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October 27, 2017

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

Dear Ms. Walli,

Re: Oshawa PUC Networks Inc. - **Board File Number EB-2017-0069**

As per Directive 3 of the Board's Procedural Order No. 1 (PO1) issued October 2, 2017, Oshawa PUC is filing with the OEB complete written responses and supporting evidence to all interrogatories relating to its Application – Board File Number EB-2017-0069.

In addition, a copy of the responses and supporting evidence has been emailed to intervenors and OEB staff. A list of supporting evidence has been provided as Appendix A. The responses to interrogatories are organized by subject matter to make it easier for review.

If you have any questions concerning this publication please contact me at the address below.

Yours truly,

Phil Martin
VP Finance and Regulatory Compliance
(905) 723-4626 ext 5250
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Encl

Appendix A

List of Attachments

Responses to Interrogatories

1. Interrogatories_Enfield/MS9
2. Interrogatories_Capital Program
3. Interrogatories_Load Forecast/COP

Model & Worksheets

1. Rate Design Model
   (EB_2017_0169_OPUCN_Rate Design Model - 2015 to 2019_RUN_1_20171027.xlsx)
2. Rate Design and Revenue Reconciliation
   (EB-2017-0169_OPUCN_Chapter2_Appendices - Tab 2-V for 2018 to 2019_20171027.xlsm)
3. New Rate Design policy for residential customers
   (*EB-2014-0101_OPUCN_Chapter2_Appendices - Tab 2-PA for 2017 to 2019_20171027.xlsm*)
4. Load Forecast Model
   (*EB_2017_0169_OPUCN_Weather Normalization_Trend Model_Mid Term 2017_20171027.xlsx*)
5. CDM Q4 2015 Status Report
   (EB_2017_0169_OPUCN_Q4 2015 CDM Status Report_Oshawa PUC Networks Inc_20171027.pdf)
6. CDM 2016 Verified Results
   (EB_2017_0169_OPUCN_Final_2016_Annual_CDM_Results_20170727.xlsx)
7. CDM 2011-2014 Final Results
   (EB_2017_0169_OPUCN_2011_2014_Final_Results_HC_OPUCN_20171027.xlsx)
8. Deferral & Variance Accounts Workform
   (*EB_2017_0069_OPUCN_2018_DVA_Continuity_Schedule_20171027.xlsb*)
9. RTSR Adjustment Workform
   (*EB_2017_0169_OPUCN_2018_RTSR_Workform_20171027.xlsm*)

OSHAWA PUC NETWORKS INC.

Responses to Interrogatories – Enfield/MS9

OEB (Board Staff)

1-Staff-1

Capital Expenditure – Enfield TS

Ref: Exhibit A attachment 1 – Hydro One CCRA

Ref: Exhibit A - page 16

Oshawa PUC stated that the revised capital contribution to Hydro One is $4 million but the capital contribution in Hydro One's CCRA dated May 31, 2017 still appears to total $13.5 million. Oshawa PUC also stated that there is an additional investment of $6.5 million to build a feeder array to integrate the Enfield TS connection to Oshawa PUC's system.

a) Please provide an explanation on what basis the $4 million is calculated.

b) Please explain why the $6.5 million for the feeder construction was not identified in the original Custom Incentive Regulation (Custom IR) application.

c) Please provide the business case or plans for the feeder array.

Response:

a) The estimated capital contribution for Enfield TS is $4.0 million, as defined under the *Connection and Cost Recovery Agreement ("CCRA") – Load* dated May 31, 2017, between Oshawa PUC Networks Inc. ("Oshawa PUC") and Hydro One Networks Inc. ("Hydro One").

As per *Schedule "B"*, page 13 of the CCRA, Hydro One's cost estimate for Enfield TS is $32.8 million and the cost allocation for the incremental capacity usage based on load forecasts provided by Oshawa PUC and Hydro One Distribution is approximately: 63% (96.4 MW) to Oshawa PUC; and, 37% to Hydro One Distribution (56.6 MW).

Under the CCRA the estimated cost amounts allocated to Oshawa PUC are as follows:

- Transformation Connection Pool Work - $18,048,570;
- Line Connection Pool Work - $0;
- Network Customer Allocated Work - $812,700; and
- Work Chargeable to Customer - $1,681,410.

Section 6.3.1 of the Transmission System Code States – *"Where a load customer elects to be served by transmitter-owned connection facilities, a transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility required to meet the load customer's needs. A capital contribution may only be required to the extent that the cost of the connection* *facility is not recoverable in connection rate revenues. To that end, the transmitter shall include in the economic evaluation the relevant annual connection rate revenues over the applicable economic evaluation period that are derived from that part of the customer's new load that exceeds the total normal supply capacity of any connection facility already serving the customer and that will be served by the new connection facility. The transmitter shall calculate any capital contribution to be made by the load customer using the economic evaluation methodology set out in section 6.5.From their DCF models, Hydro One estimated they would recover $15.9 million of the Transformation Connection Pool Work and $0.8 million (100%) of Network Customer Allocated Work."*

Under the following sections of the Transmission System Code, Hydro One estimated the amount recoverable in connection rate revenues and the remaining balance from capital contributions by Oshawa PUC:

- 6.3.1 - General principle to recover cost of capital
- 6.5.2 - Basis for the DCF Model
- 6.5.3 - True-Up Requirement for Hydro One
- Appendix 4 - Determination of Customer Risk Profile
- Appendix 5 - High-level formulas applied in DCF Model

In the table on page 15 of *Schedule "B"*, Hydro One provides its estimates for Capital Contributions and Work Chargeable to Oshawa PUC: $2.1 million in Capital Contributions; and $1.7 million in Work Chargeable. The total $3.8 million is subject to final pricing at the end of the project and was rounded to $4.0 million for the purpose of this rate application.

b) As per updated model filed May 27, 2015 *(TC_UR_OPUCN_Chapter 2 Appendicies_for 2015 to 2019_RUN 3_xlsm_20150527)*, Oshawa PUC identified the need for capital investments to address capacity constraints in its territory. Included in its planning were shared costs for Enfield TS and related infrastructure to connect the TS to Oshawa's distribution system ($13.5 million), MS9 ($7.0 million) and feeder connection infrastructure ($7.5 million) totalling $28 million.

Capital investments for shared costs in Enfield TS and the related infrastructure to connect were dependent upon finalizing the Regional Planning process between Hydro One and Oshawa PUC, and local planning assessments which were not available when Oshawa PUC's original Custom IR rate application was filed. Upon completing the planning process, estimated costs for Enfield TS and related infrastructure to connect the TS to Oshawa's distribution system, MS9 and feeder connection infrastructure total $25 million.

Capital contributions were reduced based upon the final CCRA. Feeder construction was identified in the Regional Planning process finalized after filing the CIR. Forecast costs for MS9 have remained the same.

c) Please refer to the following Regional Planning documents attached.

Local Planning Report - WilsonThoı

Regional Infrastructure Plann

Wilson TS and Thornton TS, which are currently supplying power to Oshawa PUC, have exceeded their respective normal supply capacities and will continue to do so based on the current load forecasts. This has driven the need to create more system capacity in the GTA East.

The outcome of Regional Planning was to build Enfield TS rather than expanding Wilson TS and Thornton TS. In addition to the proposed Enfield TS, feeder construction and reconfiguration is required to permanently relieve over-capacity load from Wilson TS and Thornton TS and transfer load to Enfield TS.

The estimated capital investment of $6.5 million is required to rebuild approximately eight km of existing pole lines to complete the load transfers from Wilson TS and Thornton TS, including feeder egress to connect Enfield TS to Oshawa PUC's distribution system. The following are the feeder array plans:

Enfield Feeder Projects	**Scope**
Enfield Feeders, Riser Poles and UG Cable Installation Within Enfield Station	500m x 6 (2 circuits) = 3,000m of 1,000MCM cable installation and 6 poles installation within Enfield TS station.
Enfield TS Feeder Egress from TS Station Fence to Grandview St E	Feeder egress at Townline Rd N from Enfield TS and OH Rebuild at Winchester Rd E from Townline Rd N to Hwy 407 (approx. 650m). New pole build to accommodate 2-44kV circuits and provisions for 2 additional 44kV circuits in the future. Self-supporting poles to be utilized for high risk poles with potential 4 feeder circuits.
OH Rebuild at Harmony Rd N from Winchester Rd E to Conlin Rd E	Install 1.12km of new circuits on existing poles at Winchester Rd E from Grandview St N to Harmony Rd N and rebuild 1.87km of pole line to bring Enfield feeder to MS15. Replace existing 44kV switch. Partial rebuild has been completed with 5-6 poles south of Winchester Rd E. This will provide loading relief from Wilson TS (54M3).
OH Rebuild at Harmony Rd N from Rossland Rd E to King St E and at King St E from Harmony Rd N to Farewell St	Rebuild 2.5km of line to provide loading relief from Thornton TS (52M3) by installing a new automated load break switch and rebuilding the existing pole line.

1-Staff-2

Capital Expenditures – MS9

Ref: Exhibit A – Page 17

Oshawa PUC stated that the forecast for the MS9 substation remains unchanged at $7 million. This station also required distribution feeder construction as proposed in Oshawa PUC's Custom IR.

a) Please provide a status update on the MS9 feeder project and whether the forecast remains unchanged.

Response:

a) The MS9 feeder projects is currently in the design stages with construction scheduled for 2018 and 2019. The forecasted cost of $7.5 million for these projects remains unchanged. In-service date for MS9 is 2018. Feeder array construction is scheduled for 2018 and 2019.

MS9 Feeder Projects	**Scope**
OH Rebuild at Winchester Rd E from Simcoe St N to West of Harmony Rd N	Rebuild 3km of line to bring feeders to Conlin Rd E to provide supply to MS9 and future 44kV customers. This will provide a loop for back-up supply in an emergency event.
OH Rebuild at Simcoe St N from Conlin Rd E to South of Winchester Rd E	Rebuild 2km of line to bring feeders to Conlin Rd E to provide supply to MS9 and future 44kV customers. This will provide a loop for back-up supply in an emergency event.
MS9 Riser Poles	Relocation of MS9 riser poles at Wilson Rd N and Conlin Rd E (11 poles and duct work with 2,000m of cable).
MS9 Feeders at Conlin Rd E from Wilson Rd N to Simcoe St N	Installation of new switches and feeder line to loop MS9 feeders to neighbouring feeders. This will also provide loading relief from Wilson TS to Enfield TS with strategic permanent switching using MS feeders. (850m*3 cable installation + 2 poles).
MS9 Feeder and MS15 Reconfiguration at Wilson Rd N and Taunton Rd E	Installation of new switches and feeder line (approx. 1,000m) to loop MS9 feeders to neighbouring feeders.

CCC

CCC-4

Ex. A/p. 16

Please explain the reasons for significant variance between the forecast amount and the current expected contribution to Hydro One for the Enfield TS. Is the $4 million a final amount? If not, under what circumstances could it be subject to change? Please explain when OPUCN identified the $6.5 million cost related to the feeder arrays which are required to integrate the Enfield TS connection to OPUCN's system.

Response:

Please refer to 1-Staff-1 response.

As per the CCRA, the $4 million capital contribution is subject to change – *"The actual Project cost allocation and capacity allocation will be confirmed upon completion of the Project."* We do not believe changes will be material.

CCC-5

Ex. A/p. 17

The evidence states that the forecast for the MS9 substation remains unchanged from the time of the CIR Application at $7 million. Please provide a detailed list of the expenditures made to date and a forecast of the expenditures required to complete the project. Please indicate the month in 2018 that the station is expected to be in service.

Response:

	Amount ($'000)
Expenditures to Date (Legal, Contract, Equipment)	**$ 1,850**
Remaining Contracted Expenditures	4,000
Other Remaining Expenditures (Feeders, Change Orders, Internal Labour, Material and Equipment, Project Closing Cost, , Hold-Back)	1,150
TOTAL	$ 7,000

MS9 substation is expected to be in-service by June, 2018.

VECC

4.0-VECC-5

Reference: ***Exhibit A, page 17 /EB-2014-0101, Exhibit 2, Tab A, pages 17,27***

At paragraph 39 of the evidence OPUCN states:

OPUCN's forecast for the MS9 substation remains unchanged from the time of its CIR Application at $7.0 million with an expected in-service date of 2018 as initially planned."

At Exhibit 2 of EB-2014-0101 OPUCN stated:

As a result of the accelerated development activity and customer connections over 2015- 2019, OPUCN has identified the need to construct a new municipal substation (MS9) with appropriate associated distribution feeders to service these new homes and retail or commercial premises. The approximate total cost for this 4 year project is **$9 million**. [emphasis added page 17]

And

Design phase of the proposed municipal substation (MS9). Turn-key project, including required distribution primary feeders, scheduled completion over 5 years **(2015-2019)**. [emphasis added page 27]

a) Please explain the apparent discrepancy in total costs for this project.

b) If the project is to go into service in 2018 what, if any associated capital additions are expected in 2019 for this project?

c) Please provide the capital expenditures (actuals and forecast) for MS9 in each of 2015 through 2019.

Response:

a) As per updated model filed May 27, 2015 *(TC_UR_OPUCN_Chapter 2 Appendicies_for 2015 to 2019_RUN 3_xlsm_20150527)*: forecast for MS9 was $7.0 million and remains unchanged from CIR; and, updated forecast for associated feeder array was $7.5 million and remains unchanged from the OEB-Approved amount.

b) MS9 in-service date is 2018. Part of the feeder array will be in service for 2018 and the remainder in 2019.

c) Table:

Year	Forecast ($000)	Actual/Forecast ($000)
2015	$ 750	N/A
2016	1,000	$ 260
2017	3,250	2,540 Forecast
2018	6,000	8,200 Forecast
2019	3,500	3,500 Forecast

4.0-VECC-8

Reference Exhibit A, page 16 / EB-2014-0101, Interrogatory 2.0-Staff-6

At the above EB-2014-0101 reference OPUCN made the following statements:

The local planning report is expected to be released in Q2, 2015, but as per current local planning discussions, the need to build Enfield TS has been identified with an in-service date of 2018. Based on the latest correspondence from HONI, OPUCN is expected to make a $13,500,000 capital contribution for Enfield TS.

Since we have now concluded on the selection of Enfield TS as the capacity solution for new customer load growth, the feeder supply arrangement to MS9 can now be finalised to come from two feeders out of Enfield TS rather than reconfiguration of existing feeders from Thornton and Wilson TS's. ***As a result, the Capital cost of these two feeders from Enfield to supply MS9 is estimated at $5,500,000.*** [emphasis added]

Therefore the net Capital program increase for the revised load growth plan will be $14,000,000.

a) OPUCN now forecast the feeder array to cost $6.5 million. Please explain the increase in forecasted costs.
b) What is the current forecasted net cost of the capital program for the load growth plan?

Response:

a) Please refer to 1-Staff-1 response.

b) As per updated model filed May 27, 2015 *(TC_UR_OPUCN_Chapter 2 Appendicies_for 2015 to 2019_RUN 3_xlsm_20150527)*: forecast for Enfield TS capital contributions, MS9 and feeder connection infrastructure totalled $28 million compared to our current forecast of $25 million.

4.0-VECC-9

Reference: ***Exhibit A, page 16 / Attachment 1 /Schedule B/pages 13-16 (extracts shown below)***

The Engineering and Construction Cost of the Network Customer Allocated Work is $32,806,520 plus HST in the amount of $4,264,847.60. The Engineering and Construction Cost of the Network Customer Allocated Work that is set out below is based on the Customer's share of the estimated 96.4MW (at 0.9 power factor) incremental 230 kV supply capacity based on the load forecasts provided by the Customer and Hydro One Distribution and was calculated to be approximately as follows:

	Project Cost Allocation % Estimated (Approximate)
Customer	63% (96.4 MW)
Hvdro One Distribution	37% (56.6 MW)

The actual Project cost allocation and capacity allocation will be confirmed upon completion of the Project.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
May 5, 2016*	$0	$0	$0	$165,339 plus HST in the amount of	$165,339 plus HST in the amount of
August 9, 2016**	$0	$0	$0	$330,000 plus HST in the amount of	$330,000 plus HST in the amount of
December 21, 2016***	$0	$0	$0	$500,000 plus HST in the amount of	$500,000 plus HST in the amount of
February 2, 2017****	$0	$0	$0	$175,000 plus HST in the amount of	$175,000 plus HST in the amount of
Execution Date	$2,103,400 plus HST in the amount of $273,442	$0	$0	$511,071 plus HST in the amount of $66,439	$2,614,471 plus HST in the amount of $339,881

At paragraph 35 the total cost for the Enfield TS is listed as $19.5 million of which $4 million is "confirmed as OPUCN's contribution". Please reconcile these figures with the costs shown in Schedule B of the Connection and Cost Recovery Agreement where it states the Network Customer Allocated work is $32,806,520 plus HST in the amount of $4,264,847.40. The schedule also shows the customer portion (OPCUN) to be 63%.

Please also reconcile the $4 million stated contribution with the $3,784,810 in Total Payments shown in the table at page 15 of Attachment 1 (table above).

If different from the table referenced above please provide the expected contribution payments to Hydro One in the years 2016 through 2020.

Response:

Please refer to 1-Staff-1 response.

As per the CCRA, the $4 million capital contribution is subject to change – *"The actual Project cost allocation and capacity allocation will be confirmed upon completion of the Project."* We do not believe changes will be material.

SEC

SEC-2

[Exhibit A, p.16-17]

With respect to the Enfield TS and related assets:

a) Please provide the forecast month the Applicant expected Enfield TS to be in-service.

b) [EB-2014-0101, Tech Conference Transcript p.124-125] SEC understood from the evidence in EB-2014-0101 that the Applicant required Enfield TS to be in-service prior to the MS9 substation. The pre-filed evidence in this proceeding is that MS9 substation is expected to be in-service in 2018, while Enfield TS in-serve date is delayed until 2019. Please reconcile.

c) Please provide details and a breakdown regarding the additional costs $6.5M. Please explain why the amount was not forecasted at the time of the Custom IR application.

Response:

a) Enfield TS is expected to be in-service by March, 2019. Please refer to page 5 of Exhibit A attachment 1 – Hydro One CCRA.

b) Enfield TS completion is dependent on the in-service date of Hydro One's Clarington TS, a 500/230 kilovolt (kV) transformer station that will provide supply to Enfield TS. The in-service date for Clarington TS was deferred and is now expected to be in 2018. The delay in energizing Clarington TS has deferred the in-service date for Enfield TS until March, 2019.

However, MS9 is still expected to be in-service by 2018 by connecting to the existing 44kV feeder infrastructure. The load will then be transferred to Enfield TS when this is in-service through permanent switching and after Enfield TS feeders are built and connecting to the existing 44kV feeder infrastructure by 2019.

c) Please refer to the response to OEB 1-Staff-1 (a) and (b).

SEC-3

[EB-2014-0101, Ex. 2-A, p.113]

a) With respect to the MS9 Substation:

   a. Please provide the forecast month the substation is expected to be in-service.

   b. The evidence in EB-2014-0101 was that the MS9 substation construction was to be undertaken pursuant to “RFP/RFQ for a turn-key design, construction and commissioning” contract. Please provide an update on the status of the RFP/RFQ process and if a proponent has been selected, please provide details regarding the contractor and the amount of the contract.

Response:

a) MS9 substation is expected to be in-service by June, 2018.

b) The project was awarded to Black & McDonald for a turn-key design, construction and commissioning of MS9. Contract has been executed.

OSHAWA PUC NETWORKS INC.

Responses to Interrogatories – Capital Program

<u>OEB (Board Staff)</u>

1-Staff-3

Capital Program

Ref: EB-2014-0101 – Decision and Order, November 12, 2015 page 20

The OEB directed Oshawa PUC to report annually on the status of its capital program, including an analysis of variance from the plan.

a) Please provide a list of all capital projects approved in EB-2014-0101, separated by investment categories, compared to a list of completed projects. Please provide an explanation for all projects not completed in the approved year and all material variances between forecast costs to actual costs.

Response:

a) System Access:

Appendix 2-AA
Updated Capital Projects for years 2015-2019 ($'000s)

Projects	2015	2016	2017	2018	2019
System Access					
Subdivision Expansions	2,238	0	750	780	815
Service connections/requests	916	1,170	100	100	100
Metering service connections	334	635	390	390	390
Service/Expansion Contributions	(2,080)	(1,175)	(690)	(484)	(490)
Hwy 407 Extension - Plant relocation	1,659	60	480		
Hwy 407 contribution	(856)	(240)	(300)		
Durham Region - Plant relocation	694	1,354	1,319	3,140	1,055
Durham Region Contribution	(190)	(325)	(615)	(1,270)	(285)
City of Oshawa - Plant relocation	0	0	0	805	1,250
City of Oshawa Contribution	0	0	0	(228)	(362)
Remote Disconnect/Reconnect Metering	78	54	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	79	142	125	125	125
Long Term load transfers (LTLT)					
MoE approved Micro Grid Project	0	0	45		
System Access Total	2,872	1,675	1,854	3,458	2,698

Appendix 2-AA
Capital Projects Approved by OEB for years 2015-2019 ($'000s)

Projects	2015	2016	2017	2018	2019
System Access					
Subdivision Expansions	675	725	750	1,180	1,215
Service connections/requests	120	110	100	100	100
Metering service connections	375	380	390	390	390
Service/Expansion Contributions	(650)	(675)	(690)	(705)	(730)
Hwy 407 Extension - Plant relocation	4,510	700			
Hwy 407 contribution	(3,580)	(400)			
Durham Region - Plant relocation	1,875	935	1,065	1,080	1,055
Durham Region Contribution	(506)	(235)	(265)	(280)	(255)
City of Oshawa - Plant relocation	680	595	470	460	470
City of Oshawa Contribution	(175)	(145)	(120)	(110)	(120)
Remote Disconnect/Reconnect Metering	100	100	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	150	150	125	125	125
Long Term load transfers (LTLT)					
MoE approved Micro Grid Project	110	45			
System Access Total	3,684	2,285	2,075	2,340	2,350

<u>*Variances*</u>

Hwy 407 Extension

407 Projects were budgeted prior to the release of the scope of work by the MTO. The amount of rebuild and new development planned was significantly more than actual (gross capital was approximately $3.0 million less than plan). The variance net of contributions was approximately $0.4 million on a plan of $1.2 million. Oshawa PUC does not expect to recover this variance.

Durham Region

Durham Region development will be less than plan for the years 2015 through 2017 but is expected to recover and exceed planned expectations by the end of the rate period 2019. Net of contributions, forecast capital is approximately $0.6 million less than plan on a cumulative budget of $2.9 million for the years 2015 through 2017. Forecast capital net of contributions for 2018 and 2019 is expected to exceed plan by approximately $1.0 million.

Major projects impacted by changes in Regional planning were:

- Harmony Rd (Rossland to Taunton) - original budget included the replacement of all poles in the construction area. After the Region finalised their designs, it was determined that only a portion of the poles were in conflict; negative impact of $0.4 million.
- Region determined rebuild of the Simcoe and Winchester Intersection requires the existing plant to be relocated underground due to the congestion of the intersection with Hydro One; impact of $1.9 million in additional costs, subject to final design.

City of Oshawa

Proposed City projects for 2015 through 2017 were either cancelled or, upon completion of the design, poles were not in conflict with the city construction area.

For 2018 and 2019, Oshawa PUC expects to deliver projects for the City more in line with historical trends plus is currently in discussions with the City for an additional two projects in 2018 and 2019 that will increase forecast capital over its original plan.

System Renewal:

Appendix 2-AA
Updated Capital Projects for years 2015-2019 ($'000s)

Projects	2015	2016	2017	2018	2019
System Renewal					
O/H Rebuilds	2,681	1,376	2,055	2,510	2,117
U/G Rebuilds	962	1,265	1,087	921	614
Station Rebuilds	144	111	675	500	1,000
Station Rebuilds (MS14 Switchgear in WIP end 2014)	1,632				
Reactive/emergency Plant Replacement	1,300	1,277	830	830	830
System Renewal Total	6,719	4,029	4,647	4,761	4,561

Appendix 2-AA
Capital Projects Approved by OEB for years 2015-2019 ($'000s)

Projects	2015	2016	2017	2018	2019
System Renewal					
O/H Rebuilds	2,410	2,455	2,055	2,510	2,117
U/G Rebuilds	1,133	1,007	1,087	921	904
Station Rebuilds	510	640	500	500	1,000
Station Rebuilds (MS14 Switchgear in WIP end 2014)	1,060				
Reactive/emergency Plant Replacement	830	830	830	830	830
System Renewal Total	5,943	4,932	4,472	4,761	4,851

O/H Rebuilds

O/H Rebuild of Rossland Rd planned for 2016 was postponed due to future Region road widening. The Region was unable to give us final pole locations; impact of negative $0.4 million from plan. Remedial work was completed to maintain system integrity in the interim.

Savings were obtained for remaining contractor O/H Rebuild projects in 2016; impact of negative $0.5 million from plan.

Forecast O/H Rebuilds for 2017 through 2019 is unchanged from original plan.

U/G Rebuilds

U/G Rebuild projects under plan in 2015 by $0.2 million.

U/G project planned for 2019 was completed in 2016 to address reliability concerns.

Station Rebuilds

Total Station Rebuild costs were in line with planned capital. Approximately $0.1 million less than planned capital totalling $2.7 million for the years 2015 through 2017.

Reactive

2015 U/G primary cable replacement for faults at major primary customers resulted in unusually high reactionary costs; impact of $0.2 million.

The city of Oshawa imposed new requirements for site restorations and an increased number of faults resulted in higher than normal spending in 2016 on U/G secondary and primary repairs; impact of $0.2 million.

Remainder of projects were collectively higher than the historical trend; impact of $0.5 million.

System Services:

Appendix 2-AA
Updated Capital Projects for years 2015-2019 ($'000s)

Projects	2015	2016	2017	2018	2019
System Services					
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension	155	3			
Thorton TS Capacity - HONI Contributions					
Wilson TS Capacity - HONI Contributions					
TS Capacity - HONI Contributions	0		0	0	10,463
MS9 - 44kV/13.8kV Substation				7,000	
MS9 Proposed OH distribution feeders				2,810	4,750
Neutral Reactors	0	692	358		
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	622	485	0	300	
Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)			664	135	
Smart Fault Indicators	10	25	25	25	25
Volt-Var optimization & Reduction in Distribution Losses	0	0	0	225	225
Distribution System Supply Optimization	14	24	35	85	85
System Services Total	801	1,229	1,082	10,580	15,548

Appendix 2-AA
Capital Projects Approved by OEB for years 2015-2019 ($'000s)

Projects	2015	2016	2017	2018	2019
System Services					
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension					
Thorton TS Capacity - HONI Contributions					
Wilson TS Capacity - HONI Contributions					
TS Capacity - HONI Contributions	0		0	13,500	
MS9 - 44kV/13.8kV Substation				7,000	
MS9 Proposed OH distribution feeders				4,000	3,500
Neutral Reactors	450	1,050			
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	548	280	10	10	10
Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)			350	350	255
Smart Fault Indicators	25	25	25	25	25
Volt-Var optimization & Reduction in Distribution Losses	0	0	0	225	225
Distribution System Supply Optimization	45	25	35	35	35
System Services Total	1,068	1,380	420	25,145	4,050

Refer to 1-Staff-1 for explanation on Wilson TS, Thornton TS, HONI and MS9 projects.

Neutral Reactors

Entire project was completed via fixed price contract at substantial savings from plan.

Underground

$225K budget misallocated to Overhead.

Overhead

$225 budget was misallocated to this project. It should be allocated to the Underground (see above).

General Plant:

Appendix 2-AA Updated Capital Projects for years 2015-2019 ($'000s)					
Projects	2015	2016	2017	2018	2019
General Plant					
Fleet	461	132	640	190	170
Total Facilities Leasehold Improvements	96	223	50	50	50
Major Tools and Equipment	54	51	50	50	50
Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	352	1,001	50	0	0
Mobile Work force		0	0		
ODS Replacement due to enhanced operational requirements not available with existing ODS		0	500		
GIS Enhancements for operational needs including OMS		38	60	60	60
MAS Enhancements for operational needs		0	25	50	50
ODS/CIS Enhancements for operational needs				50	50
Office IT Capital Expenditure	125	89	80	280	80
General Plant Total	1,088	1,534	1,455	730	510
Miscellaneous (2018 $'s are MS9 land)				159	
Total	**11,480**	**8,467**	**9,038**	**19,688**	**23,317**

Appendix 2-AA Capital Projects Approved by OEB for years 2015-2019 ($'000s)					
Projects	2015	2016	2017	2018	2019
General Plant					
Fleet	420	415	440	190	170
Total Facilities Leasehold Improvements	225	50	50	50	50
Major Tools and Equipment	50	50	50	50	50
Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	850	0	0	0	0
Mobile Work force		50	50		
ODS Replacement due to enhanced operational requirements not available with existing ODS		400			
GIS Enhancements for operational needs including OMS		60	60	60	60
MAS Enhancements for operational needs		25	25	50	50
ODS/CIS Enhancements for operational needs				50	50
Office IT Capital Expenditure	130	130	80	280	80
General Plant Total	1,675	1,180	755	730	510
Miscellaneous (2018 $'s are MS9 land)				159	
Total	**12,370**	**9,777**	**7,722**	**33,135**	**11,761**

Major variance relates to expanded scope of the OMS project. Purchased additional hardware to support expansion which resulted in improved accuracy of the outage predictions generated by the system.

1-Staff-9

Performance Report

Ref: OPUCN APPL Ex B 20170707

Oshawa PUC reported its reliability and noted that in 2016 there was a single significant event which is the cause of higher outage duration and frequency for 2016.

Please provide additional information on the event and the OEB staff discussion to classify this event as controllable.

Response:

The major outage event on November 14, 2016 was a result of defective equipment. A 44kV inline splice failed while in service. The failed 44kV line locked out two additional 13.8kV circuits resulting in an outage of approximately two hours and affected approximately 18,000 customers.

During the isolation and repair process, a live 44kV switch at the TS was open which sustained the outage of the 18,000 customers for a further two hours.

<u>CCC</u>

CCC-3

Ex. A/p. 16

Re: Capital Expenditures

Please re-cast Table 2-32 – Appendix 2-AA Capital Projects from EB-2014-0101 to include 2015 and 2016 Actual amounts at the same level of detail.

Response:

Please refer to 1-Staff-3 response.

CCC-6

Ex. A/p. 17

In the 2015 Decision the OEB required that at the mid-term review OPUCN provide an update related to third party requests for relocation of OPUCN's plant. The evidence states that with respect to plant relocations the cumulative total capital is expected to be approximately $2.4 million below plan at the end of 2017. It is OPUCN's position that based on City and Regional Planning and the completion of infrastructure for the 407 ETR extension, it expects the total planned capital for third-party requested relocations to be spent. Please provide a schedule setting out the relocation budget in each year of the 5-year plan, what has actually been spent to date in each year and the plan for 2018 and 2019. Please provide more detailed evidence to support the statement that the cumulative shortfall will be spent in 2018 and 2019.

Response:

Please refer to 1-Staff-3 response.

<u>VECC</u>

4.0-VECC -6

Reference: ***Exhibit A, page 16- /EB-2014-0101 Exhibit 2, Tab A, page 79***

Please provide an update of Table 2-3, showing 2015 and 2016 actuals and the reforecasted capital expenditures by category for 2017 through 2019.

Response:

Please refer to 1-Staff-3 response.

4.0-VECC-7

Reference: ***Exhibit A, / EB-2014-0101, Exhibit 2, Tab A, page 84***

Please provide the actual 2017 capital expenditures in the format of Appendix 2-AA. Please provide one column showing actual spending to-date for each project and the second column showing expected expenditures to year-end.

Response:

Please review 1-Staff-3 response.

7.0-VECC-13

Reference: ***Exhibit B, page 3***

Please provide a full description of the exceptional outage described at page 2-3 of Exhibit B (cause, duration, remedy).

Response:

Please review 1-Staff-9 response.

7.0-VECC-14

Reference: Exhibit B

a) Please provide OPUCN's SAIDI and SAIFI with/without supply for each year 2015 through 2017 period.
b) Please provide the outages by cause code for 2015, 2016 and 2017.
4.0-VECC-5.

Response:

a) Table:

	Excluding Code 2 Outages		**Including Code 2 Outages**	
Year	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
2015	1.21	1.27	1.35	2.00
2016	2.61	2.06	2.61	2.08
*2016**	*1.04*	*1.41*	*1.04*	*1.43*
2017YTD	0.65	0.70	0.67	0.89

*adjusted excluding the major outage of 14 Nov 2016.

In 2016, SAIDI, including Code 2 outages, increased by 93% and SAIFI by 4% when compared to 2015 mainly as a result of a major outage event. Please refer to 1-Staff-9 response.

b) The table below summarizes the number of interruptions by Cause form year 2015 to 2017YTD:

Cause	*Number of Interruptions*		
	2015	**2016**	**2017YTD**
Unknown/ Other: (Code 0) Customer interruptions with no apparent cause or reason which could have contributed to the outage.	12	23	12
Scheduled Outage: (Code 1) Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.	3	109	291
Loss of Supply: (Code 2) Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.	3	2	2
Tree Contact: (Code 3) Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.	9	8	16
Lightning: (Code 4) Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.	0	1	9
Defective Equipment: (Code 5) Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.	77	76	66
Adverse Weather: (Code 6) Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.	7	3	8
Adverse Environment: (Code 7) Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.	0	0	0
Human Element: (Code 8) Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.	2	4	2
Foreign Interference: (Code 9) Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.	60	66	43
TOTAL	**173**	**292**	**449**

<u>SEC</u>

SEC-4

[Exhibit A, p.17] Please provide a detailed breakdown of the difference in plant forecasted in 2018 and 2019 at the time of the Custom IR application, and the updated amount.

Response:

Please refer to 1-Staff-3 response.

SEC-5

[Exhibit A, p.17] Please provide the basis for the statement, “[h]owever, based on the City and Regional planning and the completion of infrastructure for the 407 ETR extension, OPUCN expects the total planned capital for the third-party requested plant relocations for the five years to be spent.”

Response:

Please refer to 1-Staff-3 response.

OSHAWA PUC NETWORKS INC.

Responses to Interrogatories – Load Forecast/COP

OEB (Board Staff)

1-Staff-4

Load Forecast

Ref: Exhibit A - Table 5 – 10

Oshawa PUC used a multiple regression analysis in its Custom IR application to forecast kWh purchases based on weather data, calendar variables, and economic activities. In the updated forecast Oshawa PUC has stated that the expected total customer growth for 2018 and 2019 is 1.8%.

a) Please provide the load forecast model for both 2018 and 2019.

b) On table 6, please explain how the growth rates are calculated for GS>1000kW, street lighting, sentinel light, and unmetered scattered load in 2018 and 2019.

c) Please confirm if the total growth rate of 1.8% is solely based on the Durham Regional Official Report. If so, why has Oshawa PUC not updated the multiple regression model with the latest actual data to revise its forecast?

d) If the multiple regression model was not used to calculate the load forecast for 2018 and 2019 please update the models as in the Custom IR and produce a variance analysis to the load forecast in this application.

e) Please confirm if the Conservation Demand Management forecast was updated. If so, please provide the updated forecast in the load forecast model.

f) Please explain how the average billable consumption per customer in 2018 and 2019 was calculated.

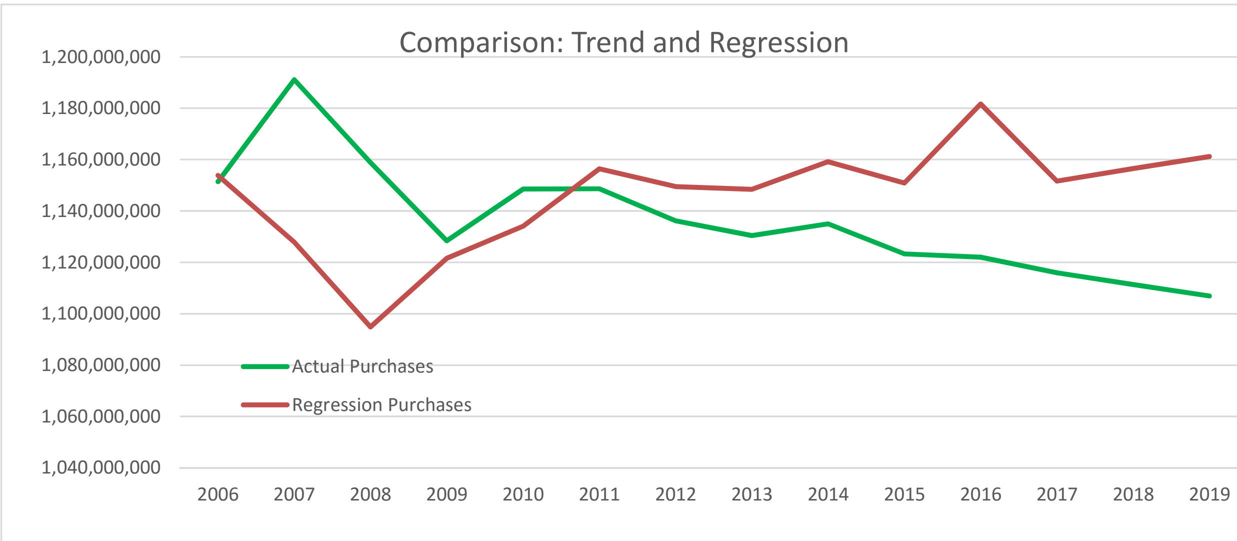
Response:

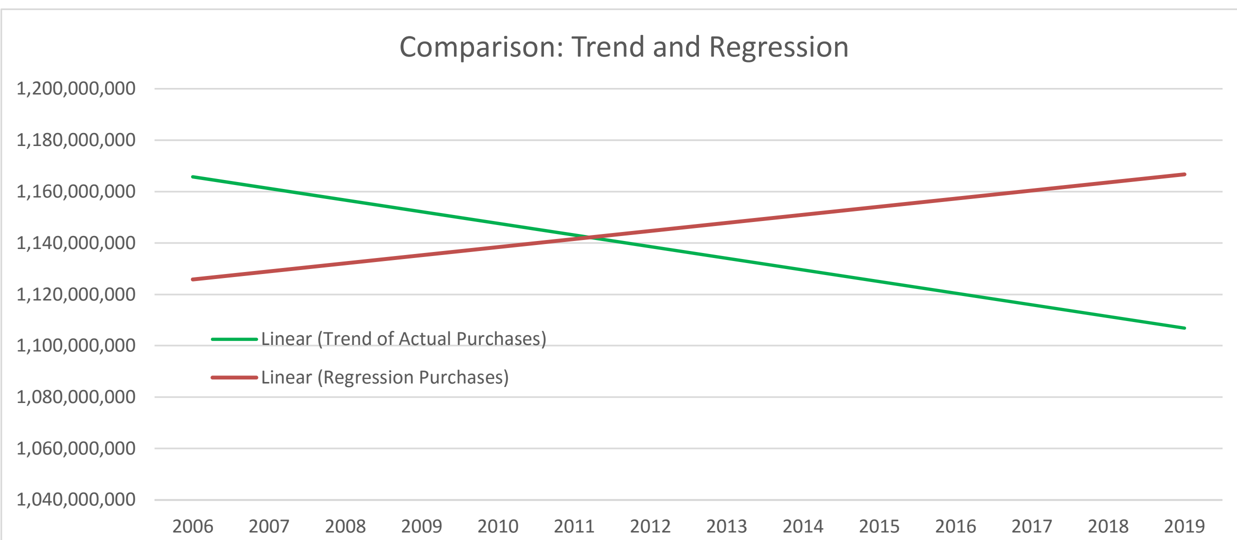
a) Model attached. (EB_2017_0169_OPUCN_Weather Normalization_Trend Model_Mid Term 2017_20171027.xlsx)

b) The geometric mean of customer growth rates, by customer rate class, for the years 2004 through 2016 was calculated to determine growth rates for 2018 and 2019. For GS>1,000kW customers, an allowance for City of Oshawa expansion was added.

c) In determining customer growth, Oshawa PUC updated the Load Forecast model for known customer connections and other contributing attributes including the latest forecast for 2017 customer connections, updated CDM targets and most recently reported loss factor. An allowance for customer growth above the historical trend (result from the base model) was added to achieve the Durham Regional Official Report. To clarify, the updated model produced growth rates that were lower than 1.8% and were adjusted up to meet the Durham Report.

d) The load forecast model used in the CIR application was used and produced results that were counter to the trend in demand and consumption experienced in Oshawa over the period. Oshawa PUC applied the regression model to determine baseline results. The baseline results were adjusted for 2018 and to reflect the historical trend rather than the results of the regression model. The following charts highlight the difference in results achieved:





From the charts, the regression model produced results that were not in line with historical trends. Oshawa PUC determined these results were not producing a fair and appropriate prediction and used the trend to calculated predicted purchases for 2018 and 2019.

e) Confirmed. Updated forecast included in attached load forecast model.

f) The average billable consumption per customer in 2018 and 2019 is determined by calculating the historical average from the regression model and adjusting the result by the impact of new CDM programs and City of Oshawa expansion beyond historical trends.

1-Staff-5

Cost of Power

Ref: Exhibit A - Table 11, 12, and 13

Oshawa PUC provided the expected kWh cost of power for both 2018 and 2019 taking into consideration the Fair Hydro Plan by a 25% reduction to 2017 base regulated price plan (RPP) prices.

a) Please provide the cost of power calculation broken down into the following costs: Commodity RPP/non-RPP, Global Adjustment non-RPP, Transmission –Network, Transmission – Connection, Wholesale Market Service, Rural or Remote Electricity Rate Protection, and Smart Meter Entity Charge.

b) Please provide a reference to where the Jan 17 – April 17 average price in Table 11 is from.

c) Please update the cost of power calculation with the latest RPP prices from "Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018", issued on June 22, 2017.

Response:

a) The table below breaks out the cost of power into its components:

Cost of Power	**2018**	**2019**
Commodity	55,025,550	55,971,393
Global Adjustment	38,719,645	39,493,124
Wholesale Market Service	3,519,065	3,513,452
Transmission-Network	7,749,307	7,889,373
Transmission-Connection	6,859,290	6,983,544
Rural Rate Assistance	329,912	329,386
Smart Meter Entity	550,162	560,065
TOTAL	**112,752,932**	**114,740,338**

b) OEB's Regulated Price Plan Report – April 20, 2017 (RPP Report), pages 4 and 13.

c) Applying the latest RPP prices from "Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018" resulted in an increase to Commodity and a decrease in Global Adjustment with a net reduction of approximately $3.5 million and $2.9 million respectively for 2018 and 2019.

   Upon further review, Oshawa PUC applied the 25% Fair Hydro Plan reduction to all its customer classes in the original cost of power estimate. After adjusting for the latest "Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018" and applying it to only eligible customers, the estimated cost of power increased by approximately $12.3 million in each of the years 2018 and 2019.

1-Staff-6

Deferral and Variance Accounts

Ref: Exhibit A – Table 16

Ref: 2018 DVA continuity schedule – Tab 5

Oshawa PUC had requested the disposition of Group 1 deferral and variance accounts (DVA) as at December 31, 2015 but has not included Account 1551 – Smart Meter Entity Charge Variance Account.

a) Please provide an explanation why Account 1551 was not included in the Group 1 disposition on tab 5.

b) Were audited Group 1 DVA balances as at December 31, 2016 available and if so why did Oshawa PUC not request disposition?

Response:

a) The necessary data to generate disposition calculations have been entered for Account 1551, but due to an issue with the template the amount is not being included in the disposal calculation. Oshawa PUC has informed the OEB and the issue will be resolved prior to final rates being calculated.

b) The balances requested for disposition are in fact the audited Dec 31 2016 balances. Oshawa PUC used the latest available OEB template in its application but was unable to change the '2015' column headings to '2016' as the template does not allow non-OEB staff to edit beyond specific input cells. Oshawa PUC has now completed and filed the July 24, 2017 version of the Deferral and Variance Account Workform. (EB_2017_0069_OPUCN_2018_DVA_Continuity_Schedule_20171027.xlsb)

1-Staff-7

Retail Transmission Service Rates (RTSRs)

Ref: OSHAWA PUC APPL 2018 RTSR Workform 20170707

Oshawa PUC used the 2017 RTSR work form and 2017 Uniform Transmission Rates (UTRs) to calculate the RTSRs.

a) Please update the RTSR work form to the 2018 RTSR Work Form.

b) Please update the 2017 UTRs when they become available.

c) Please explain for line and transformer connection why the kW load for kW billing determinate rate classes increased by approximately 3% from the previous year but the total kW billed by the IESO increased by 10%.

Response:

a) The 2018 RTSR Workform has been updated and filed as an attachment with this submission. (EB_2017_0169_OPUCN_2018_RTSR_Workform_20171027.xlsm)

b) There are no updates available at the time of this filing.

c) The total kW billed by the IESO includes all Oshawa PUC customers, while the kW billed by Oshawa PUC represents only those customers billed on demand. Oshawa PUC customers billed on a consumption basis (kWh's) are not included in this number. If these kWh's are converted and added to the kW number the year over year increase in Oshawa PUC load is comparable to the IESO increase.

1-Staff-8

Bill Impacts

Ref: OSHAWA PUC APPL 2018-2019 Bill Impacts 20170707

Ref: EB-2014-0101 - OSHAWA PUC Chapter2 Appendices for 2015 to 2019 RUN 6 20151207

Oshawa PUC used 3.59% as the loss factor for the bill impact calculations in the Bill Impact model but in the bill impact in the Chapter 2 appendices from EB-2014-0101 show a loss factor of 4.86%.

a) Please explain how Oshawa calculated the updated loss factor 3.59%.

b) Please provide evidence that the loss factor was allowed to be updated as part of the Mid-term update.

Response:

a) The loss factor is calculated annually and reported to the OEB as "RRR 2.1.5 Supply & Delivery". The calculation is done using a standard OEB methodology and template, as per the table below:

RRR 2.1.5 Supply & Delivery

Supply and Delivery Information		
For the purposes of this section, all kWhs other than in relation to distribution losses shall be reported based on		
a reading of the applicable meter, without being grossed up for loss factor.		
	2016	**2015**
A) Supply		
i. Total kWhs of electricity that has flowed into the distributor's distribution system from the IESO-contolled grid including long-term load transfer supplied, or flowed into the distribution system of a host distributor	1,116,878,154	1,119,094,008
ii. Total kWhs of electricity that has flowed into the distributor's distribution system from all embedded generation facilities	5,419,546	4,247,024
B) Delivery		
i. Total kWhs of electricity delivered to all customers in the distributor's licensed service area and to any embedded distributors	1,082,034,739	1,070,779,248
ii. Total kWhs of electricity delivered on long-term load transfer arrangements	0	0
C) Distribution Losses		
Distribution Loss in kWhs: Calculated by taking the sum of A(i) and A(ii) to arrive at total supply and reducing it by deliveries reported at B.(i) and B(ii)	40,262,962	52,561,784
D) Amount Charged ($)		
Amount charged by any host distributor for transmission or low voltage services in the year	0	0
Loss Factor	**3.59%**	**4.68%**

b) There was no explicit instruction to update the loss factor in the mid-term update.

1-Staff-10

Deferral and Variance Accounts

Ref: DVA Continuity Schedule

a) Please reconcile the December 31, 2015 Group 1 Deferral and Variance Account (DVA) balances that are being sought for disposition with the corresponding balances presented in the audited financial statements for the same period. Please explain and provide support for any differences.

b) In regards to Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account, please confirm that the applicant has used the rates established by the OEB by month or by quarter for each year. The rates that should be used are provided on the OEB's website.

c) Were the audited December 31, 2016 Group 1 DVA balances available prior to the submission of this application to the OEB? If yes, then please explain why the applicant has elected to only dispose of its Group 1 DVA balances up to December 31, 2015?

d) Does the applicant use the actual GA price to bill any entire rate classes of non-RPP Class B customers? If so, the applicant must make a proposal to exclude these customer classes from the allocation of the balance of Account 1589 and the calculation of the resulting rate riders.

e) The applicant has used the 2017 Deferral and Variance Account Workform instead of the updated version released by the OEB on July 24, 2017, applicable to 2018 rates applications. Did the applicant have Class A customers or have any customers that transitioned between Class A and Class B during the period that the Group 1 account balances accumulated (i.e. from the year the balances were last disposed)? If the response to the above is "yes" then the applicant must complete and submit to the OEB the July 24, 2017 version of the Deferral and Variance Account Workform applicable to 2018 rates applications (including the new GA Analysis tab of that workform).

f) If, from the above responses, the applicant is not required to complete and submit to the OEB the July 24, 2017 version of the Deferral and Variance Account Workform applicable to 2018 rates applications, then the applicant is still required to complete and submit to the OEB the stand-alone version of the GA Analysis Workform, which was released by the OEB July 24, 2017

Response:

a) The balances requested for disposition are in fact the audited Dec 31 2016 balances. OSHAWA PUC used the latest available OEB template in its application but was unable to change the '2015' column headings to '2016' as the template does not allow non-OEB staff to edit beyond specific input cells. OSHAWA PUC has now completed and filed the July 24, 2017 version of the Deferral and Variance Account Workform. The DVA balances reconcile with the audited financial statements.

b) The OEB prescribed interest rate has been used to calculate the carrying charges for all the DVA accounts.

c) The balances requested for disposition are in fact the audited Dec 31 2016 balances. Please refer to response to part a) above

d) No.

e) OSHAWA PUC is resubmitting the DVA Workform using the July 24, 2017 version of the Deferral and Variance Account Workform as part of this submission.

f) OSHAWA PUC has completed the GA Analysis Workform within the July 24, 2017 version of the Deferral and Variance Account Workform.

1-Staff-11

Deferral and Variance Accounts

Ref: Ex A, Deferral & Variance Account Rate Rider (p. 24-25)

a) Please provide a certification by the Chief Executive Officer (CEO), or Chief Financial Officer (CFO), or equivalent. that the applicant has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements.

b) In support of its GA claim, the applicant must provide a description of the settlement process with the IESO or host distributor Please refer to section 2.5.1 of the Chapter 2 Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications (pg 67) for information on the level of detail that an applicant must include within the description they provide.

Response:

a) Confirmed – Phil Martin, VP Finance & Regulatory Compliance.

b) On or by the fourth business day of the following month, OSHAWA PUC provides to the IESO, via its online portal, the necessary information to enable final settlement calculations of GA amounts payable. These calculations are reflected in the monthly IESO invoice to OSHAWA PUC. The key elements of OSHAWA PUC's GA settlement process with the IESO are:

- OSHAWA PUC services both Class A and Class B customers.
- Class A customers are charged GA based on their share of Ontario-wide total GA cost, using a factor assigned by the IESO to calculate the amounts.
- Class B customers are charged GA on their consumption using the 1st estimate of the GA Rate as posted by the IESO every month.
- The IESO calculates the total GA amount to be billed to OSHAWA PUC using total consumption, which includes consumption of RPP customers. OSHAWA PUC calculates RPP consumption, including unbilled kWh's, and provides this to the IESO via the monthly settlement process. This allows the IESO to include a credit on the monthly IESO invoice related to the RPP consumption and ensures OSHAWA PUC is only billed GA by the IESO for Class A and Class B.
- The monthly RPP credit above is calculated by OSHAWA PUC using the estimated GA rate, as the final rate is not available until later in the month. This exact calculation is redone the following month using the final GA rate for the month, and the difference is included in the settlement process for credit/debit on the IESO invoice according to the true-up calculation.
- OSHAWA PUC's includes embedded generation in its consumption calculations.
- OSHAWA PUC uses accrual accounting throughout.

1-Staff-12

Deferral and Variance Accounts

Ref: GA Analysis Workform

a) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approach is used:

   I. Charge Type 1142 is booked into Account 1588. Charge Type 148 is prorated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively

   II. Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.

   III. Another approach. Please explain this approach in detail. With regards to the Dec. 31, 2015 balance in Account 1589,

b) Please provide a statement confirming that the applicant pro-rates the IESO Global Adjustment Charge into RPP and non-RPP portions. If this is not the case, please provide an explanation as to why this is not being done.

c) Please indicate whether the following items (see b. i, ii, and iii below) that flow into the account are based on estimates/accruals or actuals at year end.

d) If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustment that relate to each of the following items.

   I. Revenues (i.e. is unbilled revenues trued up)

   II. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages

   III. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used With regards to the Dec. 31, 2015 balance in Account 1588:

e) Please indicate whether the following items (see f. i, ii, iii, and iv below) that flow into the account are based on estimates/accruals or actuals at year end.

f) If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items.

   I. Revenues (i.e. is unbilled revenues trued up)

   II. Expenses - Commodity (Charge Type 101)

   III. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages

IV. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

g) If no adjustment pertaining to impacts of RPP settlement true-up is proposed for Account 1588 or Account 1589, please explain why not

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Response:

a) OSHAWA PUC follow approach I. above

b) OSHAWA PUC confirms that IESO GA Charges are pro-rated into RPP and non-RPP Portions.

c) Items d. I, II, and III reflect actuals.

d) There are no material reconciling items.

e) Actuals.

f) No adjustments are proposed.

g) OSHAWA PUC completes all adjustments (eg unbilled true-up) before submitting to OEB and finalising financial statements for audit.

<u>CCC</u>

CCC-1

Ex. A/p. 10

The evidence states that OM&A was lower than forecast by 1.5% as a result of the merger discussions during 2016 and consequent deferral of planned labour expenses. Please explain how "merger discussions" reduce OM&A. What is the current status of Oshawa's merger discussions?

Response:

Mergers often result in some overlapping activities and personnel. With this in mind, extra care and consideration was given to the filling of certain vacancies and some were temporarily delayed. Oshawa PUC is no longer part of these merger discussions and has resumed normal operations.

CCC-2

Ex. A/p. 12

Please explain how OSHAWA PUC arrived at a proposed customer growth rate of 1.8%. Has the Region of Durham updated its Durham Regional Official Plan since June 26, 2015? If so, please provide a copy of the updated report. What is the current forecast from the City of Oshawa regarding forecast customer growth?

Response:

Please refer to 1-Staff-4 response. I am not aware of an updated report for the Durham Region.

CCC-7

Ex. A/p. 21

Please provide a detailed explanation as to how the $160,000 forecast revenue requirement reduction arising from the impact of the Fair Hydro Plan was calculated. Please include all assumptions. Please explain how Oshawa has applied the Fair Hydro plan in establishing its bills and rates.

Response:

The impact of the fair Hydro Plan is to significantly reduce power supply expenses (an estimated reduction of $31m in 2018). This directly reduces working capital expenses, leading to reduced working capital allowance and then rate base, the return on which is one of the components of revenue requirement. The table below illustrates this:

Impact of Fair Hydro on Rate Base	2018 Per Filing	Remove Fair Hydro	Change
Fair Hydro Estimate		**31,248**	
Total Eligible Distribution Expenses	**13,234**	**13,234**	
Power Supply Expenses	112,753	144,001	(31,248)
Total Working Capital Expenses	125,987	157,235	
Working Capital Allowance Rate	9.37%	9.37%	
Working Capital Allowance	11,805	14,733	
Average Fixed Asset Balance for Year	111,110	111,110	
Add: Working Capital Allowance	11,805	14,733	
Rate Base	**122,915**	**125,843**	(2,928)
Regulated Rate of Return	5.53%	5.53%	
Regulated Return on Capital	**6,796**	**6,963**	**(167)**

VECC

1.0-VECC-1

Reference: ***Exhibit A, page 6***
RRWF, Tab 10 – Tracking Sheet

a) Please provide a schedule that explains how the updated customer count forecast reduces Other Revenues by $6,000 in 2018 and $18,000 in 2019.

Response:

Other revenues include elements that are directly impacted by changes in customer counts. These include interest charges, collection related expenses, customer setup fees, and SSS admin fees. The forecast is principally done by uplifting the current year run rate by the percentage increase in customer count.

The schedule below shows how the increases in 2018 and 2019 are arrived at:

# of Customers	2017 Forecast as Filed 2015	ORIGINAL FILING 2015				2017 MID TERM UPDATE			
		Forecast 2017		Forecast 2018		Forecast 2017		Forecast 2018	
		Change	Count	Change	Count	Change	Count	Change	Count
Residential	52,518	2.9%	54,094	2.9%	55,717	2.4%	53,813	1.8%	54,782
GS < 50 kW	4,123	2.9%	4,247	2.9%	4,375	2.3%	4,221	1.8%	4,297
GS 50 to 999 kW (I1 & I4)	522	2.9%	538	2.9%	554	0.7%	526	1.8%	535
GS 1,000 to 4,999 kW (I2)	12	7.7%	13	0.0%	13	9.1%	13	7.0%	14
Large Use (I3)	1	0.0%	1	0.0%	1	0.0%	1	0.0%	1
Street Lighting	13,215	1.9%	13,475	1.9%	13,740	1.9%	13,472	1.9%	13,737
USL	296	0.1%	297	0.1%	297	-9.5%	271	-0.5%	269
Sentinel Lights	22	-3.4%	21	-3.4%	20	4.2%	23	-2.8%	22
TOTAL	70,710	2.7%	72,686	2.7%	74,717	2.3%	72,340	1.8%	73,658

ORIGINAL FILING 2015	2017 Forecast as Filed 2015	Balance B/F or Run Rate	Customer Count Increase	Other	Forecast 2018	Balance B/F or Run Rate	Customer Count Increase	Other	Forecast 2019
			2.7%				2.7%		
Interest Charges	296,971	296,971	8,072	900	305,943	305,943	8,260	930	315,134
Collection, Setup,Reconnect fees etc	723,806	723,806	19,674	2,193	745,674	745,674	20,133	2,266	768,073
SSS Admin Fee	163,581	163,581	4,446		168,028	168,028	4,537		172,565
	1,184,359	**1,184,359**	**32,193**	**3,093**	**1,219,645**	**1,219,645**	**32,930**	**3,196**	**1,255,771**

2017 MID TERM UPDATE	2017 Forecast as Filed 2015	Balance B/F or Run Rate	Customer Count Increase	Other	Forecast 2018	Balance B/F or Run Rate	Customer Count Increase	Other	Forecast 2019
			2.3%				1.8%		
Interest Charges	296,971	296,971	6,690	900	304,561	304,561	5,450	930	310,941
Collection, Setup,Reconnect fees etc	723,806	723,806	16,305	2,193	742,304	742,304	13,284	2,266	757,854
SSS Admin Fee	163,581	163,581	3,685		167,266	167,266	2,993		170,260
	1,184,359	**1,184,359**	**26,679**	**3,093**	**1,214,131**	**1,214,131**	**21,727**	**3,196**	**1,239,054**

CHANGE	2017 Forecast as Filed 2015	Balance B/F or Run Rate	Customer Count Increase	Other	Forecast 2018	Balance B/F or Run Rate	Customer Count Increase	Other	Forecast 2019
Interest Charges	0	0	(1,383)	0	(1,383)	(1,383)	(2,810)	0	(4,193)
Collection, Setup,Reconnect fees etc	0	0	(3,370)	0	(3,370)	(3,370)	(6,850)	0	(10,219)
SSS Admin Fee	0	0	(762)	0	(762)	(762)	(1,544)	0	(2,305)
	0	**0**	**(5,514)**	**0**	**(5,514)**	**(5,514)**	**(11,203)**	**0**	**(16,717)**

2.0-VECC-2

Reference:

Please provide a table for the period 2015 through 2019 which shows the total FTEs, the total compensation and the amount allocated to OM&A and separately the amount of compensation allocated to capital (i.e. capitalized).

Response:

This mid-term update does not allow for any changes to OM&A, capitalized or expensed, and no such changes are included in this update.

The table below, originally provided in response to an interrogatory in EB-2014-0101, provides the requested information.

	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)					
Management	19	20	20	20	20
Non-Management	61	65	64	63	61
Total	80	85	84	83	81
Total Salary and Wages including ovetime and incentive pay ($000's)					
Management	$2,110	$2,217	$2,262	$2,307	$2,353
Non-Management	$5,402	$5,731	$5,882	$5,977	$5,936
Total	$7,512	$7,948	$8,144	$8,284	$8,290
Total Benefits (Current + Accrued) ($000's)					
Management	$652	$685	$698	$713	$727
Non-Management	$1,622	$1,662	$1,684	$1,711	$1,722
Total	$2,275	$2,347	$2,383	$2,424	$2,450
Total Compensation (Salary, Wages, & Benefits) ($000's)					
Management	$2,763	$2,902	$2,960	$3,020	$3,081
Non-Management	$7,024	$7,394	$7,566	$7,688	$7,659
Total	$9,787	$10,296	$10,526	$10,708	$10,740
Total Compensation Allocation ($000's)					
OM&A	$6,676	$7,114	$7,273	$7,382	$7,339
Capital	$2,805	$2,869	$2,933	$2,999	$3,067
Other	$306	$313	$320	$327	$334
Total	$9,787	$10,296	$10,526	$10,708	$10,740

3.0-VECC-3

Reference: Exhibit A, pages 11-12 /1-Staff-4

a) Please provide a schedule setting out the number of customers by class for each month in 2017 where actual data is available.

b) If not provided in response to 1-Staff-4, please indicate how the YTD Actual customer growth rate of 1.5% was calculated.

c) Reference is made in paragraph 27 to "the most recent report". Is this the June 2015 Report referenced in footnote #13? If not, please provide a copy of the report.

Response:

a) Table:

	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Rate
R Residential	52,499	52,533	52,587	52,661	52,718	52,827	52,903	52,928	52,985	53,093	53,143	53,211	53,278	101.5%
C1 Commercial	4,150	4,150	4,144	4,150	4,151	4,160	4,154	4,158	4,157	4,169	4,165	4,167	4,169	100.5%
I1 Industrial > 50 <200	378	381	381	383	380	380	382	383	382	382	382	382	382	101.1%
I4 Industrial >200 <1000	143	143	142	141	142	143	143	143	143	143	143	143	143	99.7%
I2 Industrial > 1000 < 5000	13	13	13	13	13	12	12	12	13	13	13	13	13	97.9%
I3 Industrial > 5000	1	1	1	1	1	1	1	1	1	1	1	1	1	100.0%
S Street Lights	13,031	13,031	13,031	13,031	13,031	13,031	13,031	13,031	13,031	13,031	13,031	13,031	13,031	100.0%
UN Unmetered	274	273	272	274	274	274	274	274	274	275	274	274	274	99.9%
Total	70,489	70,525	70,571	70,654	70,710	70,828	70,900	70,930	70,986	71,107	71,151	71,221	71,290	101.1%

b) Generally, used a trend calculation.

c) Yes, it is the June 2015 report.

3.0-VECC-4

Reference: ***Exhibit A, pages 13-15 / 1-Staff-4***

a) Was the purchase power forecast model used for this application the same one as used in EB-2014-0101?

   i. If yes, were the forecasts for any of the input (explanatory) variables updated, in particular the unemployment rate?

   ii. If not, please explain why a different model was used and provide the sources for the historic and forecast values of all input variables not used in the EB-2014-0101 model.

b) The Application states that the load forecast model takes into account the latest CDM activity. Please provide copies of the IESO's reports regarding: i) OSHAWA PUCs verified 2011-2014 CDM results with persistence and ii) OSHAWA PUC's verified 2016 CDM results. (Note: In both cases please provide the Excel versions).

c) If not provided in the load forecast model, please indicate how the CDM adjustment for each customer class was determined for 2018 and 2019.

d) Based on the updated load forecast and CDM assumptions, what are the updated LRAMVA baselines for 2018 and 2019 and how were they determined?

Response:

a) Please refer to 1-Staff-4 response.

b) Attached.

   (EB_2017_0169_OPUCN_Q4 2015 CDM Status Report_Oshawa PUC Networks Inc_20171027.pdf)
   (EB_2017_0169_OPUCN_Final_2016_Annual_CDM_Results_20170727.xlsx)
   (EB_2017_0169_OPUCN_2011_2014_Final_Results_HC_OPUCN_20171027.xlsx)

   Please note – the final verified report for 2016 does not include the results from a Combined Heat and Power plat at Lakeridge Health. The EM+V for that project is ongoing and as such, we have also included the Q4 2015 report from the IESO, which provides detail on the savings for that project.

c) Included in the model provided in response to 1-Staff-4.

d) We did not update the LRAMVA baselines. Considered it to be out of scope.

5.0-VECC-10

Reference: Exhibit A, pages 16-18 1-Staff-5

If not provided in response to 1-Staff-5, please provide the worksheets supporting the cost of power results set out in Table 14.

Response:

Provided in response to 1-Staff-5.

6.0-VECC-11

Reference: ***Exhibit A, page 4 (Table 1) and pages 22-23***

OEB RRWF, Version 7.02, Tabs 11 (Issued July 2017)

a) Please explain how the updated revenue requirements for 2018 and 2019 were apportioned (allocated) to customer classes for purposes of determining the proposed rates for these years?

b) If an updated cost allocation was performed please provide a copy of the models for 2018 and 2019.

c) For each of 2018 and 2019 please provide the equivalent of Tab 11 per the OEB RRWF, Version 7.02 (Issued July 2017).

d) Were the principles used to establish the adjustments required to the Revenue/Cost ratios the same as those applied in EB-2014-0101?

e) If the response to part (d) is no, please explain why not and what the “new principles” used are.

Response:

a) The process was identical to that used in determining interim rates for 2018 and 2019 in the original application (EB-2014-0101).

b) The cost allocation was done using the same cost allocation models as in EB-2014-0101, with input data for 2018/2019 reflecting changes as noted in paragraph 12 of Exhibit A.

c) A copy of the rate design model used is filed with this submission. This is the same model used in EB-2014-0101 other than input data for 2018/2019 reflecting changes as noted in paragraph 12 of Exhibit A. The tabs ‘Cost Allocation Study’ and ‘Rates by Rate Class’ contain much the same info as Tab 11 of the OEB RRWF, Version 7.02

(EB_2017_0169_OPUCN_Rate Design Model - 2015 to 2019_RUN_1_20171027.xlsx)

d) Yes.

e) N/A.

6.0-VECC-12

Reference: ***Exhibit A, page 4 (Table 1) and pages 22-23***

OEB RRWF, Version 7.02, Tabs 12 & 13 (Issued July 2017)

a) Please explain how the proposed 2018 and 2019 fixed/variable splits for each rate class were determined.

b) If the approach used is different from that used in EB-2014-0101, please explain why.

c) Please indicate in what year OSHAWA PUC first started to implement the Board's new Residential Rate Design Policy and the EB number for the relevant application.

d) For each of 2018 and 2019 please provide the equivalent of Tabs 12 and 13 per the OEB RRWF, Version 7.02 (Issued July 2017).

e) If not explained in the responses to the preceding questions, why in Table 1 is there no change in the Residential variable rate as between the interim and final rate values?

Response:

a) The methodology for calculating the proposed fixed/variable splits was identical to that used in EB-2014-0101.

b) N/A.

c) 2017. EB-2014-0101.

d) Tab 12 refers to the New Rate Design policy for residential customers. OSHAWA PUC implemented this policy effective Jan 1 2017 with full transition to be effective in the 4th year (2020). Appendix 2-PA from EB-2014-0101 is attached. No changes to the implementation have been made in this application update.

   (EB-2014-0101_OPUCN_Chapter2_Appendices - Tab 2-PA for 2017 to 2019_20171027.xlsm)

   For Tab 13 "Rate Design and Revenue Reconciliation", please see attached Appendix 2-V from the Chapter 2 Appendices workbook.

   (EB-2017-0169_OPUCN_Chapter2_Appendices - Tab 2-V for 2018 to 2019_20171027.xlsm)

e) The residential variable rate has not changed as the reduction in variable revenue closely matches the reduction in kWh's (eg, 2018 variable revenue down ~3.7%, kWh's down ~3.9%).

SEC

SEC-1

[Ex A, p.12]

The Applicant states that it has based its customer growth forecast on discussions with the City of Oshawa. Please provide copies of any notes, emails, meeting minutes or similar documents from those discussions.

Response:

In relation to Oshawa PUC's projected customer growth, we held an informal meeting with City of Oshawa's Development Services Department to discuss:

The growth patterns over the prior years, 2014 through 2016;

Our projected growth forecast for 2017 through 2019; and

The Durham Regional Official Plan – Consolidation June 26, 2015.

The purpose of the meeting was to determine if the City's Development Services Department was aware of any events that would significantly impact our forecast.