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Joanne Richardson
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BY COURIER

April 26, 2019

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

Dear Ms. Walli:

EB-2018-0270 - Hydro One Networks Inc. MAAD S86 to Purchase all of the issued and outstanding shares of Orillia Power Distribution Corporation – Prefiled Evidence and Blue Page Update

Hydro One is providing Blue Page updates to the following prefiled evidence exhibits:

- Exhibit A, Tab 1, Schedule 1
- Exhibit A, Tab 2, Schedule 1
- Exhibit A, Tab 3, Schedule 1
- Exhibit A, Tab 4, Schedule 1, and
- Attachment 18

These exhibits have been impacted by updates to the tax calculations used in the Hydro One Earning Sharing Mechanism (Exhibit A-3-1) and the Residual Cost To Serve scenario for Year 11 (Exhibit A-4-1) and associated calculations within those exhibits, with the exception of (Exhibit A-2-1), where an additional footnote has been added to page 20 relating to a specific contingent consideration.

Additionally, as indicated by Hydro One in its letter to the Board dated March 19th, the Applicants' are now providing supplemental evidence. Please find attached the new exhibit marked as Exhibit A, Tab 5, Schedule 1 – Supplemental Evidence. This exhibit is being provided to address some of the conclusions reached by the OEB in its Decision and Order on Hydro One's distribution rate application EB-2017-0049.

All the above noted items have been submitted electronically using the Board's Regulatory Electronic Submission System. Two (2) hard copies will be sent to the Board.

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

ONTARIO ENERGY BOARD

IN THE MATTER OF an application made by Hydro One Inc. for leave to purchase all of the issued and outstanding shares of Orillia Power Distribution Corporation, made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Orillia Power Distribution Corporation seeking to include a rate rider in the current[1] Board-approved rate schedules of Orillia Power Distribution Corporation to give effect to a 1% reduction relative to their Base Distribution Delivery Rates (exclusive of rate riders), made pursuant to section 78 of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Orillia Power Distribution Corporation for leave to transfer its distribution system to Hydro One Networks Inc., made pursuant to section 86(1)(a) of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Orillia Power Distribution Corporation seeking cancellation of its distribution licence, made pursuant to section 77(5) of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Hydro One Networks Inc. seeking an order to amend its distribution licence, made pursuant to section 74 of the *Ontario Energy Board Act*, *1998*, to serve the customers of the former Orillia Power Distribution Corporation.

[1] Current rates as of the Closing Date of the transaction based upon the revenue requirement approved in EB-2015-0024.

AND IN THE MATTER OF an application made by Orillia Power Distribution Corporation for leave to transfer its rate order to Hydro One Networks Inc., made pursuant to section 18 of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Hydro One Networks Inc., seeking an order to amend the Specific Service Charges in Orillia Power Distribution Corporation's transferred rate order made pursuant to section 78 of the *Ontario Energy Board Act*, *1998*.

APPLICATION

1.0 INTRODUCTION

Hydro One Inc. ("HOI") is a corporation incorporated under the laws of the Province of Ontario and is the parent company of Hydro One Networks Inc. ("Hydro One"). Hydro One is a licensed distributor regulated by the Ontario Energy Board in accordance with the *Ontario Energy Board Act*, *1998* (the "Act"). A corporate organizational chart of Hydro One, both before and after the transaction, is provided as **Attachment 1**.

Hydro One's distribution system serves approximately 1.3 million customers in its service territory (see **Attachment 2** for further customer details).

Orillia Power Distribution Corporation ("OPDC") is, at the date of this Application, a wholly owned subsidiary of Orillia Power Corporation ("OPC"). OPC is a holding company, currently wholly owned by The Corporation of the City of Orillia (the "City"). A corporate organizational chart of OPC is provided as **Attachment 3**

OPDC's distribution system serves approximately 13,830 Residential and General Service customers in the OPDC service territory (see **Attachment 4** for further customer details).

2.0 OVERVIEW OF APPLICATION

On August 15, 2016, the City and Orillia Power Corporation (the "Vendor") and HOI (the "Purchaser") entered into a Share Purchase Agreement (the "Agreement"), the effect of which is that the Vendor and the City have agreed to sell, and the Purchaser has agreed to purchase, all of the issued and outstanding shares of OPDC. The purchase price is $41.3 million, comprising a cash payment of approximately $26.4 million for the shares and the assumption of OPDC's short- and long-term debt (including regulatory deferral account balances) of approximately $14.9 million[2]. The Agreement contemplates the closing of the transaction on the first business day of a month and at least 90 days following the Parties' receipt of all required approvals, including Ontario Energy Board ("the Board" or "OEB") approval of this Application.

The Agreement (see **Attachment 5**) contemplates the following items in addition to the sale of the shares:

(a) OPDC will apply to the OEB for approval to include a negative rate rider to OPDC's electricity rates[3] to reduce Base Distribution Delivery Rates by one per cent across residential and general service rate classes, and to have such reduced rates apply for the next five years (see **Exhibit A, Tab 2, Schedule 1 Section 2.0** for further detail);

[2] As contemplated in the Agreement, the final purchase price is subject to closing adjustments. A separate Hydro One Inc. commitment of $0.25 million to fund local community investment in Orillia will be treated as contingent consideration for accounting purposes in addition to the Agreement's $41.3 million purchase price.
[3] This refers to OPDC's base distribution delivery rates as approved in EB-2015-0024 and adjusted for the move to a monthly fully fixed charge ("Move to Fixed"), as contemplated in the Report of the Board "A New Distribution Rate Design for Residential Electricity Customers" issued April 2, 2015 under proceeding EB-2012-0410. These rates are hereafter referred to as OPDC's "Base Distribution Delivery Rates".

(b) The Purchaser or its affiliates shall offer all active employees of OPDC continued employment in the City of Orillia for a period of at least one year;

(c) The Purchaser shall establish an advisory committee (the "Advisory Committee") to provide a forum for communication between the Purchaser and the community;

(d) After closing, the community will be eligible for Hydro One's community programs;

(e) The purchase price is subject to adjustment, within 90 days following closing, for working capital, net fixed assets, regulatory accounts and long term debt, as defined in the Agreement.

The resolutions that give way for the execution of the Agreement are provided as **Attachment 6**.

This Application adheres to the principles of the "*Report of the Board on Rate-Making Associated with Distributor Consolidation*" issued on March 26, 2015 ("Amended Report"). The Amended Report provides Board policy pronouncements pertaining to rate-making for associated distributor consolidation transactions. These include: (1) an extension to the rate rebasing deferral period, to a duration of up to ten years after the close of the transaction; (2) a requirement for use of an earning sharing mechanism ("ESM") where an applicant seeks a deferral period greater than five years and up to ten years; (3) utilization of the incremental capital investment module ("ICM") by the consolidating entity during the rate rebasing period; and (4) clarifications as to which incentive plan would apply to distributors who are party to a merger, amalgamation, acquisition, and divestiture ("MAAD") transaction during any deferred rebasing period. Further guidance was provided by the Board with the release of the "*Handbook to Distributor and Transmitter Consolidations and Filing Requirements for Consolidation Applications"* (the "Handbook") released on January 19, 2016. Hydro One has considered the intent of these reports in developing this Application.

The proposed Transaction will both benefit and protect ratepayers:

- Ratepayers will receive the benefit of: (i) a reduction of 1% in their Base Distribution Delivery Rates in Years 1 to 5; (ii) a rate increase of less than inflation in years 6 to 10 (inflation less productivity stretch factor); and (iii) a further guaranteed ESM amount of $3.2 million. In addition, customers will benefit in the longer term from the lower ongoing cost structures.
- The implementation of a guaranteed ESM protects OPDC ratepayers from the risk of Hydro One failing to achieve the forecast level of synergy.

3.0 PREVIOUS MAAD APPLICATION

On September 27, 2016, Hydro One Inc. applied (EB-2016-0276) to the OEB to acquire the shares of OPDC, and sought other approvals as discussed in that application. On April 12, 2018 the OEB issued its Decision and Order on this application denying the acquisition, but indicating that with the exception to pricing, the transaction met the no harm test[4]. In this regard, the evidence in this application is similar to that provided in EB-2016-0276, with the exception of updates to reflect current variables to costs and other metrics. Additionally, in the EB-2016-0276 Decision, the OEB indicated that it required additional evidence on what Hydro One "expects the overall cost structure to be following the deferral period and to explain the impact on Orillia's customers". As a result, Hydro One has complied with the Board's order and has provided a new exhibit (**Exhibit A, Tab 4, Schedule 1**) on Future Cost Structures.

[4] See - Page 12 of Decision and Order, saying that the OEB accepts that the acquisition will lead to some savings on account of eliminating redundancies; Page 16 saying the Board is satisfied that OPDC's quality and reliability of service would be maintained and that the requirement to report on reliability and quality of service would confirm to the OEB that any reduction in service quality would become apparent; and, Page 17 accepting that there will be no adverse impact on Hydro One's financial viability as a result of its proposals for financing the transaction.

4.0 OEB APPROVAL REQUESTS

The following OEB approvals are requested under Sections 86(2)(b), 86(1)(a), 77(5) and 74 of the Act:

- Hydro One is applying to the Board pursuant to section 86(2)(b) of the Act, seeking leave to acquire all the issued and outstanding shares of Orillia Power Distribution Corporation from the City.
- OPDC is applying pursuant to section 86(1)(a) of the Act to dispose of its distribution system to Hydro One.
- If the Board grants leave for OPDC to dispose of its distribution system to Hydro One, after closing and upon integration of the proposed transactions, OPDC requests, pursuant to section 77(5) of the Act, that its electricity distribution licence be cancelled. Hydro One requests, pursuant to section 74 of the Act, that Hydro One's distribution licence be amended such that Appendix B, Tab 1 of Schedule 1 include *The City of Orillia, County of Simcoe as at October 31, 1991*, as described in Schedule 1 of OPDC's licence.
- If the Board grants leave for OPDC's distribution system to be transferred to Hydro One and amends Hydro One's distribution licence to include the former service territory of OPDC, pursuant to section 18 of the Act, Hydro One is also requesting the Board transfer OPDC's rate order to Hydro One.
- OPDC is seeking approval pursuant to section 78 of the Act, to include a rate rider to its OEB-approved rate schedules, to give effect to a 1% reduction relative to the Base Distribution Delivery Rates applicable at the time of closing. This rate rider is proposed to be implemented during the first five years of the deferred rebasing period.
- Hydro One is seeking pursuant to section 78 of the Act to update OPDC's Specific Service Charges to align with the Specific Service Charges that are, or will be, approved by the OEB for Hydro One Distribution.

- Upon completion of integration, HOI will transfer the assets and liabilities of the electricity distribution business from OPDC to Hydro One.
- If the Board grants leave for OPDC to dispose of its distribution system to Hydro One, Hydro One is seeking approval to establish a new deferral account to record the costs of the ESM refund amount for future disposition. Principal amounts recorded in this account will be added annually, and those balances will attract interest calculated consistent with the Board's approved methodology using the Board's Prescribed Interest Rates.

5.0 OTHER APPROVALS AND CONSIDERATIONS

- Hydro One is applying for approval to defer the rate rebasing of OPDC for ten years from the date of closing of the proposed transaction, consistent with the new Board policy set out in the Amended Report.
- Hydro One is applying for approval to continue to track costs to the regulatory asset accounts currently approved by the OEB for OPDC and to seek disposition of their balances at a future date. See **Exhibit A, Tab 2, Schedule 1, Section 3** for further details.
- All OPDC rate riders will continue as per OPDC's existing rate schedules until expiry.
- Hydro One is applying for approval to utilize US GAAP for OPDC financial reporting.
- Hydro One is applying for approval to use an ESM to operate during the extended deferred rebasing period (i.e., years six to ten), consistent with page 16 of the Handbook. Hydro One's proposed ESM is described in **Exhibit A, Tab 3, Schedule 1**.
- Hydro One is applying to use an Incremental Capital Module ("ICM"), should it be required for the former OPDC service territory, consistent with the OEB's policies for an ICM as described on page 17 of the Handbook.
- During the extended deferred rebasing period, rates of customers of OPDC will be set using the Price Cap Index adjustment mechanism as described in **Exhibit A, Tab 2, Schedule 1**.

This transaction was completed on a commercial basis between a willing seller and a willing buyer. It is a demonstration of the types of benefits that can be realized from voluntary consolidation, and it will deliver cost synergies and economy of scale savings contemplated by the Ontario Distribution Sector Review Panel. Hydro One submits that the evidence supports approval of the Application, as the transaction will have a positive or neutral effect on the attainment of the OEB's statutory objectives, and the customers of both local distribution companies will be held harmless. This is achieved as a result of the following:

- The application has no adverse impact on the price, adequacy, reliability and quality of electricity service of OPDC or Hydro One;
- The application has no adverse impact on the promotion of electricity conservation and demand management, the use and generation of electricity from renewable energy sources, and it facilitates the implementation of a smart grid in Ontario;
- Hydro One is committed to promoting the education of consumers through community involvement and customer consultation for future rate-setting applications;
- The implementation of Hydro One's ESM benefits and protects OPDC customers during the extended deferred rebasing period by guaranteeing $3.2 million, established on an estimate of savings from the transaction. The guaranteed amount of $3.2 million corresponds to approximately 45% of OPDC's current Board-approved base revenue requirement;
- The transaction eliminates the duplication of effort between Hydro One and OPDC and results in a single electricity service provider for the Orillia area, the northeastern portion of Simcoe County. This will ultimately create downward pressure on cost structures across both Hydro One and OPDC service areas.

Hydro One respectfully requests a written hearing for this Application.

Hydro One requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

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IMPACT OF THE PROPOSED TRANSACTION

1.0 INTRODUCTION

This exhibit provides HOI's impact assessment of the proposed transaction and also provides a discussion of the impact of the transaction on OPDC's and Hydro One's future operations in relation to the OEB's statutory objectives. It elaborates on how the transaction promotes economic efficiency and cost-effectiveness in the distribution sector and also discusses other related matters pertaining to this transaction.

2.0 IMPACT OF THE PROPOSED TRANSACTION

The *Handbook to Electricity Distributor and Transmitter Consolidations* (the "Handbook"), Schedule 2 Filing Requirements requires applicants to provide evidence to demonstrate the impact of the proposed transaction with respect to the OEB's first two statutory objectives. The Handbook recognizes that there are other instruments and tools that will ensure that the OEB's remaining statutory objectives, relating to conservation and demand management, implementation of smart grid and the use and generation of electricity from renewable resources, will not be adversely impacted by a consolidation. Therefore, the Board has determined that there is no need or merit in further review of these statutory objectives as part of a consolidation transaction[1].

SECTION 2.1: OBJECTIVE 1 – PROTECT CONSUMERS WITH RESPECT TO PRICE AND ADEQUACY, RELIABILITY AND QUALITY OF ELECTRICITY SERVICE

This Application demonstrates that the ongoing cost structures following the closing of the transaction will result in expected ongoing operations, maintenance and administrative

[1] Handbook, Page 6

("OM&A") savings of approximately $4.7 million per year and reductions in capital expenditures of approximately $0.2 million per year (based on the level of savings achieved by Year 10). These efficiencies represent an ongoing OM&A reduction of approximately 70% of OPDC's Year 10 status quo forecast. This will result in downward pressure on OPDC's cost structures relative to the status quo and will be realized while maintaining adequacy, reliability and quality of electricity service. These savings are expected to continue beyond the 10-year deferred rebasing period. Table 1 illustrates the projected cost savings from this transaction. How these savings will be attained is further discussed in Section 2.2.

Table 1 savings, illustrated below, are based on a comparison of OPDC's operations as a stand-alone distribution company relative to the costs of operating OPDC's service territory once it is integrated within Hydro One. Year 1 in the table represents a 12 month period post-closing of the transaction. This period is assumed to most closely align with calendar year 2020.

Table 1: Projected Cost Savings - $M

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
OM&A										
Status Quo Forecast	5.5	5.7	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.6
Hydro One Forecast	4.1	2.0	2.1	1.7	1.7	1.7	1.8	1.8	1.8	1.9
Projected Savings	**1.4**	**3.7**	**3.7**	**4.2**	**4.3**	**4.4**	**4.4**	**4.6**	**4.7**	**4.7**
Capital										
Status Quo Forecast	3.2	4.3	1.5	1.8	2.8	2.8	2.9	3.0	11.1	3.2
Hydro One Forecast	3.4	2.4	2.4	2.5	2.6	2.8	2.8	2.9	2.9	3.0
Projected Savings	**(0.2)**	**1.9**	**(0.9)**	**(0.7)**	**0.2**	**0.0**	**0.1**	**0.1**	**8.2**	**0.2**

Hydro One's 2017 OM&A cost to serve customers in its high density residential rate class (UR) is $179/customer[2], compared to OPDC's cost of $352/customer[3]. Hydro One's urban rate class covers areas containing 3,000 or more customers with line density of at least 60 customers per circuit kilometre. As such, it is reasonable to believe that if this transaction proceeds, Hydro One will be able to serve OPDC's service area, which has approximately 13,800 customers and a density of 57 customers per km of line, at a cost that is comparable to Hydro One's UR rate class.

Price of Electricity Service

The acquired OPDC customers will have rates adjusted in the next ten years as discussed below.

Rate-setting in Years 1-5 of the Deferred Rebasing Period

OPDC's current Base Distribution Delivery Rates[4] will be reduced by 1%, for residential and general service customers of OPDC, and frozen for a period of five years from closing of this transaction[5].

Table 2 shows the customer bill impact of this reduction applied to the average consumption levels for residential and general service rate classes. The impacts on total bill as well as distribution rates are provided. The rate reductions vary slightly from the 1% reduction as a result of rounding from using two decimal places for fixed charges and four decimal places for volumetric charges, as prescribed by the Board, and also due to the fact that the 1% rate

[2] EB-2016-0081, 2017 Draft Rate Order Filed November 18, 2016
[3] Average value for all OPDC customers as shown in the 2017 OEB Yearbook. For the OPDC residential class (which comprises ~ 90% of their customers), the cost to serve is estimated to be $208/customer.
[4] As defined in Exhibit A, Tab 1, Schedule 1, page 3, Footnote 2.
[5] A negative rate rider will result in a 1% reduction to OPDC's Base Distribution Delivery Rates, as approved by the OEB at the time of closing, will be implemented over that term.

reduction does not apply to other existing rate riders or LV rates which are also included in the table below under distribution delivery rates.

Table 2: Bill Impacts for OPDC Customers[6]

Rate Class[7]	Change in Distribution Delivery Rates	Change in Total Bill (%)
Residential	(0.96%)	(0.25%)
General Service less than 50 kW	(1.08%)	(0.27%)
General Service 50 to 4,999 kW	(0.97%)	(0.07%)

Detailed calculations of customer bill impacts and the determination of the rate riders can be found in **Attachment 7** and **Attachment 8**. For the purpose of this application, Hydro One proposes the residential variable rider, to effect the 1% reduction between years one to five of the deferral period, be rounded to five decimal places. This is an exception to the OEB's general rule, of four decimal places. The five decimal places will facilitate Hydro One providing a rider to benefit OPDC customers. The other riders will continue to be rounded to four decimal places, per OEB policy[8]. The proposed rate schedules, which include the requested rate rider for the area currently served by OPDC, effective after closing, are filed as **Attachment 9.**

The cost of providing this rate rider (approximately $80,950 per year[9]) will be recovered from synergies that are generated from consolidating OPDC's operations into Hydro One. This negative rate rider will be discontinued at the end of Year 5 of the deferral period.

[6] Based on OPDC's OEB-approved 2018 rates (EB-2017-0264)
[7] The proposed 1% rate reduction only applies to residential and GS rate classes.
[8] Hydro One asked the Board to approve a variable rate rider to five decimal places in EB-2017-0049 Exhibit H1 Tab 1 Schedule 1
[9] Based on the Residential, and General Service rate class revenues from the OEB 2017 Yearbook for OPD (totaling ($8,095k) multiplied by 1%

OPDC's residential distribution rates will continue to be adjusted to move to a fully fixed distribution charge, per OEB Policy "*A New Distribution Rate Design for Residential Customers*" (EB-2012-0410). In EB-2015-0024, the OEB approved a four-year transition period for OPDC to move to fixed rates, beginning in 2016 and is expected to culminate in fully fixed residential rates by the end of 2019.

All other OPDC tariffs will remain as approved in OPDC's last rate order[10]; with the exception of Specific Service Charges ("SSCs") which Hydro One is seeking approval to amend to align with the SSCs as approved, or will be approved[11], by the OEB for Hydro One Distribution. .

Specific Service Charges

Amending OPDC's rate schedules to reflect Hydro One's SSCs is the most reasonable and cost-effective solution. This approach simplifies and reduces the cost of billing system modifications and/or manual workarounds to accommodate different charges, reduces call centre staff training and provides for a consistent customer experience.

Rate Riders

Table 3 below is a (i) summary of OPDC's current Rate Riders, and (ii) Hydro One's requests for those applicable rate riders.

[10] EB-2017-0264
[11] Hydro One has proposed updates to its SSCs in its 2018-22 distribution rate filing [EB-2017-0049], currently before the OEB.

Table 3: Proposed updates to Orillia's Rate Riders

Current Rider Description	**Proposed Rider Description or Amendments in Proposed OPDC 2020 Rate Schedules**
Rate Rider for Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	In effect until the effective date of the next cost of service-based rate order
Smart Metering Entity Charge[12] - effective until December 31, 2022	Will remain in effect until December 31, 2022
Rate Rider for Application of Tax Change (2018) - effective until April 30, 2019	This Rider expires in April, 2019. It will be deleted if the transaction closes after this date.
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 *Applicable only for Non-RPP Customers*	This Rider expires in April, 2019. It will be deleted if the transaction closes after this date.
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	This Rider expires in April, 2019. It will be deleted if the transaction closes after this date.
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 *Applicable only for Non-Wholesale Market Participants*	This Rider expires in April, 2019. It will be deleted if the transaction closes after this date.

[12] The Smart Metering Entity Charge is a component of the "Distribution Charge" on a customer's bill, established by the OEB through a separate order. Decision and Order, EB-2017-0290, March 1, 2018

Rate-setting in Years 6-10 of the Deferred Rebasing Period

Beginning in year six through to year ten, rates for the former customers of OPDC will be set using the Price Cap adjustment mechanism, as outlined in the Board's Report: "*Rate Making Associated with Distributor Consolidation*" issued March 26, 2015 ("Amended Report"). At the commencement of year six, Hydro One will apply the OEB's Price Cap Index formula utilizing the former OPDC's efficiency cohort factor (0.3%). This will be anchored to then current OPDC Base Distribution Delivery Rates, and applied annually.

Rate-setting Post the Deferred Rebasing Period (Future Cost Structures)

The OEB, as requested in Hydro One's EB-2016-0276 application, wants information on future cost structures that will underpin the rate-setting that will be applicable to the customers of OPDC in the post-deferral period. As a result, Hydro One is filing evidence on potential rate setting mechanisms in years 11 and beyond (see **Exhibit A, Tab 4, Schedule 1)**.

Earnings Sharing Mechanism ("ESM")

Since Hydro One is requesting a 10-year deferred rebasing period, Hydro One will also be implementing an ESM, in accordance with the Amended Report. As outlined in the Handbook, the ESM as set out in the Amended Report may not achieve the intended objectives for all types of consolidation proposals. Hydro One is therefore proposing an ESM that protects OPDC customer interests during the extended deferred rebasing period. Further details on Hydro One's proposed ESM are found in **Exhibit A, Tab 3, Schedule 1**.

Hydro One Legacy Customers

The proposed transaction also protects Hydro One's existing customers. On March 31, 2017, Hydro One filed a five-year Custom Incentive Regulation (EB-2017-0049) application for rates effective from 2018 through to 2022, which is currently awaiting a Board decision/approval. This application did not include any costs associated with serving the customers of OPDC. Costs to serve these customers will not be included in any Hydro One revenue requirement application until the deferred rebasing period has expired.

Adequacy, Reliability and Quality of Electricity Service

Once the transaction is approved by the OEB, the Vendor intends to transfer OPDC's regulated distribution assets so that they are owned by HOI. Transfer of the distribution system from HOI to Hydro One Networks Inc. is expected to occur within 18 months after the close of the Agreement. Once integration is complete, the assets will be integrated with, and form part of Hydro One's existing distribution system. This change in control is expected to maintain or improve adequacy, reliability and quality of service.

Hydro One endeavors to maintain or improve reliability and quality of electricity service for all of its customers. Hydro One currently has existing assets serving many customers in close proximity to the current OPDC service territory (please see map filed as **Attachment 10**), making Hydro One a natural consolidator for OPDC. As part of the proposed consolidation, Hydro One will retain local knowledge from existing OPDC staff. This local knowledge, in coordination with Hydro One's regional operations and staff, will allow Hydro One to maintain or improve reliability.

The existing reliability metrics for OPDC and Hydro One's local metrics are provided in Table 4 below. Hydro One has used distribution stations (Bass Lake D.S, Rugby D.S & Silver Lake DS) in the vicinity of OPDC to compare with OPDC's metrics provided in the OEB Yearbook.

Table 4: Reliability Metrics*

	2013	2013	2014	2014	2015	2015	2016	2016	2017	2017
	Hydro One	**Orillia Power**[13]	**Hydro One**	**Orillia Power**	**Hydro One**	**Orillia Power**	**Hydro One**	**Orillia Power**	**Hydro One**	**Orillia Power**
Duration (SAIDI)	2.28	1.13	0.57	2.15	3.16	1.06	2.76	0.52	4.31	3.63
Frequency (SAIFI)	1.02	1.03	0.30	1.28	1.01	2.44	0.83	1.10	1.20	0.92

*Excluding LOS[14]

Based on reliability statistics for 2013 to 2017, Hydro One customers in the vicinity of the City of Orillia experienced a level of service in terms of duration and frequency of interruptions similar to the level experienced by OPDC customers. For 2014, Hydro One performed better than OPDC in terms of duration of outages, whereas OPDC performed better in the other years; for 2013, 2014, 2015 and 2016, Hydro One performed better than OPDC in terms of frequency of outages.

Hydro One's 2016 and 2017 SAIDI statistic is higher than OPDC. In 2016, two separate incidents caused by tree contact resulted in 302 customers having service interruptions – one lasted approximately 4.3 hours and the second approximately 3 hours. Both of the 2016 tree contacts occurred in the winter season. The first, resulting in a 4.3 hour outage occurred on November 20, 2016 at approximately 9:00 PM, during heavy storm cell activity across the province. A tree had fallen on one of the conductors of that feeder resulting in a need to replace the line conductor section of the circuit between the closest two poles. On that day, there was

[13] Data-sources for OPDC reliability metrics are the applicable OEB Yearbooks
[14] Loss of Supply ("LOS") interruptions attributable to assets that are not part of the Hydro One distribution System or the OPDC Distribution System

wide spread freezing rain, heavy snow and high winds through Ontario. Hydro One's Ontario Grid Control Centre ("OGCC") activated a 'Level 1'[15] emergency response. During that time Hydro One had approximately 50,000 customers interrupted throughout the province. Hydro One's current service territory in the vicinity of Orillia (non-OPDC territory) is the Central Region, and was heavily hit. The second 2016 interruption occurred on December 6th at approximately 7:00 PM in middle of winter conditions after dark. The winter condition and night interruption in rural areas normally are more challenging for Hydro One line crews to arrive, locate and restore power safely. This interruption was due to tree growth into lines and Hydro One Forestry needed to be routed to the location to trim the trees. This interruption was restored in 3 hours.

In 2017, Hydro One's SAIDI was again slightly higher than OPDC's. Both the OPDC and Hydro One SAIFI for 2017 reflect durations of heavy storm activity that occurred in this area of Ontario. One notable common storm cell occurred between the 2nd and 5th of August impacting approximately 91,000 Hydro One customers throughout the province. The OGCC activated a 'Level 1' emergency response during this time. Again, Hydro One's Central Region (Hydro One's service territory adjacent to OPDC's service territory is in the Central Region) was impacted heavily.

Hydro One has recently changed its Vegetation Management Strategy, moving from an 8-year maintenance schedule, which focused on clearing corridors completely and maintaining hazard trees, to a 3-year vegetation cycle that focuses on defects versus complete clearances. Hydro One expects this approach will reduce system interruption and/or equipment damage resulting from tree contact and other vegetation[16].

[15] A Hydro One OGCC 'Level 1' event is triggered by either; an outage that results in more than 10,000 customers being interrupted, an outage duration that is estimated to exceed 24-hours, or there are 100 active incidents in the Hydro One Outage Management system.
[16] For further information on the new Vegetation Strategy see EB-2017-0049 Exhibit Q, Tab 1, Schedule 1

Hydro One anticipates that reliability for OPDC customers may in fact improve with the combination of pre-existing Hydro One and former OPDC resources optimized for the broader Orillia area, and the implementation of Hydro One's new vegetation strategy.

In the long term, OPDC customers are expected to benefit from operational efficiencies expected by having the OPDC assets integrated into Hydro One's larger distribution system. Scale efficiencies are expected in the areas of operating and maintaining the distribution system, planning capital replacement and the overhead and management functions. The foregoing is discussed further in Section 2.2. Hydro One is committed to ensuring that quality and reliability of the former OPDC's customers' electricity service will not be adversely impacted as a result of this transaction. As the Board indicated in the EB-2016-0272 Board Decision, Hydro One will be required to report on reliability and quality of service metrics, thus if there is a risk of harm to Hydro One's customers, the OEB's reporting requirements will make this apparent and will need to be addressed.

Other Items

There are no net metering customers in the current OPDC service area. Therefore, the net metering thresholds as a result of this consolidation will remain unchanged.

Hydro One has agreed to establish an Advisory Committee to provide a forum for communication between Hydro One and the community. Under the terms of the Agreement, the Vendor may appoint three representatives to the committee, and Hydro One will include both senior management and local staff representation.

The City of Orillia will retain the current OPDC Operating Centre on West Street for future redevelopment. Hydro One has agreed to enter into a five-year lease agreement with the City to lease this centre. Conditional on the completion of the sale, Hydro One intends to commence construction, during the lease period, of a permanent operations and administration building within the City of Orillia. This new centre will consolidate operations between Hydro One's pre-existing Orillia Operating Centre and OPDC's Operating Centre on West Street.

SECTION 2.2: OBJECTIVE 2 – PROMOTE ECONOMIC EFFICIENCY AND COST EFFECTIVENESS AND FACILITATE THE MAINTENANCE OF A FINANCIALLY VIABLE ELECTRICITY INDUSTRY

Hydro One submits that this transaction will promote economic efficiency and cost effectiveness which will result in lower ongoing cost structures.

Economic efficiency is attained through sector consolidation, which ultimately eliminates redundant activities. Cost effectiveness reduces OM&A and capital expenditures and is achieved by leveraging Hydro One's economies of scale. These together result in sustained operational efficiencies, both quantitative and qualitative.

With the integration of OPDC's staff and operations with Hydro One's existing operations, Hydro One expects sustained operational efficiencies to be realized in distribution operations, administration, information technology and customer service.

Staff Integration

As Hydro One already has an operating organization in place that provides many of the same functions as OPDC, certain redundant positions will no longer be required. Table 5 shows the 2017 actual OPDC labour split between staff occupying direct and indirect positions. Direct staff, such as line and forestry employees, work directly on the distribution assets. Indirect staff are considered support staff such as back-office, customer service, finance, etc.

Table 5: Current OPDC Staff

	Direct	**Indirect**
Management	-	8
Back Office	-	7
Trades & Technical	15	4
Total	**15**	**19**

OPDC's direct staff will be integrated into Hydro One's local operations and will become part of the area's pool of resources working within the larger Hydro One service area, which encompasses OPDC's current service territory. Hydro One will expand its current Central region to include the OPDC service territory. The 15 direct OPDC positions, currently focused solely on servicing the OPDC service area, will be eliminated. However, as a result of this transaction, 9 new local Hydro One positions will be required and are anticipated to be sourced from the existing 15 OPDC staff complement. Therefore, the result is a net reduction of 6 local trades and technical positions to serve the same territory. In addition, Hydro One will eliminate all 19 indirect positions solely focused on the OPDC territory in the management, back office, and indirect trades and technical areas. The remaining 25 personnel will be absorbed into vacancies within Hydro One Networks.

Although certain functions and positions will be eliminated as part of the integration process leading to efficiency gains, Hydro One, due to its size and current staff retirement profile, is able to offer continued employment to existing OPDC staff. OPDC personnel currently in these roles will have the opportunity to transition to existing positions within the Hydro One organization. This will allow Hydro One to leverage the industry knowledge of existing OPDC staff to meet customer needs. As Hydro One will now be planning the electricity requirements for the entire Orillia area, it will be able to more efficiently manage both the operating and capital costs associated with serving customers across the area.

Distribution Operations

Local area operating and capital savings will result in a more efficient distribution system due to the elimination of an artificial electrical boundary and thereby realizing benefits from contiguity.

Hydro One's existing service territory is situated immediately adjacent to the territory served by OPDC. The geographic advantage of contiguity allows for economies of scale to be realized at the field and operational levels through the eventual integration of OPDC's and Hydro One's local systems.

The elimination of the artificial electrical boundary between these contiguous distributors will result in operational efficiencies in various areas. Hydro One will be able to rationalize local space needs through the elimination or repurposing of duplicate facilities such as service and operating centres; more efficiently schedule operating and maintenance work and dispatch crews over a larger service area; and, more efficiently utilize work equipment (e.g., trucks and other tools), leading to lower capital replacement needs over time. The elimination of the service area boundary allows for more rational and efficient planning and development of the distribution system. All of the above provide the potential to result in operating and capital savings, both immediate and over time, which will provide long-term benefits to ratepayers relative to the status quo.

This situation is common throughout the Province and is shown in the attached map (see **Attachment 11**) depicting the current fragmented pattern of the local distribution system, with small- and medium-sized LDCs contiguous to or surrounded by Hydro One.

Hydro One's Asset Risk Assessment ("ARA") process will also assist in achieving ongoing distribution operational efficiencies. Hydro One's ARA process determines the state of Hydro One's distribution system, identifies current asset needs, and creates a line of sight to future needs, which enables an in-depth view of asset risk, and improved decision-making. The ARA incorporates field asset assessment including visual inspections and evaluation. This process allows Hydro One to assess the state of its assets, assess the risks that those assets pose and to develop appropriate plans in order to ensure reliability and service quality are met. This assessment will allow Hydro One to consider the state of the OPDC distribution system, identify current asset needs, and create a line of sight to future asset needs.

Administration

Sustained administrative efficiencies will result due to (a) the elimination of redundant activities and (b) efficiencies resulting from economies of scale.

The following stand-alone OPDC activities provide examples of what will be consolidated into Hydro One's portfolio of activities.

- Financial: financial accounting, planning, forecasting, management reporting, procurement, treasury, tax, and audit functions.
- Regulatory and legal: rate-setting applications, OEB initiatives, compliance, RRR reporting, and other regulatory reporting (e.g., CDM program administration costs, IESO Market Rules).
- Executive and governance: duplicative functions performed by OPDC senior management would be eliminated, and OPDC's Board of Directors would no longer be required.
- Human Resources: Hydro One will have savings in recruitment, training, and staff development costs, as trained and experienced OPDC staff will be available to Hydro One to replace expected retirements and other attrition. As well, there will be a reduction in external consultants and contractor engagement between the two companies.

Hydro One's cost of borrowing is typically lower than that of local LDCs, leading to savings in financing costs over time. For example, in June 2018, Hydro One Inc. issued $250 million of 7-year debt with a 2.97% coupon rate, and $700 million of 31-year debt with a 3.63% coupon rate.

The cost of long-term debt included in OPDC's rates is 6.25% compared to the 4.47% submitted by Hydro One Distribution in its recent 2018 rate application (EB-2017-0049, Exhibit Q, Tab 1, Schedule 1). OPDC's current debt will be refinanced prior to closing of this acquisition. Consequently, the savings that arise from Hydro One's ability to refinance OPDC's debt upon maturation at a lower rate will lead to lower debt return on rate base, relative to the status quo.

Benefits are also expected to accrue to various agencies within the Ontario energy industry. For example, the costs to regulate and administer the sector may be reduced as this and further acquisitions are completed. The IESO, the OEB, and Ministry of Energy can achieve potential savings through reduced regulatory burden and industry oversight. Further, enhanced regional planning efficiencies may also be achieved by having fewer distribution companies planning for larger areas. For instance, capital can be deployed more efficiently than with the current fragmented approach.

Information Technology

A larger customer base resulting from the creation of a larger regional distributor leads to costs for processing systems, such as billing, customer care, human resources and financial, being spread over a larger group of customers. Consolidation of these functions is expected to result in efficiency benefits as duplicate systems are eliminated, leading to lower capital, operating and maintenance costs over time.

The integration of Hydro One and OPDC will allow for efficiency gains to be realized through eliminating duplication in transaction-processing functions. For example, Hydro One currently processes financial, human resource, information technology, and work management transactions for its existing customers and staff. OPDC processes very similar transactions for its own service area. This means that if the transaction proceeds, Hydro One has the opportunity to eliminate these sources of duplication.

OPDC utilizes a Survalent Supervisory Control and Data Acquisition System ("SCADA") which monitors and controls the distribution network. Integration of OPDC into Hydro One will result in the OPDC SCADA being integrated onto Hydro One's SCADA system and eliminating the need for the master stations. This represents a savings of IT capital and ongoing upgrades.

Customer Service

Hydro One is undergoing a historic customer service transformation. From front line service repairs to operational planning to Board of Directors meetings, Hydro One is today more sharply focused on what's best for the customer. The following describes some of the initiatives and ongoing customer services that Hydro One provides its customers, and which would be offered to the customers of OPDC.

Call Centre

Responding to requests for more convenient hours that fit customer schedules, Hydro One has Contact Centres open on Saturdays from 9:00 a.m. to 3:00 p.m. and extended weekday hours from 7:30 a.m. to 8:00 p.m. – making Hydro One the first electricity service provider in Ontario to do so. For power outages and other emergencies, Hydro One provides 24 hour assistance. The Hydro One Call Centre is open 4½ hours per day longer on Monday to Friday than OPDC's call centre and is supported by an award-winning 24/7 Interactive Voice Response ("IVR") system in addition to customer service staff. This IVR provides customers the ability to self-serve, for many of their most common account and service needs, such as reporting a power outage and obtaining their current account balance. This allows the customer to quickly and accurately get responses to many of their inquiries and allows call centre agents to focus on the more complex questions. Hydro One also insourced its Contact Centre representatives back from a third-party provider, allowing Hydro One employees to better serve customers, by providing a more seamless experience. This transition has also delivered improved service quality. By coming back into the organization, the customer representatives will play a large part in advancing

Hydro One's renewed service culture, assuring customers they are now connecting directly with Hydro One service leaders and decision makers who will be better equipped to serve them.

Increased Community Service and Presence:

Hydro One continues to increase its presence in local communities through drop-in sessions, its mobile Electricity Discovery Centre and by opening regional customer service desks at the Sudbury Field Business Centre and piloting customer service offices at the London and Markham Contact Centres. Hydro One also has a traveling customer service team that visited over 20 cities, towns and Indigenous communities throughout the year, meeting customers face-to-face to help answer questions about their bills, provide information about smart meters and help them learn more about conserving energy and reducing their usage.

Outages

When an outage occurs, Hydro One customers can use other channels, such as online access via smart-phone or other battery-charged laptops and devices, for information about outage details, including estimated restoration time. Customers have the option to sign up for e-mail or text outage notifications. OPDC customers currently do not have these outage notifications, but upon integration, these channels will be become available to OPDC customers as well.

Initiatives to Help Customers Manage their Bills

Hydro One helps customers reduce their monthly bills through electricity conservation programs. Hydro One is committed to delivering industry leading Conservation and Demand Management ("CDM") initiatives that help customers save on their electricity usage and bills. In addition to CDM programs, Hydro One typically tops-up Low Income Energy Assistance Program ("LEAP") funding to help those least able to afford their electricity bills. This is not done by OPDC today. Hydro One also eliminated security deposits for residential customers and significantly reduced deposit requirements for business customers and expanded relief measures to help customers who accumulated balances on their accounts over the winter. Customers can sign up for digital notices that include notifications that their eBill is ready, how much electricity they are consuming mid-month, and payment receipt alerts. All of these alerts provide Hydro One customers with the information they need to effectively manage their energy consumption and their finances. Additionally, Hydro One provides a range of support to Indigenous customers through the First Nations Delivery Credit, First Nations Conservation program and Hydro One's Get Local program.

New Services

Hydro One has redesigned the *HydroOne.com* website and *myAccount* self-service portal to make them more intuitive, providing an array of information and tools, such as *Predict My Bill*. The format of Hydro One's electricity bills were also completely redesigned following extensive research and substantial direct feedback from thousands of customers. The new, easy to understand electricity statements began in December 2017. The new version of the bill also translates well digitally as an e-bill on both web and mobile applications. The new bill changes have seen improvements to our customers understanding of their bills.

OPDC's LEAP funds provided annually between 2015 and 2018, were fully utilized, and in each year were depleted by mid-year, with no additional funding available to assist with remaining potentially eligible customers. If this transaction is approved, OPDC's customers would benefit from Hydro One's top-up of LEAP funding.

Service Guarantees

Hydro One was the first of its kind for any electric utility in Ontario to offer Service Guarantees. These guarantees provide tangible evidence Hydro One is prepared to stand behind the service provided to its customers. If Hydro One fails to meet commitments (e.g., misses an appointment, takes longer than 5 business days to connect a new service once all connection requirements are met, does not return a phone call within one business day)[17], the residential customer's account is proactively credited $75.

Incremental Transaction and Integration Costs

Both parties to the transaction will have incurred some incremental costs associated with the transaction.

Hydro One's incremental transaction costs are estimated to be approximately $3 million. These include legal, and tax costs relating to completion of the transaction, and costs associated with the necessary regulatory approvals.

Integration costs include incremental up-front costs to transfer the customers into Hydro One's customer and outage management. These costs are estimated to be approximately $6 million. Hydro One is not expecting to incur any ongoing integration costs.

All of the above incremental costs will be financed through productivity gains associated with the transaction, will not be included in Hydro One's revenue requirement, and thus will not be funded by ratepayers.

Financial Viability/Premium/Financing

As contemplated in the share purchase agreement, Hydro One Inc. will pay $41.3 million for the acquisition of OPDC. This comprises a cash payment of approximately $26.4 million for the shares and the assumption of short and long-term debt of approximately $14.9 million[18]. The

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[17] The terms and conditions for these Service Guarantees can be found at: https://www.hydroone.com/about/corporate-information/our-service-guarantees

[18] As contemplated in the Agreement, the final purchase price is subject to closing adjustments. A separate Hydro One Inc. commitment of $0.25 million to fund local community investment in Orillia will be treated as contingent consideration for accounting purposes in addition to the Agreement's $41.3 million purchase price.

purchase price represents the commercial value of the underlying assets established through negotiations with an arms length third party.

The premium paid over the asset's book value will not have a material impact on Hydro One Inc.'s financial viability. This transaction price accounts for less than 1% of Hydro One Distribution's net fixed assets. In addition, the premium paid will not be included in Hydro One's revenue requirement and thus will not be funded by ratepayers. Copies of OPDC's, Hydro One Distribution's and Hydro One Inc.'s Financial Statements for 2016 and 2017 are provided in **Attachments 12 to 17**.

HOI will initially finance the proposed transaction through cash or its short-term commercial paper program, which is operational and fully backed by a syndicated bank line of credit maturing June, 2022. Long-term financing will be through its Medium-Term Note program, which is fully operational and valid until April 2020, and planned to be renewed thereafter.

3.0 OTHER RELATED MATTERS

Regulatory Assets and Rate Riders

OPDC's deferral and variance accounts will be held separately from Hydro One Network's deferral and variance accounts. The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report ("EDDVAR") provides that under the Price Cap IR, the distributor's Group 1 audited account balances will be reviewed and disposed if the pre-set disposition threshold is met. In the letter Update to EDDVAR Report, released July 2009, dated July 25, 2014, distributors may seek to dispose Group 1 balances that do not exceed the threshold. Hydro One will comply with this policy during the deferred rebasing period and will propose disposition of the former OPDC Group 1 balances once they meet the threshold established by the Board, consistent with this policy.

OPDC is requesting a rate rider to reduce the residential and general service rate classes' Base Distribution Delivery Rates that are in effect at the time this transaction closes, by 1% for years one through five of the deferral period. All other OPDC rate riders will continue as per their existing rate schedules until expiry.

The OPDC regulatory assets currently approved by the OEB will continue to be tracked in their respective accounts, and disposition will be sought at a future date.

Also, Hydro One requests approval to establish and use a regulatory account to track costs associated with the proposed ESM, which is proposed to be active in the deferral period years six through ten as part of this Application. If approval is granted, Hydro One will submit a Draft Accounting Order for the Board's approval either as a condition of this Application's approval, or as a subsequent filing. More detail on Hydro One's proposed ESM is at **Exhibit A, Tab 3, Schedule 1**.

Incremental Capital Module

To encourage consolidation, the Handbook has now explicitly extended the availability of an ICM, for any prudent discrete capital projects, for consolidating distributors that are on either Price Cap Incentive Regulation ("PCIR") or Annual IR Index. Currently, OPDC rates are set in accordance with PCIR.

Hydro One understands, from the Handbook, that an ICM will be made available for the former OPDC service territory should the need arise. Hydro One currently has no plan to apply for ICM relief during the deferred rebasing period, however if circumstances prevail where Hydro One does require an ICM, the details pertaining to the ICM will be provided in that future application.

US GAAP

OPDC's financial statements are currently prepared under IFRS. Hydro One Distribution received OEB approval to utilize US Generally Accepted Accounting Principles ("US GAAP") as its approved framework for rate setting, regulatory accounting and regulatory reporting in the Decision with Reasons in EB-2011-0399 (issued on March 23, 2012). In addition, in the Hydro One Norfolk MAAD (EB-2013-0187/196/198) Decision and Order, the Board decided that using US GAAP methodology in accounting for Norfolk Power Distribution Inc. (the acquired utility) will be more efficient than continuing to use Modified IFRS. Since that Decision, the OEB has also approved the use of US GAAP for Haldimand County Hydro Inc. (EB-2014-0244) and Woodstock Hydro Services Inc. (EB-2014-0213) in their MAAD applications.

Hydro One requests similar approval to utilize US GAAP for accounting purposes in relation to OPDC. Approval to use US GAAP for OPDC will simplify any future rate integration, will avoid incremental costs or productivity losses by simplifying processes and avoiding the need for workarounds, and will facilitate Hydro One Inc.'s consolidated reporting for securities filing purposes (including future U.S. Securities and Exchange Commission), thus avoiding incremental costs and/or reduced productivity. By using one uniform standard of reporting, Hydro One seeks to achieve integration and scale efficiencies. Given the relative small size of the OPDC operations (when compared to Hydro One), Hydro One believes it would be inefficient and costly to maintain two different accounting regimes for divisions within Hydro One.

Compliance Matters

Pending approval of this transaction and after notification to the Board that integration is completed, OPDC's distribution system and Rate Order will be transferred to Hydro One, and Hydro One's distribution licence will be amended to include the OPDC service territory. The customers, assets, systems, processes and operations of OPDC will be fully integrated into Hydro One's business activities.

Hydro One confirms that it is materially in compliance with its regulatory requirements, subject to any approved regulatory exemptions. The list of specific code requirements from which Hydro One has been exempted can be found in Schedule 3 of Hydro One's Electricity Distribution Licence.

To the best of OPDC's knowledge, it is in compliance with all relevant licence and code requirements per its Electricity Distribution Licence. It is expected that following the approval and completion of the transaction and after integration of OPDC's distribution business activities into those of Hydro One, Hydro One will continue to be materially compliant with all applicable Legislation, Regulations, Market Rules, other Licence Conditions and Codes.

Hydro One's compliance policy will continue to require that confirmed instances of non-compliance be disclosed and mitigated as necessary including applications for exemptions from such requirements, if necessary. Any potential instances of non-compliance associated with OPDC's distribution business activities will be addressed during the integration process.

During the period after closing of the transaction and prior to full integration, service level agreements in compliance with the OEB's *Affiliate Relationships Code for Electricity Distributors and Transmitters* will be drafted between OPDC and Hydro One affiliates.

SUMMARY

For the reasons addressed in the preceding sections, both qualitative and quantitative savings and efficiencies are expected to result from this transaction. Overall, Hydro One's analysis shows the ongoing synergies will accrue as a result of this transaction, benefiting ratepayers of both utilities. These attributes allow Hydro One and OPDC to conclude that the transaction will not cause harm to ratepayers, and indeed will provide benefits to all ratepayers in the long term. Moreover, this application embodies the current regulatory policies and principles of the Board in pursuing the objectives established by section 1 of the Act.

EARNING SHARING MECHANISM

1.0 INTRODUCTION

Consistent with the Amended Report, Hydro One is proposing to implement an Earning Sharing Mechanism ("ESM") to operate during the term of the extended deferred rebasing period[1] (i.e., for years six to ten beyond the initial five-year deferral period). The ESM will ensure that customers share in the benefits from consolidation during that period.

The Handbook provides further details on the Board's expectations of an ESM, and in some instances, references details that would apply specifically to a transaction, including these key aspects:

- Consolidating entities that propose to defer rebasing beyond five years must implement an ESM for the period beyond five years. The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period;
- Excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE;
- Earnings will be assessed each year once audited financial statements are available, and excess earnings beyond 300 basis points will be shared with customers annually;
- An ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals. For these cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests during the deferred rebasing period[2].

[1] EB-2014-0138, Amended Report, page 6
[2] Handbook, Pages 16-17

With these factors in mind, Hydro One is proposing an ESM that simplifies its administration, thereby keeping costs low and providing a guaranteed cost reduction to ratepayers, while adhering to the Board's principles outlined in its recent policies and decisions on consolidation applications.

2.0 PROPOSED ESM

Hydro One's ESM will guarantee a cumulative $3.2 million amount of over-earnings will be shared with former OPDC customers as a result of the implementation of the ESM in years six to ten.

The following are the key aspects of Hydro One's proposal, each of which will be discussed in detail below:

- *Term and Eligibility* - Hydro One is proposing to implement an ESM in years six through ten of the deferred rebasing period. Excess earnings above 300 basis points on the allowed ROE in that period will be shared 50:50 with customers of the former OPDC.
- *Mechanics of the ESM* - The ESM has been calculated on forecast OM&A and capital costs based upon Table 1 in the evidence, provided at **Exhibit A, Tab 2, Schedule 1**.
- *Ratepayer Refund* - The projected over-earning amounts shared with customers will be recorded in a regulatory account and interest-improved.

2.1 Term and Eligibility

Hydro One is proposing to implement an ESM in years six through ten of the deferred rebasing period, consistent with the Amended Report and the Handbook. The ESM will employ a 50:50 sharing of earnings 300 basis points over OPDC's current-approved ROE. The excess earnings will be shared with customers, who at the time of disposition will be customers of Hydro One in what is currently OPDC's service territory. The sharing of the earnings solely with OPDC's customers is consistent with the Board's direction in the Handbook, where the Board suggested that "a large distributor that acquires a small distributor may demonstrate the objective of consumer protection by proposing an ESM where excess earnings will accrue only to the benefits of the customers of the acquired distributor"[3]. This is also consistent with the comments delivered by the Board in Hydro One's Woodstock Hydro Services Inc. MAAD Decision[4] where the Board expressed concerns that the ESM as proposed by Hydro One (over-earnings based on Hydro One's Financial Statements) would not ensure that potential savings would be seen by the existing customers within the Woodstock service territory. The over-earnings will be calculated on the operations of the acquired entity opposed to the consolidated new entity's earnings.

2.2 Mechanics of the ESM

An essential aspect of consolidation is to attain as many synergies as possible to the ultimate benefit of all ratepayers of the consolidating entities. Elimination of redundant financial records, external audits and reporting is a key element to lowering cost structures. Hydro One is on record that it does not intend to provide separate financial statements for any of the acquired utilities. This was discussed during the Woodstock MAAD oral hearing[5]. To do so would not only decrease forecast synergies but would also add new one-time and ongoing costs to set up business units in Hydro One's financial systems, thus diminishing costs savings that would otherwise be available to ratepayers.

Hydro One proposes to fully integrate OPDC into its Distribution business within 18 months of the close of the transaction. Once complete, the companies will be fully integrated, both operationally and financially, including having one set of financial records. Since separate financial statements will no longer exist for OPDC, Hydro One will not be in a position to report

[3] Handbook, Page 16
[4] EB-2014-0213, Page 17
[5] EB-2014-0213, Transcript, Day 2, page 48

the earnings of the acquired distributor. Instead, Hydro One proposes to calculate excess earnings in years six to ten based upon forecast costs as presented in Table 1 below.

In this Application, Hydro One proposes to commit to a pre-calculated ESM guaranteeing a defined benefit to ratepayers of the former OPDC service territory as set out in Section 2.3 below. An ESM using forecast OM&A and capital expenditures has two benefits. Firstly, it reduces both ongoing and one-time costs to serve the customers in the former OPDC service territory, maximizing their share of excess earnings. The tracking of costs required to produce financial statements would substantially reduce the savings available from consolidation activities. Secondly, it provides Hydro One with a strong incentive to achieve the forecast efficiency savings, which are significant as a percent of the existing OM&A and rate base of OPDC. Committing to a pre-calculated refund, regardless of actual costs, drives Hydro One to seek as many efficiencies as possible. Once achieved, this will result in lower ongoing cost structures[6] to the benefit of all Hydro One ratepayers.

A significant benefit to OPDC customers is that the OM&A costs used in the model are *incremental* costs only, which do not include corporate overheads. Including corporate overheads would reduce net income, thereby reducing shared earnings. Hydro One's Year-10 forecast OM&A costs are approximately 70% less compared to OPDC's status quo Year-10 OM&A forecast.

Table 1 below describes the key components used in the Hydro One ESM model.

[6] Both during and post the deferred rebasing period.

Table 1: ESM Components

Rate Base

- OPDC's Board-approved rate base[7] was adjusted for net in-service additions that have accumulated since its last rate rebasing to calculate rate base at the closing of the transaction.
- Additions to rate base during the deferred rebasing period are the forecast in-service capital additions as shown in Table 1 provided in Exhibit A, Tab 2, Schedule 1, plus working capital.
- The starting point for calculating OPDC's forecast rate base was OPDC's 2017 audited Financial Statements (Attachment 12 to Application) and assuming OPDC's Status Quo capital expenditures for 2018 and 2019 to bridge the rate base to 'Year 1', which is assumed to be 2020. The forecast rate base equals the NBV of Property, Plant and Equipment ("PP&E") less capital contributions plus a calculation for working capital, using the Board's methodology. During the 10 year rate rebasing deferral period, the calculated rate base includes additional in-service additions sourced from the forecast capital expenditures provided in Exhibit A, Tab 2, Schedule 1, Table 1, and applying the half-year rule. The modeling assumption used is that capital expenditures from Table 1 are treated as 100% in-serviced in the year incurred.
- Equity Component of rate base is 40% of the total rate base

Revenue

- OPDC's 2018[8] current OEB-approved base distribution rates are adjusted by the *Price Cap Incentive Rate-setting* mechanism for the extended deferral period:
  - The inflation rate is sourced from the IHS Global Insights February 2018 inflation forecast for Ontario.
  - OPDC's productivity factor is 0.3%.
- OPDC's distribution revenue forecast, used in the ESM model, incorporates adjustments for customer and load growth and is calculated using the above rates multiplied by the forecast load and customer profiles of the OPDC service area.
- The forecast load and customer profiles used to forecast revenue in Hydro One's ESM model were generated taking into account the latest information on OPDC's actual load and customer numbers as well as local and provincial demographic and economic trends.

OM&A

- OM&A costs during the deferred rebasing period align with the forecast provided in Table 1 provided in Exhibit A, Tab 2, Schedule 1. OM&A costs used are direct costs only.
- Hydro One is assuming all operational risks during the 10-year deferred rebasing period. These risks include:
  - The risk that the OM&A forecast is not achieved;
  - The risk that assets are not in the condition anticipated;
  - The risk that the anticipated load and customer load profiles do not materialize.

  Hydro One will also need to manage, over a 10-year period, any changes to labour (collective agreements, benefits, pension) and material costs, the impact of innovation and technology on operations, and any political and regulatory changes. Irrespective of the actual results, OPDC customers will receive the ESM sharing benefit. As a result of the risks assumed by Hydro One in committing to the guaranteed ESM, a 20% risk factor has been applied to the OM&A forecast. This means that prior to calculating the forecast savings from the transaction that would be shared with customers, Hydro One has multiplied the forecast OM&A costs by 1.20.

Depreciation

- The acquired assets are depreciated based on their remaining useful life as determined by Hydro One. The assets purchased post-transaction in Table 2 are depreciated in accordance with Hydro One Distribution's approved depreciation rates.

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7 EB-2009-0273, Draft Rate Order
8 EB-2017-0264

▪ Annual depreciation is calculated on the opening Gross Asset Values as of Year 1 of the Deferral period. Hydro One's OEB-approved depreciation rates are used which will also be used for financial accounting post transaction close.
Financing Costs
▪ Interest expense is calculated by applying the long and short term debt rates, outlined below, to 60% of the OPDC rate base ▪ The cost of debt is that embedded in OPDC's current approved rates: ▪ Long-term debt is 6.25%. ▪ Short-term debt is 1.33%.
Taxes
▪ Taxes are calculated using the existing provincial and federal tax rates, totalling 26.5%.
Return on Equity
▪ The ROE used to establish the 300 basis point differential is OPDC's current-approved ROE of 9.85%[9].

2.3 Ratepayer Refund

Table 2 below provides Hydro One's proposed refund to customers using the ESM as above-described. The ESM is calculated using the OM&A and capital costs identified in **Exhibit A, Tab 2, Schedule 1**, Table 1 of this Application.

Hydro One believes that the proposed ESM, based upon forecast cost savings, benefits and provides a fair return to ratepayers. OPDC ratepayers receive a guaranteed sharing of $3.2 million earned during the ESM period. Hydro One will have a strong incentive to ensure that these savings are achieved so that its ability to recover acquisition costs will not be eroded. The resultant synergy savings will then form the basis of future revenue requirements, which will benefit all of Hydro One customers through lower cost structures. Pursuing the more conventional ESM alternative of tracking costs separately and maintaining separate financial records would increase both OM&A and capital costs, which would ultimately erode the synergies of this transaction, thereby reducing the ESM share that will be available to the customers of the former OPDC.

[9] EB-2009-0273

1 **Table 2: Earning Sharing Mechanism Sharing - Years 6 to 10 ($000's)**

	Deferral Period Year	**6**	**7**	**8**	**9**	**10**
	Calendar Year	**2025**	**2026**	**2027**	**2028**	**2029**
1	Rate Base	47,887	49,503	51,237	52,996	54,722
2	Equity Component of Rate Base	19,155	19,801	20,495	21,198	21,889
3	Revenue	9,310	9,515	9,725	9,946	10,158
4	OM&A[10]	2,075	2,120	2,166	2,212	2,260
5	Depreciation	1,442	1,211	1,274	1,340	1,408
6	Interest	1,702	1,759	1,821	1,883	1,944
7	Tax	794	813	832	853	870
8	**Net Profit After Tax**	3,297	3,612	3,633	3,657	3,674
9	Achieved ROE (%) (Line 8 ÷ Line 2)	17.21%	18.24%	17.73%	17.25%	16.79%
10	Less: Approved ROE% for OPDC	(9.85%)	(9.85%)	(9.85%)	(9.85%)	(9.85%)
11	ROE% above Approved ROE%	7.36%	8.39%	7.88%	7.40%	6.94%
12	Less: 300 Basis Points Threshold	(3.00%)	(3.00%)	(3.00%)	(3.00%)	(3.00%)
13	Total Over-Earnings (%)	4.36%	5.39%	4.88%	4.40%	3.94%
14	Total Over-Earnings (Line 13 x Line 2)	$836	$1,067	$999	$933	$862
15	50% of Overearnings Shared with to OPDC customers	$418	$534	$500	$467	$431
16	Tax Effected Earnings Sharing (26.5%)	$568	$726	$680	$635	$586
17	Cumulative Tax Effected Earnings Sharing (Years 6 to 10)					**$3,195**

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[10] Includes risk factor adjustment

2.4 Ratepayer Refund

Hydro One will record the guaranteed refund due to ratepayers in a deferral account. These amounts will be interest-improved, in accordance with the OEB's prescribed interest rates. Hydro One will accrue the balance in this account until the end of the extended deferred rebasing period. At this time, OPDC customers are expected to be transitioned to an appropriate existing or new Hydro One rate class. In Year Ten of the deferral period, Hydro One will apply to the Board to dispose of the balance in this account in one of the following manners: (1) Hydro One will apply these funds to offset the cost of any rate mitigation that may be required to transition these customers to their new rates. That application will recommend the duration of the disposition period; (2) If the total balance in the deferral account is not completely required to fund rate mitigation, then Hydro One will offer rate mitigation for a defined period of time, and any remaining balance will be disposed of via a one-time credit; or (3) If no rate mitigation is required, the balance of the deferral account will be completely refunded to the customers by a one-time credit. This method of disposition ensures that there is no cross-subsidization between the legacy Hydro One customers and OPDC customers[11]. Hydro One is not opposed to refunding the ESM earnings on an annual basis in years 6 through 10, if the OEB should order such disposition, as was decided in EB-2017-0269[12]:

> "NT Power will be required to implement an ESM in a manner consistent with the 2015 Report and Handbook – i.e., … to share these earnings annually with customers once audited financial results are available."

OPDC last had its rates rebased in 2010. If this application is approved, the next rebasing of distribution rates which includes costs for OPDC would be 2030, a period of twenty (20) years. Though there will be significant savings as a result of this consolidation, the 20-year gap

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[11] Hydro One at a later date will file a separate application to request the establishment of a regulatory account to track these costs.
[12] EB-2017-0269 Decision and Order, page 20

between rebasing may result in a disparity between cost structures and rates. Regardless of the rate class to which these customers will be transitioned, rate mitigation may be required. The disposition of the accumulated OPDC ESM sharing balance in years 11 and forward will help to offset any required rate mitigation. It is for this reason that Hydro One proposes recording the ESM refund amount in a deferral account for future disposition.

2.5 ESM Summary

Hydro One believes that the proposed ESM meets the objectives of the Board's policy. The guaranteed refund to customers not only accommodates the circumstances of the transaction; it also provides an incentive for Hydro One to derive increased efficiencies and provides a mechanism to help mitigate rates at the next rebasing. This allows the shareholder to continue to recover transaction costs, while ensuring that customers of the former OPDC are protected from the risk of unrealized synergies, and benefit from the efficiencies and savings that the new distributor expects to achieve from consolidation.

The proposed refund to customers is a significant amount: Hydro One is guaranteeing a total $3.2 million refund to the former customers of OPDC. This equates to approximately 45% of OPDC's current Board-approved revenue requirement[13].

[13] EB-2009-0273

FUTURE COST STRUCTURES

1.0 PREAMBLE

In EB-2016-0276 the Board wrote in its Decision[1]:

> "The OEB is of the view that it would have been reasonable to see a forecast of costs to service Orillia customers beyond the ten year period and an explanation of the general methodology of how costs would be allocated to Orillia ratepayers after the deferral period. . . . The OEB recognizes that any forecast of cost structures and cost allocation 10 years out would include various assumptions and could not be expected to be 100% accurate. However, the OEB has highlighted its concern and its need to better understand the implications of how Orillia customers will be impacted by the consolidation beyond the ten year period. In the absence of information to address that OEB concern, the OEB cannot reach the conclusion that there will be no harm."

Based on the above, Hydro One is providing evidence on "Future Cost Structures" for OPDC in relation to revenue requirement and a general explanation as to how costs would be allocated beyond the deferred rebasing period.

2.0 UNDERLYING COST STRUCTURES TO SERVE OPDC'S SERVICE TERRITORY

To understand if the cost structures and/or rates for the acquired customers, beyond the 10-year deferral period proposed in this Application, are no higher than they would have been in absence of the transaction, (a) OPDC has calculated for Year 11 the estimated revenue requirement for

[1] Decision and Order, page 13

the Orillia service territory in the circumstances where the system continues to be owned and operated by OPDC (i.e. the "Status Quo" scenario) and (b) Hydro One has calculated the estimated revenue requirement, based on the residual cost to serve (i.e. the "Residual" scenario) this territory, after accounting for the synergies and efficiency gains that are anticipated during the deferral period under the proposed transaction.

2.1 OPDC "STATUS QUO" REVENUE REQUIREMENT

Table 1 below reflects OPDC's Status Quo revenue requirement for Year 11.

Table 1
Orillia Distribution Status Quo Scenario
Year 11 Estimated Revenue Requirement ($000's)

Average NBV of Assets	49,244
Working Capital	4,434
Rate Base[2]	53,678
OM&A	$6,754
Depreciation	$2,882
Cost of Capital – Debt Interest	$1,300
Cost of Capital – Equity Return	$1,932
Tax	$575
Revenue Requirement	**$13,443**

To calculate Year 11 rate base, OPDC started with their audited 2017 Financial Statements and factored the annual capital expenditures forecast in Table 1 of **Exhibit A, Tab 2, Schedule 1**. **Attachment 18** provides further details of the forecast for OPDC rate base growth, since the

[2] Rate Base is the average of the current and prior year closing NBV of assets plus the current year Working Capital

time of the last rebasing, through to Year 11. The OPDC rate base is forecast to increase from the 2010 OEB approved amount[3] of $20.8M to $53.7M by 2030, an increase of $32.9M or approximately 158% over the 20 years from the last approved rebasing in 2010.

This level of rate base increase, over a 20 year period, aligns with the increases approved by the OEB in recent 2017 and 2018 distributor rebasing applications submitted after their Incentive Rate Making ("IRM") period. **Attachment 19** shows the average OEB-approved five year increase in rate base is approximately 26% going up to over 60% for some distributors. At the time of the next proposed rebasing, in 2030, OPDC will not have rebased their rates for 20 years - a fourfold period compared to the analysis provided for the 2017 and 2018 rebasing entities in **Attachment 19**.

Further details on the assumptions used to calculate these Year-11 numbers are found in **Exhibit A, Tab 4, Schedule 1, Attachment 20**. As set out in Table 1 above, the Year 11 revenue requirement for OPDC operating Status Quo is $13.4 million.

2.1.1 LV Rates

OPDC is currently an embedded distribution customer of Hydro One. Consequently, in addition to being charged base distribution rates that reflect OPDC's revenue requirement, OPDC's customers also currently pay a Low Voltage ("LV") charge on their monthly bills. The LV charge, which is an OEB-approved rate, reflects Hydro One's upstream distribution cost to serve embedded customers. Therefore, LV charges are not part of OPDC's forecast revenue requirement, as set out in Table 1 above, however they do represent a real distribution cost to OPDC's customers. In 2017, OPDC's LV charges, payable to Hydro One, were approximately $0.7M, and Hydro One estimates these costs will be approximately $1.0M by 2030. Following rate harmonization, customers in the former OPDC service area would no longer incur LV

[3] (EB-2009-0273)

charges on their monthly bills. Rather, the ongoing upstream distribution costs necessary to provide them service would be accounted for within the revenue requirement underlying the new distribution rates proposed by Hydro One for the OPDC service area following harmonization – in other words, customers of Hydro One do not pay a separate LV rate as part of their monthly bill. Therefore to fairly compare OPDC and Hydro One distribution rates, the LV charges must be added to OPDC's Status Quo revenue requirement.

Table 2 Status Quo to Serve OPDC customers Year - 11 ($000s)	
Revenue Requirement	13,443
LV Charges	1,005
Total Cost to Serve	14,448

2.2 OPDC "RESIDUAL" REVENUE REQUIREMENT

Table 3 below reflects the scenario for Hydro One's forecast revenue requirement of the Residual Cost to Serve the OPDC territory, after accounting for the synergies and efficiency gains anticipated during the deferral period, assuming the proposed transaction is approved and the distribution system is owned and operated by Hydro One.

Table 3 Residual Cost to Serve Scenario Year 11 Estimated Revenue Requirement ($000's)	
Average NBV of Assets	49,181
Working Capital	3,725
Rate Base[4]	52,906

[4] Rate Base is the average of the current and prior year closing NBV of assets plus the current year Working Capital

OM&A	1,921
Depreciation	1,433
Cost of Capital – Debt Interest	1,373
Cost of Capital – Equity Return	1,905
Tax	227
Revenue Requirement	**6,859**

The OM&A and capital expenditures are based on the Hydro One forecast provided in Table 1 of **Exhibit A, Tab 2, Schedule 1**. Year 11 OM&A and capital expenditures are calculated by inflating the Year 10 forecast by 2%[5]. Further details on the assumptions used to calculate these numbers are found in **Attachment 20** to this exhibit. As set out in Table 3 above, the Year 11 revenue requirement for serving the OPDC service territory, under the Residual Cost to Serve scenario, is approximately $6.9M.

2.3 SUMMARY OF "STATUS QUO" COST TO SERVE VS. "RESIDUAL" COST TO SERVE

As illustrated in Tables 2 and 3 above, the Residual Cost to Serve customers of OPDC, excluding Shared Cost, would be approximately $7.5M lower ($14.4M SQ cost less $6.9M Residual cost) in Year 11 following the transaction than under the OPDC Status Quo scenario. This difference reflects the elimination of functions, resources and assets that are currently used to serve that service territory and which, for example, due to duplication, would no longer be needed to provide service. Examples of duplicated services include Board of Director's fees, executive leadership, system control staff/facilities and operations facilities that are specifically, planning, finance, regulatory, human resources, information technology etc.

[5] Ontario CPI growth rate forecast. Source: IHS Global Insight, April 2018.

The analysis in Tables 1 through 3 above provide a clear illustration of benefits the former OPDC service territory customers can expect to flow to them as a result of this transaction by lowering the cost structures of the former OPDC service territory to $6.9M, compared to the revenue requirement OPDC have forecast in their Status Quo scenario, $13.4M (not including the LV Charge).

3.0 HYDRO ONE SHARED COSTS

If the transaction is approved, the underlying cost structures for serving the former OPDC customers will be reduced by an estimated $7.5M to a revenue requirement of $6.9M under the Residual scenario. The $6.9M Residual revenue requirement does not reflect OPDC customers paying their full share of the costs for services that Hydro One would be providing to OPDC customers. Hydro One considers the costs of the functions, resources and assets used to provide such services to be its “Shared Costs”. More particularly, Hydro One’s Shared Costs reflect (i) shared facilities used to provide operations and maintenance services (i.e. service centres and maintenance yards), billing and IT system costs, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources, information technology, customer services and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former OPDC customers (i.e. costs formerly captured under LV charges).

In Year 11, upon harmonizing rates for customers in the OPDC service territory with Hydro One’s rates for its existing customer base, the underlying cost structures would continue, as illustrated in Table 1 of **Exhibit A, Tab 2, Schedule 1.** The synergies and efficiencies realized during the 10-year deferral period would continue to have a mitigating effect on rates for customers in the former OPDC service territory. However, through rate harmonization (post 10-year deferral period), Hydro One would have an opportunity to begin collecting a portion of its

Shared Costs from customers in the former OPDC service territory. At that time, the prior Status Quo cost structures will have been reduced through synergies and efficiencies of the proposed consolidation. Given that those customers will receive benefits from the functions, resources and assets that are carried out or held centrally by Hydro One, it will be appropriate for those customers to bear responsibility for some of the Shared Costs. The manner in which Shared Costs will be allocated, and the amount that will ultimately be borne by former OPDC customers following the deferral period, will be matters for the OEB to consider and determine at such time that Hydro One proposes a rate structure and rate harmonization plan as part of its rebasing application following the 10-year deferral period.

At that time, Hydro One would determine the quantum of its Shared Costs and the appropriate methodology for allocating those Shared Costs among all of its customer groups, including its distribution customers in the former OPDC service territory, resulting in what it then believes to be an appropriate amount of Shared Costs to be collected from the former OPDC customers.

There are a number of factors that are likely to be taken into consideration at that time, both by Hydro One in developing its proposed methodology and by the panel of the OEB in considering that proposal and making a final determination on that methodology and the amount of Shared Costs to be included in rates for former OPDC customers. In particular, consideration would likely be given to factors such as the impact on rates for former OPDC customers, the impact on rates for Hydro One’s other customers, the OEB’s cost allocation policies and preferred cost allocation practices at the time, the outcome from the pending EB-2017-0049 Decision as it relates to Hydro One’s previous Acquired Customers, as well as general principles of rate making.

3.1 PROPOSED METHODOLOGY FOR ALLOCATING COSTS AFTER DEFERRAL PERIOD

After the deferral period, Hydro One will allocate costs to serve the former OPDC customers using the OEB's cost allocation model, adjusted to reflect the cost to serve the acquired OPDC customers. Hydro One proposes within the harmonization and rebasing application following the deferral period, that it would ensure that the total cost, including a portion of Hydro One's Shared costs, to be collected from the former OPDC customers would be between, (a) the Residual Cost to Serve Scenario plus LV charges (totaling $7.9M), and (b) the Year 11 revenue requirement under the OPDC Status Quo scenario plus Year 11 LV charges (totaling $14.4M).

Table 4 below provides the calculation of these two costs.

Table 4
Calculation of Residual and Status Quo Costs ($000s)

Revenue Requirement – OPDC Status Quo	13,443
Estimated LV Charges[6] – OPDC Status Quo	1,005
Total Cost to Serve – OPDC Status Quo	**14,448**
Revenue Requirement – Residual Cost to Serve Former OPDC	6,859
Estimated Revenue Requirement associated with providing LV services to Former OPDC	1,005
Total Residual Cost to Serve	**7,864**

As illustrated above, Hydro One could collect from the former OPDC customers a revenue requirement as low as $7.9M. This would mean that all savings from the transaction would accrue to the former customers of OPDC. Hydro One's legacy customers would not be harmed, as the former OPDC customers would be paying for their residual cost to serve. On the other

[6] Year 11 LV charges would reflect Hydro One's costs of providing host distributor services.

hand, Hydro One could collect from the former OPDC customers a revenue requirement of up to $14.4M, and still be at or below their Status Quo cost to serve. This would mean that all savings from the transaction would accrue to Hydro One legacy customers. Any revenue requirement collected from the former OPDC customers between these two amounts (i.e. between $7.9M and $14.4M), would result in a sharing of the benefits between the two customer groups.

At this time, Hydro One is not in a position to determine the specific amount of costs that would be collected from OPDC's customers, as that will depend on the cost allocation and rate design proposed for the harmonized rate classes in Year 11. However, any adjustments to the OEB's cost allocation model to reflect the cost to serve the acquired OPDC customers in Year 11 would remain in place for subsequent years.

In Year 11, to calculate the status quo forecast, Hydro One would use the forecast as provided in this Application. However, that base amount would need to be adjusted to reflect any unknown or unforeseen costs at that time that would be applicable to serving the former OPDC customers if the transaction did not occur. For instance, if new legislative or OEB requirements or environmental regulations give rise to unanticipated costs, or unanticipated events such as political change (e.g. trade tariffs impacting costs) or storm damage results in the need for additional capital expenditures in the former OPDC service territory during the deferral period, those costs would have been incurred regardless of the transaction and would therefore need to be added to the OPDC status quo forecast. The base amount would also need to be adjusted to reflect the weighted average cost of capital applicable at that time.

For the ten year deferral period, Hydro One will track the incremental costs (OM&A and Capital) to serve customers in the former OPDC service territory, and have their asset plans distinguished in Hydro One's Distribution System Plan until rate integration in Year 11.

4.0 SUMMARY OF FUTURE COST STRUCTURES

Hydro One has provided evidence that the Residual cost to serve the former customers of OPDC integrated into Hydro One is less than it would have been under OPDC's Status Quo scenario. The underlying cost structures to serve the former OPDC service territory area will be reduced by approximately $6.5 million prior to an allocation of Shared Costs.

Evidence showing that the former customers of OPDC will benefit from this transaction includes:

- Former OPDC customer rates will not be rebased via a Cost of Service Rate application until 2030. This is a 20 year period from the time their rates were last rebased[7].
- As of December 2017, $20.7M capital expenditures[8] have been added to OPDC's rate base since their last rate rebasing in 2010, a period of seven years (2011 to 2017). These are not reflected in its current OEB-approved rate base, which is the basis for the rates that Orillia customers will continue to pay until Year 11.
- OPDC will continue to incur capital expenditures in 2018 and 2019 until the time the proposed acquisition is forecast to close, followed by Hydro One incurring capital expenditures to maintain service reliability and system capital requirements for the 10-year deferral period. None of these capital expenditures[9] will be reflected in the rate base that underpins the rates the former customers of OPDC will be charged, yet customers have received and will receive benefits from these capital expenditures.

[7] OPDC rates were last rebased in 2010 (EB-2009-0273)
[8] 2017 OPDC F/S
[9] This excludes any capital expenditures that may be undertaken and approved by the OEB through an ICM applications

- Hydro One emphasizes that under OPDC's Status Quo scenario OPDC's customers rates would increase as a result of the growth in rate base compared to the rates these customers will receive as a result of this transaction. Hydro One maintains it is a reasonable assumption to expect that rate base will increase, under both Status Quo and Residual scenarios given that the OPDC service territory's rates will not have been rebased for a 20-year period.

- OPDC has already made it public that its current rates are not sufficient to sustain its electricity distribution operations over the long term.

> "If the sale to Hydro One is not approved, OPDC will be required to file for a distribution rate increase (known as a Cost of Service rate application) with the OEB at least twice over the next 10 years. It is estimated that distribution rates will increase by an average annual rate of 2-4% over the next 10-year period[10]."

This message was included in a bill insert to customers from OPDC in May 2018.

- OPDC has not adjusted their rates through the Board's IRM mechanism since 2016.[11] This further confirms that OPDC ratepayers have benefited from this transaction.

- Hydro One is confident that it can produce savings and synergies operating and managing the former OPDC service territory under OPDC's OEB-approved revenue requirement, effectively reducing the cost structures for the OPDC service territory compared to the Status Quo. This benefits the ratepayers, not only by decreasing their Base Distribution Delivery Rates by 1% and freezing those reduced rates for five years, but it avoids at

[10] Provided to Orillia customers as a bill insert by OPDC (refer to Attachment 21)
[11] EB-2015-0286

least two cost of service rebasing events over the ten year deferral period, that OPDC would otherwise require.

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Hydro One is providing former OPDC customers a guaranteed ESM. This protects these customers to ensure they share in any increased benefits from consolidation during the deferred rebasing period. The ESM is based on only the incremental cost to serve customers in the former OPDC service territory.

With respect to former OPDC customers, Hydro One anticipates transitioning those customers to one of its proposed new Acquired Rate Classes or to a new rate class to be proposed after the deferred rebasing period has elapsed. At the time of that rate proposal, Hydro One will determine an appropriate rate class for the former OPDC customers (e.g. taking into account density characteristics and bill impacts). Hydro One, as has been directed in previous MAAD decisions[12], will ensure the new proposed rates will reflect the cost to serve the newly acquired customers in the former OPDC service territory. To achieve this, at the time of rebasing, Hydro One will examine the cost to serve these customers to ensure that they will only be charged for the assets that are used to serve them.

Hydro One has also provided an illustration of how Shared Costs could be collected from customers of the former OPDC post the 10-year deferral period. This evidence shows that both legacy customers and the acquired customers will benefit from this transaction. If the revenue collected from the former OPDC's customers through rates is equal or less than OPDC's Status Quo revenue requirement plus LV costs, then customers will not be harmed. If Hydro One's legacy customers' rates are not increased as a result of the transaction, they too are not harmed by the transaction. The annual savings of $6.5[13] million expected from this transaction can be

[12] EB-2013-0187/0196/0198, EB-2013-0213, EB-2013-0244
[13] Calculated as OPDC's Status Quo Total Cost to Serve, of $14.4M, less, Hydro One's Total Residual Cost to Serve of $7.9M = $6.5M.

shared by these two customers groups such that each group will have rates derived from a lower revenue requirement that would have otherwise applied in Year 11 and beyond. Therefore, the transaction meets the No Harm Test.

SUPPLEMENTAL EVIDENCE

1.0 PREAMBLE

On September 26, 2018 Hydro One filed a MAAD application to purchase OPDC. Included in that Application was an exhibit, "Future Cost Structures" (Exhibit A, Tab 4, Schedule 1), to assist the Board in understanding Hydro One's rate plans for OPDC's customers after the deferred rebasing period. The purpose of this Supplemental Evidence is to explain in detail Hydro One's proposed cost allocation and rate design for OPDC customers at the end of the rebasing deferral period. The Supplemental Evidence demonstrates that the application of Hydro One's proposed cost allocation and rate design to OPDC customers in a Year 11 rebasing will: (a) result in an allocation of costs to OPDC customers that reflects the cost to serve them; (b) result in rates that collect costs from OPDC customers that are less than what those customers would have paid in the absence of the proposed transaction; and (c) leave Hydro One legacy customers unharmed or slightly better off than they would have been in the absence of the proposed transaction. In fact, the outcome of the cost allocation model and rate design reflects the sharing of cost savings in Year 11 and beyond for the benefit of both OPDC and Hydro One legacy customers.

2.0 DISTRIBUTION SECTOR EFFICENCY

Hydro One's consolidation of the distribution sector has and will continue to result in beneficial outcomes for all customers - both for the customers of acquired utilities and Hydro One's legacy customers. This aligns with the key objective of the OEB's consolidation framework, to seek out efficiencies through consolidations.

Hydro One's purchase of OPDC will result in over $6.5 million of savings in Year 11 (i.e., the first rebasing year), as shown in Table 1 below.

Table 1: Savings Resulting from Hydro One's Acquisition of OPDC ($M)

OPDC Status Quo Total Cost to Serve	$14.4	*Ex. A, Tab 4, Schedule 1 – Table 4*
Total Residual Cost to Serve	7.9	*Ex. A, Tab 4, Schedule 1 – Table 4*
Ratepayer Savings (Year 11)	**$6.5**	

3.0 TRACKING COST TO SERVE

(a) Tracking Costs during Deferred Rebasing Period

In Exhibit A, Tab 2, Schedule 1, Table 1 of this MAAD application, Hydro One has provided the forecast incremental OM&A and capital cost to serve the customers of OPDC, and commits to tracking the *actual* incremental OM&A and capital costs to serve OPDC customers until the end of the ten year deferral period. This tracking will allow the Board to compare the actual incremental costs to serve OPDC customers with that forecast in this application. The actual incremental OM&A and capital costs to serve OPDC customers will be reflected in Hydro One's revenue requirement upon rebasing of rates at the end of the ten year deferral period.

(b) Tracking Costs from Year 11 Onwards

In response to concerns raised in EB-2017-0049 (the "Distribution Rates Decision") relating to not updating in future rate-setting applications the adjustment factors[1] (that were to be used in determining the allocation of fixed assets to previously acquired customers within the cost allocation model), Hydro One will track the capital costs to serve OPDC customers *after* the rebasing period (i.e., Year 11 onwards). Hydro One will review the adjustments factors taking into account the actual capital costs at the time of future cost of service applications (see Section 4.0 below). By doing so, the direct assignment of capital costs to OPDC customers will continue

[1] Adjustment factors are generically used to shift costs allocated between rate classes.

to remain accurate in the long term, and the fixed asset adjustment factors will reflect the most up-to-date asset cost data.

The OEB's cost allocation model uses fixed assets as the primary allocator for the costs of operating and maintaining distribution assets and since Hydro One proposes to use the principles embedded within the cost allocation model to allocate all other OM&A costs (e.g., customer, and administration and general costs), Hydro One will only track OPDC's incremental OM&A costs until the time that OPDC is harmonized into Hydro One's rate structure. The OM&A cost tracking during the deferral period will demonstrate the savings achieved from the acquisition at the time rates are harmonized, but is not required thereafter for use within the cost allocation model.

Hydro One cannot track, on an actual basis, either during the deferral period or after, the costs associated with certain Hydro One resources that OPDC customers will enjoy the benefit of (i.e., those resources that are also required by and paid for by legacy customers). These costs, referred to as Shared Costs in Exhibit A, Tab 4, Schedule 1 (page 6 of 12) of this Application, include costs that cannot be directly associated with serving a specific group of customers. Any assignment of these Shared Costs to a specific customer group or rate class must be done through a cost allocation methodology.

4.0 COST ALLOCATION AND RATE DESIGN

This section of the Supplemental Evidence is intended to assist the Board by clarifying the cost allocation and rate design methodology that Hydro One proposes for acquired utilities, including any future harmonization of OPDC.

(a) <u>Separate Rate Classes</u>

Hydro One believes that the best way to ensure that OPDC customers are charged only their costs to serve is to introduce new rate classes for them. Creating new rate classes allows Hydro One to allocate to OPDC customers only the cost of fixed assets used to serve them given the customer density and distribution system configuration of OPDC's service area. As discussed below, fixed assets are a key driver of the majority of costs within the OEB's cost allocation model.[2] As a result, in order to determine the total cost to serve the acquired OPDC customers, it is critically important that those customers are appropriately allocated their specific fixed asset costs.

Setting the rates for the new OPDC customer rate classes in Year 11 and beyond will involve two key steps:

- a cost allocation methodology that ensures an appropriate allocation of fixed assets and their associated costs, as well as an allocation of Shared Costs; and
- a rate design methodology that utilizes the Board's approved range of revenue-to-cost ratios.

Both of these steps are aimed at ensuring that the costs to serve OPDC customers are accurately reflected in rates. These steps also ensure that the rates payable by both OPDC customers and Hydro One legacy customers are lower (or at least no greater) than they would be otherwise (i.e., had no acquisition occurred). Hydro One's proposals with respect to each of these steps are detailed below.

[2]As shown in Tab E4 "TB Allocation Details" of the OEB's cost allocation model, the allocation of the OM&A costs in UsofA 5005-5055 and 5085-5175 which captures all distribution related costs, are allocated based on the rate classes' share of fixed asset accounts. In addition, the allocation of net income, interest, and depreciation costs to rate classes are also driven by fixed assets.

(b) Cost Allocation

In order to ensure the equitable treatment of both legacy and acquired customers, Hydro One proposes to use the principles underlying the OEB's cost allocation model to determine the cost allocation to all rate classes. To the extent necessary, the OEB's cost allocation model will be adjusted to achieve the following objectives:

1. Ensure that costs[3] allocated to the OPDC rate classes reflect the fixed assets specifically used in OPDC's service area.
2. Ensure that the OPDC rate classes are appropriately allocated Shared Costs[4], which includes a share of upstream distribution assets required to provide service to OPDC's service area.

Hydro One fully anticipates that the cost allocation process described above, and detailed in the following sections, will result in a fair and reasonable allocation of costs to the OPDC rate classes that will be less than what the cost-to-serve the OPDC customers would be if OPDC is not acquired.

Allocation of Costs Based on Actual Fixed Asset Cost

The allocation of fixed assets within the cost allocation model is the key factor driving the allocation of the bulk of a utility's revenue requirement, including: a large portion of OM&A, depreciation, net income, and interest costs. The OEB's cost allocation model allocates a utility's total fixed assets costs to each rate class based on the peak load and number of

[3] Costs include capital related costs such as depreciation, net income, and interest costs, as well as operations and maintenance costs associated with fixed assets used in OPDC's service area,

[4] Hydro One's Shared Costs reflect: (i) shared facilities used to provide operations and maintenance services (i.e. service centres and maintenance yards), billing and IT system costs, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources, information technology, customer services and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former OPDC customers (i.e. costs formerly captured under LV charges).

customers in each rate class relative to the other classes. This approach to the allocation of fixed assets is appropriate when allocating costs to rate classes whose customers are spread out across a utility's service territory. However, if the objective is to determine the costs of serving a specific area within a utility's service territory, this approach does not take into account the unique characteristics (e.g. customer density, distribution system configuration) of the service area for which costs are being allocated.

Use of Adjustment Factors to More Accurately Reflect Costs

Given the critical role of fixed assets in the allocation of costs, and the fact that OPDC's customers are located within a defined service area with its own unique characteristics, the use of adjustment factors within the cost allocation model is a way to ensure that the amount of fixed assets allocated to the OPDC rate classes matches the amount of fixed assets specifically used to serve the customers within their service area. At the time of harmonization of OPDC, Hydro One will know the amount of fixed assets that are used to serve the former OPDC service territory[5] and proposes to include adjustment factors in its cost allocation model to ensure the appropriate amount of fixed assets are allocated to the OPDC rate classes. This is effectively a direct allocation of locally-used fixed assets to OPDC customers. In other words, the adjustment factor ensures a more accurate reflection of the fixed assets, and associated costs, required to serve OPDC customers.

Adjustment factors are not a new concept within cost allocation models. Since 2012, the Board has approved the use of density factors to adjust the amount of costs allocated to Hydro One's density-based rate classes. A Street Light Adjustment Factor is used to adjust the number of customer connections associated with the streetlight class for cost allocation purposes. Weighting factors for Services and for Billing and Collections are used within the OEB's cost

[5] Consisting of the fixed assets at the time of acquisition plus any capital additions since acquisition.

allocation model to ensure that rate classes are allocated an appropriate share of costs related to those functions.

Accordingly, Hydro One proposes to use the adjustment factors discussed above within its cost allocation model to determine the amount of gross fixed assets allocated by the model to the OPDC rate classes. Given that depreciation and net fixed assets are directly associated with the value of gross fixed assets, Hydro One also proposes corresponding adjustments for those quantities.

Hydro One acknowledges that over time the adjustment factors may change as assets that were installed over a period of many years are replaced at current costs. However, the adjustment factors will always need to reflect the specific attributes (e.g. customer density, distribution system configuration) of the acquired utilities' service territory. In order to mitigate concerns with how those adjustment factors will be set in the future, as mentioned previously, Hydro One proposes to continue tracking the distribution gross fixed asset costs associated with serving the OPDC customers, and update the adjustment factors at the time of future cost of service applications, as necessary.

Allocation of Shared Costs

Hydro One proposes to allocate Shared Costs to OPDC's rate classes by applying the same allocation principles and allocators[6] normally used in the OEB's cost allocation model to allocate such costs. No adjustment factors will be applied for the purposes of allocating Shared Costs. This will ensure that the same principles and allocators are used to allocate Shared Costs to both Hydro One's legacy customers and OPDC's rate classes, in order to equitably establish the costs of serving all rate classes.

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[6] E.g., number of customers, weighted number of bills.

Included in Shared Costs are the costs associated with upstream distribution facilities used by former OPDC customers (i.e. costs formerly captured under LV charges). Hydro One will ensure that only the portion of the OPDC load that was previously supplied through upstream distribution facilities (i.e. not supplied directly from the transmission system) is used to determine the allocation of upstream distribution costs to the OPDC rate classes.

(c) <u>Rate Design</u>

The appropriate rate design applicable to OPDC customers will be determined in the Year 11 rebasing, based on the OEB's rate design policies in effect at the time. However, based on the OEB's current practice, Hydro One proposes to determine the rates revenue to be collected from OPDC customers as follows: (a) determine the revenue to cost ("R/C") ratio for all rate classes, including OPDC rate classes, by comparing the total revenue collected at current rates[7] against the costs allocated to each rate class; and (b) adjust the R/C ratios for each class if necessary to bring them within the Board's approved range. The Board's approved range of R/C ratios is a recognition of the fact that determination of costs by rate class is an *allocation* process that by its very nature is not a precise determination of the actual cost-to-serve a particular rate class[8]. Rates established based on a R/C ratio within the Board's approved range are considered to appropriately reflect the Board's rate setting objectives.

Hydro One fully anticipates that it will be possible to set rates for the OPDC rate classes that result in a R/C ratio that both falls within the Board's approved ranges *and* results in an

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[7] Current rates for OPDC will be the distribution rates that were frozen at the time of acquisition, plus any OEB-approved adjustments to those rates since the end of the rate-freeze period.

[8] Page 2, of EB-2007-0667 Report of the Board – Application of Cost Allocation for Electricity Distributors issued November 28, 2007 states "The Board also recognizes however, that cost allocation is by its very nature, a matter that calls for the exercise of some judgement, both in terms of the cost allocation methodology itself and in terms of how and where cost allocation principles fit within the broader spectrum of rate setting principles that apply to – and the objectives sought to be achieved in – the setting of utility rates".

allocation of savings to both legacy and OPDC customers. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One is committing to charge OPDC customers no more than the higher goal post amount of $14.4M and no less than their residual cost to serve of $7.9M. Rates that collect revenues below the upper goal post ($14.4M) will result in savings to the customers of OPDC, while rates that collect revenues greater than the lower goal post ($7.9M) will result in savings to legacy customers.

(d) <u>Outcome of Cost Allocation and Rate Design – "No Harm"</u>

Hydro One fully anticipates that the cost allocation methodology described above will result in a fair and reasonable allocation of costs to the OPDC rate classes that will be less than what the cost-to-serve the OPDC customers would be if OPDC is not acquired.

Hydro One is also confident that the rate design process will result in rates that fall within the Board's approved R/C ratio ranges and will collect revenues from OPDC customers that will be between the goal posts as described in Exhibit A, Tab 4, Schedule 1. This will ensure that no customers are harmed from a rate perspective.

Hydro One engaged Navigant Consulting Ltd. to evaluate whether the cost allocation and rate design approaches described in this supplemental evidence are appropriate and consistent with accepted regulatory practices. This includes, with respect to rate design, whether the adjustment of the revenue-to-cost ratio as described in the supplemental evidence is appropriate and consistent with accepted regulatory practices. Navigant concluded that the cost allocation and rate design approaches that Hydro One has described in this evidence are appropriate and consistent with accepted regulatory practices. A copy of Navigant's report is attached at Appendix A to this exhibit.

5.0 SHARING OF CONSOLIDATION SAVINGS

The question is not whether the OPDC transaction will result in consolidation savings, but rather how those savings will be shared amongst customer groups. The outcome of the cost allocation model, and the resulting rates to be charged to legacy and OPDC customers using the methodology described above, will establish the extent to which customers share the savings resulting from the harmonization. OPDC's customers will be charged no more than what they would otherwise have been paying (i.e., costs to be collected will be between the "goal posts"). Hydro One's legacy customers will similarly be charged no more than what they would pay in the absence of an OPDC acquisition. Any recovery of costs from OPDC's customer classes "between the goal posts" (i.e., over their Total Residual Cost to Serve but less than the OPDC Status Quo Total Cost to Serve) means that Hydro One legacy customers will receive benefits from the consolidation, as will OPDC's customers.

To demonstrate that the cost allocation methodology is about the sharing of savings between OPDC's customers and Hydro One legacy customers (and that neither of these customer groups will incur additional costs), Hydro One has provided in Table 2 below an illustrative example of Hydro One's proposed cost allocation and rate design in the context of a consolidation.

Table 2: Illustrative Cost Allocation Exercise ($M)

	Hydro One Legacy	**Acquired Utility**	**Combined**
Status Quo Revenue Requirement to be Collected From Customers	**$1000**	**$50**	**$1050**
Post-Consolidation Cost to Serve	1000	30	1030
Impact of Cost Allocation Model Treatment of Shared Costs	(15)	15	0
Post-Consolidation Cost Allocation	**985**	**45**	**1030**
Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement Collected from Customers	5	(5)	0
Post-Consolidation Rates Revenue Requirement	**$990**	**$40**	**$1030**
Consolidation Benefits	**($10)**	**($10)**	**($20)**

In the Table 2 illustration, the Status Quo revenue requirement to be collected from Hydro One's legacy customers is $1000M in Year 11. If there were no consolidations, Hydro One would recover this revenue requirement from existing Hydro One legacy customers. Similarly, the Status Quo revenue requirement of the acquired utility is $50M, which the acquired utility (in the absence of the consolidation transaction) would need to recover from its customers in Year 11. The combined distribution sector revenue requirement would be $1050M.

However, through consolidation, Hydro One is able to achieve savings of $20M to operate the distribution system of the acquired utility, thereby reducing the combined post-consolidation distribution sector revenue requirement to $1030M. These distribution sector savings of $20M align with the objective of the OEB's consolidation framework – namely, to ensure that the consolidation of the distribution sector results in beneficial outcomes for customers. There are clearly tangible benefits from this transaction. The question is only: how will the benefits achieved from the consolidation be shared among customers?

Hydro One believes that the savings from consolidation should benefit both legacy and acquired customers. As described in the cost allocation section above, Hydro One will use the OEB's cost allocation model to allocate costs to all customers, including customers of the acquired utility. The costs allocated will include both the residual costs to serve the acquired utility and a portion of Shared Costs. This allocation of Shared Costs represents the "savings" that will accrue to Hydro One's legacy customers.

In the Table 2 illustration, the cost allocation model has allocated $45M to the acquired utility ($30M in residual costs to serve plus $15M in Shared Costs). The $15M in Shared Costs are costs that will no longer be allocated to serve legacy customers. If the acquired utility has not had its rates rebased for an extended period of time, there could be a disparity between cost structures and rates in Year 11 regardless of the significant savings achieved. If this is the case, Hydro One will need to set R/C ratios within the Board's approved R/C ranges, which will impact the acquired utility's rates revenue requirement. For example, if the acquired utility's cost to serve of $45M is reduced by $5M as a result of setting the R/C ratios that will mean a total rates revenue requirement of $40M to be collected from the acquired utility's customers. This shifts $5M of the savings achieved from Hydro One legacy customers to the acquired customers. However, Hydro One's legacy customers will still benefit from the consolidation – their revenue requirement collected through rates is $10M lower than it would have been in the Status Quo. At the same time, the acquired utility's revenue requirement collected through rates is $40M versus $50M in the Status Quo.

Independent review of proposed cost allocation and rate design approach

Prepared in the context of the Hydro One and PDI and Hydro One and OPDC MAAD applications

Prepared for

hydro one

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April 26, 2019

Name and qualifications

My name is Benjamin Grunfeld. I am a Managing Director in Navigant's Global Energy Practice. I am the Canadian Power and Utilities Client Segment Leader. In this role, I am responsible for overseeing Navigant's business with regulated utilities and non-regulated energy companies in Canada. My area of expertise, as it relates to this proceeding, is cost allocation and rate design. For over 10 years I have advised clients in Ontario, across Canada, and around the world on cost allocation and utility rates design matters.

Scope of review

Navigant was engaged to evaluate whether the cost allocation and rate design approaches described in Hydro One's evidence are appropriate and consistent with accepted regulatory practices, including, with respect to rate design, whether the adjustment of the revenue-to-cost ratio as described in the evidence is appropriate and consistent with accepted regulatory practices.

Evidence reviewed

Navigant reviewed the following:

- Hydro One's September 26, 2018 mergers, acquisitions, amalgamations, and divestitures (MAAD) application to purchase OPDC, OEB proceeding EB 2018-0270 ("OPDC MAAD Application"), and Hydro One's October 12, 2018 MAAD application to purchase PDI, OEB proceeding EB-2018-0242 ("PDI MAAD Application");
- Hydro One's April 26, 2019 supplemental evidence filed in the OPDC MAAD Application at Exhibit A, Tab 5, Schedule 1 ("OPDC Supplemental Evidence") and Hydro One's April 26, 2019 supplemental evidence filed in the PDI MAAD Application at Exhibit A, Tab 5, Schedule 1 ("PDI Supplemental Evidence"); and
- The 2021 cost allocation model that Hydro One filed as part of Hydro One's 2018 to 2022 distribution rate application ("Distribution Rate Cost Allocation Model") as part of OEB proceeding EB-2017-0049 at Exhibit G1, Tab 3, Schedule 1, Attachment 4; and
- The relevant sections (i.e. those related to Issue 56) of the OEB's decision and order regarding Hydro One's 2018 to 2022 distribution rate application ("Distribution Rate Decision") as part of OEB proceeding EB-2017-0049.

The proposed approach to cost allocation and rate design described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence incorporates changes relative to the approach outlined in the Distribution Rate Cost Allocation Model. However, several elements are the same, and the Distribution Rate Cost Allocation Model provided Navigant with a worked, numerical, example of the approach upon which to perform a detailed review.

Summary conclusions

Navigant believes that the cost allocation and rate design approaches described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence are appropriate and consistent with accepted regulatory practices.

Basic principles of cost allocation

The primary purpose of cost allocation is to aid in the design of rates. The National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual describes five ways regulators rely on cost allocation studies:

1. To attribute costs to different categories of customers based on how those customers cause costs to be incurred;
2. To determine how costs will be recovered from customers within each customer class;
3. To calculate costs for individual types of service based on the costs each service requires the utility to expend;
4. To determine the revenue requirement for the monopoly services offered by the utility in both monopoly and competitive markets; and
5. To separate shared costs between different regulatory jurisdictions.[1]

Preparing a cost allocation study involves three fundamental steps:

1. Functionalising a utility's costs (e.g., production, transmission, distribution, customer service, general and administrative);
2. Classifying the costs (demand, energy, customer); and
3. Allocating the costs to customer classes.

The result of a cost allocation study is a summation of costs attributed to the provision of service to a group, or class, of customers. The study generally takes as the starting point the utility's prudent costs of doing business. From there, several basic principles guide the process of allocating costs to different customer classes. The foremost principle is cost causation – costs should be borne by those causing the

[1] NARUC. "Electric Utility Cost Allocation Manual". January 1992.

incurrence of such costs or benefitting from the service. Additional guiding principles include ensuring fair allocation between groups and avoiding undue discrimination.

Cost causation refers to an attempt to determine what, or who, is causing costs to be incurred by the utility. Direct assignment is always the preferred approach for attributing costs to customer classes and should be used where a direct link can be made between costs and the service provided to specific customers. However, usually only a small percentage of a utility's costs can be directly assigned because most costs are incurred by a utility to jointly serve many classes of customers. Costs that cannot be directly assigned, such as joint or common costs, are allocated. Utility operational structures may also dictate which costs can be directly assigned to specific customer classes. Utility operations are typically organised to provide service to customers without regard to their rate class.

Cost allocation studies and the resulting attribution of costs to customer classes often appear to be quite precise. In practice, however, any allocation framework requires many assumptions and subjective judgements.

OEB principles of cost allocation for electricity distribution

The OEB established a uniform way to functionalise, classify, and allocate electricity distribution costs to customer classes. The Uniform System of Accounts (USofA) is organised by function and is the required form for functionalising costs incurred by electricity distribution companies. A trial balance by account is one of the first inputs to a cost allocation study. For Ontario electricity distributors, the process of classifying and allocating costs is also standardised through the OEB's cost allocation model (CAM). Through the CAM, each USofA is assigned as either demand- or customer-related (or a combination of both), and specific allocation factors are assigned to spread the relevant costs across customer classes.

Navigant is familiar with the CAM, including the establishment of customer classes and development of allocation factors. Generally, the policies embedded in the CAM are consistent with cost allocation principles and policies employed across the industry in North America.

Navigant is aware of a limited number of exceptions to the standard application of the CAM. Hydro One, for example, has density-based rate classes and applies adjustment factors within the CAM to modify the allocation of costs between the density-based rate classes (e.g., urban, rural, etc.) within a given customer segment (e.g., residential, demand-billed general service, etc.). These exceptions require the approval of the OEB and are thoroughly reviewed through the application process.

Basic principles of rate design

Likely the most widely cited work on utility ratemaking is the 1961 publication “Principles of Public Utility Rates” by Professor James C. Bonbright in which he identified guiding principles for rate design. To paraphrase, rates should be designed:

1. To yield enough revenue to recover costs;
2. Based on a fair apportionment of costs among different customers and avoiding ‘undue discrimination’ in rate relationships;
3. To provide efficient price signals and discourage wasteful usage; and
4. To be relatively stable, predictable, simple, and easy to understand.

The cost allocation study provides the basis for ensuring costs and revenue are apportioned fairly among customer classes. While great effort is expended to identify cost drivers and appropriate allocation factors to spread costs among customer classes, allocation factors are naturally subject to judgment and imprecision.

The theoretical ideal of cost-of-service-based rate design is to develop rates that precisely recover the costs allocated to a respective customer class. When revenue equals allocated costs, the class has a revenue-to-cost ratio of one. In practice, this outcome is rarely achieved. Consequently, it is generally accepted that an appropriate outcome is a revenue-to-cost ratio that falls within a range around one. Determining the appropriate level of tolerance that can be allowed and still result in rates that are just and reasonable is the subject of much debate.

Approaches for tying rate design to cost allocation studies vary widely across Canada and the United States. Navigant has not performed an exhaustive study of standards applied by regulators and public service commissions in each province or state, but we are aware that various policies are followed. Examples range from requiring all classes to be within one percent of cost of service, to simply viewing the cost allocation study as one of many factors to be considered when setting rates. Navigant believes it is generally recognised that allowing a utility flexibility to deviate from a revenue-to-cost ratio of one is an appropriate response to the imprecise cost allocation process and a reasonable approach to balance competing rate design objectives.

OEB principles of rate design for electricity distribution

Like the cost allocation protocols employed in the CAM, the OEB has established standardised classes and a standardised rate structure for each class.

In 2007, the OEB adopted a policy recognising “bands or ranges of tolerance” around revenue-to-cost ratios of one. The OEB concluded that a range approach is preferable to the implementation of a specific revenue-to-cost ratio, stating, “a revenue-to-cost ratio of one may not be achievable or desirable for other reasons (for example, to accommodate different rate design objectives)”.[2] The OEB decision was informed by an analysis of existing ranges in place across electricity distributors, reflecting the assumptions and judgments at the time when determining the respective levels of rates. The OEB approach was an incremental step, moving toward cost-of-service-based rates, and the OEB expects that over time the bands will narrow and move closer to one.

Criteria for assessing whether cost allocation approach described in the OPDC Supplemental Evidence and PDI Supplemental Evidence is appropriate and consistent with accepted regulatory practices

Navigant was asked to review whether Hydro One’s cost allocation as described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence is appropriate and consistent with accepted regulatory practices. Navigant’s review focused on the proposal’s adherence to the principle of cost causation and consistency with methods adopted in the OEB cost allocation model. To the extent Hydro One’s proposal represents a deviation from approved OEB policy, Navigant reviewed the proposed method and associated justification to determine whether the departure remained consistent with general cost allocation principles.

Assessment of Hydro One approach

Hydro One proposed to use the existing CAM framework – in particular, using allocated fixed assets (or plant) and customer numbers as the primary basis for allocating operations, maintenance, and administrative costs, and other elements of Hydro One’s revenue requirement – to determine the cost to serve acquired utility customers.

The OEB’s CAM follows many well-established cost allocation practices for distribution utility functions. Consistent with the principles described in the NARUC Electric Utility Cost Allocation Manual, the CAM classifies plant accounts as either demand or customer related, or a combination of both. The classified plant is allocated based on the contribution of each class to peak demand or total customers. The same

[2] Ontario Energy Board, Application of Cost Allocation for Electricity Distributors, Report of the Board, EB-2007-0667, November 28, 2007.

allocation approach is applied to the depreciation expense. Allocated plant is then used to derive the allocation of most operation and maintenance expenses, which in turn is used to allocate administrative costs.[3] Allocated plant is also used to spread net income, taxes, and interest expense to each customer class.

To distinguish customers in the acquired utility service territory from legacy customers, Hydro One proposed to create unique customer classes for customers from the acquired utility. Hydro One supports the creation of new customer classes stating, "[it] allows Hydro One to allocate to [acquired] customers only the actual cost of fixed assets used to serve them given the customer density and distribution system configuration of [the acquired] service area". To the extent that the cost to serve the acquired utility customer classes is different from the cost to serve Hydro One's legacy customer classes, this is a valid justification for creating unique classes for customers from the acquired utility.

Hydro One proposed to include an adjustment factor within the CAM to modify the gross fixed assets and depreciation expense allocated to the acquired utility customer classes. Hydro One proposed to develop the adjustment factor by comparing the gross value of directly tracked fixed assets plus the gross value of the portion of Hydro One's upstream distribution facilities that supply the acquired customers to the value of gross fixed assets that is allocated to the acquired classes using the CAM's standard demand and customer allocation factors.

Application of the adjustment factor serves three purposes:

1. To restate the gross fixed assets allocated to the acquired customers as if those costs were directly assigned;
2. To restate the depreciation expense allocated to the acquired customers; and
3. To allow the adjusted gross fixed assets by customer class to flow through the CAM to derive allocation factors for accounts that are allocated based on allocated plant.

Direct assignment of gross fixed assets in the acquired utility service territory, quantified as the recorded value of the assets at the time of acquisition plus subsequent capital additions, is the distinguishing feature of Hydro One's proposed approach. Directly tracking the distribution plant in service for the benefit of specific customers provides a basis for allocating operation and maintenance costs, along with shared administrative costs, among acquired and legacy customers and determining the cost to serve each

[3] Customer/bill counts by class are also used to allocate expense in customer-related operations, maintenance and administrative accounts

group. Similar approaches are commonly utilised by multi-jurisdictional utilities with assets and customers dispersed over distinct geographies or regulatory jurisdictions.

As stated previously, direct assignment is always the preferred approach for allocating costs to customer classes and should be used where a direct link can be made between the costs incurred and the service provided to specific customers. Navigant believes the fixed asset adjustment factors are a reasonable representation of a direct assignment of gross plant to the acquired customers.

In Hydro One’s Distribution Rate Cost Allocation Model depreciation expense related to the accounts corresponding to the directly-assigned assets was also scaled by the gross fixed asset adjustment factors. Navigant believes this adjustment is required to match the allocation of gross plant and depreciation expenses.

The downstream impacts of the adjustment factors result in a reasonable allocation of operations, maintenance, and administrative costs and the other elements of Hydro One’s revenue requirement to both the acquired and legacy customers, as the allocation follows the standard approach within the CAM.

In the OPDC Supplemental Evidence and the PDI Supplemental Evidence Hydro One committed to continue to track capital costs to serve acquired customers beyond the Year 11 rebasing and “update the adjustment factors at the time of future cost of service applications”. This commitment is important because it enables Hydro One to maintain the proper apportionment of plant to the acquired customer classes as subsequent capital is invested and other circumstances (e.g., system configuration, customer mix, usage patterns, etc.) in the acquired service territory change.

Navigant believes the cost allocation approach embedded in the CAM is consistent with accepted cost allocation principles and industry practice. Furthermore, the adjustments proposed by Hydro One, provide a reasonable basis for determining the cost to serve the acquired utility customers.

Criteria for assessing whether rate design, in particular the use of revenue-to-cost ratio, as described in the OPDC Supplemental Evidence and PDI Supplemental Evidence is appropriate and consistent with accepted regulatory practices

Navigant was asked to review whether Hydro One’s proposed application of the revenue-to-cost ratio to acquired utility customer classes as described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence is appropriate and consistent with accepted regulatory practices. Navigant’s review focused on whether it is reasonable to establish acquired customer class revenue targets at a revenue-to-cost ratio other than one. Navigant evaluated Hydro One's proposed application of the revenue-to-cost ratio and associated justification to gauge the extent to which it adhered to general rate design principles and OEB policy.

Assessment of Hydro One approach

After the 10-year rate stabilisation period, Hydro One's Year 11 rebasing filing will provide an updated comparison of the costs allocated to each rate class and the revenue collected at then-current rates. Hydro One anticipates adjusting rates and hence the expected revenue recovered from each class as needed to ensure acquired customer classes fall within the OEB approved revenue-to-cost ratio range while at the same time maintaining expected revenue between the status quo and the residual cost to serve the acquired utility customers.

The actual effect of rebasing acquired customer rates through Hydro One's proposed cost allocation method will not be known for many years. At the time of the Year 11 rebasing filing, rates for acquired customers will not have been rebased for a period of at least ten years and are likely to fall short of recovering the allocated costs. For example, in the Distribution Rate Cost Allocation Model several acquired customer rate classes were well within the OEB established revenue-to-cost range, while others were below the low end of the range and required adjustment.

Navigant believes that providing a range of acceptable revenue-to-cost ratios is a reasonable approach to provide the necessary flexibility to recognise the imprecision inherent in cost allocation as a determinant of cost to serve and the need to balance potentially competing rate design objectives such as setting rates that reflect the cost to serve while mitigating large one-time rate increases. Navigant's assessment is grounded in the practical reality that, while theoretically ideal, a revenue-to-cost ratio of one is seldom achieved. For various reasons utility regulators rarely, if ever, set immovable point targets for the revenue-to-cost ratio recognising that flexibility within a range is desirable to enable other fundamental objectives of the rate design process.

Hydro One's proposal, to continue to recognise the OEB-approved revenue-to-cost ratio ranges, provides flexibility when setting rates through which the benefits of the acquisition can be shared between the acquired and legacy customers while protecting the acquired customers from rates that could exceed the status quo cost of service. Over time, Hydro One should view the revenue-to-cost ratios for the acquired rate classes through the same lens it views the revenue-to-cost ratios for similar legacy customer classes. As rates harmonise and the benefits of the acquisition are realised by customers, the range of revenue-to-cost ratios achieved could narrow and trend toward a ratio of one.

ATTACHMENT 18
OPDC Growth in Revenue Requirement Related Elements

The calculation of forecast revenue requirement for the Status Quo scenario was modeled by OPDC.
For the Hydro One Residual scenario, forecast revenue requirement is calculated based on the same model used by Hydro One in the calculation of the ESM, presented in Exhibit A, Tab 3, Schedule 1, of this Application and that in EB-2016-0276.

	2010	2017	2018[1]	2019[1]	2029[1]	2030[1]	2030[1]
OPDC Operating Model Scenario	Status Quo	Status Quo	Status Quo	Status Quo	Residual	Residual	Status Quo
Significance of Year	Most recent OEB rebasing of OPDC rates	Most recent OPDC Audited Financial Year	Bridge Year of OPDC Operation	Bridge Year of OPDC Operation	Year 10 of Deferred Rebasing Period	Year 11 OPDC Rebasing Expected	Year 11 OPDC Rebasing Expected
Source of Data	EB-2009-0273	OPDC 2017 F/Statements	OPDC Forecast	OPDC Forecast	HONI Forecast	HONI Forecast	OPDC Forecast
Years Since Rebasing	N/A	7	8	9	19	20	20
	($000's)	**($000's)**	**($000's)**	**($000's)**	**($000's)**	**($000's)**	**($000's)**
Rate Base	20,806	33,683	35,241	37,742	51,215	52,906	53,678
OM&A	4,346	4,870	5,134	5,431	1,883	1,921	6,754
Depreciation	1,408	1,142	1,275	1,420	1,408	1,433	2,882
Tax	343	59	193	201	210	227	575
Cost of Capital							
Cost of Debt	739	1,197	1,252	1,341	1,329	1,373	1,300
Cost of Equity	820	1,327	1,388	1,487	1,844	1,905	1,932
Total Cost of Capital	**1,559**	**2,524**	**2,641**	**2,828**	**3,173**	**3,277**	**3,232**
Revenue Requirement	**7,656**	**8,595**	**9,243**	**9,880**	**6,675**	**6,859**	**13,443**

[1] Please refer to Attachment 20 to this Application for the list of assumptions used for this forecast period.
[2] Blue Page Updates (02-27-2019) to tax calculation.