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BY E-MAIL

December 30, 2015

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

**Re: Ottawa River Power Corporation (ORPC)
2016 Distribution Rate Application
OEB Staff Interrogatories
OEB File No.: EB-2014-0105**

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories in the above noted proceeding. ORPC and all intervenors have been copied on this filing.

ORPC's responses to interrogatories are due by January 27, 2016.

Yours truly,

Original Signed By

Birgit Armstrong
Advisor – Electricity Rates & Prices

Attach.

**OEB Staff Interrogatories
2016 Cost of Service Rate Application
Ottawa River Power Corporation (ORPC)
EB-2014-0105
December 30, 2015**

Administration

1-Staff-1

Ref: Exhibit 1, p. 30 of 73

ORPC noted that it has purchased an online survey to be completed by its customers in the fall of 2015.

- a) Please provide the current status of the customer engagement survey.
- b) Please provide the results and explain if and how the survey impacts ORPC investment and operational decisions going forward.
- c) What is the cost of the survey, and please indicate whether and, if so, where the costs for the customer engagement survey are being recovered in this Application.

1-Staff-2 Conditions of Service

- a) Please identify any rates and charges that are included in the Applicant's Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.
- b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2012 to 2014 inclusive, and the revenues forecasted for the 2015 bridge and 2016 test years.
- c) Please explain whether, in the Applicant's view, these rates and charges should be included on the Applicant's tariff sheet of approved rates and charges.

1-Staff-3 Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial application. Entries for changes and adjustments should be included in

the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 10 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

1-Staff-4 Updated Appendix 2-W, Bill Impacts

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.).

1-Staff-5 Evolution of Customer Engagement

Chapter 2 of the Filing Requirements states, “The RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations.” (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and any previous customer engagement undertaken by the distributor. Please explain how customer engagement has been enhanced in the preparation of this Application.

1-Staff-6 Impact of Customer Engagement

Chapter 2 of the Filing Requirements states, “Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application”.

What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

2-Staff-7

Ref: Exhibit 2, p. 18 – 26 of 58 and Appendix 2-AA

Please provide table 2-AA showing capital project by category from 2010 to 2016 in one table in aggregate, not separated by accounts. Please add a column showing actual capital expenditures for the 2015 bridge year up to December 31, 2015.

2-Staff-8

Ref: Exhibit 2, p. 18 – 26 of 58 and Appendix 2-AA

Appendix 2-AA shows capital expenditures of \$108K in system renewal. Please reconcile with the amount of \$194K shown in appendix 2-AB of the DSP.

2-Staff-9 Pacing and Distribution Rate Impacts

The Applicant's annual capital spending since the last COS year (2010) has been about 32.5% or \$378,950 greater than the amount the Board approved in its 2010 decision.

- a) In its annual capital planning and implementation for the years 2010 to 2016 did the applicant take into account the cumulative impact its capital expenditures would have on rates in 2016?
- b) What changes ensued from these considerations?

Distribution System Plan

Ref: Exhibit 2, p. 47 – DSP – Section 5.4.1 Capital Expenditures

ORPC provided a DSP for the years 2015-2019. Since this application is for the 2016 test year, please explain why the DSP was not extended to cover a 5 year period from 2016 to 2020 inclusively.

2-Staff-10

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, p. 5.

At the reference, ORPC states: "Two substations will require upgrading in the next 10 years and the addition of a new substation is planned for future growth beyond 2020."

- a) Please identify any costs associated with the two planned substation upgrades included in the present capital expenditure forecast.
- b) Please identify any costs associated with the planned new substation included in the present capital expenditure forecast.

2-Staff-11

Ref: Exhibit 2, p. 47 – DSP Section 5.2.1: Distribution System Plan Overview, p. 15.

At the reference, ORPC states: "ORPC intends to adopt a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner, as they approach their high probability of failure zone of their lifecycle. ORPC's strategy is

to replace end-of-life assets under planned and coordinated circumstances, as opposed to under emergency or after hour's circumstances which add unnecessary risk and expense."

- a) Please quantify the anticipated annual incremental cost of adopting the new asset replacement approach.
- b) Please show how the incremental cost of adopting the new asset replacement approach will be distributed between the four expenditure categories.

2-Staff-12

Ref: Exhibit 2, p. 47 – DSP Section 5.2.2: Co-ordinated Planning with Third Parties, Regional Planning Consultations, p. 17.

At the reference, ORPC states: "At the time of preparing this DS Plan, the Regional Infrastructure Planning initiative is still in the early stages of development and as such many of the elements of the planning process have not yet been implemented. As per the "Integrated Planning Requirements – Part 1: regional Infrastructure Planning", the transition and implementation to Regional Infrastructure Planning (RIP) is expected to take four (4) years."

- a) Does ORPC expect that the regional planning process will impact the investments identified in this DSP?
- b) If yes to a), please quantify the expected impacts.

2-Staff-13

Ref: Exhibit 2, p. 47 – DSP Section 5.2.2: Co-ordinated Planning with Third Parties, Consultations with Municipal Planning Office, p. 19.

At the reference, ORPC states: "ORPC is currently aware of two significant development projects being coordinated through the Planning Office of Pembroke and Almonte for the 2015 planning horizon."

- a) Are the *"two significant development projects"* expected to impact the forecast capital expenditures identified in this DSP?
- b) If yes to a), please quantify any costs associated with these developments that will be borne by ORPC ratepayers.

2-Staff-14

Ref: Exhibit 2 p. 47 – DSP Section 5.2.3.5: System Reliability and Performance, Overall System Performance [Table], p. 30.

Including loss of service from HONI (Code 2)	SAIDI	3.20	1.21	10.69	3.31	3.97	1.74
	SAIFI	2.87	1.40	6.01	2.25	3.04	3.99
	CAIDI	1.11	0.86	1.78	1.47	1.30	0.44
Excluding Loss of service from HONI (Code 2)	SAIDI	2.66	0.71	2.39	1.69	0.91	1.24
	SAIFI	2.10	0.79	1.43	1.08	0.81	0.79
	CAIDI	1.27	0.89	1.67	1.57	1.13	1.57

- Please describe the major causes of fluctuations in the SAIDI metric excluding loss of service from HONI over the period 2009 to 2014.
- Please describe the HONI events that caused the high SAIDI and SAIFI results, with particular focus on 2011.
- Has ORPC consulted with HONI to identify ways to mitigate the poor performance metric results caused by the HONI loss of service events?
- If yes to c), please describe the mitigating actions that have been taken, or that are planned.

2-Staff-15

Ref: Exhibit 2, p. 47 – DSP Section 5.3: Asset Management Process, p. 37.

At the reference, ORPC states: “An asset’s health is based on its relative age compared to industry established life expectancies (Kinetric’s Report), as well as information that quantifies its operating capacity. Assessing age and operating load allow for the probability of failure to be assigned. Based on this approach, ORPC will develop a profile of the order in which assets are expected to fail, categorized by asset type. The year during which an asset is expected to fail due to exceeding its failure risk tolerance is called its “Adjusted End-of Life” (AEOL). The AEOL profile of assets drives ORPC’s pace of capital reinvestment needs for sustainment or development activities (also referred to as asset lifecycle management).”

- Please confirm that ORPC intends to assess the condition of its assets by
 - Comparing individual asset ages against average actuarial values taken from the Kinectrics Report.
 - Comparing actual asset loading against calculated capacity.

- b) Is the approach described in this section an interim process that will be superseded once ORPC has collected adequate asset condition information to determine the risk of asset failure?
- c) Please describe ORPC's asset condition assessment and testing approaches, including frequency of testing for different asset classes such as poles and transformers.

2-Staff-16

Ref: Exhibit 2, p. 47 – DSP Section 5.3.1: Asset Management Process Overview (Step 2), p. 40.

At the reference, ORPC states: "The output of this step is a populated asset register that contains all pertinent attribute and condition data. The populated asset register enables data analysis to be performed on individual assets or on asset groups or classes."

- a) Has ORPC assembled an asset register that includes condition assessments for all its assets?
- b) If NO to a), when does ORPC expect to have assembled an asset register that includes condition assessments for all of its assets?

2-Staff-17

Ref: Exhibit 2, p. 47 – DSP Section 5.3.1: Asset Management Process Overview (Step 3), p. 41.

At the reference, ORPC states: "The resulting end-of-life estimations are referred to as "Adjusted End-of-Life" (AEOL) projections. The AEOL value profile for asset classes essentially generates a listing that reflects ORPC's best guess as to the order in which assets will fail.

The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. ORPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

The AEOL profile for each asset class is updated annually to incorporate the latest available inspection, condition testing and performance data results. The end-of-life profile of assets allows ORPC to focus on the portion of assets that require special attention over the planning horizon. In other words, it allows ORPC to focus its attention on the assets that demand attention.

With ORPC's replacement cost data available at the asset level, ORPC is able to quickly and easily generate high level cost projections for long range planning purposes"

- a) Does ORPC plan to replace assets (such as poles) based solely on age?
- b) Is the Adjusted End-of Life (AEOL) used to determine which assets will be replaced, or is it only used to assemble budgets for expected replacement costs over the planning period? Please explain.

2-Staff-18

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Poles, p. 82.

At the reference, ORPC states: "Wood poles installed 50 years ago during the expansion and electrification across Pembroke service area are now approaching end of life. Approximately 35% of the poles installed exceed the TUL as mentioned in the Kinectrics report. To help ensure reliability and public safety, ORPC plans to replace 50 wood poles in 2015"

- a) Are the 50 poles being replaced because they have exceeded the actuarial life estimate given in the Kinectrics Report, or because their conditions have been assessed and determined to be unacceptable?

2-Staff-19

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Poles, p. 82.

At the reference, ORPC states: "Poles which are deemed to be at the end of their useful service life due to excessive deterioration have been estimated at approximately 25 poles per year. It is also important to note that wood poles frequently (on average five per year) fail prematurely, due to sudden devastating damage incurred by external influence such as wood peckers, snow ploughs or pole fires."

- a) ORPC has stated that it intends to replace 50 wood poles in 2015. Does ORPC expect to reduce the number of annual pole replacements to 25 after the year 2015?

2-Staff-20

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Pole Inspection, p. 83.

At the reference, ORPC states: "With 4300 poles in our distribution system, more than 1,500 poles will need to be replaced in the next 10 years. The Typical Useful Life of a wood pole is approximately 45 years. ORPC recommends a replacement rate on average of 125 poles a year in to keep pace, which represents 2.90% of the entire population of distribution poles. Increase in the amount of poles replaced will reduce the risk of having poles in a critical or poor condition."

- a) Please reconcile ORPC's plan to replace 125 poles per year with the statement in Section 5.3.2: Overview of Assets Managed, Poles, p. 82 - "Poles which are deemed to be at the end of their useful service life due to excessive deterioration have been estimated at approximately 25 poles per year."

2-Staff-21

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Pole Capital [Table], p. 84.

At the reference, ORPC states: "ORPC estimates that it may require approximately 500 poles replaced to sustain the existing population of 4,299 over the current planning cycle. Wood pole replacements have been identified as having a significant impact on the DS Plan."

ORPC Pole replacement schedule	
2011	25
2012	25
2013	25
2014	25
2015	100
2016	100
2017	100
2018	100
2019	100
2020	100

- a) Please reconcile the planned replacement of 100 poles shown year in the table above, with the replacement of 125 poles per year discussed in Section 5.3.2: Overview of Assets Managed, Pole Inspection, p. 83 and the replacement of 25 poles per year reaching end of service life discussed in Section 5.3.2: Overview of Assets Managed, Poles, p. 82.

2-Staff-22

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Transformer Capital, p. 88.

At the reference, ORPC states: “The age distribution of the population of the 1583 pole mounted transformers is not evenly distributed. The population has high positive skew, and as such, approximately 61% (972 transformers) will require replacement over the first half of the lifecycle period (over the next 20 years).”

- a) How many pole mounted transformers does ORPC plan to replace during each forecast year?
- b) What is the average cost of each transformer replacement?
- c) Will ORPC's proposed transformer replacement program address the "skewed" transformer vintage, in other words, will replacements be staged to avoid replication of the same issue in the future?
- d) Does ORPC consider that there is high risk in operating a pole mounted transformer that has exceeded its Useful Life (“UL”) but which otherwise has been evaluated as being in good operating condition?

2-Staff-23

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Overhead Distribution Assets Optimization Policies and Practices, Overhead Transformers, p. 104.

At the reference, ORPC states: “ORPC does not refurbish overhead transformers and generally speaking transformers do not require maintenance. Historically transformers were run to failure, or alternately, were replaced in poorly accessible areas (back lot construction) at the same time that the wood poles to which they were mounted to were replaced. ORPC’s new asset management approach is to transition to a just-in-time replacement approach, such that replacements are conducted under planned and coordinated circumstances, as opposed to under emergency repair circumstances. Factors that influence transformer replacements include the relative health of the transformer as determined by ORPC’s asset management process, as well as the

impact of failure. ORPC must ramp up its replacement program, beginning with replacements that are found to have the lowest health and highest impact of failure. ORPC's asset management process is utilized to prioritize the order in which individual transformers require replacing."

- a) Has ORPC conducted a cost benefit analysis of changing from a "run-to-fail" to a "just-in-time" replacement program for overhead transformers?
- b) If YES to a), please provide the results of the analysis.
- c) What is the expected incremental annual capital cost of ORPC's transition to the proposed "just-in-time" replacement approach?
- d) Will transformer condition be assumed by comparing asset age against the Kinectrics TUL, or will the asset condition be physically tested or evaluated?
- e) How does the transformer program correlate to the pole replacement program?

2-Staff-24

Ref: Exhibit 2, p. 47 – DSP Section 5.4.1: Capital Expenditure Summary Plan, Linking Investment Categories to Planning Process Outcomes, Planned System Access, p. 110.

Capital Expenses as per OEB Categories 2015-2019

DESCRIPTION	2015	2016	2017	2018	2019
System Access	\$500,850	\$500,850	\$452,200	\$392,700	\$392,700
System Renewal	\$449,820	\$194,100	\$248,750	\$193,200	\$193,200
System Service	\$270,800	\$474,800	\$345,849	\$573,650	\$293,200
General Plant	\$212,200	\$376,200	\$255,200	\$116,200	\$134,200
TOTAL	\$1,433,670	\$1,545,950	\$1,301,999	\$1,275,5700	\$1,013,300

At the reference, ORPC states: "Planned System Access investments are dedicated towards the upgrade of infrastructure for new customer connections. ORPC has planned for customer growth over the forecast period and as such, has allocated capital expenditures towards customer driven load expansions. A total of \$ 500k has been allocated towards System Access expenditures, representing 45% of the total planned capital expenditures over the 2015 forecast period."

- a) Given the relatively flat population growth and modest historical annual customer connection count, what is the basis for the high forecast levels of System Access expenditures as a proportion of overall capital investments?

- b) What portion of the system access costs are recovered through capital contributions and what is added to rate base in each of the 5 years?

2-Staff-25

Ref: Exhibit 2, p. 47 – DSP Section 5.4.1: Capital Expenditure Summary Plan, Linking Investment Categories to Planning Process Outcomes, System Renewal, p. 110.

At the reference, ORPC states: “System Renewal is by far the most dominant investment category demanding capital reinvestment. ORPC has to upgrade obsolete transformer station equipment and protection and historically has operated in a “Maintenance Mode”.

- a) Please reconcile the above statement that System Renewal is the dominant investment category with the information provided showing that System Renewal expenditures will be lower than either System Access or System Service expenditures in almost all forecast years.
- b) Given that forecast 2015 System Renewal expenditures of approximately \$450,000 comprise just over 31% of total 2015 capital expenditures”, please explain the statement: “Approximately 45% of all planned capital expenditures over the 2015 forecast period are towards System Renewal”.

2-Staff-26

Ref: Exhibit 2, p. 47 – DSP Section 5.4.1: Capital Expenditure Summary Plan, Linking Investment Categories to Planning Process Outcomes, System Service, p. 111.

At the reference, ORPC states: “System Service expenditures are largely driven by ORPC’s desire to achieve operational objectives including; customer preference; maintaining/improving service reliability; and the elimination of potential safety hazards. Over the 2015 forecast period ORPC has committed a total of \$270k towards the System Service category, which represents approximately 25% of total planned capital expenditures. Significant planned activities under this category include the installation of a fire barrier in 2017, a \$15k Outage Management System in 2015, a total of \$120k towards operational reliability improvements, and \$115k towards eliminating safety hazards. The Outage Management System (OMS) will enable ORPC to respond to outages proactively, assist in pin-pointing equipment failures, offer improved oversight of the performance of ORPC’s distribution system, as well as improve customer communication regarding outages. The elimination of identified safety hazards as well

as strategic reliability improvements projects are also included in this category.”

- a) Please explain the causes driving the relatively large and year-to-year uneven expenditures in the System Service category over the forecast period.
- b) Please confirm that ORPC has categorized expenditures primarily driven by asset condition as System Renewal investments.

2-Staff-27

Ref: Exhibit 2, p. 47 – DSP Section 5.4.4: Capital Expenditure Summary, Criteria for Prioritizing Capital Projects [Table], p. 121.

Capital Project Name	2014	2015	2016	2017	2018	2019	Total
Fully Dressed Wood Pole Replacement Program	\$34,000	\$64,500	\$64,500	\$64,500	\$64,500	\$64,500	\$322,500
Overhead & Pad-Mounted Transformer Replacement Program	\$59,600	\$59,500	\$103,300	\$103,300	\$103,300	\$103,300	\$472,700
Conductors	\$220,359	\$60,200	\$44,500	\$14,000	\$14,000	\$14,000	\$146,700
Fleet Vehicle Replacement Program	\$49,066	\$61,000	\$300,000	\$60,000	\$60,000	-	\$481,000
Scada		\$18,000	\$45,000	\$45,000		\$45,000	\$153,000
Transformer Station – Power Transformer Fire Barrier				\$65,000			\$65,000
Information System	\$35,425	\$10,000			\$26,000	\$47,000	\$83,000
Transformer Station - 44kV Breaker Replacement				\$108,000		\$108,000	\$216,000
Engineering Studies			\$86,000				\$86,000
Outage Management System			\$78,000				\$78,000
44 KV tie Line Almonte				\$100,000			\$100,000
Substation upgrades	\$84,000				\$228,000		\$228,000
Almonte Substation					\$280,000		\$280,000
Substation Design	\$74,600				\$73,000	\$115,000	\$188,000
Scattered Residential and Subdivisions	\$203,500	\$400,850	\$400,850	\$290,700	\$290,700	\$290,700	\$1,673,800
Commercial	\$108,370	\$100,500	\$100,500	\$161,500	\$91,500	\$91,500	\$545,500
2015 Misc. Small Capital Projects		\$285,250					\$285,250
2016 Misc. Small Capital Projects			\$424,100				\$424,100
2017 Misc. Small Capital Projects				\$219,700			\$219,700
2018 Misc. Small Capital Projects					\$226,550		\$226,550
2019 Misc. Small Capital Projects						\$222,900	\$222,900

- a) Please categorize each of the above projects and programs by primary Capital Expenditure driver, i.e.: System Access, System Renewal, System Service or General Plant.
- b) Please state if engineering cost of \$86,000 are capitalized. If so, please identify the related project.

2-Staff-28

Ref: Exhibit 2, p. 47 – DSP Section 5.4.4: Capital Expenditure Summary, *Criteria for Prioritizing Capital Projects [Table]*, p. 123.

DESCRIPTION	2010	2011	2012	2013	2014
System Access	\$206,026	\$369,429	\$231,185	\$302,943	\$340,430
System Renewal	\$513,921	\$307,425	\$344,841	\$407,204	\$459,780
System Service	\$0	\$0	\$0	\$0	\$216,819
General Plant	\$384,678	\$71,365	\$228,960	\$664,092	\$181,206
TOTAL	\$1,104,625	\$748,219	\$804,986	\$1,374,239	\$1,198,235

DESCRIPTION	2015	2016	2017	2018	2019
System Access	\$500,850	\$500,850	\$452,200	\$392,700	\$392,700
System Renewal	\$449,820	\$194,100	\$248,750	\$193,200	\$193,200
System Service	\$270,800	\$474,800	\$345,849	\$573,650	\$293,200
General Plant	\$212,200	\$376,200	\$255,200	\$116,200	\$134,200
TOTAL	\$1,433,670	\$1,545,950	\$1,301,999	\$1,275,700	\$1,013,300

- a) Please explain the departure from historical trends of the forecast expenditures in the System Access, System Renewal and System Service categories.
- b) Please explain the decrease in capital expenditures over the IRM term and describe the expected impact of this decrease on ROE.
- c) Please provide the capital: depreciation ratio over the five year period.

2-Staff-29

Ref: Exhibit 2, p. 47 – Rate Base Trend, PDF p. 6

At the reference, ORPC states: “Under the new management, ORPC started the asset review portion of its Distribution System Plan in early 2014 which triggered a higher level of capital investment in its distribution system.”

- a) Please describe the drivers of the increased level of capital additions in 2013, given that the asset review portion of ORPC's DSP was started in early 2014?

2-Staff-30

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, p. 6.

At the reference, ORPC states: “An analysis of load flow and load loss was completed in the 2005-2007 period. The analysis provided a system load study of which concluded that:

- Marginal implications were required to rebalance the system by changing individual load phase connections; and
- No additional options for loss reduction need be considered (e.g. increasing conductor size).”

- a) How did ORPC determine that no additional options for loss reduction need to be considered?
- b) Did ORPC conduct a cost-benefit analysis to investigate the economics of implementing any loss reduction projects? If NO, please explain.
- c) If yes to b), please provide more information.

2-Staff-31

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, Customer Statistics [Table], p. 13.

General Statistics	For the year ended December 31, 2012	For the year ended December 31, 2013	For the year ended December 31, 2014
Population Served	20,200	20,200	20,200
Municipal Population	20,200	20,200	20,200
Seasonal Population	-	-	-
Residential	9,136	9,250	9,298
General Service (<50 kW)	1,351	1,322	1,316
General Service (50-4999 kW)	146	146	146
Large User (>5000 kW)	-	-	-
Sub Transmission	-	-	-
Total Customers	10,633	10,718	10,791
Rural Service Area (sq. km)	-	-	-
Urban Service Area (sq. km)	35	35	35
Total Service Area (sq. km)	35	35	35
Overhead km of Primary Line		270	270
Underground km of Primary Line		25	25
Total km of Line		295	295
Total kWh Delivered (excluding losses)	188,134,284	188,547,051	186,751,366
Total Distribution Losses (kWh)	4,896,238	12,469,321	7,794,424
Total kWh Purchased	193,030,522	201,016,372	194,545,791
Winter Peak (kW)	35,963	36,856	43,158
Summer Peak (kW)	33,570	29,294	33,756
Average Peak (kW)	29,443	26,575	31,681
Capital Additions in 2012	\$ 822,268	\$ 1,336,555	\$ 1,198,235
Full time equivalent number of employees	28	28	27

- Was the exceptional winter peak in 2014 caused primarily by unusually cold weather?
- Please identify if there were other material drivers contributing to this peak demand.
- Please identify and describe the key drivers for the 60% increase in capital additions from 2012 to 2013.

2-Staff-32

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, Customer Statistics, p. 14.

ORPC stated that “the institutional sector in particular has seen significant increases over the past five years, including the construction of a new 50,000 square foot medical centre in 2009, the construction of the new Algonquin College Waterfront Campus in 2011, and the current construction of a new 22,000 square foot Ontario Provincial Police headquarters.”

- a) Are any costs directly associated with the Ontario Provincial Police (“OPP”) headquarters included in the present capital expenditure forecast?
- b) If so, please identify where the quantum of these expenditures.

2-Staff-33

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, Customer Statistics, p. 14.

Population projections are as follows:

- Total new residential construction in the planning period is expected to be approximately 38 units per year.
- Low density housing is expected to continue to account for the majority (60%) of housing completions. The demographic shifts anticipated in the population profile (aging of population), along with the natural pace of urban growth, suggest a gradual continued shift toward higher density housing demand in the City of Pembroke over the next three decades. It is expected that medium and high density housing will account for about 40% of the total residential construction in the future.”

- a) What is ORPC’s average cost per residential connection?
- b) If there is a material difference between the per unit connection costs for low, medium and high density housing, please provide the average connection costs per category.

2-Staff-34

Ref: Exhibit 2, p. 47 – DSP Section 5.2.1: Distribution System Plan Overview, p. 16.

At the reference, ORPC states that “ORPC plans to expend significant effort in quantifying and characterizing its distribution system and general plant with the assistance of a Geographic Information System (GIS). ORPC has created an asset register that contains both quantitative data such as the age of individual assets. It is

anticipated that we will enhance the asset register with key qualitative data, such as inspection and condition testing results including detailed asset information in the next two years. This enhancement will enable ORPC to project when individual assets are expected to reach the end of their useful service life, at which time the assets have a high probability of failure.”

- Has ORPC established a mechanism to translate qualitative asset condition assessment information into replacement decisions?
- Does the capital expenditure forecast associated with this DSP incorporate the expected incremental costs of applying the new replacement methodology?

2-Staff-35

Ref: Exhibit 2, p. 47 / Tab 5 / Schedule 2 – DSP Section 5.2.3: Performance Measurement for Continuous Improvement [Table], p. 21.

Scorecard - Ottawa River Power Corporation										9/24/2014
Performance Outcomes	Performance Categories	Measures	2009	2010	2011	2012	2013	Trend	Target	
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	98.60%	100.00%	100.00%	↑	90.00%	
		Scheduled Appointments Met On Time	100.00%	100.00%	100.00%	100.00%	100.00%	↑	90.00%	
		Telephone Calls Answered On Time	99.40%	99.80%	99.80%	99.90%	99.90%	↑	85.00%	
	Customer Satisfaction	First Contact Resolution								
		Billing Accuracy								
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved, and distributors deliver on system reliability and quality objectives.	Safety	Public Safety (measure to be determined)								
		Average Number of Hours that Power to a Customer is Interrupted	2.66	0.71	2.39	1.69	0.91	↓	at least within 0.71 - 2.66	
	System Reliability	Average Number of Times that Power to a Customer is Interrupted	2.10	0.79	1.43	1.08	0.81	↓	at least within 0.79 - 2.10	
		Asset Management								
	Cost Control	Efficiency Assessment				3	3			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to ministerial directives to the Board).	Conservation & Demand Management	Total Cost per Customer ¹	\$452	\$449	\$487	\$470	\$505			
		Total Cost per Km of Line ¹	\$32,146	\$31,795	\$34,703	\$33,773	\$32,410			
		Net Annual Peak Demand Savings (Percent of target achieved) ²			13.00%	13.00%	10.70%		1.61MW	
	Connection of Renewable Generation	Net Cumulative Energy Savings (Percent of target achieved)			34.00%	60.00%	77.50%		8.97GWh	
		Renewable Generation Connection Impact Assessments Completed On Time								
Financial Performance Financial viability is maintained, and savings from operational effectiveness are sustainable.	Financial Ratios	New Micro-embedded Generation Facilities Connected On Time					100.00%		90.00%	
		Liquidity: Current Ratio (Current Assets/Current Liabilities)	3.65	3.29	2.70	2.32	1.54			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.74	0.74	0.73	0.72	0.73			
		Profitability: Regulatory Return on Equity			9.85%	9.85%	9.85%			
		Deemed (included in rates)			10.58%	11.60%	5.90%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Legend:
↑ up
↓ down
flat
target met
target not met

- What caused the step change in “Achieved Return” in 2013?

2-Staff-36

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.1: Service Quality and Reliability Performance [Table], p. 22.

Service Quality Indicator	Minimum Standard	2009	2010	2011	2012	2013	2014
Connection of New Services – Low Voltage	90% or better	100	100	100	100	100	200
Connection of New Service – High Voltage	90% or better	n/a	n/a	n/a	n/a	n/a	n/a
Appointment Scheduling	90% or better	100	100	100	100	100	100
Appointments Met	90% or better	100	100	100	100	100	100

- a) Please confirm if “Connection of New Services – Low Voltage” result of 200 for 2014 is a typo.

2-Staff-37

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.5: System Reliability and Performance, Killaloe Outage Performance, p. 29.

On page 29, ORPC stated that “a Hydro One consultation was completed to determine if future improvements can be achieved. The installation of multiple remote operated switches was determined to be extremely costly and ORPC decided that the improvement not be completed at this time.”

- a) Please provide the cost estimates developed to determine the economic viability of installing “multiple remote operated switches”.

2-Staff-38

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.6 a: Conservation and Demand Management, kWh Savings, p. 32.

On page 32, ORPC stated that “with the anticipated EERI project completions, the HAP program results, as well as the large HPNC project noted above (600,000 kWh), ORPC expects to meet its energy target of 9 GWh. A final report is to be released in September; whereby, the excluded savings will be included.”

- a) Please provide the final report that was released in September 2015.

2-Staff-39

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.6 b: Connection of Renewable Generation, Anticipated Renewable Generation Connection Request [Table], p. 34.

At the reference, ORPC states: “Given the level of interest expressed by Ottawa River Power Corporation’s customers’ to-date, the forecasted of Micro-FIT applications is presented in the table below. These numbers provided are speculative in nature, but they are based on experience dealing with customers over the past several years. 2014 has been forecasted higher than the following years. This year the largest shareholding municipality put micro-Fit projects on a number of their facilities. This will not repeat itself in the future.”

Application Type	2014	2015	2016	2017	2018
Forecast micro FIT Connections	7-10	4-5	4-5	4-5	4-5

- a) Please provide the number of actual 2014 connections and the number of year to date 2015 connections.

2-Staff-40

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Poles, p. 82.

At the reference, ORPC states: “ORPC would have to replace 685 poles installed in the 1960’s to keep pace with the lifecycle of wood poles. ORPC has identified that at least 980 poles may need to be replaced due to a minimum height requirement of 40 feet to comply with new ESA guidelines.”

- a) Does the new Electrical Safety Authority (ESA) guideline mandate that existing poles less than 40 ft. tall must be replaced?
- b) Does ORPC consider that the 30 ft. and 35 ft. poles in its existing portfolio present safety risks to workers or the public?

2-Staff-41

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Pole Capital, p. 84.

At the reference, ORPC states: “The age distribution of the population of 4,299 wood poles is fairly evenly distributed over one lifecycle period beginning in 2015. The population is therefore not skewed, and as such, approximately the same number of assets will require replacement over the first and second half of the lifecycle. ORPC adopted a UL of 45 years, and based on the average age of 17 years for the population.”

- a) The last sentence in the above paragraph appears to be incomplete. Please provide a full explanation or clarification of the evidence.

2-Staff-42

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Remote SCADA, p. 101.

At the reference, ORPC states: “As underground cables cannot be inspected, ORPC plans on starting a cable condition testing program in 2015. The purpose of the program will be to determine the degree of cable jacket deterioration, from which replacement or sustainment activities will be identified and prioritized. ORPC plans on smoothing out the age profile of cable runs through the utilization of cable sustainment investments. ORPC must also be mindful that cable replacements cannot practically be performed during the winter months.”

- a) Has the cost of conversion from coaxial cable to fibre optic communications been included in this DSP?
- b) If yes to a), please provide the estimated cost by year of expenditure.
- c) Can underground cable condition be non-destructively tested?

2-Staff-43

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, Overhead Distribution Assets Optimization Policies and Practices, Fully Dressed Wood Poles, p. 104.

At the reference, ORPC states: “As ORPC has experienced considerable premature failures of wood poles due to flaws in the manufacturer’s treatment process, ORPC has been able to avoid unnecessary expense through the reuse of “like new” components.”

- a) Has ORPC taken action to avoid or minimize the risk of acquiring poles with flawed treatment? Please describe.

Operating Revenues

3-Staff-44

Ref: Exhibit 3, Tables 3-2

Please update Table 3-2 with 2015 actuals.

3-Staff-45

Ref: Exhibit 3, p. 12 – 17 of 71

On page 17 of 71, ORPC states that it did not use number of customers as a variable because monthly historical counts were not readily available until 2011.

On page 14, ORPC used economic data for the Kingston-Pembroke economic region as reported in Statistic Canada's Monthly Labour Force Survey (CANSIM). ORPC noted that this variable was rejected due to a negative correlation and coefficient.

On page 15, ORPC notes that a March monthly variable is used to account for higher load due to the school break during that month.

- a) Please a further explanation why ORPC is not able to obtain monthly historical customer data.
- b) Please confirm that annual customer data is available in aggregate.
 - i) If so, please provide an alternative model using pro-rated monthly data derived from the yearly data to include customer numbers in the regression analysis and provide the resulting load forecast.
- c) Please state what other economic data was considered (e.g. housing sales, new housing development, manufacturing statistics, or municipal statistics for the communities covered by ORPC's service territory).
 - i) If no other data was considered, please explain why.
 - ii) It is not clear as to why the school break in March would lead to higher system consumption, as higher residential consumption would be offset, at least in part, by lower consumption in schools. Please provide further explanation as to why a binary variable for March is justified to explain higher consumption what would be accounted for by other factors, such as HDD.
- d) Please provide further information on alternative model specifications (model form, alternative exogenous variables) attempted, and the reasons why ORPC prefers its proposed model rather than an alternative.

3-Staff-46

Ref: Load forecast model – Tab 10, CDM adjustment

ORPC provided the following CDM adjustment:

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	
Weight Factor for each year's CDM program impact on 2014 load forecast	0	0	0.5	1	0.5	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	Full year persistence of 2011 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.	Full year persistence of 2012 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.	Full year impact of persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the load forecast.	Full year impact of persistence of 2014 programs on 2015 load forecast. 2014 CDM programs not in base forecast.	Only 50% of 2015 CDM programs are assumed to impact the 2015 load forecast based on the "half-year" rule.	

The table above shows CDM adjustment on the 2015 load forecast.

- Please update the table to show persistence of 2014 and 2015 programs on the 2016 load forecast and explain the 50% impact of 2013 programs. Please use Appendix 2-I from the Chapter 2 Appendix of the Filing Requirements for 2016 Cost of Service Distribution Rate Applications, and file in working excel format.
- Please update the CDM allocation to the 2016 load forecast accordingly.

3-Staff-47

Ref: Exhibit 3, p. 50 of 71 and Appendix 2-H

Please provide Appendix 2-H including a column showing other revenues for the 2015 bridge year (unaudited) and compare to 2014 year-end actuals.

3-Staff-48

Ref: Exhibit 3, p. 50 – 57 of 71 and Appendix 2-H

On p. 55 of 71, ORPC notes that during 2014 it saw a large decrease in contract work of close to \$60K and expects this decline to continue. Please provide further detail and reasoning for this decline in contract work and why ORPC expects the decline to continue into the future.

3-Staff-49

Ref: Exhibit 3, p. 50 – 57 and Appendix 2-H

In Appendix 2-H, ORPC is showing moderate growth in Account 4210-Rent from Electric Property. During ORPC's community day presentation, ORPC discussed the

rental of land to solar installations. Please provide further detail and a breakdown of this revenues flowing into this account. In particular, please discuss the rental of land for the purpose of installing solar panels, parties involved and relevant contracts.

3-Staff-50

Ref: Exhibit 3, p. 50 – 57 of 71 and Appendix 2-H

On p. 56 of 71, ORPC states that it no longer has any short term investment, which led to a decline of \$55K in Account 4405 – Interest and Dividend Income. Please provide further detail.

Operating Expenses

4-Staff-51 Benefits from OM&A Increases

The proposed OM&A costs in 2016 of \$3,294,964 represent an increase of \$951,696 or 40.61% over the 2010 actual OM&A.

- a) Please outline the outcomes and higher level of services that customers will receive for the relatively higher rates they are paying.
- b) Please identify any customer engagement that supports the further increases proposed in this application.
- c) Please provide the analysis that was performed to assess whether ORPC's planning decisions reflect best practices of Ontario distributors.
- d) Please identify any initiatives considered and/or undertaken by the applicant, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.
- e) Please provide a further explanation for the 40.6% increase in ORPCs OM&A expenses over 2010 actual and elaborate on the drivers for the increase.

4-Staff-52

Ref: Exhibit 4, p. 7 of 70, Exhibit 1, p. 54 of 73 and Appendix 2-JA and 2-JB

Appendices 2-JA and 2-JB are labeled CGAAP and new CGAAP.

- a) Please confirm ORPCs conversion to MIFRS on January 1, 2015.

On p. 54 of Exhibit 1, ORPC states that it attests that it does not and will continue not to capitalize administration and other general overhead costs no longer permitted under IFRS, as clarified by the Board in its letter dated 21 February 24, 2010.

- b) Please confirm that the conversion to MIFRS has not impacted the ORPCs OM&A costs in the 2015 bridge or 2016 test year.

4-Staff-53 Corporate Cost Allocation

Ref: Exhibit 3, p. 61 of 71, Exhibit 4, p. 25 – 28 of 68 and Appendix 2-N

In Exhibit 4, pp. 26-28 ORPC provided tables for shared services up to 2014. In Appendix 2-N, ORPC provided costs for shared services up to 2016. ORPC did not complete the corporate cost allocation tables of Appendix 2-N.

- a) Please update Appendix 2-N to show how costs are allocated between ORPC and its affiliates.
- b) ORPC states that Ottawa River Energy Solutions Inc. has a seven member Board of Directors that is separate from ORPC. Please confirm that there is no overlap between the two Boards that would require a corporate cost allocation.

4-Staff-54

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, p. 7 and Exhibit 4, pp. 7-10

On page 7 of the DSP, ORPC states that “CHEC members have clearly stated the value of membership to be in excess of one full time equivalent position. A review of membership in CHEC by a third party consultant summarized the benefits as indicated by Members to include:

- Collaboration, security and best business practices;
- Provides “peace of mind” – simplified services, someone else is on it, one less thing on the collective TO DO list, support and knowledge that you are not alone;
- Compliance issues addressed through single provider, consistency in deliverables and messaging to OEB and OPA with the efficiency of a single submission; and
- Validation and clarity on emerging business pressures.”

On pages 8-9 of 70, ORPC notes that it joined the CHEC group in 2014 at a cost of \$23,000. In 2015 ORPC shows a membership cost driver of 13.5K for CHEC and EDA membership.

- a) What are the annual fixed and variable costs of ORPC's membership in CHEC in 2016?
- b) What is the cost for the EDA membership in 2016?
- c) Has the membership led to any offsetting efficiency gains?
 - i. If so, please describe how the savings have been incorporated into ORPC's operating budget.
 - ii. If not, please explain why not.

4-Staff-55 OM&A Program Table
Ref: Exhibit 4, p. 15 of 70 and Appendix 2-JC

Please provide appendix 2-JC including a column showing year-end OM&A costs for the 2015 bridge year and a column showing the same period in 2014.

4-Staff-56 Community Relations
Ref: Exhibit 4, p. 15 of 70, Appendix 2-JC

ORPC shows an increase of \$11,548 or 20.8% in community relations and safety for 2016 test year over 2015 actual. OEB staff notes that ORPC actual spending in this category never reached the OEB-approved amount of \$58,624.

- a) Please provide the actual amount spent up-to-date and explain this increase in more detail.
- b) Please ORPC's under spending in this category over the IRM term.

4-Staff-57 Meter reading
Ref: Exhibit 4, p. 15 of 70, Appendix 2-JC and Exhibit 2, pp. 32-42 – Meter Reading

On p. 32, Exhibit 2, ORPC noted that it had completed 100% of its smart meter initiative by December 31, 2012. In Appendix 2-JC ORPC shows an increase of \$20,335 or 68% in meter reading expenses for the 2016 test year over 2014 actual. Meter reading expenses also spiked in 2013.

- a) Please provide an explanation for the spikes in meter reading expenses in the 2013 rate year as well as the 2015 bridge year and 2016 test year.

4-Staff-58 Overhead and Underground lines
Ref: Exhibit 4, p. 15 of 70, Appendix 2-JC and Exhibit 2, p. 18 and 20 of 58, Appendix 2-AB

ORPC is showing an increase in operating expense regarding overhead and underground lines of 23.7% and 25.1% respectively in the 2016 test year over 2014 actual. In its DSP, ORPC's system renewal capital spending is declining significantly over the 2015 bridge year and 2014 actuals.

- a) Please explain the increase in OM&A cost.
- b) Please explain how this cost increase relates to the decline in capital spending for system renewal.

4-Staff-59 Substation Operations and Maintenance
Ref: Exhibit 4, p. 15 of 70, Appendix 2-JC and Exhibit 2, p. 18 and 20 of 58, Appendix 2-AB

ORPC's OM&A costs for substation operations and maintenance is declining by 14.2% in the 2016 test year over 2014. Please provide a detailed explanation for this decrease.

4-Staff-60 Monthly Billing

Ref: Exhibit 4, p.11

On page 11, ORPC states that "Acct 5315 billing and collecting [is] expected to increase by \$78,414 with the implementation on January 1, 2015 of monthly billing. Postage costs of \$55,000 as well as additional billing staff. Please note that bad debts are expected to decrease by \$23,464."

- a) Please confirm that ORPC is not expecting any other cost associated with the implementation of monthly billing. If other cost are expected please provide a breakdown of the costs.
- b) Please quantify any offsetting costs (benefits) associated with the implementation of monthly billing.
- c) Please identify the percentage of customers on e-billing as of December 31, 2015. If Applicant does not provide e-billing to its customers please explain the reasons.
- d) Please describe the Applicant's efforts to promote e-billing to its customers.
- e) Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

4-Staff-61 Compensation

Ref: Exhibit 4, pp. 18-20 and Appendix 2-K

The applicant has proposed a 3% increases in headcount (1 FTE) but a 20.5% in employee compensation for the Test year relative to the 2010 OEB approved levels.

- a) Please provide the rationale for these increases in compensation.
- b) What objectives has the applicant established for its operations?
- c) Please provide specific information on why the proposed cost increases are necessary for the applicant to achieve the objectives that the applicant has targeted in the capital and operating expenditure sections of its application, and the alternative methods for achieving these objectives that were considered and rejected in favour of the proposed headcount and compensation increases.

4-Staff-62 Benchmarking

Ref: Exhibit 1, p. 72

While ORPC provided the scorecard on p. 72 of Exhibit 1, ORPC did not show any relevant studies of its proposed increases in compensation/headcount on the basis of compensation benchmarking, or any other external comparators, and appears to have justified its proposed increases solely on the basis of its anticipated needs without any specific reference to any external comparators. Please explain what analyses and data ORPC used to derive its proposed compensation per headcount for the bridge and test years.

4-Staff-63 Apprenticeship Tax Credits

Ref: Exhibit 1, p. 20 of 73

On page 20 of Exhibit 1, ORPC notes that Employee compensation has increased by \$300K over the 2010 Cost of service application which is a 17% total increase over the last 5 years. This represents a 13% change in management compensation and a 19% change in non-management. A primary factor is the progression of a number of apprentices.

In Exhibit 3, page 61 of 68, ORPC notes that it is not claiming any Apprenticeship Tax Credits in calculating its PILS for the 2016 test year.

- a) Please describe the level of progression of ORPC apprentices and explain why the tax credit is no longer applicable.

4-Staff-64 PILS

Ref: PILs Workform

On tab A – Data Input Sheet, ORPC used 2015 cost of capital parameters to calculate the PILs amount to be included in 2016 rates. Please update the PILs model to the latest cost of capital parameters, issued October 15, 2015.

4-Staff-65 Regulatory Cost

Ref: Exhibit 4, p. 41-42 and Appendix 2-M

- a) In Appendix 2-M, ORPC included \$15,000 of IRM filing costs related to ORPC's IRM filing in the year 2012-2014. Please explain why past IRM costs

are included in the regulatory costs of \$130,000 to be amortized over the next five years.

- b) On page 42 of Exhibit 4, ORPC projected regulatory costs of an aggregated amount of \$20,000 or \$5,000 for each of the next four IRM years. Please state how this amount is included in the total regulatory costs of \$105,000 in the 2016 test year.
- c) In Appendix 2-M, ORPC included intervenor costs of \$20,000 in the total regulatory expense of \$130,000, which is amortized over five years. In addition, ORPC is also showing intervenor costs of \$4,000 for the 2015 bridge and 2016 test year separately. Please explain.

4-Staff-66

Ref: Ex 4, T6, S2 – LRAMVA

ORPC has requested approval to recover its LRAMVA amount in Account 1568 in the total amount of \$93,051.87 which includes lost revenues from CDM Programs implemented in 2011, 2012, 2013 and 2014.

OPRC noted that it has relied on the most recent final evaluation report from the OPA in support of its LRAMVA claim and included all Final Results Reports for 2011, 2012 and 2013 CDM programs as part of its application. OPRC also included its 2014 CDM Results Q4 Status Report from the IESO (formerly the OPA).

- a) Please update the LRAMVA calculations to include all final verified results from OPRC's 2014 Final Results Report from the IESO.
- b) Please include any adjustments to the final results from each program year that are outlined in the 2014 Final Results Report.
- c) Please provide all references to the distribution volumetric rates that OPRC has used when calculating its LRAMVA amounts.
- d) When updating the LRAMVA calculations using the 2014 Final Results, please also update the distribution volumetric rates used to calculate all lost revenue amounts to ensure that the distribution rates accurately reflect the distribution rates that were in place over the calendar year. As OPRC has new rates effective May 1st of a particular year, OPRC should be using a blended distribution rate when calculating the annual lost revenues from CDM Programs. For example, since the 2011 CDM savings took place over the 2011 calendar year (i.e., January to December), OPRC should be applying the 2010 distribution rates that were in place for 1/3 of the 2011 CDM savings (in order to recognize these rates were in place from January to April) and the 2011 distribution rates

for 2/3 of the 2011 CDM savings (as these rates were in place from May to December).

- e) Please confirm that all CDM savings from the Business Programs (e.g., Retrofit, Direct Install Lighting) has been applied to OPRC's GS<50 kW rate class.

4-Staff-67 OPEBs
Exhibit 4, p. 7 of 70, Appendix 2-JB

ORPC has recovered OPEBs in rates previously.

- a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since ORPC started to recover OPEBs.
- b) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year ORPC started recovering amounts for OPEBs.

OPEBs	First year of recovery to 2011	2012	2013	2014	2015	2016	Total
Amounts included in rates							
OM&A							
Capital							
Sub-total							
Paid benefit amounts							
Net excess amount included in rates greater than amounts actually paid							

- c) Please describe what ORPC has done with the recoveries in excess of cash benefit payments.

Cost of Capital

5-Staff-68
Ref: Exhibit 5, p. 3 of 17, Appendix 2-OA and RRWF

On page 3, OPRC calculated its cost of capital based on 2015 cost of capital parameters.

OEB staff notes that in the RRWF, ORPC used the following parameters.

Cost of Capital

Long-term debt Cost Rate (%)	7.25%
Short-term debt Cost Rate (%)	2.07%
Common Equity Cost Rate (%)	8.98%
Preferred Shares Cost Rate (%)	

- a) As a result ORPC shows a weighted cost of capital of 7.73%. OEB staff cannot reconcile the ROE used in this calculation with the 2015 or 2016 cost of capital parameters or p. 3 of 17 in Exhibit 5. Please reconcile and update the application is necessary.

OEB staff notes that the OEB updated the cost of capital parameters for distribution rates effective in 2016 in a letter issued on October 15, 2015 are as follows:

Cost of Capital

Long-term debt Cost Rate (%)	4.54%
Short-term debt Cost Rate (%)	1.65%
Common Equity Cost Rate (%)	9.19%

- b) Please update the application and the RRWF to reflect the most recent cost of capital parameters for short-term debt and the ROE.

Cost Allocation

7-Staff-69 Cost Allocation

Ref: Cost Allocation Model, Tab I6.2 – Customer Data and Exhibit 1, p.7 of 73

In tab I6.2 of the Cost Allocation Model, ORPC shows an input of 74,122 bills in total. On page 7 of Exhibit 1, ORPC stated that it moved to monthly billing as of January 1, 2015.

- a) OEB staff notes that for the residential class, the number of bills is based bi-monthly billing, while other classes reflect a monthly billing cycle. Please explain.
- b) Please update the model, if necessary. If there is a change to status quo ratios, please update the relevant tables and confirm that there is no change the proposed ratios.

On page 10 of 16, Exhibit 7, ORPC shows proposed revenue-to-cost ratios as follows:

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2010	$(7C + 7E) / (7A)$	$(7D + 7E) / (7A)$	
	%	%	%	%
Residential	107.00	95.45	96.90	85 - 115
General Service < 50 kW	88.00	103.49	103.93	80 - 120
General Service > 50 to 4999 kW	103.00	116.33	110.00	80 - 120
Sentinel Lighting	70.00	74.08	85.08	80 - 120
Streetlighting	70.00	96.40	94.80	85 - 115
Unmetered Scattered Load	80.00	42.77	60.00	70 - 120

2

- c) Please provide further explanation as to how the change to monthly billing impacted the status quo revenue-to-cost ratios.
- d) Please provide further detail to justify the weighting factors used for billing and collecting.
- e) Please provide ORPC rational for its proposed revenue-to-cost ratios in particular for classes that are moving away from parity, while the USL class is outside the OEB prescribed target range.

Rate Design

8-Staff-70 Maximum Fixed Charge - Minimum System with PLCC Adjustment Ref: Cost Allocation Model, Tab O2 and Exhibit 8, p. 7, Table 8.2 and 8.3

On page 7 of Exhibit 8, Table 8.2 – Minimum and Maximum Fixed Charge as per the Cost Allocation Model shows the ceiling for the monthly fixed charge (MFC) for the GS>50kWh customer class at \$378.72.

- a) Please confirm that the ceiling amount for this class as per the cost allocation model is \$105.06.
- b) Please confirm that the \$378.72 is the current MFC for this class.
- c) Table 8.3 shows a proposed MFC of \$423.48. Tables 8.2 a - d show a MFC of \$378.72. Please confirm that ORPC proposes to maintain the current charge at \$378.72.
- d) IF yes to a) and c) please update the tables 8.2 and 8.3 and show the proposed F/V split.

8-Staff-71 Regulatory Charges Ref: Decision and Order, EB-2015-0294

On November 19, 2015 the OEB issued a decision and order which established regulatory charges for the 2016 rate year. Please confirm that ORPC will update its application accordingly and provide updated bill impacts calculations.

8-Staff-72 Specific Service Charges

Ref: Exhibit 3, p. 58 of 71 and proposed tariff of rates and charges

On page 58 of 71, ORPC provided a table of current and proposed specific service charges. ORPC proposed the following change.

	Current	Proposed
Return Cheque charge (plus bank charges)	\$ 15	\$ 20
Meter dispute charge plus Measurement Canada fee (if meter found correct)	\$0	\$45

In the 2006 EDR Handbook, the OEB provided a rate of \$15 for the Return Cheque charge and \$30 for Meter Dispute Charge following the methodology below:

Specific Service Charge Description:		\$30 Specific Service Charge Calculation		
Used For:				
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)				
Special meter reads				
Collection of account charge - no disconnection				
Meter dispute charge plus Measurement Canada fees (if meter found correct)				
Service call - customer-owned equipment				
	Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L Direct Labour (inside staff) Straight Time	23.00	0.5		\$11.50
A Direct Labour (inside staff) Overtime				
B Direct Labour (field staff) Straight Time	27.00	0.3		\$8.10
O Direct Labour (field staff) Overtime	27.00			
U Other Labour (Specify)				
R Payroll Burden %	30%			\$5.88
Total Labour Cost				\$25.48
O Small Vehicle Time	10.00	0.3		\$3.00
T Large Vehicle Time	42.00			
H Other:	Material			
E	Contract			
R	Other	2.00		\$2.00
Total Other				\$5.00
Total Cost				\$30.48
Specific Service Charge Value Requested - Round to nearest \$5				\$30.00

- Please provide a breakdown of the requested charges in this level of detail shown in the table above.
- Please state why the OEB should approve distributor specific special service charges given that a review of specific service charges (EB-2015-0304) is currently underway.

8-Staff-73 Low Voltage Charges

Ref: Exhibit 8, p. 21, Table 8.11

ORPC shows the following historic and proposed LV charges:

Historic and Proposed LV charges

	2010	2011	2012	2013	2014	2015	2016
4075 - Billed LV	-189,060	-205,210	-202,887	-206,776	-202,825	-205,000	-205,000

4750 - Charges LV	0	0	0	65,791	167,195	205,000	205,000
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- a) Please explain the \$0 charge booked in account 4570 for 2010, 2011 and 2012 and confirm that ORPC has been an embedded distributor to Hydro One Networks Inc. during this time.
- b) Please provide further justification for the amounts booked in 2013 and 2014 and explain the proposed charges for the bridge and test year.

8-Staff-74 Total Loss Factor

Ref: Exhibit 8, p. 23

ORPC is proposing a total loss factor of 1.0457 based on the historic average of the last five years. Please explain the increase and discuss how capital investments in the system renewal category will impact the line losses going forward. If ORPC does not expect any impact, please explain.

8-Staff-75 Residential Rate Design

Ref: Exhibit 8, p. 4, Table 8.2 and Appendix 2-PA

In table 8.2, ORPC shows incremental changes in of \$3.00 in 2017, \$2.59 in 2018 and 2.63 in 2019. Appendix 2-PA shows a change in fixed rates of \$3.22.

- a) Please provide table 8.2 to include the 2015 rate year.
- b) Please provide a further explanation how ORPC calculated these amounts and explain the deviation from \$3.22 shown in Appendix 2-PA.

Deferral and Variance Accounts

9-Staff-76 Stranded Meters

Ref: Exhibit 2, pp. 43 – 45

In table 2.30a) – Summary of Proposed Charge Parameters, ORPC shows a net book value of \$398,964 as of December 31, 2011, which is the amount requested for recovery. ORPC did not apply any further amortization to the net book value of stranded meters.

- a) Please confirm that amortization expenses related to stranded meters continue to be embedded in ORPC's rates until the effective date of 2016 rates.
- b) If yes to a), please explain why the net book value request for recovery has not been reduced by the accumulated amortization for the 2012, 2013, 2014 and 2015 rate years.
- c) If no to a), please explain.
- d) Please update table 2.30a to include accumulated amortization up to December 31, 2015 and re-calculate the residual net book value accordingly.
- e) Please recalculate the stranded meter rate rider based on the net book value as of December 31, 2015.
- f) ORPC did not show any proceeds on disposition. Where any of these assets sold for scrap metal? If so, please provide the proceeds from the sale and apply towards the amount requested for recovery.

9-Staff-77 Smart Meters

Ref: Smart Meter Model, Tab 3 – Cost of Capital Parameters

ORPC used the 2010 cost of capital parameters for the years 2010 – 2014. For the bridge and test years ORPC used the following short-term (ST) debt rate 2.07% and a return on equity (ROE) of 8.98%. On October 15, 2015 the OEB issued a letter updating the cost of capital parameters for the 2016 rate year as follows:

Cost of Capital Parameter	Value for Applications for rate changes in 2016
ROE	9.19%
Deemed LT Debt rate	4.54%
Deemed ST Debt rate	1.65%

- a) Please justify the cost of capital parameters use for the 2015 bridge year.
- b) Please update the smart meter model for 2016 test year cost of capital parameters for 2016 and historic cost of capital parameter for the 2015 bridge year.

9-Staff-78 Smart Meter

Ref: Smart Meter Model, Tab 3 – Cost of Capital Parameters

Row 40 of the Tab 3 of the smart meter model provides instructions to enter the effective tax rate for any given year, including the rates used in the IRM Tax sharing model, i.e. a rate of 15.5% for the 2014 rate year.

Please update the smart meter model to input the correct tax rates for the 2010 rate years of 16%, 2013 and 2014 of 15.5% and 20.35% for the 2016 test year. Please confirm the accuracy of all other inputs in row 40.

9-Staff-79

Ref: Smart Meter Model, Tab 8 – Interest rates

On tab 8 of the smart meter model ORPC provided for interest revenue on the smart meter funding adder up until September 2015.

- a) Please explain why ORPC did not calculate interest up until April 30, 2016 since the SMDR will be effective as of May 1, 2016.
- b) Please update the smart meter model accordingly.

9-Staff-80

Ref: Smart Meter Model, Tab 9 – Average number of customers

In cell AA46 on tab 9 of the smart meter model, ORPC has input 1000 for the average number of customers. OEB staff notes that ORPC shows a customer count of 9,463 for the residential and 1,281 for the GS<50 kWh customer classes. Please justify the input and update the model, if necessary.

9-Staff-81

Ref: Smart Meter Model, Tab 10A

ORPC proposed a disposition period of 2 year to recovery a net deferred revenue requirement of \$1,019,716.92 through a Smart Meter Disposition Rate Riders (SMDRs) . Please provide two scenarios of a 3 and 4 year disposition period for the SMDRs.

9-Staff-82 Smart Meters

Billing systems of electricity distributors should not be duplicating functions provided by the MDM/R. Please confirm that none of the projects included in information system investment or miscellaneous projects over the DSP term do not duplicate the functions provided by the IESO's MDM/R in any way.

9-Staff-83

Ref: Exhibit 9, p. 4 of 45

On line 13, ORPC stated that it used an interest rate of 0% to calculate the interest on balances for the period of January 1, 2014 to April 30, 2016. Please update the application and include the actual interest rate.

9-Staff-84 Account 1592

Ref: Exhibit 9, p. 15 of 45 and RRR 2.1.7 Trial Balance

In Exhibit 9, on page 15, ORPC shows a balance of \$32,159 in account 1592 for disposition. On page 17, ORPC states that "Ottawa River Power has not amounts in account 1592 Tax Variance". The RRR 2.1.7 – Trial Balance shows an account balance of \$(686,317) as of December 31, 2014. Please explain the balance in light of the statement above.

9-Staff-85 Interest

Ref: Exhibit 9, p. 22 – 24 of 45

On page 22, ORPC stated that it has used the latest OEB prescribed interest rates and shows closing interest balances of December 31, 2014 adjusted for disposition during 2015. The EDDVAR continuity schedule does not show any entries for interest amounts in 2015 and 2016.

OEB prescribed rates can be found by clicking to the link below or shown in the table below:

<http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates>

<u>Quarter by Year¹</u>	<u>Approved Deferral and Variance Accounts</u> Prescribed Interest Rate (per the Bankers' Acceptances-3 months Plus 0.25 Spread)	<u>CWIP Account</u> Prescribed Interest Rate (per the FTSE TMX Canada (formerly DEX) Mid Term Bond Index All Corporate Yield ²⁾
Q1 2016	1.10	2.92
Q4 2015	1.10	2.55
Q3 2015	1.10	2.55
Q2 2015	1.10	2.28
Q1 2015	1.47	2.89

Please update the application to apply interest on principle balances up until April 30, 2016.

9-Staff-86

Ref: Exhibit 9, Table 9.2, and Table 9.3, Appendix 2-EC Fixed Asset Continuity Schedule_20150828 and Appendix 2-BA)

Ottawa River has calculated the WACC component of Account 1576 for one year. However, the proposed rate rider term is two years. Please update and file the amount to be returned to the customers in Table 3, as well as the rate rider calculation.

9-Staff-87

Ref: Exhibit 9, Table 9.2, and Table 9.3, Appendix 2-EC Fixed Asset Continuity Schedule_20150828 and Appendix 2-BA)

- a) Appendix 2-EC Ottawa River has calculated Appendix 2-EC for differences in PP&E for years 2013 and 2014, but not for 2015. Please update Appendix 2-EC and all other schedules necessary to reflect the PP&E differences for 2015 (e.g. rate rider calculation).
- b) Appendix 2-EC does not match the Appendices 2-BAs. It appears that the Opening Net PP&E for 2013 and 2014 is incorrect for both, former CGAAP and revised CGAAP. Ottawa River has used the Gross beginning PP&E number instead of the net. Please re-file a corrected schedule.
- c) The Accumulated Depreciation opening balance per 2014 Appendix 2-BA does not match the closing balance for Accumulated Depreciation per Appendix 2-BA for 2013. Closing balance in 2013 is -\$18,056,150, and the opening for 2014 is -\$18,015,400. Please explain and re-file the necessary schedules.
- d) Appendix 2-BA for 2015 under IFRS has a different depreciation expense for the year than the Depreciation Expense schedule on file.
 - Appendix 2-BA filed October 5, 2015 shows Depreciation expense to be \$763,303
 - Appendix 2-CD shows the depreciation expense to be \$868,028.Please update the schedules as necessary.
- e) Please update 2015 forecast figures for Account 1576 if necessary and provide the reasons of the update (i.e. adjustments identified, audited by external auditor).

9-Staff-88

Ref: Exhibit 9, Table 9.2, and Table 9.3, Appendix 2-EC Fixed Asset Continuity Schedule_20150828 and Appendix 2-BA)

Ottawa River has calculated a balance of zero for Account 1575 as of the changeover date of January 1, 2015. OEB staff notes that Ottawa River had a credit of approximately \$1.6 Million in Account 1995 – Customer Contributions as of the changeover date. According to APH Article 510, under IFRS, customer contributions received subsequent to the transition date are recognized as deferred revenue. Customer contributions recognized prior to the transition date are not reclassified to deferred revenue as a result of electing the optional exemptions (emphasis added).

- a. Please confirm that Ottawa River has reviewed Article 510 in determining that account 1575 should have a zero balance as of the changeover date of January 1, 2015.
- b. If confirmed, please explain why there is a zero balance. If the balance is to be revised, please provide the calculation. While OEB staff has not identified any other impacts that should be captured in account 1575, for customer contributions, there may need to be an amount for the difference between Ottawa River's revised CGAAP based amount for customer contributions as of the changeover date, and the MIFRS based amount for customer contributions as of the same date.

9-Staff-89

Ref: Exhibit 9, page 4, EDDVAR model

OEB staff notes that Ottawa River has calculated a volumetric rate rider for its Group 2 balances and for the 1576 rate rider. According to the April 2, 2015 OEB report *Board Policy: A New Distribution Rate Design for Residential Electricity Customers*, which was reiterated in the 2016 Chapter 2 Filing Requirements, distributors are expected to propose changes to residential rates consistent with this policy. Generally speaking, distributors must propose a fully fixed rate design for charges applicable to the residential class provided that those charges are specifically related to distribution of electricity. Examples of distribution-specific charges include: Group 2 Deferral and Variance Accounts including balances in accounts 1575/1576.

- a. Please calculate and update the Group 2 rate riders and 1576 rate riders in compliance with the OEB policy.

9-Staff-90

Ref: Exhibit 9, page 4, EDDVAR model

Please note that Account 1592 appears to have been missed from the rate rider calculations. Please make the appropriate changes and re-file schedules as necessary.