General expenses. Account 5625 shows a large annual credit transferred out. Please provide details.

OPDC RESPONSE:

In Table 4-8 OPDC breaks down the components of its Administration and General expenses. Account 5625 represents the cost of shared administrative services billed to its affiliate OPGC. Shared administration costs are allocated based on the OPDC FTEE as a percentage of the consolidated OPC permanent FTEE as shown in Exhibit 4 / 5 / 1 / p5 Table 4-12. Details of the credit amount transferred are included in Exhibit 4 - Appendix 4-C Shared Services Methodology pages 3 through 7. The first entry for each year 2006 Actual through 2010 Test details the administrative services shared, the price charged for these services and the % allocation used.

28. Misclassification error in 2006 EDR Model

Ref: Exhibit 4 / 3 /1 / p1

The Applicant notes that in the preparation of the current application it discovered, that due to an error in its 2006 EDR, $258,975 in distribution control centre costs were not included in the approved rates for May 1, 2006 and have not been in rates for the 2007, 2008 and 2009 rate years. It further notes that the correction of this omission accounts for almost 40% of the after tax revenue deficiency quoted in the application. Please provide a detailed explanation with emphasis on the 2010 entry and clarification as to how this $259k is represented in historical cost tables; e.g. in Table 4-4 is this amount simply omitted from the 2006 EDR column but included for all column entries in 2006 to 2010?

OPDC RESPONSE:

OPDC wishes to confirm that the description of how this amount is represented is accurately described in the above question.

That is in Table 4-4, control room costs are omitted from the 2006 EDR column and therefore were omitted from OPDC's 2006 revenue requirement. Control room costs are included for all actual expenditure column entries for 2006 to 2008, the bridge year costs in 2009 and the test year costs for 2010. Budgeted control room costs for the 2010 test year total $261,000 and are included in the 2010 revenue requirement.

29. Sale of segment of Sub Transmission Line

Ref: Exhibit 4 / 3 / 2 / p6

The Applicant explains that as a result of the planned system reconfiguration and tie in to the Hydro One grid related to the Matthias sub transmission line, it is planning to sell the remaining segment of this line to Orillia Power Generation Corporation. It is also noted that with the transaction expected to take place at the end of 2009, there are no budgeted maintenance costs for the Applicant in 2010.

a) Making reference to the pre-filed evidence, please show how the sale value of the sub transmission line is included in the current application.

b) Since the asset will be sold to an independent company, please explain the analysis that took place to ascertain the value of the asset (as distinct from simply relying on its book value).

c) Please identify the expected maintenance savings included in the application.

OPDC RESPONSE:

Response to (a):
As the asset is intended to be transferred to OPGC for proceeds equal to net book value, there is no gain or loss anticipated on the transaction.

It was initially felt that OPDC would be in a position to connect to the Hydro One grid in 2009. Subsequent to filing this application, it was determined that there were new and unanticipated protection and control issues that Hydro One required satisfaction on before a connection could be made. This means that the connection will not be made (and therefore the sale) in 2009 and is delayed substantially into 2010 or possibly beyond 2010.

Ultimately, before a connection into the Hydro One system can be made, OPDC must satisfy Hydro One that all relevant protection and control issues have been dealt with. OPDC is working with Hydro One to make this happen but the timetable for signoff is not clear.

At this point, OPDC is proposing to not make any adjustments to its application in order to reflect this change in anticipated transaction date.

Response to (b):
In ascertaining the value of the asset being sold by OPDC to OPGC, the applicant looked at book value, replacement value and fair market value. Replacement cost as a means of valuing the asset was discounted as replacement cost represents the cost of a completely new asset, which would have an extensive useful remaining life and would require minimal maintenance upgrading and refurbishment in the short-term. This is certainly not the case with this asset as it is older and requires regular, costly, on-going maintenance.

Determining market value assumes that there is a market, with a potential buyer or buyers for the asset. Given that there are no other utilities in the proximity of this section of line that would have any interest in purchasing the line, it was determined that the asset had a market value of zero. Furthermore, given the regulatory obligation for OPDC to dismantle and remove an unused pole line within six months, one could argue that in fact there is a negative value associated with this line, as OPDC would be required to undertake a costly removal of the line. Given the information above, it was determined that book value represented the most reasonable method of determining value for both OPDC and OPGC.

Response to (c):
The expected annual maintenance savings, based upon average maintenance spending over the past six years, is identified as $50,000 per year. These savings have been reflected in the application.

30. Employee Performance Plan

Ref: Exhibit 4 / 4 / 1 / p3

The Applicant explains that all its employees share in the payout of the plan on a "pro-rata basis". Please explain in detail how the payout calculations are made.

OPDC RESPONSE:

This information is provided in Appendix 4-B, but relevant sections of the Appendix 4-B have been extracted and are included below.

EPP Pool & Performance Measures

The EPP is based on the concept of a pool of funds to be distributed to the employee group. The maximum size of the pool available in any given year is determined by the board of directors during the budgeting process and will be communicated to the employees at the beginning of the year. The pool amount set by the board of directors is the amount that would be paid out if all performance measures are achieved or exceeded for the given year.

The EPP measures, as referred to above, are indicators which track our achievement of key corporate objectives and goals. The measures will be reviewed / set on an annual basis by management and the board of directors. Each year, the details of the measures and the associated weightings will be communicated to staff.

The value of the pool available for distribution to employees would be reduced if we fail to achieve the performance targets for any individual measure. Each measure is treated independently; therefore, failure to achieve the target in one particular measure reduces the pool by the weighting for that measure alone. For example, if the environmental standard was not achieved, there would be a 5% reduction from the pool. To further illustrate, if the initial value of the pool was $60,000 and the environmental standard, weighted at 5%, was not achieved, there would be a $3,000 reduction in the pool ($60,000 X 5%). Therefore, the pool available for distribution to employees would be $57,000.

Individual Payout Calculations

Once any deductions for measures that were not achieved have been calculated, the residual value of the pool of EPP funds will be used to calculate individual payouts. The payout for each eligible employee is based on a pro-rata calculation using individual basic compensation of each employee over the total basic compensation of all eligible employees. For example, if Employee A has basic compensation of $56,000 per year and the total basic compensation of all eligible employees is $2,800,000 then Employee A would be eligible for 2.0% of the pool ($56,000 / $2,800,000 X100). Assuming the pool in that given year was $60,000 Employee A would be eligible for an EPP of $1,200

($60,000 X 2%).

An employee's basic compensation is defined as their hourly rate (as of December 31st for the year being measured) times their regular scheduled hours in a week times 52 weeks. Therefore, if Employee A earns $28.55 per hour and has a regular work week of 40 hours, their basic compensation would be $59,384 ($28.55 X 40 hours X 52 weeks).

Once the individual payout is calculated, based on the achievement of measures and the pro-rata portion of individual compensation, an attendance factor will be applied to the individual payout. The attendance factor works as follows:

- An employee with three (3) or less sick leave absence occurrences in the calendar year, will receive their full individual EPP payout
- If an employee has four (4) sick leave absence occurrences during the year, their individual EPP payout will be reduced by 1/6th
- Each subsequent sick leave absence occurrence will reduce the individual payout by an additional 1/6th

A sick leave absence occurrence is defined as a period of work missed due to sickness that begins from the first day of work missed and continues until the employee returns to work. For example, if an employee calls in sick on Wednesday morning and returns to work Thursday, they are absent for one day and that is considered one sick leave absence occurrence. If the employee did not return to work until the Friday, they would have missed two days of work, but it would only be considered one sick leave absence occurrence. If however, the employee was off sick on Wednesday, returned to work on Thursday, but called in sick again on Friday, that would be considered two sick leave absence occurrences.

To illustrate the impact of the attendance factor, assume that Employee A is eligible for an individual EPP of $1,200 prior to applying the attendance factor. If Employee A had five sick leave absence occurrences during the year, their individual payout would be reduced by 2/6ths or $400 ($1,200 X 2/6). If Employee A had incurred three or less sick leave absence occurrences during the year, there would have been no reduction in their individual payout and they would have received $1,200.

31. Employee Costs

Ref: Exhibit 4 / 4 / 1 / p4

In Table 4-10 for the years 2006 to 2010 and separately for Management and Union, the Applicant shows the sub-tables:

- Number of Employees (FTEs)
- Number of Part Time Employees
- Total Salaries and Wages
- Total Benefits
- Total Compensation (Salary, Wages and Benefits)

Please recalculate the last three sub-tables showing:

a) The dollar value on an FTE basis

b) The year-to-year changes in a) on a percent basis.

OPDC RESPONSE:

In Table 4-10 for the years 2006 to 2010 and separately for Management and Union, the OPDC shows the sub-tables:

- Number of Employees (FTEs)
- Number of Part Time Employees
- Total Salaries and Wages
- Total Benefits
- Total Compensation (Salary, Wages and Benefits)

Response to (a):
The dollar value reported in the last three sub-tables is reported on an FTE basis in the application.

Response to (b):
The year-to-year changes in (a) on a percent basis are shown in the following table:

Description	2006	2007	2008	2009	2010
TOTAL SALARIES AND WAGES					
Management	484,124	613,816	656,887	679,141	702,025
Union (includes part time employees)	1,355,124	1,362,960	1,462,913	1,525,926	1,637,731
Total Salaries and Wages	1,839,248	1,976,776	2,119,800	2,205,067	2,339,756
% Change Year over Year					
Management		26.8%	7.0%	3.4%	3.4%
Union (includes part time employees)		0.6%	7.3%	4.3%	7.3%
Total Salaries and Wages		7.5%	7.2%	4.0%	6.1%
TOTAL BENEFITS					
Management	87,729	112,137	120,762	126,129	133,988
Union (includes part time employees)	241,691	243,660	262,021	279,214	309,472
Total Benefits	329,420	355,797	382,783	405,343	443,460
% Change Year over Year					
Management		27.8%	7.7%	4.4%	6.2%
Union (includes part time employees)		0.8%	7.5%	6.6%	10.8%
Total Benefits		8.0%	7.6%	5.9%	9.4%
TOTAL COMPENSATION (SALARY, WAGES AND BENEFITS)					
Management	571,852	725,953	777,649	805,270	836,013
Union (includes part time employees)	1,596,815	1,606,621	1,724,933	1,805,140	1,947,203
Total Compensation	2,168,667	2,332,574	2,502,582	2,610,410	2,783,216
% Change Year over Year					
Management		26.9%	7.1%	3.6%	3.8%
Union (includes part time employees)		0.6%	7.4%	4.6%	7.9%
Total Compensation		7.6%	7.3%	4.3%	6.6%

Annual reviews of FTE positions resulted in an increase of 1.1 management staff and 0.4 union staff at Dec 31/07 and 0.1 management staff and 0.2 union staff at Dec 31/08. The changes are related to increasing electricity distribution regulatory compliance and reporting requirements in finance, distribution and engineering departments including but not limited to CDM and smart meters initiatives, ESA audits, EUSA ZeroQuest Safety Audits and website administration.

OPDC employee count at Dec 31 remained the same every year until 2010 when count increases by one with the addition of a new engineering technician. Average labour rate increases year over year of 3% to 3.5% are discussed in Exhibit 4 / 2 / 1 pp 6-8. Additional variances in total salaries and wages are due to staffing changes discussed in Exhibit 4 / 4 / 1 pp 6-8. The increase in total benefits is also influenced by average increases year over year in employee benefits plan dues (2007 - 3 to 4%, 2008 - 4 to 5%, 2009 - 9 to10%, 2010 - 7%).

32. Charging of Employee Costs

Ref: Exhibit 4 / 4 / 1 / p5

In Table 4-10 (cont.) the Applicant shows the 2010 Total Compensation of $2,783,216 is being charged to OM&A ($2,383,216) and capitalized ($190,000). Board staff notes that the sum of the two cost components ($2,383,216 plus $190,000) is $210,000 less than the 2010 compensation total of $2,783,216.
Please:

a) Explain how the $216,000 balance is charged.

b) Provide details of the $190,000 that has been capitalized.

OPDC RESPONSE:

In Table 4-10 (cont.) OPDC shows the 2010 Total Compensation of $2,783,216 is being charged to OM&A ($2,383,216) and capitalized ($190,000). Board staff notes that the sum of the two cost components ($2,383,216 plus $190,000) is $210,000 less than the 2010 compensation total of $2,783,216.

Response to (a):
The following tables provide detail on the balance of compensation not charged to capital or OM&A:

Description	2006	2007	2008	2009	2010
TOTAL COMPENSATION CHARGED TO OM&A					
Total Compensation	2,168,667	2,332,574	2,502,582	2,610,410	2,783,216
Less Charged to Capital	165,303	187,216	172,482	180,000	190,000
Subtotal	2,003,364	2,145,358	2,330,100	2,430,410	2,593,216
Less recoverable from:					
Developer projects / City of Orillia projects	161,385	118,812	230,701	220,000	230,000
OPGC Shared Services	181,188	142,845	169,681	170,000	170,000
Subtotal recoverable	342,573	261,657	400,382	390,000	400,000
Total Compensation Charged to OM&A	**1,660,791**	**1,883,701**	**1,929,718**	**2,040,410**	**2,193,216**

In preparing this table, we discovered that the formula used in calculating the total compensation charged to OM&A inadvertently missed deduction of the amount capitalized.

Developer/City projects includes subdivision projects and city-driven capital projects (eg road widening) for which OPDC recovers costs incurred for work required to be performed by OPDC staff. OPGC shared services are described in Exhibit 4 / 5 / 1 pp1-3.

Response to (b):
$190,000 is shown as compensation charged to capital in 2010. The 5 year historic average is $187,000. Based on expected capital expenditures summarized in Exhibit 2 / 4 / 1 p2, we used the 5 year average rounded to the nearest $10,000. This amount is further supported by OPDC plans for overhead projects detailed in Exhibit 2 / 4 / 1 pp9-10. Overhead projects are generally expected to be labour intensive.

33. Shared Services / Corporate Cost Allocation

Ref: Exhibit 4 / 3 / 2 / p6, Exhibit 4 / 4 / 1 / p10 and Exhibit 4 / 5 / 1 / pp1-9

In Schedule 3, page 6 the Applicant provides information regarding the sale of the sub transmission line segment. In Table 4-12 the Applicant shows the allocation of shared services staff to itself and Orillia Power Generation Corporation (OPGD). In Exhibit 4 / 5 / 1 / pp1-9 the Applicant discusses the bases on which shared services costs are allocated and explains that OPGD expects to complete a connection from the Matthiasville plant to the Hydro One transmission system.

a) Please explain how the allocation of shared services costs between the Applicant and OPGD was modified in light of the sale of the sub transmission line segment.

b) Please explain the audit process conducted – and its frequency – to verify the allocation of costs between the Applicant and OPGD.

c) Please identify any costs associated with the connection from the Matthiasville plant to the Hydro One transmission system that the Applicant will pay for.

OPDC RESPONSE:

Response to (a):
It was not necessary to modify the allocation of shared services costs between OPDC and OPGC in light of the sale of the sub transmission line segment. Employees of OPGC are not part of the calculation of OPDC FTE count for shared services. OPGC employee costs are charged 100% to OPGC. Contract work performed between the companies is billed using fully allocated cost plus a rate of return. There are no intercompany contract services related to the sub transmission line included in the application for 2010.

Response to (b):
OPDC conducts an internal review of the allocation of costs between OPDC and OPGC during budget preparation and at year end. This includes informal discussions with staff regarding work load based on both current and future needs. Unexpected events may trigger additional reviews.

Furthermore, OPDC's external auditor gives an opinion each year that OPDC and OPGC financial statements are fairly presented. Related party transactions are disclosed as a note the financial statements and are subject to detailed scrutiny by the auditor.

Response to (c):

The net costs to the applicant associated with the connection from the Matthiasville plant to the Hydro One transmission system will be zero. There are upfront connection related costs, estimated at $242,000 that OPDC will pay for, however, these costs will be added to the value of the asset and included in the sale price to OPGC.

34. Purchase of Products and Services from Non-Affiliates

Ref: Exhibit 4 / 6 / 1 / pp1-3

The Applicant identifies the products and services it acquires from non-affiliate companies and shows that some are priced by RFP, RFQ, sole source, tender, etc. Please explain the basis for selecting a particular acquisitioning method.

OPDC RESPONSE:

OPDC policy for selecting a particular acquisitioning method is described in Exhibit 4 / Appendix 4-D: Expenditure Controls Policy, page 4: "Sourcing Limits for Goods and Services". An RFQ, written or verbal, is typically used for most purchases. Purchases over $1,500 up to $40,000 require written quotes. An RFP is generally used for major expenditures from $40,000.

35. Depreciation

Ref: Exhibit 4 / 7 / 1 / pp1-9

The Applicant explains it depreciation methodology and provides depreciation values.

a) Please explain the increase in depreciation for Poles and Wires from 2009 to 2010 as shown in Table 4-16.

b) Please explain why in Table 4-16 there is zero depreciation shown for Computer Software for both 2009 and 2010.

c) Please expand on the explanation the Applicant has already given for choosing not to use the Board's guidance regarding the half-year depreciation rule and instead including a full year of depreciation in the year that an asset is acquired.

d) Please recalculate Table 4-16 based on adherence to the Board's half-year depreciation rule.

e) Please provide quantitative evidence that supports the Applicant's intention to now amortize SCADA equipment over a 10 year period rather than the previous 15 year period.

OPDC RESPONSE:

Response to (a):
In 2010, the budgeted capital investment in the poles and wires category is $1,300,000 ($1,019,000 for overhead conductors and devices and $281,000 for underground – reference Exhibit 2 / 4 /1 – page 2). This increase in asset base multiplied by the amortization rate of 4% for assets in this category explains the increase in depreciation for poles and wires from 2009 to 2010.

Response to (b):
Depreciation for computer software was grouped with deprecation for computer hardware for 2009 and 2010 in error. The breakdown between deprecation for hard ware and depreciation for software in 2009 and 2010 is as follows.

		2009 Bridge	2010 Test
1920	Computer Equipment - Hardware	27,000	19,000
1925	Computer Software	56,000	26,000
	Combined Total reported in 1920	**83,000**	**45,000**

Response to (c):
Question (c) states that OPDC has not followed the Board's guidance regarding the half-year depreciation rule. OPDC is not aware of where this "guidance" has been outlined. The filing guidelines on depreciation / amortization included in the latest filing requirements issued in May 2009 have been attached in their entirety below:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications

Ontario Energy Board May 27, 2009

2.5.7 Depreciation/Amortization/Depletion
The information outlined below is required for Depreciation/Amortization/Depletion:

- The applicant must provide details for Depreciation, Amortization and Depletion by asset group for the Historical, Bridge and Test Years, including asset amount and rate of depreciation. This should tie back to the accumulated depreciation expense continuity schedule under Rate Base.
- The applicant must provide a statement as to whether it adheres to the Board's guidelines on amortization/depreciation rates (Appendix B of the *2006 Electricity Distribution Rate Handbook*). If not, the applicant must summarize the differences from the handbook, and indicate whether these have been previously reviewed and approved by the Board (if so, file relevant references).
- Where the applicant is proposing new or changed depreciation/amortization rates, supporting documentation, preferably a depreciation study, must be provided.
- The applicant must provide a copy of depreciation/amortization policy, if available. If not, the applicant should state that such a policy does not exist, or explain why it is not available.

Appendix 2-N should be completed

The Board's own filing requirements for distribution rates do not discuss full year vs half year rule for deprecation. There is also no prescriptive guidance in either the CICA Handbook or the OEB APH stating that only one half year's depreciation should be taken in the year of acquisition.

The APH states that "Consistent with the CICA Handbook, this APH Handbook does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, the estimated useful lives or amortization rates. Instead it is expected that in the absence of an objective study to support the changes to the current methods, lives or rates, **utilities will continue to use methods, lives or rates consistent with past practice.**"

As a result, OPDC is unaware where the Board's half-year depreciation rule has been clearly documented for distributors to follow.

OPDC's past practice has always been to take a full year of depreciation in the year of acquisition and has consistently applied this method as part of this rate application.

The 2010 rates process will establish OPDC's revenue requirement for the next four years. Using a full year of depreciation on asset additions in 2010 to establish a revenue requirement for the next four years is a much closer representation of the expense to be incurred by OPDC for deprecation on 2010 asset additions in all the years going forward past the rate year.

Using the half year rule for additions in 2010 means that revenue requirement will not be enough to recover depreciation expense on 2010 additions in three of the four years involved in the rates rebasing schedule. It also means that the rate of return on equity deemed by the Board to be appropriate will not be achievable by the LDC after the first year due to an increase in depreciation expense alone all else remaining equal.

OPDC has pointed out in its application (Ex 4 Tab 7 Sch 1 page 3) that:

> "*Depreciation expense is expected to increase between 2010 and 2014 (next rebasing year after 2010). The level of capital expenditures required in order to maintain OPDC's aging infrastructure in good operating condition has been increasing over the last few years. These additions are adding more to depreciation expense than is dropping off due to assets becoming fully depreciated (disposals). Table 2-18 presented in Exhibit 2 is repeated here to illustrate the level of capital expenditures expected over the next few years. A review of disposals (assets becoming fully depreciated) scheduled for the years 2011 through 2013 compared to projected capital spending indicates that this trend will continue. It is expected that depreciation expense in 2011, 2012 and 2013 will be at levels HIGHER than the amount OPDC is seeking to recover in the 2010 Test Year.*"

While OPDC recognizes that we would not be allowed to recover more than the 2010 Test amount, OPDC believes it should be allowed to recover at least the 2010 Test amount of $1,449,000.

Response to (d):

The table below recalculates Table 4-16 using the half-year depreciation rule.

DEPRECIATION CALCULATION USING THE HALF YEAR RULE FOR 2010 ADDITIONS	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
Distribution station equipment	82,600	90,900	89,800	93,000	91,200
Poles and wires	646,400	668,500	661,600	669,000	718,000
Line transformers	158,400	158,700	160,200	159,900	160,100
Services and meters	137,800	139,300	136,400	128,600	127,700
Land, land rights and buildings	43,500	44,900	59,500	35,600	35,100
Information technology	60,200	62,300	63,800	74,200	39,300
Equipment	176,300	124,000	171,000	194,800	215,300
Other distribution assets	16,100	2,900	5,600	25,000	21,000
TOTALS SUMMARY INFORMATION	**1,321,300**	**1,291,500**	**1,347,900**	**1,380,100**	**1,407,700**

1806	Land Rights	1,900	1,900	3,100	3,200	1,200
1820	Distribution Station Equipment - Normally Pri	82,600	90,900	89,800	93,000	91,200
1835	Overhead Conductors and Devices	448,600	461,700	471,800	476,200	515,600
1840	Underground Conduit	197,800	206,800	189,800	192,800	202,400
1850	Line Transformers	158,400	158,700	160,200	159,900	160,100
1855	Services	79,400	79,800	76,200	67,800	66,800
1860	Meters	58,400	59,500	60,200	60,800	60,900
1908	Buildings and Fixtures	41,600	43,000	56,400	32,400	33,900
1915	Office Furniture and Equipment	19,200	17,100	16,300	4,800	5,500
1920	Computer Equipment - Hardware	21,400	19,500	19,200	23,500	16,500
1925	Computer Software	38,800	42,800	44,600	50,700	22,800
1930	Transportation Equipment	113,700	71,800	123,200	164,300	184,100
1935	Stores Equipment	2,900	2,900	2,900	3,000	3,000
1940	Tools, Shop and Garage Equipment	30,500	32,200	28,600	22,700	22,700
1960	Miscellaneous Equipment	10,000	-	-	-	-
1980	System Supervisory Equipment	27,800	14,700	23,600	25,000	21,000
1985	Sentinel Lighting	2,900	2,000	1,800	2,000	1,000
1995	Contributions and Grants	(11,700)	(11,800)	(18,000)	-	-
TOTALS DETAILED GENERAL LEDGER		**1,324,200**	**1,293,500**	**1,349,700**	**1,382,100**	**1,408,700**
1985	Sentinel Lighting Non LDC	2,900	2,000	1,800	2,000	1,000
TOTALS DETAILED LDC		**1,321,300**	**1,291,500**	**1,347,900**	**1,380,100**	**1,407,700**

Response to (e):
OPDC does not have specific quantitative evidence.

The rationale used by OPDC to amortize the new SCADA equipment over a ten year period rather than a 15 year period is based on the fact that the equipment replaced is specifically the hardware (server) and software to run the central control portion of the SCADA system. Although some components of a SCADA system, such as remote terminal units (RTU's) that are located in the field, may have a useful life of 15 years, the 2008 investment did not include any of these components and was specifically focused on the central control components. Given that hardware and software is widely accepted to have a useful life of approximately five years, OPDC feels it is being very conservative in only reducing the amortization period to 10 years.

36. Tax Calculations

Ref: Exhibit 4 / 8 / 1 / pp1-4

Effective July 1, 2010, Ontario Small Business Income Rate will drop from 5.5% to 4.5% and the surtax will be eliminated.

a) Please explain whether the Applicant has included these changes in tax rate in its PILs calculations and how it has interpreted the capital tax and income tax changes that will become effective on July 1, 2010 with respect to proration in 2010.

b) Please show the calculations and provide the Tax Act references to illustrate the Applicant's method.

c) If the Applicant has not already included the July 1, 2010 changes, please repeat the calculations including these.

OPDC RESPONSE:

Response to (a):
OPDC believes that it has properly included these changes in its tax calculations. Table 4-27 on Ex 4 Tab 8 Sch 1 page 4 of 4 outlines the rates used to determine taxes.

Where rates were changing in the middle of the year the rate was prorated to the effective rate.

The Ontario budget proposes to decrease the provincial general rate from 14% to 12% July 1, 2010 and OPDC used the weighted average rate of 13% as an effective rate for 2010.

The Ontario budget decreases the small business rate from 5.5% to 4.5% July 1, 2010 and OPDC used the weighted average rate of 5% as the effective rate for 2010.

As also noted in the Board's own tax model, the Capital Tax rate is reduced to 0.15% effective Jan 1, 2010 and to NIL July 1, 2010. This is equivalent to an effective rate of 0.075% for the year which OPDC uses.

Response to (b):
OPDC used KPMG's Tax Advisory Bulletin on Income Tax Rates for CCPCs 2008 through to 2011 as its source of information on tax rates. In addition, it was able to use the Energy Board's PILs model as a reference to verify its approach to income and capital tax rates. A copy of schedule B from that model is attached below. It can be seen that the Board calculates an effective tax rate for 2010 of 31% and for 2011 of 28.25%. Using prorated rates OPDC's effective tax rate is 29.2% or in the middle..

Tax Rates & Exemptions

Tax Rates **Federal & Provincial** **As of March 26, 2009**		**Effective January 1, 2006**	**Effective January 1, 2007**	**Effective January 1, 2008**	**Effective January 1, 2009**	**Effective January 1, 2010**	**Effective January 1, 2011**
Federal income tax							
General corporate rate	1	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	2	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	3	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Surtax (4% of line 3)	4	1.12%	1.12%	0.00%	0.00%	0.00%	0.00%
		29.12%	29.12%	28.00%	28.00%	28.00%	28.00%
Rate reduction		-7.00%	-7.00%	-8.50%	-9.00%	-10.00%	-11.50%
		22.12%	22.12%	19.50%	19.00%	18.00%	16.50%
Ontario income tax		14.00%	14.00%	14.00%	14.00%	13.00%	11.75%
Combined federal and Ontario		36.12%	36.12%	33.50%	33.00%	31.00%	28.25%
Federal & Ontario Small Business							
Federal small business threshold		400,000	400,000	400,000	500,000	500,000	500,000
Ontario Small Business Threshold		400,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate		13.12%	13.12%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate		5.50%	5.50%	5.50%	5.50%	5.00%	4.50%

Ontario surtax claw-back of 4.25% starts at $500,000 and eliminates the SBC at $1,500,000.

Ontario Capital Tax						
Capital deduction	10,000,000	12,500,000	15,000,000	15,000,000	15,000,000	
Capital tax rate	0.300%	0.225%	0.225%	0.225%	0.075%	

OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.

NOTES:

1. Based on the federal government's October 30, 2007 Economic Statement.
Bill C-28 received Royal Assent on December 14, 2007.

2. Ontario Economic Statement of December 13, 2007 became Bill 44 and received Royal Assent on May 14, 2008.
Capital tax rate changes and small business deduction income thresholds made retroactive to January 1, 2007.

3. Federal Budget of January 27, 2009 The federal small business limit was increased from $400,000 to $500,000 on

3. Federal Budget of March 26, 2009 The provincial corporate tax rate was reduced

Response to (c):

OPDC believes this is not applicable as it believes its calculations included the appropriate rates to calculate taxes.

Cost of Capital and Capital Structure

37. Cost of Long-Term Debt

Ref: Exhibit 5 / 1 / 2 / p1

The Applicant explains that its only long-term debt is a promissory note with the City of Orillia, its municipal shareholder, for $9.762 million. The promissory note was issued on November 1, 2000 with a 30 year term which includes terms and conditions that 1/5 of the principal can be called within any year with six months notice. The copy of the promissory filed shows the interest rate to be7.5% p.a. Please expand on the rationale given in the pre-filed evidence that since the promissory note is with an affiliate and has a callable element, the Applicant is entitled to a return on long-term debt for the 2010 Test Year of 7.62%.

OPDC RESPONSE:

In accordance with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006, on page 14 it states:

> *"**For all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate**. When setting distribution rates at rebasing these debt rates will be adjusted regardless of whether the applicant makes a request for the change."*

Based on this statement and a number of Board Decisions for 2008 and 2009 rebased/cost of service rate applications, it is OPDC understanding that it is entitled to a return on long-term debt for the 2010 test year based on the Board's deemed long-term debt rates. OPDC expects the Board to update its deemed long-term debt rate in the winter/spring of 2010 and the updated rate would be applied to the referenced promissory note. Currently the Board's deemed long-term debt is 7.62% which was assumed for purposes of preparing the application.

Rate Design

38. Current Fixed-Variable Split

Ref: Exhibit 8 / 2 / 1 / p1

Table 8-4 shows for each customer class, the 2010 fixed base and variable base revenues with 2009 approved rates and also the 2010 fixed-variable split. Please reproduce the table using 2009 rate data throughout.

OPDC RESPONSE:

Table 8-4 reflects the fixed and variable split for revenue at existing rates which is determined by apply 2009 rate data throughout the analysis by the 2010 forecast of customers, kWh and kW. As a result, it is OPDC's view, table 8-4 provides the requested information.

39. Monthly Service Charge

Ref: Exhibit 8 / 2 / 1 / p2

The Applicant summarizes the Board's stated expectations regarding distributors making changes to the Monthly Service Charge (MSC) that result in a charge that is greater than the ceiling. Please calculate the percentage difference for each customer class between the ceiling and the 2010 proposed MSC and identify any plans the Applicant has to correct any large differences.

OPDC RESPONSE:

The requested information is provided in the following table

Rate Classification	Proposed 2010 Monthly Service Charge	120% of Customer Unit Cost per month - Minimum System with PLCC Adjustment	%Difference
Residential	$15.41	$15.95	-3%
GS <50 kW	$35.56	$31.19	14%
GS>=50 kW	$376.11	$74.68	404%
Street Light	$2.70	$11.24	-76%
Sentinel	$3.68	$11.68	-68%
Unmetered Scattered Load	$8.13	$8.27	-2%

In the Report of the Board's EB-2007-0667 Application of Cost Allocation for Electricity Distributors it states the following under section 4.2.2. of the report

4.2.2 Upper Bound for the Monthly Service Charge

The Methodology set a ceiling for the MSC based on the avoided costs plus the allocated customer costs. The Discussion Paper proposed that the ceiling for the MSC be 120% of this level. Some participants believed that the results of the sensitivity analysis were not an appropriate basis for setting an upper bound.

The Board considers it to be inappropriate to make significant changes to the ceiling for the MSC at this time, given the number of issues that remain to be examined. The appropriateness of the methodologies cited above, used to set the MSC is an issue that will be examined within the scope of the Rate Review. The Rate Review will also examine the role of rate design in achieving various objectives, including conservation of energy. Both of these undertakings will have determinative impacts on the fixed/variable ratio policy.

In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time.

Based on the above and specifically the statement in the second paragraph in italic suggests to OPDC that the Board has not yet established a ceiling for the MSC. It would appear to OPDC that the issue of the appropriate ceiling and related issue of the proper fixed/variable split is still under review. In addition, considering the Board has approved MSC in recent rebased/cost of service rate applications that are above the MSC reference above also suggest to OPDC that a ceiling for the MSC has not yet been established. As a result, OPDC does not plan to make adjustments to the MSC in this regard until the rate review process has been completed and a ceiling is established.

40. Transformer Allowance

Ref: Exhibit 8 / 2 / 2 / p2

The Applicant states that the General Service >50kW volumetric charge will increase by $0.3585 per kW to recover the Transformer Allowance. Please show the calculation of the $0.3585 per kW value.

OPDC RESPONSE:

(A) / (B) = $0.3585 per kW

(A) = $142,380 in transformation allowance provided to the GS >50kW class

(B) = 397,192 kW is the forecasted 2010 kWs for the GS >50kW class

41. Low Voltage Costs

Ref: Exhibit 8 / 2 / 2 / p3 and Exhibit 8 / 4 / 1 / p1

In Table 8-8 the Applicant shows the allocation of its 2010 $185k Low Voltage Charge. In Exhibit 8 / 4 / 1 / p1 the Applicant explains how the percentage of power provided by Hydro One will increase from 94% to 100% in early 2010. Please confirm that Table 8-8 takes into account the expected increase in power purchased from Hydro One.

OPDC RESPONSE:

OPDC confirms that Table 8-8 takes into account the expected increase in power purchased from Hydro One.

42. Retail Transmission Service Rates

Ref: Exhibit 8 / 3 / 1 / pp 1-4

The Applicant provides its rationale and supporting data for leaving the Retail Transmission Service Rates (RTSR) unadjusted at this time. While there is no significant trend over the full period covered by Graph 8-1, there is an approximate $400k change in the second half of the period for the two accounts combined – a change that is worsening rather than improving the balance in the accounts.

a) Please determine the RTSR rate changes necessary to rectify the increasing out-of-balance in the two accounts assuming the current balances in these are disposed of as requested in the application.

b) Please determine the effect of the rate changes in a) on the customers' total bills for Residential customers (at 800 kWh) and General Service < 50kW (at 2,000 kWh)

OPDC RESPONSE:

Response to (a):
The RTSR rate changes necessary to rectify the increasing out-of-balance in the two accounts assuming the current balances in these are disposed of as requested in the application is provided in the table shown below. The RTSR have been adjusted assuming a cost to revenue ratio of 92.1% for transmission network service and 88.9% for transmission connection service. These ratios represent the percentage of "Costs" to "Retail Billing" shown in Exhibit 8 / 3 / 1 / p 1 of 4, Table 8.8 for the period January to June 2009.

Rate Classification	Current RTR - Network Service	Current RTR - Line & TX Connection	UOM	OEB 42 a RTR - Network Service	OEB 42 a RTR - Line & TX Connection	Change in RTR - Network Service	Change in RTR - Line & TX Connection
Residential	$0.0038	$0.0035	$/kWh	$0.0035	$0.0031	($0.0003)	($0.0004)
GS <50 kW	$0.0033	$0.0032	$/kWh	$0.0030	$0.0028	($0.0003)	($0.0004)
GS>=50 kW	$1.4236	$1.2955	$/kW	$1.3109	$1.1519	($0.1127)	($0.1436)
Street Light	$1.0487	$0.9659	$/kW	$0.9657	$0.8589	($0.0830)	($0.1070)
Sentinel	$1.0541	$0.9862	$/kW	$0.9707	$0.8769	($0.0834)	($0.1093)
Unmetered Scattered Load	$0.0033	$0.0032	$/kWh	$0.0030	$0.0028	($0.0003)	($0.0004)

Response to (b):

If the RTSR are adjusted as in the response to (a) the customer's total bills will decline from what has been proposed in this rate application as per the table below.

Description	Increase in Total Bill	% Increase in Total Bill	Increase in Total Bill	% Increase in Total Bill
	Per Rate App as Filed		With Adjusted TX Rates	
Residential - 800 kWh per month	**$3.82**	**4.3%**	**$3.23**	**3.6%**
GS < Than 50 kW - 2000 kWh per month	**$10.25**	**4.5%**	**$8.77**	**3.9%**

Decrease due to adjustment of transmission rates

Residential - 800 kWh per month	**($0.59)**	**-0.7%**
GS < Than 50 kW - 2000 kWh per month	**($1.48)**	**-0.6%**

43. Loss Factors

Ref: Exhibit 8 / 4 / 1 / pp 1-3

In Table 8-11 the Applicant shows the actual Supply Facility Loss Factors (SFLF) from 2002 to 2008 and the SFLF Average 2006-2008. Given the evident trend in the SFLF over the 2005 to 2008 period, please calculate 2009 and 2010 SFLF values based on the four years of trend data as distinct from using the average.

OPDC RESPONSE:

OPDC has calculated 2009 and 2010 SFLF values based on the four years of trend data listed in Table 8-11 from 2005 to 2008 (1.0332, 1.0319, 1.0211, 1.0218) using the TREND function in Excel. The resulting value was 1.0157.

44. Transformer Discount kW

Ref: Exhibit 8 / 5 / 1 / p4

In Table 8-13 the Applicant shows the Transformer Discount kW value for General Service >50kW to be 237,300. Please provide the supporting data and calculation.

OPDC RESPONSE:

In 2008, 59.7% of kWs in the General Service >50kW class received the Transformer Discount. When you apply the 59.7% to the 2010 forecast of 397,192 kW for the General Service >50kW class, the forecast of 2010 kWs that are expected to receive the Transformer Discount is 237,300 kW.

45. Distribution Rates

Ref: Exhibit 8 / 2 / 2 / p1 and Exhibit 8 / 5 / 2 / p3
In Table 8-7 the Applicant shows the Proposed Variable Distribution Charge before TX Allowance for all customer classes. In Table 8-15 the Applicant shows the Proposed Volumetric Distribution Charge excluding LV Charge for all customer classes. Except for the GS>50kW customer class, the values in the respective columns in both tables are the same. Please reconcile the difference for the GS>50kW customer class; i.e. $3.0674 vs. $3.4259.

OPDC RESPONSE:

In Table 8-7 the OPDC shows the Proposed Variable Distribution Charge before TX Allowance for GS > 50kW as $3.0674. Once you add on the cost of the transformation allowance of $0.3585 per kW discussed in #40 above the resulting rate is $3.4259 per kW.

Deferral and Variance Account Disposition

46. Regulatory Audit Bulletin – Account 1588

Ref: Exhibit 9 / 1 / 1 / pp1-3

On October 15, 2009, the Board's Regulatory Audit & Accounting group issued a bulletin related to Regulatory Accounting & Reporting of Account 1588 RSVA Power and Account 1588 RSVA Power Sub-account Global Adjustment. Please confirm whether or not the Applicant plans on making any changes to its filing with respect to Account 1588.

OPDC RESPONSE:

On October 15, 2009, the Board's Regulatory Audit & Accounting group issued a bulletin related to Regulatory Accounting & Reporting of Account 1588 RSVA Power and Account 1588 RSVA Power Sub-account Global Adjustment. OPDC does not plan on making any changes to its filing with respect to Account 1588.

47. Allocation Factors and Calculation of Rate Riders

Ref: Exhibit 9 / Appendix 9-B / p1

The Applicant used 2008 data by rate class to allocate Account balances and to calculate rate riders.

a) Please clarify if the allocation factors and billing determinants used to calculate the riders reflect 2008 actual data or the most recent Board-approved volumetric forecast.

b) If 2008 actual data were used, please provide the rationale for the departure from the Board's policy (Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative) which stipulates that in the normal course, the most recent Board-approved volumetric forecast should be used to derive the rate riders.

The Applicant proposes to allocate the balance in Account 1588 on the basis of kWh.

c) Please clarify if the balance in the Global Adjustment sub-account was allocated to all customers on the basis of KWh or to non-RPP customers on the basis of KWh.

d) If kWh were used for all customers, please provide the rate riders associated with an allocation of the Global Adjustment sub-account on the basis of KWh for non-RPP customers.

OPDC RESPONSE:

OPDC used 2008 data by rate class to allocate account balances and to calculate rate riders.

Response to (a):
Allocation factors and billing determinants used to calculate the riders reflect 2008 actual data.

Response to (b):
OPDC acknowledges that using 2008 actual data is a departure from the Board's policy (Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative) which stipulates that in the normal course, the most recent Board-approved volumetric forecast should be used to derive the rate riders. Our rationale is based on the claim that the most recent Board-approved forecast is out of date and does not reflect changes in current consumption patterns as shown in Exhibit 3 / 1 / 2 p2 . The most recent Board-approved volumetric forecast is OPDC's 2006 Electricity Distribution Rate Decision effective May 1, 2006 which is based on 2004 customer count multiplied by a 3 year average kWh per customer (2002, 2003, 2004).

OPDC proposes to allocate the balance in Account 1588 on the basis of kWh.

Response to (c):
The balance in the Global Adjustment sub-account was allocated to all customers on the basis of KWh.

Response to (d):

OPDC has recalculated its Regulatory Asset Continuity Schedule to provide rate riders associated with the allocation of the Global Adjustment sub-account on the basis of KWh for non-RPP customers using 2008 actual data. The new rate riders are provided in the following table:

Acct #	Allocator	Amount Claimed	Residential	GS < 50	GS > 50	Unmetered	Sentinel	Street Lights
1580	kWh	**(2,596,606)**	(893,850)	(401,279)	(1,270,915)	(7,005)	(2,799)	(20,758)
1584	kWh	**(645,108)**	(222,071)	(99,695)	(315,750)	(1,740)	(695)	(5,157)
1586	kWh	**(668,283)**	(230,048)	(103,276)	(327,093)	(1,803)	(720)	(5,342)
1588	kWh	**2,548,206**	877,189	393,800	1,247,226	6,874	2,747	20,371
1588	Non RPP kWh	**200,924**	25,978	9,690	162,052			3,205
Subtotal RSVA		**(1,160,867)**	**(442,802)**	**(200,761)**	**(504,480)**	**(3,674)**	**(1,468)**	**(7,682)**
1508	Dist Revenue	**69,949**	35,699	13,326	19,470	465	176	812
1508	Dist Revenue	**202,269**	103,230	38,535	56,302	1,345	509	2,348
1518	Customers	**(87,485)**	(76,342)	(9,197)	(1,058)	(259)	(621)	(7)
1548	Customers	**14,341**	12,514	1,508	173	43	102	1
1550	kWh	**536,781**	184,780	82,954	262,729	1,448	579	4,291
Subtotal NON RSVA		**735,855**	**259,881**	**127,126**	**337,616**	**3,042**	**744**	**7,445**
Totals For Rider Calc		**($425,012)**	**($182,921)**	**($73,635)**	**($166,864)**	**($632)**	**($724)**	**($236)**

RATE RIDERS	**kWh**	**kWh**	**kW**	**kWh**	**kW**	**kW**
Billing Determinant Used	**109,814,584**	**49,299,469**	**394,737**	**860,590**	**954**	**7,083**
RSVA	**(0.0040)**	**(0.0041)**	**(1.2780)**	**(0.0043)**	**(1.5389)**	**(1.0845)**
Non RSVA	**0.0024**	**0.0026**	**0.8553**	**0.0035**	**0.7800**	**1.0512**
RSVA and Non RSVA	**(0.0017)**	**(0.0015)**	**(0.4227)**	**(0.0007)**	**(0.7589)**	**(0.0334)**

48. Account 1590

Ref: Exhibit 9 / 1 / 2 / p2

The Applicant is not proposing the clearance of account 1590. According to the July 31, 2009 report of the Board, EB-2008-0046 (Electricity Distributors' Deferral and Variance Account Review Initiative) (EDDVAR), account 1590 is part of Group 1, i.e. the group of accounts that do not require a prudence review. The only stipulation is that the associated rate rider must have ended at the time of disposition (page 6 of the EDDVAR report).

a) Has the rate rider associated with the balance in account 1590 expired?

b) If so, would the Applicant reconsider and ask the Board to disposition the balance in account 1590?

OPDC RESPONSE:

OPDC is not proposing the clearance of account 1590 in our application. According to the July 31, 2009 report of the Board, EB-2008-0046 (Electricity Distributors' Deferral and Variance Account Review Initiative) (EDDVAR), account 1590 is part of Group 1, i.e. the group of accounts that do not require a prudence review. The only stipulation is that the associated rate rider must have ended at the time of disposition (page 6 of the EDDVAR report).

Response to (a):
The rate rider associated with the balance in account 1590 expired May 1, 2008.

Response to (b):
OPDC has reconsidered and asks the Board to dispose of the balance in account 1590. OPDC proposes to recalculate its Regulatory Asset Continuity Schedule to include disposition of this account.

OPDC has recalculated its Regulatory Asset Continuity Schedule to provide rate riders associated with the allocation of account 1590 using the allocation method provided in Board's 2010 IRM model, "EDR2010_2010 IRM Deferral and Variance Account WorkformV3.XLS". The rate rider calculation also includes adjustment for the Global Adjustment sub-account on the basis of KWh for non-RPP customers using 2008 actual data as requested in the Board's question 47 d). The new rate riders are provided in the following table:

Acct #	Allocator	Amount Claimed	Residential	GS < 50	GS > 50	Unmetered	Sentinel	Street Lights
1580	kWh	**(2,596,606)**	(893,850)	(401,279)	(1,270,915)	(7,005)	(2,799)	(20,758)
1584	kWh	**(645,108)**	(222,071)	(99,695)	(315,750)	(1,740)	(695)	(5,157)
1586	kWh	**(668,283)**	(230,048)	(103,276)	(327,093)	(1,803)	(720)	(5,342)
1588	kWh	**2,548,206**	877,189	393,800	1,247,226	6,874	2,747	20,371
1588	Non RPP kWh	**200,924**	25,978	9,690	162,052			3,205
Subtotal RSVA		**(1,160,867)**	**(442,802)**	**(200,761)**	**(504,480)**	**(3,674)**	**(1,468)**	**(7,682)**
1508	Dist Revenue	**69,949**	35,699	13,326	19,470	465	176	812
1508	Dist Revenue	**202,269**	103,230	38,535	56,302	1,345	509	2,348
1518	Customers	**(87,485)**	(76,342)	(9,197)	(1,058)	(259)	(621)	(7)
1548	Customers	**14,341**	12,514	1,508	173	43	102	1
1550	kWh	**536,781**	184,780	82,954	262,729	1,448	579	4,291
1590	2006 EDR	**(33,164)**	(45,670)	(7,458)	18,848		128	988
Subtotal NON RSVA		**702,691**	**214,212**	**119,668**	**356,464**	**3,042**	**872**	**8,433**
Totals For Rider Calc		**($458,176)**	**($228,590)**	**($81,093)**	**($148,016)**	**($632)**	**($596)**	**$752**

RATE RIDERS	**kWh**	**kWh**	**kW**	**kWh**	**kW**	**kW**
Billing Determinant Used	**109,814,584**	**49,299,469**	**394,737**	**860,590**	**954**	**7,083**

RSVA	**(0.0040)**	**(0.0041)**	**(1.2780)**	**(0.0043)**	**(1.5389)**	**(1.0845)**
Non RSVA	**0.0020**	**0.0024**	**0.9030**	**0.0035**	**0.9140**	**1.1907**
RSVA and Non RSVA	**(0.0021)**	**(0.0016)**	**(0.3750)**	**(0.0007)**	**(0.6249)**	**0.1061**

49. Smart Meters

Ref: Exhibit 9 / 1 /2 / p2

The Applicant indicated that it is not requesting clearance of the smart meter variance accounts at this time, and that once smart meters are fully deployed, and all costs are known, it will come forward with an application to dispose of the balances in the smart meter accounts. Please indicate if the Applicant intends to proceed by means of a separate application to deal with this matter.

OPDC RESPONSE:

OPDC intends to proceed by means of a **separate** application to deal with this matter subsequent to this proceeding being concluded and OPDC's 2010 core rates being established.

50. Global Adjustment

Ref: Exhibit 9 / 1 / 1 / Attachment 1

Board staff requests additional information to that requested in question 47 b), c) and d).

a) Please provide an allocation of the December 31, 2008 balance of the 1588 Global Adjustment ("GA") sub-account (plus interest to April 30, 2010) based on the 2008 kWhs for non-RPP customers.

b) Please calculate a separate rate rider for the recovery/refund of the proposed GA sub-account balance using the allocated amounts in part a. and the 2010 non-RPP consumption data (kWh or kW as applicable) as the billing determinant.

c) Please calculate a rate rider for all other allocated amounts sought for disposition (i.e. total balance including carrying charges minus the GA sub-account balance including carrying charges) using the 2010 consumption data (kWh or kW as applicable) as the billing determinant.

OPDC RESPONSE:

Board staff requested additional information for question 47 b), c) and d).

Response to (a):
OPDC has calculated an allocation of the December 31, 2008 balance of the 1588 Global Adjustment ("GA") sub-account (plus interest to April 30, 2010) based on the 2008 kWhs for non-RPP customers. Allocation of this sub-account based on 2008 kWhs for non-RPP customers is highlighted in the table prepared for Board question 47 d) above and shown again in part b) to this question.

Response to (b):
Using the allocated amounts determined in part a. and 2010 non-RPP consumption data (kWh) and 2010 total consumption data (kW) as the billing determinants (OPDC does not have the information to calculate non RPP kW), OPDC has calculated a separate rate rider for the refund/recovery of the proposed GA sub-account balance summarized in the following table:

Acct #	Allocator	Amount Claimed	Residential	GS < 50	GS > 50	Unmetered	Sentinel	Street Lights
1588	Non RPP kWh	**200,924**	25,978	9,690	162,052			3,205

RATE RIDERS 1588 Sub-account GA	kWh	kWh	kW	kWh	kW	kW
Billing Determinant - 2010 Non RPP	**17,226,964**	**6,425,972**	**397,192**			**7,098**

RSVA power sub-account GA	**0.0015**	**0.0015**	**0.4080**			**0.4515**

Response to (c):

OPDC has calculated a rate rider for all other allocated amounts sought for disposition (i.e. total balance including carrying charges minus the GA sub-account balance including carrying charges) using the 2010 consumption data (kWh or kW as applicable) as the billing determinant summarized in the following table:

Acct #	Allocator	Amount Claimed	Residential	GS < 50	GS > 50	Unmetered	Sentinel	Street Lights
1580	kWh	**(2,596,606)**	(905,697)	(401,948)	(1,258,057)	(6,856)	(2,707)	(21,340)
1584	kWh	**(645,108)**	(225,014)	(99,861)	(312,555)	(1,703)	(672)	(5,302)
1586	kWh	**(668,283)**	(233,097)	(103,449)	(323,783)	(1,765)	(697)	(5,492)
1588	kWh	**2,548,206**	888,816	394,456	1,234,607	6,728	2,656	20,942
Subtotal RSVA		**(1,361,791)**	**(474,993)**	**(210,802)**	**(659,789)**	**(3,596)**	**(1,419)**	**(11,192)**
1508	Dist Revenue	**69,949**	35,699	13,326	19,470	465	176	812
1508	Dist Revenue	**202,269**	103,230	38,535	56,302	1,345	509	2,348
1518	Customers	**(87,485)**	(76,342)	(9,197)	(1,058)	(259)	(621)	(7)
1548	Customers	**14,341**	12,514	1,508	173	43	102	1
1550	kWh	**536,781**	187,229	83,092	260,070	1,417	560	4,412
1590	2006 EDR	**(33,164)**	(45,670)	(7,458)	18,848		128	988
Subtotal NON RSVA		**702,691**	**216,661**	**119,806**	**353,806**	**3,011**	**853**	**8,554**
Totals For Rider Calc		**($659,101)**	**($258,332)**	**($90,996)**	**($305,983)**	**($585)**	**($567)**	**($2,638)**

RATE RIDERS excl. 1588 Sub-account GA	**kWh**	**kWh**	**kW**	**kWh**	**kW**	**kW**
Billing Determinant - 2010 Data	**108,676,163**	**48,230,452**	**397,192**	**822,688**	**896**	**7,098**

RSVA	**(0.0044)**	**(0.0044)**	**(1.6611)**	**(0.0044)**	**(1.5843)**	**(1.5768)**
Non RSVA	**0.0020**	**0.0025**	**0.8908**	**0.0037**	**0.9518**	**1.2051**
RSVA and Non RSVA	**(0.0024)**	**(0.0019)**	**(0.7704)**	**(0.0007)**	**(0.6325)**	**(0.3717)**