EB-2018-0242/0270

HYDRO ONE/PETERBOROUGH/ORILLIA MAADS

COMPENDIUM OF MATERIALS

SCHOOL ENERGY COALITION

SEC INTERROGATORY # 44

Reference:
[I/1/3, p. 2,3]

Interrogatory:
Please update the tables on these pages to reflect the proposals in A/5/1, including the proposed allocation of Shared Costs. If these tables remain valid, please explain why. In either case, please provide details of each adjustment factor applied to the Year 11 figures and the dollar impact of those adjustment factors.

Response:
Below is an update to the tables provided in Exhibit I, Tab 1, Schedule 3 to reflect the assumptions and output from the cost allocation and rate design completed in the response to Exhibits 1, Tab 1, Schedules 48 and 49:

PDI	Today (2019)[1,2,3]	Year 10 (2029) with consolidation[2,3,4]	Year 10 (2029) without consolidation[2,3,5]	Year 11 (2030) with consolidation[6]	Year 11 (2030) without consolidation[2,3,7]
Revenue Collected					
Residential	$9,972,113	$10,778,546	$14,864,540	$11,995,089	$15,259,604
GS < 50kW	$2,654,781	$2,882,231	$3,988,616	$3,262,266	$4,096,265
GS 50-4,999 kW	$3,551,950	$3,904,773	$5,308,166	$3,844,882	$5,449,494
Other	$990,062	$1,078,764	$1,479,201	$1,447,995	$1,518,637
Total	**$17,168,906**	**$18,644,315**	**$25,640,523**	**$20,550,232**	**$26,324,000**
Revenue Collected per Customer					
Residential	$300	$308	$424	$341	$433
GS < 50kW	$749	$741	$1,026	$831	$1,044
GS 50-4,999 kW	$9,567	$9,763	$13,272	$9,543	$13,525
Other	$107	$109	$150	$145	$153
Total	**$370**	**$379**	**$521**	**$415**	**$532**

[1] Total revenue collected from rates is derived by applying approved IRM increases between 2013 and 2019 to the approved revenue collected from rates in 2013.
[2] External revenues are held constant at 2013 approved values.
[3] Estimated values for revenues related to LV charges have been added to the total distribution revenue collected as described in Exhibit A-4-1, pg 3.
[4] Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.55% for 2025-2029.
[5] Total revenue collected (including external revenues) per Exhibit I, Tab 1, Schedule 10, part (d).
[6] Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus $1.5M in estimated revenue collected from the "combined classes").
[7] Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

Hydro One	Today (2019)[1]	Year 10 (2029) with consolidation[2,3]	Year 10 (2029) without consolidation[2,3]	Year 11 (2030) with consolidation[4]	Year 11 (2030) without consolidation[2,3]
Revenue Collected					
Residential (UR)	$97,456,815	$121,420,723	$121,420,723	$134,691,875	$135,017,893
GS<50kW (UGe)	$23,037,678	$28,770,504	$28,770,504	$28,030,967	$28,101,853
GS>50kW (UGd)	$28,548,646	$35,752,868	$35,752,868	$31,931,011	$32,017,420
Other	$1,348,816,751	$1,685,459,484	$1,685,459,484	$1,710,108,678	$1,714,555,596
Total	**$1,497,859,890**	**$1,871,403,579**	**$1,871,403,579**	**$1,904,762,530**	**$1,909,692,763**
Revenue Collected per Customer					
Residential (UR)	$424	$469	$469	$515	$517
GS<50kW (UGe)	$1,276	$1,520	$1,520	$1,472	$1,475
GS>50kW (UGd)	$16,413	$19,665	$19,665	$17,458	$17,506
Other	$1,275	$1,504	$1,504	$1,519	$1,523
Total	**$1,146**	**$1,337**	**$1,337**	**$1,353**	**$1,356**

[1] Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[2] Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.

[3] External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[4] Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus $1.5M in estimated revenue collected from the "combined classes").

Please refer to Exhibit I, Tab 1, Schedule 48 (b) for details on the adjustment factors applied in calculating the Year 11 figures.

OEB STAFF INTERROGATORY # 12

Reference:

Exhibit A-4-1

Interrogatory:

Questions:

a) Please provide a table which estimates Hydro One and OPDC revenue requirements and revenue requirements per customer:

i. Today (e.g. 2019)
ii. In Year 10 with the proposed consolidation
iii. In Year 10 without the proposed consolidation
iv. In Year 11 with the proposed consolidation, including all costs that are expected to be allocated to OPDC
v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, General Service greater than 50 kW and total of all customer types (i.e. total revenue requirement).

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, pleas ensure that they do.

Response:

a) The tables below provide the requested information for Hydro One's Urban rate classes and OPDC.

OPDC	Today (2019)[1,2,3]	Year 10 (2029) with consolidation[2,3,4]	Year 10 (2029) without consolidation[2,3,5]	Year 11 (2030) with consolidation[6]	Year 11 (2030) without consolidation[2,3,7]
Revenue Requirement					
Residential	$4,471,729	$4,886,300	$7,110,967	$5,073,009	$7,281,348
GS < 50kW	$1,623,718	$1,779,756	$2,602,179	$1,538,976	$2,665,364
GS 50-4,999 kW	$2,400,644	$2,676,069	$3,798,964	$2,385,875	$3,889,680
Other	$363,045	$395,662	$596,908	$588,293	$611,972
Total	**$8,859,135**	**$9,737,786**	**$14,109,018**	**$9,586,153**	**$14,448,364**
Revenue Requirement per Customer					
Residential	$357	$356	$518	$366	$526
GS < 50kW	$1,155	$1,162	$1,699	$997	$1,726
GS 50-4,999 kW	$14,430	$14,958	$21,234	$13,241	$21,587
Other	$90	$95	$143	$140	$146
Total	**$489**	**$496**	**$719**	**$485**	**$731**

[1] Total revenue collected from rates is derived by applying approved IRM increases between 2010 and 2019 to the approved revenue collected from rates in 2010.

[2] External revenues are held constant at 2010 approved values.

[3] Estimated values for revenues related to LV charges have been added to the total distribution revenue collected (refer to Exhibit I, Tab 3, Schedule 9).

[4] Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.7% for 2025-2029.

[5] Total revenue collected (including external revenues) per Exhibit I, Tab 2, Schedule 17.

[6] Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus $0.6M in estimated revenue collected from the "combined classes").

[7] Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

Hydro One	Today (2019)[1]	Year 10 (2029) with consolidation[2,3]	Year 10 (2029) without consolidation[2,3]	Year 11 (2030) with consolidation[4]	Year 11 (2030) without consolidation[2,3]
Revenue Requirement					
Residential (UR)	$97,456,815	$121,420,723	$121,420,723	$137,202,655	$137,390,232
GS<50kW (UGe)	$23,037,678	$28,770,504	$28,770,504	$28,015,108	$28,054,505
GS>50kW (UGd)	$28,548,646	$35,752,868	$35,752,868	$31,919,505	$31,966,604
Other	$1,348,816,751	$1,685,459,484	$1,685,459,484	$1,709,828,767	$1,712,281,421
Total	**$1,497,859,890**	**$1,871,403,579**	**$1,871,403,579**	**$1,906,966,036**	**$1,909,692,763**
Revenue Requirement per Customer					
Residential (UR)	$424	$469	$469	$525	$526
GS<50kW (UGe)	$1,276	$1,520	$1,520	$1,471	$1,473
GS>50kW (UGd)	$16,413	$19,665	$19,665	$17,452	$17,478
Other	$1,275	$1,504	$1,504	$1,519	$1,521
Total	**$1,146**	**$1,337**	**$1,337**	**$1,354**	**$1,356**

[1] Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[2] Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.

[3] External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[4] Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus $0.6M in estimated revenue collected from the "combined classes").

b) Confirmed.

Comparison of Assumed Cost Per Customer Increases

Rate Class	*2019*	*2030*	*Increase*	*CAGR*
Hydro One				
UR	$424.00	$517.00	21.93%	1.82%
UGe	$1,276.00	$1,475.00	15.60%	1.33%
UGd	$16,413.00	$17,506.00	6.66%	0.58%
Orillia (no deal)				
Residential	$357.00	$526.00	47.34%	3.58%
GS<50	$1,155.00	$1,726.00	49.44%	3.72%
GS>50	$14,430.00	$21,587.00	49.60%	3.73%
Peterborough (no deal)				
Residential	$300.00	$433.00	44.33%	3.46%
GS<50	$749.00	$1,044.00	39.39%	3.07%
GS>50	$9,567.00	$13,525.00	41.37%	3.20%

Sources:

EB-2018-0242 SEC #44

EB-2018-0270 Staff #12

MR. HARPER: Okay.

MR. ANDRE: Then in terms of the second part of your question, so the number there, the equivalent number there is the $20,550,000, and that is the revenue that would be collected from those PDI customers.

MR. HARPER: Right. Then when you go down, I think there is a comparable part for the Hydro One part, and that's with consolidation and that would show the revenue to be collected from the, you know, the revenue collected --

MR. ANDRE: That's correct.

MR. HARPER: -- it's the same -- okay, no, that's fine.

MR. ANDRE: So it's the revenue collected. So it's got some of the revenue that has been -- that's being collected from the PDI customers, to the extent that there's been some shared costs that are now being collected. The combination of those two is the -- aligns with the cost allocation model.

MR. HARPER: It also has the fact that for most classes, the revenue-to-cost is one sort of thing. So it isn't the allocated costs; it is the costs that will be collected.

MR. ANDRE: Collected, that's correct.

MR. HARPER: I have to figure out where I am now, now that you have managed to --

MR. ANDRE: Skip through a few questions?

MR. HARPER: Exactly. That's great. So if we could to staffing where we might have part-time or contract or temporary workers that are allowing us, in this period of uncertainty, to keep the utility running as we should run it.

However, if the regulatory decision is to decline this approval, we've got to look at it as if -- essentially regroup. We're doing a distribution system plan. We're filing a cost of service. There's a couple of years' worth of work there, as you well know.

But we've got to essentially reset the utility going forward and say, you know, okay we brought back a retiree on a part time contract basis to help us out in this time of uncertainty. Going forward, if we're running this utility, we would probably make a different decision. We would go out and hire a full time person. They would be on, you know, our pension and benefits plan.

So those costs are essentially worked into these numbers going forward and then from 2020 to 2030, as Mr. Hurley said, we'd essentially use an inflationary factor of 2 percent a year.

MR. SHEPHERD: So, Mr. Hurley, how much is -- that five million 542 for 2020, how much is that more than 2018 actual?

MR. HURLEY: It is about $500,000 more.

MR. SHEPHERD: So your status quo is about five million more over the ten years than what you're spending right now?

MR. HURLEY: How much did you say?

MR. SHEPHERD: Five million, $500,000 a year for ten years.

MR. HURLEY: Oh, okay. That's fair. Inflated by 2 percent.

MR. SHEPHERD: I am going to stop there. Thank you very much.

MR. MILLAR: Thank you, Mr. Shepherd. I would like to go a few minutes more before our break.

Mr. Kehoe, I know you travelled here from out of town and would probably prefer to get done today. Are you prepared to ask your questions?

MR. KEHOE: Yes.

MR. MILLAR: Are you prepared to go?

MR. KEHOE: I've got it here.

EXAMINATION BY MR. KEHOE:

MR. KEHOE: Now, in the discussion, we're in a scenario that Ontario Power, at least Orillia Power Distribution here is under pressure from the municipality not to sell at any cost to supplement their agenda.

There isn't a situation anywhere that you could say would run a comparison between the debt that Hydro One has to assume and the record refurbishing of Darlington and the power lines that were built in the 1950s, that they could even remotely compete with Orillia's distribution.

Orillia's distribution has held a long-time record as being in the lowest 5 percent of all the collective municipal utilities. And they did so with the work ethic that their employees had, and a goal to work totally in the status quo?

MR. SHEPHERD: Yes.

MR. HURLEY: Yes, we did that.

MR. SHEPHERD: You did that. Okay. So what's the assumed long-term debt rate in your status quo?

MR. HURLEY: We used the latest available Board-approved rates that we had at the time, and I believe it was 4.16.

MR. SHEPHERD: So you did not use the 6.25 on the note?

MR. HURLEY: No, we did not.

MR. SHEPHERD: But that's --

MR. HURLEY: That is looking out to 2030. We went all the way out using 4.16.

MR. SHEPHERD: But Hydro One, when you did the ESM calculation, you used 6.25, right?

MR. FLANNERY: That's correct, for the ESM it uses the rates embedded in Orillia's last approved cost of service.

MR. SHEPHERD: So if we looked at the difference between the interest in the status quo calculation and the ESM calculation, that's that difference of 6.25 to 4.16? You didn't make any other adjustments?

MR. FLANNERY: No.

MR. SHEPHERD: Okay. And Hydro One's long-term debt rate, is it lower than 4.16 or higher?

MR. FLANNERY: The recently approved Hydro One Distribution debt grade in its last application was higher than the Board's 2019 approved cost of capital, I believe.

MR. SHEPHERD: It is like 4.3 or 4.25 or something, right?

MR. FLANNERY: It is higher. I think it is in, it is in A-3-1 and I can -- let's check. It may not be in A-03-01. It may be in attachment 20 to either application. I believe the number is -- so this is attachment 20, page 2 -- 4.47.

MR. SHEPHERD: All right. And then also on number 3, SEC number 3, you talk about the increase in capital expenditures for the new OPDC operation centre.

Now, first I want to ask the question of OPDC. You have a plan that if you are not acquired, you are going to have to build a new op centre, right?

MR. HIPGRAVE: That's correct.

MR. SHEPHERD: And that's in roughly 2027, 2028?

MR. HIPGRAVE: I believe in the schedules it falls in 2028, assuming that year one is 2020.

MR. SHEPHERD: Now, you actually have a sort of a fairly urgent need for that, don't you?

MR. HIPGRAVE: Urgent is a relative term. We began a process in 2013 of having a full-scale building assessment done by professionals. And as a result of that, there was obviously, you know, options to repair, refurbish or replace.

And at that time the decision was that we would begin the process of looking to design a new building, as that was the most -- the best fit really going forward for the organization, the best business decision.

willing to show us how you calculated that 9-million-880?
MR. HURLEY: It's a very big model. I mean, it is not that I am -- I am not trying to be uncooperative. I just don't understand why you need it.
MR. SHEPHERD: Okay, so I will explain. So your existing rates have in them a ROE which is about 100 basis points higher than the current rate, right?
MR. HURLEY: A hundred basis points -- we're at 9.85, yes.
MR. SHEPHERD: Right. Your existing rates have a working capital allowance of 15 percent, right?
MR. HURLEY: Correct.
MR. SHEPHERD: Your existing rates have your old depreciation rates, right?
MR. HURLEY: Sorry?
MR. SHEPHERD: They have your old depreciation rates.
MR. HURLEY: Yes.
MR. SHEPHERD: Not the new ones.
MR. HURLEY: Correct.
MR. SHEPHERD: There's a bunch of changes like that that are quite significant. Is that true?
MR. HURLEY: Yes. To go forward, yes, there are.
MR. SHEPHERD: And so what I would like to see is how did you take those into account to get to an increase in revenue requirement when you are already making lots of money.
We can see -- you have reported already what you're making.

line 2, the one thing I would point out is you can see in the historical, just out of interest, 2015 is where we actually did the one substation that I referred to. Not all of the cost is in that distribution station line. I referred to it being 2.1, but you can also see the run rate on the actual capital spend and distribution stations has been by band-aid. There hasn't been any money spent.

And then forecasting going forward, I think that we're looking probably at one a year over the next nine years.

MR. SHEPHERD: So then I want to ask the same --

MR. JOHN STEPHENSON: I could get more detail for you for -- roughly.

MR. SHEPHERD: That's good. So how many distribution stations, substations are in the Hydro One plan?

MR. FALTOUS: So this plan has been developed to be able to address the risks associated with six substations for Peterborough over the ten years.

MR. SHEPHERD: So whereas they were going to replace nine, based on their very close knowledge of the situation, you are only going to replace six?

MR. FALTOUS: I think, to clarify -- so the approach that we take to asset investments is based on condition. It may not be based on age and it may be a little bit different than Peterborough's.

So, you know, what we deemed was a prudent number to address over the ten years was six in this particular case.

MR. SHEPHERD: Thank you.

MS. GIRVAN: Can I just follow up? Is there any way for Hydro One to provide more detailed assumptions regarding how they derived their forecast? Because we have two numbers that are significantly different based on the same service territory, and I think what everybody is trying to understand is how do we test -- how do we test that evidence?

How do we look at what Peterborough says they are required to do, which we see in front of us on the screen, versus what Hydro One is saying that's required, which is considerably less than this?

MR. SHEPHERD: Could you prepare something like attachment 1 to SEC 23?

[Hydro One witness panel confers]

MR. FALTOUS: Yes, so I would like to clarify that the investment is actually not materially different.

As I mentioned, if you look at the total numbers over the ten years, Hydro One's numbers are $60 million, and Peterborough's are 65.

So I would not say that is a significant difference. It is less than 10 percent of a difference in terms of investment.

MR. SHEPHERD: Let me just stop you there. If your unit costs are much higher and clearly your rate base is much higher, so they probably are, then you are actually doing a lot less work for the same money.

MR. FALTOUS: No, that is not the case. Don't forget that Hydro One has -- there are savings as a result of the economic efficiencies that we have talked about that are

MS. RICHARDSON: It is for the shareholders to cover their acquisition premium costs as per the Board's policies.

After the deferral period, then all customers, as we show in evidence, both legacy and acquired customers, will benefit from the transaction.

MR. SHEPHERD: Now, in SEC number 8 -- I am specifically looking at B, so B, we said, do you have any studies showing that on all of these other acquisitions the costs to serve those acquired customers went down because of your acquisition?

And in B you have refused to answer the question. So -- because you say the past acquisitions are not relevant. And the reason I am saying it is relevant is because you have claimed that there is going to be savings. If you never had savings before, then your claim is probably wrong.

MS. RICHARDSON: So...

[Witness panel confers]

MS. RICHARDSON: So you're talking about the transactions that occurred ten, 20 years ago, and those costs weren't tracked. But what we have tracked is the costs for our recently-acquired utilities, Norfolk, Woodstock, and Haldimand, and the evidence in the rate filing, the distribution rate filing, which you are familiar with, Mr. Shepherd -- was that in 2021, we had planned to increase the revenue requirement for Hydro One Networks by 10.7 million, which was the incremental cost to serve those customers.

Our legacies' revenue requirement would still only be increased by the inflation factor which was allowed for Hydro One.

Our evidence is also that the status quo of those utilities would have been, on a OM&A basis, 20.2 million and we have reduced it to 10.7.

So we do have evidence of our recent acquisitions. We just did not track it back in 2010.

MR. SHEPHERD: So my question was going to be -- you've refused because my question was irrelevant. And that is what it says.

And my question is: Do you have any studies about -- of the costs to serve previous acquisitions, prior to Norfolk. Do you have any studies like that?

MS. RICHARDSON: No, we do not.

MR. SHEPHERD: Why not?

MR. KEIZER: Well, first of all, it continues to be irrelevant. Given the fact that the Board in considering the no-harm test should be considering it in the context of the evidence related to the particular transaction, and a review of previous transactions isn't relevant to this transaction. And that's Hydro One's position.

MR. SHEPHERD: Well, of course, what the Board has said in the distribution case is you told us there would be no harm and now we find out that these guys have rate increases, that's not okay. Isn't that what the Board said?

MR. KEIZER: Well, I am not going to interpret the Board's decision here today for that purpose.

But I think certainly a distinguishing factor is that was at the end of a deferral period -- and I don't want to get into a debate or submissions as to what the Board said or didn't say in that case.

What the Board is to do in this case is to consider what it believes to be the consequence of the transaction going forward for this particular transaction, based upon these particular forecasts of status quo and otherwise.

MR. SHEPHERD: And so, Mr. Keizer, I am inviting you to provide whatever evidence you have that your past acquisitions have resulted in lower costs to serve those customers.

If you have no evidence of that, that's great, but I am inviting you to file it.

MR. KEIZER: And my response to it is whether there is or there isn't is irrelevant, and that is the position of Hydro One.

MR. SHEPHERD: All right. Remember where the onus is. Okay. My next question is on SEC 10.

I am not sure I understand why in the ESM model Hydro One used a 6.25 debt rate, when clearly that isn't what would normally happen and it isn't what you are going to in fact pay in debt costs, and it isn't what would happen if there was no transaction.

It's not one of the possible futures. So I am not sure I understand why 6.25 makes sense.

Comparison of Distribution Rate Increases 2005 to 2013 to 2019 - Hydro One Acquired Distributors - Residential

Monthly Consumption *750 kwhr*

Acquired Distributor	Rate	2005 Dx. Rates			2013 Dx. Rates			Inc. 2005	2019 Dx. Rates			Inc. 2013	Inc. 2005
	Class	Fixed	Variable	Annual	Fixed	Variable	Annual	to 2013	Fixed	Variable	Annual	to 2019	to 2019
Hydro One (Ailsa Craig)	R1	$7.67	0.00660	$151.44	$23.85	0.03353	$587.97	288.25%	$27.89	0.03227	$625.11	6.32%	312.78%
Hydro One (Arkona)	R1	$3.93	0.00210	$66.06	$23.85	0.03353	$587.97	790.05%	$27.89	0.03227	$625.11	6.32%	846.28%
Hydro One (Arnprior	R1	$8.49	0.01170	$207.18	$23.85	0.03353	$587.97	183.80%	$27.89	0.03227	$625.11	6.32%	201.72%
Hydro One (Arran-Elderside)	R1	$6.47	0.00760	$146.04	$23.85	0.03353	$587.97	302.61%	$27.89	0.03227	$625.11	6.32%	328.04%
Hydro One (Artemesia)	R1	$9.44	0.00590	$166.38	$23.85	0.03353	$587.97	253.39%	$27.89	0.03227	$625.11	6.32%	275.71%
Hydro One (Bancroft)	R1	$10.04	0.00760	$188.88	$23.85	0.03353	$587.97	211.29%	$27.89	0.03227	$625.11	6.32%	230.96%
Hydro One (Bath)	R1	$9.96	0.00690	$181.62	$23.85	0.03353	$587.97	223.74%	$27.89	0.03227	$625.11	6.32%	244.19%
Hydro One (Blandford-Blenheim)	R1	$8.56	0.00720	$167.52	$23.85	0.03353	$587.97	250.98%	$27.89	0.03227	$625.11	6.32%	273.16%
Hydro One (Blyth)	R1	$5.01	0.00730	$125.82	$23.85	0.03353	$587.97	367.31%	$27.89	0.03227	$625.11	6.32%	396.83%
Hydro One (Bobcaygeon)	R1	$10.83	0.00780	$200.16	$23.85	0.03353	$587.97	193.75%	$27.89	0.03227	$625.11	6.32%	212.31%
Hydro One (Brighton)	R1	$8.54	0.00860	$179.88	$23.85	0.03353	$587.97	226.87%	$27.89	0.03227	$625.11	6.32%	247.52%
Hydro One (Caledon CH 02)	R1	$11.41	0.00820	$210.72	$23.85	0.03353	$587.97	179.03%	$27.89	0.03227	$625.11	6.32%	196.65%
Hydro One (Campbellford/Seymour)	R1	$9.10	0.00860	$186.60	$23.85	0.03353	$587.97	215.10%	$27.89	0.03227	$625.11	6.32%	235.00%
Hydro One (Cavan-Millbrook-N. Monaghan)	R1	$11.27	0.01070	$231.54	$23.85	0.03353	$587.97	153.94%	$27.89	0.03227	$625.11	6.32%	169.98%
Hydro One (Centre Hastings)	R1	$8.59	0.00770	$172.38	$23.85	0.03353	$587.97	241.09%	$27.89	0.03227	$625.11	6.32%	262.63%
Hydro One (Chalk River)	R1	$10.48	0.01090	$223.86	$23.85	0.03353	$587.97	162.65%	$27.89	0.03227	$625.11	6.32%	179.24%
Hydro One (Champlain Twp.)	R1	$7.55	0.00710	$154.50	$23.85	0.03353	$587.97	280.56%	$27.89	0.03227	$625.11	6.32%	304.60%
Hydro One (Clarence-Rockland)	R1	$6.78	0.00740	$147.96	$23.85	0.03353	$587.97	297.38%	$27.89	0.03227	$625.11	6.32%	322.49%
Hydro One (Cobden)	R1	$9.86	0.01410	$245.22	$23.85	0.03353	$587.97	139.77%	$27.89	0.03227	$625.11	6.32%	154.92%
Hydro One (Deep River)	R1	$12.55	0.01830	$315.30	$23.85	0.03353	$587.97	86.48%	$27.89	0.03227	$625.11	6.32%	98.26%
Hydro One (Deseronto)	R1	$9.57	0.00890	$194.94	$23.85	0.03353	$587.97	201.62%	$27.89	0.03227	$625.11	6.32%	220.67%
Hydro One (Dundalk)	R1	$10.83	0.00870	$208.26	$23.85	0.03353	$587.97	182.32%	$27.89	0.03227	$625.11	6.32%	200.16%
Hydro One (Durham)	R1	$12.34	0.00990	$237.18	$23.85	0.03353	$587.97	147.90%	$27.89	0.03227	$625.11	6.32%	163.56%
Hydro One (Eganville)	R1	$10.34	0.01220	$233.88	$23.85	0.03353	$587.97	151.40%	$27.89	0.03227	$625.11	6.32%	167.28%
Hydro One (Erin)	R1	$9.76	0.01520	$253.92	$23.85	0.03353	$587.97	131.56%	$27.89	0.03227	$625.11	6.32%	146.18%
Hydro One (Exeter)	R1	$11.34	0.00770	$205.38	$23.85	0.03353	$587.97	186.28%	$27.89	0.03227	$625.11	6.32%	204.37%
Hydro One (Fenelon Falls)	R1	$4.13	0.00770	$118.86	$23.85	0.03353	$587.97	394.67%	$27.89	0.03227	$625.11	6.32%	425.92%
Hydro One (Forest)	R1	$11.46	0.00760	$205.92	$23.85	0.03353	$587.97	185.53%	$27.89	0.03227	$625.11	6.32%	203.57%
Hydro One (Georgian Bay Energy - Chatsworth)	R1	$7.00	0.00760	$152.40	$23.85	0.03353	$587.97	285.81%	$27.89	0.03227	$625.11	6.32%	310.18%
Hydro One (Georgina)	R1	$8.63	0.00790	$174.66	$23.85	0.03353	$587.97	236.64%	$27.89	0.03227	$625.11	6.32%	257.90%
Hydro One (Glencoe)	R1	$9.58	0.00620	$170.76	$23.85	0.03353	$587.97	244.33%	$27.89	0.03227	$625.11	6.32%	266.08%
Hydro One (Grand Bend)	R1	$10.12	0.00700	$184.44	$23.85	0.03353	$587.97	218.79%	$27.89	0.03227	$625.11	6.32%	238.92%
Hydro One (Hastings)	R1	$12.41	0.01080	$246.12	$23.85	0.03353	$587.97	138.90%	$27.89	0.03227	$625.11	6.32%	153.99%
Hydro One (Havelock-Belmont-Methuen)	R1	$11.40	0.00910	$218.70	$23.85	0.03353	$587.97	168.85%	$27.89	0.03227	$625.11	6.32%	185.83%
Hydro One (Kirkfield)	R1	$3.53	0.00800	$114.36	$23.85	0.03353	$587.97	414.14%	$27.89	0.03227	$625.11	6.32%	446.62%
Hydro One (Lanark Highlands)	R1	$8.30	0.00820	$173.40	$23.85	0.03353	$587.97	239.08%	$27.89	0.03227	$625.11	6.32%	260.50%
Hydro One (Larder Lake)	R1	$11.93	0.00810	$216.06	$23.85	0.03353	$587.97	172.13%	$27.89	0.03227	$625.11	6.32%	189.32%
Hydro One (Latchford)	R1	$9.90	0.00710	$182.70	$23.85	0.03353	$587.97	221.82%	$27.89	0.03227	$625.11	6.32%	242.15%

Hydro One (Lucan/Granton)	R1	$8.63	0.01130	$205.26	$23.85	0.03353	$587.97	186.45%	$27.89	0.03227	$625.11	6.32%	204.55%
Hydro One (Malahide Twp.)	R1	$8.19	0.00700	$161.28	$23.85	0.03353	$587.97	264.56%	$27.89	0.03227	$625.11	6.32%	287.59%
Hydro One (Mapleton Twp.)	R1	$10.03	0.00740	$186.96	$23.85	0.03353	$587.97	214.49%	$27.89	0.03227	$625.11	6.32%	234.35%
Hydro One (Markdale)	R1	$10.70	0.00690	$190.50	$23.85	0.03353	$587.97	208.65%	$27.89	0.03227	$625.11	6.32%	228.14%
Hydro One (Marmora)	R1	$8.53	0.00740	$168.96	$23.85	0.03353	$587.97	247.99%	$27.89	0.03227	$625.11	6.32%	269.98%
Hydro One (McGarry Twp.)	R1	$9.54	0.00750	$181.98	$23.85	0.03353	$587.97	223.10%	$27.89	0.03227	$625.11	6.32%	243.50%
Hydro One (Meaford)	R1	$9.46	0.00780	$183.72	$23.85	0.03353	$587.97	220.04%	$27.89	0.03227	$625.11	6.32%	240.25%
Hydro One (Middlesex Centre)	R1	$10.61	0.00630	$184.02	$23.85	0.03353	$587.97	219.51%	$27.89	0.03227	$625.11	6.32%	239.70%
Hydro One (Napanee)	R1	$11.02	0.00820	$206.04	$23.85	0.03353	$587.97	185.37%	$27.89	0.03227	$625.11	6.32%	203.39%
Hydro One (Nipigon Twp.)	R1	$11.33	0.01310	$253.86	$23.85	0.03353	$587.97	131.61%	$27.89	0.03227	$625.11	6.32%	146.24%
Hydro One (North Dorchester Twp.)	R1	$6.43	0.00690	$139.26	$23.85	0.03353	$587.97	322.21%	$27.89	0.03227	$625.11	6.32%	348.88%
Hydro One (North Dundas Twp.)	R1	$8.19	0.00780	$168.48	$23.85	0.03353	$587.97	248.99%	$27.89	0.03227	$625.11	6.32%	271.03%
Hydro One (North Glengarry Twp.)	R1	$5.45	0.00820	$139.20	$23.85	0.03353	$587.97	322.39%	$27.89	0.03227	$625.11	6.32%	349.07%
Hydro One (North Grenville - Kemptville)	R1	$10.78	0.01320	$248.16	$23.85	0.03353	$587.97	136.93%	$27.89	0.03227	$625.11	6.32%	151.90%
Hydro One (North Perth - Listowel)	R1	$11.04	0.00840	$208.08	$23.85	0.03353	$587.97	182.57%	$27.89	0.03227	$625.11	6.32%	200.42%
Hydro One (North Stormont)	R1	$3.59	0.00740	$109.68	$23.85	0.03353	$587.97	436.08%	$27.89	0.03227	$625.11	6.32%	469.94%
Hydro One (Omemee)	R1	$11.25	0.01200	$243.00	$23.85	0.03353	$587.97	141.96%	$27.89	0.03227	$625.11	6.32%	157.25%
Hydro One (Perth East Twp.)	R1	$4.02	0.00630	$104.94	$23.85	0.03353	$587.97	460.29%	$27.89	0.03227	$625.11	6.32%	495.68%
Hydro One (Prince Edward County)	R1	$10.66	0.00840	$203.52	$23.85	0.03353	$587.97	188.90%	$27.89	0.03227	$625.11	6.32%	207.15%
Hydro One (Quinte West - Frankford)	R1	$4.52	0.00740	$120.84	$23.85	0.03353	$587.97	386.57%	$27.89	0.03227	$625.11	6.32%	417.30%
Hydro One (Rainy River)	R1	$11.41	0.00840	$212.52	$23.85	0.03353	$587.97	176.67%	$27.89	0.03227	$625.11	6.32%	194.14%
Hydro One (Ramara Twp.)	R1	$4.47	0.00760	$122.04	$23.85	0.03353	$587.97	381.78%	$27.89	0.03227	$625.11	6.32%	412.22%
Hydro One (Red Rock Twp.)	R1	$12.04	0.01800	$306.48	$23.85	0.03353	$587.97	91.85%	$27.89	0.03227	$625.11	6.32%	103.96%
Hydro One (Russell)	R1	$9.74	0.01150	$220.38	$23.85	0.03353	$587.97	166.80%	$27.89	0.03227	$625.11	6.32%	183.65%
Hydro One (Schreiber Twp.)	R1	$12.31	0.01470	$280.02	$23.85	0.03353	$587.97	109.97%	$27.89	0.03227	$625.11	6.32%	123.24%
Hydro One (Severn Twp)	R1	$7.74	0.00720	$157.68	$23.85	0.03353	$587.97	272.89%	$27.89	0.03227	$625.11	6.32%	296.44%
Hydro One (Shelburne)	R1	$10.57	0.01060	$222.24	$23.85	0.03353	$587.97	164.57%	$27.89	0.03227	$625.11	6.32%	181.28%
Hydro One (South Bruce Peninsula - Wiarton)	R1	$11.92	0.01240	$254.64	$23.85	0.03353	$587.97	130.90%	$27.89	0.03227	$625.11	6.32%	145.49%
Hydro One (South Glengarry)	R1	$6.82	0.00600	$135.84	$23.85	0.03353	$587.97	332.84%	$27.89	0.03227	$625.11	6.32%	360.18%
Hydro One (South River)	R1	$10.63	0.01000	$217.56	$23.85	0.03353	$587.97	170.26%	$27.89	0.03227	$625.11	6.32%	187.33%
Hydro One (Springwater Twp.)	R1	$8.69	0.00660	$163.68	$23.85	0.03353	$587.97	259.22%	$27.89	0.03227	$625.11	6.32%	281.91%
Hydro One (Stirling-Rawdon Twp.)	R1	$9.30	0.00830	$186.30	$23.85	0.03353	$587.97	215.60%	$27.89	0.03227	$625.11	6.32%	235.54%
Hydro One (Thedford)	R1	$9.46	0.00650	$172.02	$23.85	0.03353	$587.97	241.80%	$27.89	0.03227	$625.11	6.32%	263.39%
Hydro One (Thessalon)	R1	$11.70	0.00840	$216.00	$23.85	0.03353	$587.97	172.21%	$27.89	0.03227	$625.11	6.32%	189.40%
Hydro One (Thorndale)	R1	$2.71	0.00710	$96.42	$23.85	0.03353	$587.97	509.80%	$27.89	0.03227	$625.11	6.32%	548.32%
Hydro One (Tweed)	R1	$2.84	0.00760	$102.48	$23.85	0.03353	$587.97	473.74%	$27.89	0.03227	$625.11	6.32%	509.98%
Hydro One (Wardsville)	R1	$6.97	0.00780	$153.84	$23.85	0.03353	$587.97	282.20%	$27.89	0.03227	$625.11	6.32%	306.34%
Hydro One (Warkworth)	R1	$11.45	0.00940	$222.00	$23.85	0.03353	$587.97	164.85%	$27.89	0.03227	$625.11	6.32%	181.58%
Hydro One (West Elgin)	R1	$9.89	0.01130	$220.38	$23.85	0.03353	$587.97	166.80%	$27.89	0.03227	$625.11	6.32%	183.65%
Hydro One (Woodville)	R1	$2.28	0.00760	$95.76	$23.85	0.03353	$587.97	514.00%	$27.89	0.03227	$625.11	6.32%	552.79%
Hydro One (Wyoming)	R1	$8.47	0.00650	$160.14	$23.85	0.03353	$587.97	267.16%	$27.89	0.03227	$625.11	6.32%	290.35%
Averages - Hydro One Medium Density Acquireds		$8.92	0.00877	$185.91	$23.85	0.03353	$587.97	216.26%	$27.89	0.03227	$625.11	6.32%	236.24%

Hydro One (Brockville)	UR	$9.12	0.00750	$176.94	$16.50	0.02529	$425.61	140.54%	$19.57	0.01779	$394.95	-7.20%	123.21%
Hydro One (Caledon OH 01)	UR	$14.07	0.00460	$210.24	$16.50	0.02529	$425.61	102.44%	$19.57	0.01779	$394.95	-7.20%	87.86%
Hydro One (Carleton Place)	UR	$10.59	0.01430	$255.78	$16.50	0.02529	$425.61	66.40%	$19.57	0.01779	$394.95	-7.20%	54.41%
Hydro One (Dryden)	UR	$10.68	0.01320	$246.96	$16.50	0.02529	$425.61	72.34%	$19.57	0.01779	$394.95	-7.20%	59.92%
Hydro One (Georgian Bay Energy - Owen Sound)	UR	$7.00	0.00860	$161.40	$16.50	0.02529	$425.61	163.70%	$19.57	0.01779	$394.95	-7.20%	144.70%
Hydro One (Lindsay)	UR	$11.90	0.00810	$215.70	$16.50	0.02529	$425.61	97.32%	$19.57	0.01779	$394.95	-7.20%	83.10%
Hydro One (Perth)	UR	$10.83	0.00970	$217.26	$16.50	0.02529	$425.61	95.90%	$19.57	0.01779	$394.95	-7.20%	81.79%
Hydro One (Quinte West - Trenton)	UR	$4.52	0.00740	$120.84	$16.50	0.02529	$425.61	252.21%	$19.57	0.01779	$394.95	-7.20%	226.84%
Hydro One (Smiths Falls)	UR	$9.36	0.01130	$214.02	$16.50	0.02529	$425.61	98.86%	$19.57	0.01779	$394.95	-7.20%	84.54%
Hydro One (Thorold)	UR	$10.20	0.01170	$227.70	$16.50	0.02529	$425.61	86.92%	$19.57	0.01779	$394.95	-7.20%	73.45%
Hydro One (Whitchurch-Stouffville)	UR	$7.69	0.00820	$166.08	$16.50	0.02529	$425.61	156.27%	$19.57	0.01779	$394.95	-7.20%	137.81%
Averages - Hydro One Urban Acquireds		$9.63	0.00951	$201.17	$16.50	0.02529	$425.61	111.56%	$19.57	0.01779	$394.95	-7.20%	96.32%
Hydro One Legacy	R1	$15.99	0.02100	$380.88	$23.85	0.03353	$587.97	54.37%	$27.89	0.03227	$625.11	6.32%	64.12%
Hydro One Legacy	UR	$11.82	0.01610	$286.74	$16.50	0.02529	$425.61	48.43%	$19.57	0.01779	$394.95	-7.20%	37.74%

Comparison of Distribution Rate Increases 2005 to 2013 to 2019 - Hydro One Acquired Distributors - General Service

Monthly Consumption *100 kW*

Acquired Distributor	Rate Class	2005 Dx. Rates			2013 Dx. Rates			Inc. 2005 to 2013	2019 Dx. Rates			Inc. 2013 to 2019	Inc. 2005 to 2019
		Fixed	Variable	Annual	Fixed	Variable	Annual		Fixed	Variable	Annual		
Hydro One (Ailsa Craig)	GSd	$13.11	3.35000	$4,177.32	$55.62	11.37000	$14,311.44	242.60%	$106.94	20.25300	$25,586.88	78.79%	512.52%
Hydro One (Arkona)	GSd	$1.82	1.58000	$1,917.84	$55.62	11.37000	$14,311.44	646.23%	$106.94	20.25300	$25,586.88	78.79%	1234.15%
Hydro One (Arnprior	GSd	$16.36	2.96000	$3,748.32	$55.62	11.37000	$14,311.44	281.81%	$106.94	20.25300	$25,586.88	78.79%	582.62%
Hydro One (Arran-Elderside)	GSd	$6.32	2.63000	$3,231.84	$55.62	11.37000	$14,311.44	342.83%	$106.94	20.25300	$25,586.88	78.79%	691.71%
Hydro One (Artemesia)	GSd	$14.95	4.40000	$5,459.40	$55.62	11.37000	$14,311.44	162.14%	$106.94	20.25300	$25,586.88	78.79%	368.68%
Hydro One (Bancroft)	GSd	$18.78	2.96000	$3,777.36	$55.62	11.37000	$14,311.44	278.87%	$106.94	20.25300	$25,586.88	78.79%	577.37%
Hydro One (Bath)	GSd	$7.78	3.01000	$3,705.36	$55.62	11.37000	$14,311.44	286.24%	$106.94	20.25300	$25,586.88	78.79%	590.54%
Hydro One (Blandford-Blenheim)	GSd	$18.34	2.90000	$3,700.08	$55.62	11.37000	$14,311.44	286.79%	$106.94	20.25300	$25,586.88	78.79%	591.52%
Hydro One (Blyth)	GSd	$16.56	2.69000	$3,426.72	$55.62	11.37000	$14,311.44	317.64%	$106.94	20.25300	$25,586.88	78.79%	646.69%
Hydro One (Bobcaygeon)	GSd	$17.82	3.48000	$4,389.84	$55.62	11.37000	$14,311.44	226.01%	$106.94	20.25300	$25,586.88	78.79%	482.87%
Hydro One (Brighton)	GSd	$17.58	3.39000	$4,278.96	$55.62	11.37000	$14,311.44	234.46%	$106.94	20.25300	$25,586.88	78.79%	497.97%
Hydro One (Caledon CH 02)	GSd	$18.62	4.58000	$5,719.44	$55.62	11.37000	$14,311.44	150.22%	$106.94	20.25300	$25,586.88	78.79%	347.37%
Hydro One (Campbellford/Seymour)	GSd	$12.21	3.01000	$3,758.52	$55.62	11.37000	$14,311.44	280.77%	$106.94	20.25300	$25,586.88	78.79%	580.77%
Hydro One (Cavan-Millbrook-N. Monaghan)	GSd	$17.08	3.74000	$4,692.96	$55.62	11.37000	$14,311.44	204.96%	$106.94	20.25300	$25,586.88	78.79%	445.22%
Hydro One (Centre Hastings)	GSd	$13.96	2.46000	$3,119.52	$55.62	11.37000	$14,311.44	358.77%	$106.94	20.25300	$25,586.88	78.79%	720.22%
Hydro One (Chalk River)	GSd	$16.32	4.56000	$5,667.84	$55.62	11.37000	$14,311.44	152.50%	$106.94	20.25300	$25,586.88	78.79%	351.44%
Hydro One (Champlain Twp.)	GSd	$15.73	2.31000	$2,960.76	$55.62	11.37000	$14,311.44	383.37%	$106.94	20.25300	$25,586.88	78.79%	764.20%
Hydro One (Clarence-Rockland)	GSd	$5.07	2.07000	$2,544.84	$55.62	11.37000	$14,311.44	462.37%	$106.94	20.25300	$25,586.88	78.79%	905.44%
Hydro One (Cobden)	GSd	$16.80	5.19000	$6,429.60	$55.62	11.37000	$14,311.44	122.59%	$106.94	20.25300	$25,586.88	78.79%	297.95%
Hydro One (Deep River)	GSd	$18.41	5.75000	$7,120.92	$55.62	11.37000	$14,311.44	100.98%	$106.94	20.25300	$25,586.88	78.79%	259.32%
Hydro One (Deseronto)	GSd	$7.37	3.08000	$3,784.44	$55.62	11.37000	$14,311.44	278.17%	$106.94	20.25300	$25,586.88	78.79%	576.11%
Hydro One (Dundalk)	GSd	$18.11	4.14000	$5,185.32	$55.62	11.37000	$14,311.44	176.00%	$106.94	20.25300	$25,586.88	78.79%	393.45%
Hydro One (Durham)	GSd	$18.55	3.45000	$4,362.60	$55.62	11.37000	$14,311.44	228.05%	$106.94	20.25300	$25,586.88	78.79%	486.51%
Hydro One (Eganville)	GSd	$16.34	5.88000	$7,252.08	$55.62	11.37000	$14,311.44	97.34%	$106.94	20.25300	$25,586.88	78.79%	252.82%
Hydro One (Erin)	GSd	$31.56	1.89000	$2,646.72	$55.62	11.37000	$14,311.44	440.72%	$106.94	20.25300	$25,586.88	78.79%	866.74%
Hydro One (Exeter)	GSd	$8.34	3.29000	$4,048.08	$55.62	11.37000	$14,311.44	253.54%	$106.94	20.25300	$25,586.88	78.79%	532.07%
Hydro One (Fenelon Falls)	GSd	$15.10	2.42000	$3,085.20	$55.62	11.37000	$14,311.44	363.87%	$106.94	20.25300	$25,586.88	78.79%	729.34%
Hydro One (Forest)	GSd	$19.18	2.99000	$3,818.16	$55.62	11.37000	$14,311.44	274.83%	$106.94	20.25300	$25,586.88	78.79%	570.14%
Hydro One (Georgian Bay Energy - Chatsworth)	GSd	$7.88	2.91000	$3,586.56	$55.62	11.37000	$14,311.44	299.03%	$106.94	20.25300	$25,586.88	78.79%	613.41%
Hydro One (Georgina)	GSd	$13.18	4.08000	$5,054.16	$55.62	11.37000	$14,311.44	183.16%	$106.94	20.25300	$25,586.88	78.79%	406.25%
Hydro One (Glencoe)	GSd	$8.35	2.04000	$2,548.20	$55.62	11.37000	$14,311.44	461.63%	$106.94	20.25300	$25,586.88	78.79%	904.12%
Hydro One (Grand Bend)	GSd	$17.01	3.12000	$3,948.12	$55.62	11.37000	$14,311.44	262.49%	$106.94	20.25300	$25,586.88	78.79%	548.08%
Hydro One (Hastings)	GSd	$17.57	4.26000	$5,322.84	$55.62	11.37000	$14,311.44	168.87%	$106.94	20.25300	$25,586.88	78.79%	380.70%
Hydro One (Havelock-Belmont-Methuen)	GSd	$17.00	3.86000	$4,836.00	$55.62	11.37000	$14,311.44	195.94%	$106.94	20.25300	$25,586.88	78.79%	429.09%
Hydro One (Kirkfield)	GSd	$11.01	4.73000	$5,808.12	$55.62	11.37000	$14,311.44	146.40%	$106.94	20.25300	$25,586.88	78.79%	340.54%
Hydro One (Lanark Highlands)	GSd	$14.00	4.21000	$5,220.00	$55.62	11.37000	$14,311.44	174.17%	$106.94	20.25300	$25,586.88	78.79%	390.17%
Hydro One (Larder Lake)	GSd	$15.40	3.44000	$4,312.80	$55.62	11.37000	$14,311.44	231.84%	$106.94	20.25300	$25,586.88	78.79%	493.28%
Hydro One (Latchford)	GSd	$1.56	1.95000	$2,358.72	$55.62	11.37000	$14,311.44	506.75%	$106.94	20.25300	$25,586.88	78.79%	984.78%
Hydro One (Lucan/Granton)	GSd	$12.85	3.69000	$4,582.20	$55.62	11.37000	$14,311.44	212.33%	$106.94	20.25300	$25,586.88	78.79%	458.40%
Hydro One (Malahide Twp.)	GSd	$12.05	4.34000	$5,352.60	$55.62	11.37000	$14,311.44	167.37%	$106.94	20.25300	$25,586.88	78.79%	378.03%
Hydro One (Mapleton Twp.)	GSd	$16.50	4.34000	$5,406.00	$55.62	11.37000	$14,311.44	164.73%	$106.94	20.25300	$25,586.88	78.79%	373.31%
Hydro One (Markdale)	GSd	$17.66	2.03000	$2,647.92	$55.62	11.37000	$14,311.44	440.48%	$106.94	20.25300	$25,586.88	78.79%	866.30%
Hydro One (Marmora)	GSd	$7.27	2.66000	$3,279.24	$55.62	11.37000	$14,311.44	336.43%	$106.94	20.25300	$25,586.88	78.79%	680.27%
Hydro One (McGarry Twp.)	GSd	$15.40	4.54000	$5,632.80	$55.62	11.37000	$14,311.44	154.07%	$106.94	20.25300	$25,586.88	78.79%	354.25%

Hydro One (Meaford)	GSd	$18.49	3.12000	$3,965.88	$55.62	11.37000	$14,311.44	260.86%	$106.94	20.25300	$25,586.88	78.79%	545.18%
Hydro One (Middlesex Centre)	GSd	$13.14	2.64000	$3,325.68	$55.62	11.37000	$14,311.44	330.33%	$106.94	20.25300	$25,586.88	78.79%	669.37%
Hydro One (Napanee)	GSd	$16.99	3.23000	$4,079.88	$55.62	11.37000	$14,311.44	250.78%	$106.94	20.25300	$25,586.88	78.79%	527.15%
Hydro One (Nipigon Twp.)	GSd	$17.91	2.70000	$3,454.92	$55.62	11.37000	$14,311.44	314.23%	$106.94	20.25300	$25,586.88	78.79%	640.59%
Hydro One (North Dorchester Twp.)	GSd	$11.96	2.28000	$2,879.52	$55.62	11.37000	$14,311.44	397.01%	$106.94	20.25300	$25,586.88	78.79%	788.58%
Hydro One (North Dundas Twp.)	GSd	$10.07	1.94000	$2,448.84	$55.62	11.37000	$14,311.44	484.42%	$106.94	20.25300	$25,586.88	78.79%	944.86%
Hydro One (North Glengarry Twp.)	GSd	$13.43	2.26000	$2,873.16	$55.62	11.37000	$14,311.44	398.11%	$106.94	20.25300	$25,586.88	78.79%	790.55%
Hydro One (North Grenville - Kemptville)	GSd	$15.59	4.33000	$5,383.08	$55.62	11.37000	$14,311.44	165.86%	$106.94	20.25300	$25,586.88	78.79%	375.32%
Hydro One (North Perth - Listowel)	GSd	$22.87	2.53000	$3,310.44	$55.62	11.37000	$14,311.44	332.31%	$106.94	20.25300	$25,586.88	78.79%	672.91%
Hydro One (North Stormont)	GSd	$3.55	2.02000	$2,466.60	$55.62	11.37000	$14,311.44	480.21%	$106.94	20.25300	$25,586.88	78.79%	937.33%
Hydro One (Omemee)	GSd	$16.28	3.71000	$4,647.36	$55.62	11.37000	$14,311.44	207.95%	$106.94	20.25300	$25,586.88	78.79%	450.57%
Hydro One (Perth East Twp.)	GSd	$10.98	3.26000	$4,043.76	$55.62	11.37000	$14,311.44	253.91%	$106.94	20.25300	$25,586.88	78.79%	532.75%
Hydro One (Prince Edward County)	GSd	$17.54	3.56000	$4,482.48	$55.62	11.37000	$14,311.44	219.28%	$106.94	20.25300	$25,586.88	78.79%	470.82%
Hydro One (Quinte West - Frankford)	GSd	$2.25	2.65000	$3,207.00	$55.62	11.37000	$14,311.44	346.26%	$106.94	20.25300	$25,586.88	78.79%	697.84%
Hydro One (Rainy River)	GSd	$14.69	4.47000	$5,540.28	$55.62	11.37000	$14,311.44	158.32%	$106.94	20.25300	$25,586.88	78.79%	361.83%
Hydro One (Ramara Twp.)	GSd	$16.03	2.68000	$3,408.36	$55.62	11.37000	$14,311.44	319.89%	$106.94	20.25300	$25,586.88	78.79%	650.71%
Hydro One (Red Rock Twp.)	GSd	$16.57	4.92000	$6,102.84	$55.62	11.37000	$14,311.44	134.50%	$106.94	20.25300	$25,586.88	78.79%	319.26%
Hydro One (Russell)	GSd	$14.67	5.68000	$6,992.04	$55.62	11.37000	$14,311.44	104.68%	$106.94	20.25300	$25,586.88	78.79%	265.94%
Hydro One (Schreiber Twp.)	GSd	$15.82	5.89000	$7,257.84	$55.62	11.37000	$14,311.44	97.19%	$106.94	20.25300	$25,586.88	78.79%	252.54%
Hydro One (Severn Twp)	GSd	$16.99	2.68000	$3,419.88	$55.62	11.37000	$14,311.44	318.48%	$106.94	20.25300	$25,586.88	78.79%	648.18%
Hydro One (Shelburne)	GSd	$15.26	2.23000	$2,859.12	$55.62	11.37000	$14,311.44	400.55%	$106.94	20.25300	$25,586.88	78.79%	794.92%
Hydro One (South Bruce Peninsula - Wiarton)	GSd	$18.28	4.79000	$5,967.36	$55.62	11.37000	$14,311.44	139.83%	$106.94	20.25300	$25,586.88	78.79%	328.78%
Hydro One (South Glengarry)	GSd	$13.19	1.90000	$2,438.28	$55.62	11.37000	$14,311.44	486.95%	$106.94	20.25300	$25,586.88	78.79%	949.38%
Hydro One (South River)	GSd	$16.94	3.90000	$4,883.28	$55.62	11.37000	$14,311.44	193.07%	$106.94	20.25300	$25,586.88	78.79%	423.97%
Hydro One (Springwater Twp.)	GSd	$15.68	2.73000	$3,464.16	$55.62	11.37000	$14,311.44	313.13%	$106.94	20.25300	$25,586.88	78.79%	638.62%
Hydro One (Stirling-Rawdon Twp.)	GSd	$18.55	3.29000	$4,170.60	$55.62	11.37000	$14,311.44	243.15%	$106.94	20.25300	$25,586.88	78.79%	513.51%
Hydro One (Thedford)	GSd	$13.52	2.70000	$3,402.24	$55.62	11.37000	$14,311.44	320.65%	$106.94	20.25300	$25,586.88	78.79%	652.06%
Hydro One (Thessalon)	GSd	$14.38	2.58000	$3,268.56	$55.62	11.37000	$14,311.44	337.85%	$106.94	20.25300	$25,586.88	78.79%	682.82%
Hydro One (Thorndale)	GSd	$10.87	2.60000	$3,250.44	$55.62	11.37000	$14,311.44	340.29%	$106.94	20.25300	$25,586.88	78.79%	687.18%
Hydro One (Tweed)	GSd	$5.87	2.49000	$3,058.44	$55.62	11.37000	$14,311.44	367.93%	$106.94	20.25300	$25,586.88	78.79%	736.60%
Hydro One (Wardsville)	GSd	$9.11	2.53000	$3,145.32	$55.62	11.37000	$14,311.44	355.01%	$106.94	20.25300	$25,586.88	78.79%	713.49%
Hydro One (Warkworth)	GSd	$16.31	3.58000	$4,491.72	$55.62	11.37000	$14,311.44	218.62%	$106.94	20.25300	$25,586.88	78.79%	469.65%
Hydro One (West Elgin)	GSd	$11.57	1.77000	$2,262.84	$55.62	11.37000	$14,311.44	532.45%	$106.94	20.25300	$25,586.88	78.79%	1030.74%
Hydro One (Woodville)	GSd	$12.77	3.47000	$4,317.24	$55.62	11.37000	$14,311.44	231.50%	$106.94	20.25300	$25,586.88	78.79%	492.67%
Hydro One (Wyoming)	GSd	$13.15	3.66000	$4,549.80	$55.62	11.37000	$14,311.44	214.55%	$106.94	20.25300	$25,586.88	78.79%	462.37%
Averages - Hydro One Medium Density Acquireds		$14.10	3.30544	$4,135.77	$55.62	11.37000	$14,311.44	246.04%	$106.94	20.25300	$25,586.88	78.79%	518.67%
Hydro One (Brockville)	UGd	$16.58	1.99000	$2,586.96	$32.32	6.91400	$8,684.64	235.71%	$111.74	11.54800	$15,198.48	75.00%	487.50%
Hydro One (Caledon OH 01)	UGd	$19.71	4.28000	$5,372.52	$32.32	6.91400	$8,684.64	61.65%	$111.74	11.54800	$15,198.48	75.00%	182.89%
Hydro One (Carleton Place)	UGd	$18.18	4.25000	$5,318.16	$32.32	6.91400	$8,684.64	63.30%	$111.74	11.54800	$15,198.48	75.00%	185.78%
Hydro One (Dryden)	UGd	$14.55	2.64000	$3,342.60	$32.32	6.91400	$8,684.64	159.82%	$111.74	11.54800	$15,198.48	75.00%	354.69%
Hydro One (Georgian Bay Energy - Owen Sound)	UGd	$7.88	2.91000	$3,586.56	$32.32	6.91400	$8,684.64	142.14%	$111.74	11.54800	$15,198.48	75.00%	323.76%
Hydro One (Lindsay)	UGd	$18.41	3.49000	$4,408.92	$32.32	6.91400	$8,684.64	96.98%	$111.74	11.54800	$15,198.48	75.00%	244.72%
Hydro One (Perth)	UGd	$15.19	2.30000	$2,942.28	$32.32	6.91400	$8,684.64	195.17%	$111.74	11.54800	$15,198.48	75.00%	416.55%
Hydro One (Quinte West - Trenton)	UGd	$2.25	2.65000	$3,207.00	$32.32	6.91400	$8,684.64	170.80%	$111.74	11.54800	$15,198.48	75.00%	373.92%
Hydro One (Smiths Falls)	UGd	$7.13	2.66000	$3,277.56	$32.32	6.91400	$8,684.64	164.97%	$111.74	11.54800	$15,198.48	75.00%	363.71%
Hydro One (Thorold)	UGd	$17.36	3.81000	$4,780.32	$32.32	6.91400	$8,684.64	81.67%	$111.74	11.54800	$15,198.48	75.00%	217.94%
Hydro One (Whitchurch-Stouffville)	UGd	$16.73	2.35000	$3,020.76	$32.32	6.91400	$8,684.64	187.50%	$111.74	11.54800	$15,198.48	75.00%	403.13%
Averages - Hydro One Urban Acquireds		$14.00	3.03000	$3,803.97	$32.32	6.91400	$8,684.64	128.30%	$111.74	11.54800	$15,198.48	75.00%	299.54%

86 percent, but, yes, it is below one.

MR. SHEPHERD: And when you forecast the savings for these customers at the time of the MAADs applications, did you tell them what their rates were going to be when they were brought into Hydro One?

MR. ANDRE: No, as I recollect the discussion about rates was we laid out several options in terms of how their rates might be set at the time of rate harmonization. That was a matter that was not discussed as part of the MAADs application, per the rules, my understanding, anyway, of how MAAD applications are intended to work, but there was just -- there was no discussion of the rates specifically, there was only a discussion of the process that would be used for setting the rates.

MR. SHEPHERD: And at that time you expected to use the old method, didn't you, that your original plan was that you would simply fold these acquired utilities into your legacy rate classes and harmonize, right, as you did with the other 92 you've acquired?

MR. ANDRE: I believe that was one of the options. I think we laid that as one option. We could create new rate classes to serve them was the other option, and I think the third one was, you know -- I can't recall, but I do recall there was a third, more generic option, so the potential to create new classes was discussed at the time of the MAADs, as far as I can recollect. I don't know if it was for all three, but I know that was discussed.

MR. SHEPHERD: So during the -- for these three acquired utilities, you have had savings, right? You have had savings over the last seven, eight years that you've owned them, or the total seven, eight years until you integrated, right?

MR. ANDRE: That's my understanding, yes.

MR. SHEPHERD: But you said -- and if you go to page 54 of K10.7, you said at the technical conference -- and I'm quoting you on line 23, "The savings are to Hydro One as a whole." Right? It's not savings to the acquired customers, it's savings to the enterprise, and then you have to figure out who gets them, right?

MR. ANDRE: Yes, so as an example, if the utilities had stayed on their own I think they would have been spending 19.7 million on OM&A costs and when they are integrated into Hydro One there is only a ten point -- I can't remember -- 10.1 or 10.7 in incremental OM&A, 10.7, my colleague confirms -- so that's the incremental OM&A that Hydro One has to spend to serve those same acquireds, as opposed to the 19.7 in OM&A that they would have served had they remained independent.

MR. SHEPHERD: Well, that's not their savings, though, right? That is total savings, because you are actually allocating 17 million to acquired customers; right?

MR. ANDRE: That is the savings to Hydro One to serve both its existing customers and the acquired customers.

MR. SHEPHERD: So here's where I'm going with this: I'm right, am I not, that for the 92 acquisitions you did before these three, you simply folded them all in, and they went into the -- your existing rate classes; it took a while, because some of them had big rate increases, right?

MR. ANDRE: That's right, it took -- the integration period for some of the classes was four years.

MR. SHEPHERD: And it's true that some of them had two, three, four hundred percent rate increases, right?

MR. ANDRE: I recall there was one utility -- it was Ailsa Craig -- that did have a significant increase. I can't remember the exact amount, Mr. Shepherd.

MR. SHEPHERD: Well, lots of them had very significant increases, right? Lots of them had more than 100 percent increases, right?

MR. ANDRE: Well, and I think it was that experience, in terms of attempting to fold acquired utilities into Hydro One's existing rate structure that drove the Board in the decisions for these three acquired utilities to say, no, you have to make sure that you charge them their cost to serve, because by being folded into either our R2 or R1 class, yes, it did generate those kinds of large impacts, and I think it drove the thinking with respect to the new -- the three acquired utilities.

MR. SHEPHERD: So issue 56 in this proceeding says -- and I can read it:

> "Due to costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings."

And you've tried to do that by taking a new approach to both cost allocation and rate design for acquireds;

Hydro One anticipates this new approach will achieve similar benefits but on an accelerated pace due to the increased system coverage enabled by a shorter cycle and a refined scope. The new strategy will quickly reduce the maintenance backlog and enable program optimization. The shorter cycles will improve public safety, reliability, and asset condition providing a more detailed understanding of current and future workloads. Shorter cycles will also reduce customer and environmental impacts due to more frequent, less impactful maintenance.

2.2 UPDATE OF COST ALLOCATION TO NEW ACQUIRED CUSTOMER CLASSES AND COMPARISON OF BILL IMPACTS

As discussed in Section 2.2.3 of Exhibit G1, Tab 3, Schedule 1, Hydro One developed adjustment factors for use in the 2021 Cost Allocation Model ("CAM") to ensure that the costs allocated to the six new acquired residential and general service rate classes (AUR, AUGe, AUGd, AR, AGSe and AGSd) appropriately reflect the cost of serving the customers in these rate classes. Hydro One continues to believe the overall methodology used to develop the adjustment factors is appropriate. However, upon further consideration, Hydro One submits that it is appropriate to also include the cost of distribution stations in its adjustment factor calculations. The proposed change, rationale and results of making this change are described in the following sections.

The updated cost allocation, rates and bill impacts evidence provided below was prepared with reference to Hydro One's 2021 and 2022 revenue requirement as proposed in the Application as of June 2017. The changes to the 2021 and 2022 revenue requirement that will result from the updates discussed in Section 1 of this Exhibit are not captured by the updated evidence provided below. Hydro One notes that the 2021 revenue requirement of $1,684 million shown in Table 2 of this Exhibit is only $4 million (0.2%) higher than the revenue requirement underpinning the revised cost allocation, rates and bill impacts that are presented in the sections that follow. As such, the difference in revenue requirement will not materially impact the analysis and conclusions that are presented below.

2.2.1 Including Distribution Station Equipment in the Calculation of Adjustment Factors

In Exhibit G1, Tab 3, Schedule 1, section 2.2.3, Hydro One stated that adjustment factors were developed to align the amount of gross fixed assets ("GFA") in USofA accounts 1830 to 1860 (i.e. poles, towers, fixtures, overhead/underground conductors and devices, line transformers and meters) allocated by the CAM for these locally used assets with the amount of GFA specifically required to serve the new acquired rate classes. Upon further consideration since filing its Application, Hydro One has added distribution station equipment (USofA accounts 1815 to 1820) to the assets that should be included in the adjustment factor calculations. Similar to the assets covered by USofA accounts 1830 to 1860, distribution stations can be considered "local" assets that are essentially used to serve just the new acquired rate classes. As such, it is appropriate and necessary that USofA accounts 1815 and 1820 also be included in the GFA adjustment factor calculations.

The change in the GFA adjustment factor in turn impacts the calculation of the NFA and NFA ECC allocators in the CAM's "E2 Allocator" tab, which are adjusted using the same methodology as described in the Application.

Similarly, the depreciation adjustment factor has also been revised to include the depreciation assigned by the CAM to USofA accounts 1815 to 1820 for the new acquired rate classes using the same methodology as described in the Application.

In addition, Hydro One has also made a correction to two items: i) a correction to the 2015 year-end GFA values used for Haldimand and Norfolk in determining the GFA adjustment factor, and ii) including USofA 1830-5 Secondary poles in the calculation of the depreciation adjustment factor. The impact of these corrections is minor and is noted for the sake of transparency. The changes to the allocation of overall costs, shown below, are mainly driven by the proposed change to the allocation of distribution station equipment.

2.2.2 Costs Allocated to the Acquired Classes

The 2021 CAM has been updated with the revised adjustment factors as described above. Adding distribution station equipment costs to the adjustment factor calculations has reduced the costs allocated to the new acquired rate classes by about $5.5 million, or 12%, when compared to the 2021 CAM included in the Application as of June 2017. The revised costs allocated to each of the acquired rate classes are shown in the "O1 Revenue to Cost Output Sheet" provided in Attachment 3. The revised CAM has also been provided in MS Excel format as Q-01-01-03.xlsx. As a result of this change, the updated revenue-to-cost ratios of the six new acquired rate classes are much closer to the OEB-approved range, as shown in Table 11 below.

Table 11: Impact of Updated Cost Allocation on Revenue-to-Cost Ratios

Rate Class	2021 R/C Ratio from the CAM	
	Evidence (June 2017)	Updated Cost Allocation
UR	1.10	1.10
R1	1.10	1.10
R2	0.97	0.97
Seasonal	1.11	1.10
GSe	1.00	1.00
GSd	0.93	0.92
UGe	1.01	1.00
UGd	0.91	0.90

UNDERTAKING – JT 3.21

Undertaking

To provide an explanation that shows for 1815 and 1820, or for all of them, what was allocated in March and how and what was allocated in June and how.

Response

The table below summarizes the values for USofAs 1815 and 1820 that were initially allocated to the new acquired rate classes in the 2021 CAM, compared to the adjusted values allocated to the acquired classes using the cost allocation approach described in Exhibit G1, Tab 3, Schedule 1 (March 2017 and June 2017), and Exhibit Q, Tab 1, Schedule 1 Section 2.2 (December 2017).

		Application (March 2017)		Blue Page Update (June 2017) (Note 1)		Exhibit Q Update (December 2017) (Note 2)	
USofA	**USofA Description**	**Allocated by CAM**	**After Adjustment to CAM Allocation**	**Allocated by CAM**	**After Adjustment to CAM Allocation**	**Allocated by CAM**	**After Adjustment to CAM Allocation**
1815	Transformer station equip - above 50kV	$7,335,788	$7,335,788	$7,788,401	$ 7,788,401	$7,788,401	$9,212,494
1820	Distribution station equip - below 50kV	$41,646,316	$41,646,316	$40,639,443	$40,639,443	$40,639,443	$8,223,341

Witness: ANDRE Henry

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
13																		
14			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
15	ID and Factors	Total	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	AUR	AUGe	AUGd
151																sume no density adjustment on acquire		
152	Density Factors		1.000	1.900	4.800	3.600	2.400	2.200	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
162																		
163	DCP1	6,243,791	426,417	1,124,090	971,897	117,469	317,774	296,363	94,027	107,301	120,546	2,713	3,878	10,880	2,594,035	25,276	9,071	22,055
164	DCP4	23,810,775	1,753,984	4,165,467	3,417,006	384,270	1,216,713	1,245,467	362,208	486,164	46,182	5,844	15,586	26,479	10,461,621	93,332	33,492	96,963
165	DCP12	65,104,491	4,676,562	10,730,684	8,775,129	987,462	3,371,522	3,649,203	997,896	1,440,425	120,546	14,777	47,127	66,807	29,633,994	201,255	102,794	288,308
166																		
257																		
258	DCP1-DA	6,243,791	147,145	736,997	1,609,803	145,927	366,602	346,620	45,198	57,044	120,546	2,713	3,878	10,880	2,594,035	25,276	9,071	22,055
259	DCP4-DA	23,810,775	621,053	2,802,337	5,807,511	489,826	1,404,685	1,470,686	174,236	260,944	46,182	5,844	15,586	26,479	10,461,621	93,332	33,492	96,963
260	DCP12-DA	65,104,491	1,663,949	7,254,279	14,986,768	1,264,842	3,889,721	4,315,366	479,696	774,261	120,546	14,777	47,127	66,807	29,633,994	201,255	102,794	288,308

As long as that split is in between those goalposts, that's going to be what we say is a fair allocation.

It might be more to legacy customers; it might be more to the acquired customers. But it's the output of the cost allocation and rate design process.

MR. SHEPHERD: And you don't have a plan for what happens if it's not within the goalposts, right?

MR. ANDRE: No, we do. There's a number of IR responses that have dealt with what would happen if you fall outside those goalposts.

Like if the results of the model would say collect more from the acquired customers than their status quo costs would have been, our proposal is we back off the revenue-to-cost ratios to ensure that only the maximum savings that was generated by the acquisition flows to legacy customers.

We are not going to allocate more than the savings generated by the acquisition to legacy customers. We are going to cap it at that value.

Then at the other end, we do the same. If we -- you know, if we were proposing to actually allocate less than the residual costs --

MR. SHEPHERD: Which would be surprising.

MR. ANDRE: -- which would be surprising, but in that case we would bump up the revenue-to-cost ratios to make sure we had at a minimum collect that residual cost.

MR. SHEPHERD: Isn't that exactly the same methodology you put to the Board in 2017-0049, the allocation with adjusting factors and play with the revenue-to-cost ratios?

MR. ANDRE: Yeah, we didn't -- as I said earlier, I don't think we did as good a job as we could have in terms of explaining those goalposts. That was our argument, that those costs fell in between.

But I don't know that we did a good enough job. Obviously, we didn't do a good enough job explaining it to the Board so they understood that principle and understood the inherent fairness in that principle.

MR. SHEPHERD: So aside from refinements to the adjustment factors -- because I understand you have improved the adjustment factors, right, in that process?

MR. ANDRE: Yes.

MR. SHEPHERD: But aside from that, you are basically saying to the Board we want you to approve what you refused to approve in 0049, but this time we're giving you better information so that you will understand it better.

MR. ANDRE: I think we've done a much better job of explaining our proposals around the goalposts in the evidence that is part of this application.

MR. SHEPHERD: Thank you.

MR. PIETREWICZ: I will leave it with one more question from me, and leave it to others to determine where we go next.

I would like to turn our attention to on PDI again, SEC 43. That's Exhibit I, tab 2, schedule 11 -- I'm sorry, schedule 43, page 1 of 1 of SEC 43.

And what this table shows is some estimates of monthly factors from the model.

MR. SHEPHERD: It would certainly be 10- or 20- or $30 million higher, right?

MR. ANDRE: I don't know about the exact quantum, but, yes, it would be notably higher.

MR. SHEPHERD: All right. So here's why I am asking the question. So you have got these 92 acquireds that you have already got in the fold, and then you have got these three new ones. Is it 92? Is that right? Niagara-on-the-Lake said 92, but you said 80 plus --

MR. ANDRE: 89 -- I thought it was 89, and then there was another one -- it's around 90, Mr. Shepherd. I don't know the exact number.

MR. SHEPHERD: Let's say 90 and we will pretend it's right. If -- so those -- the customers in those acquired utilities are paying -- they have a different deal than these ones. This is what you said on Tuesday. They have a different approach to their rates being set. They go into the regular classes, and so the costs that they are bearing are significantly higher than these acquireds; right? It was not just the 46 million, as you say, it's higher than that.

MR. ANDRE: You're correct. The costs are higher, Mr. Shepherd. The proposal around the integration of those 90 acquired utilities was fully explored as part of the 2006 application, and there would have been different circumstances around those 90. I mean, some of those 90 utilities included utilities that had 300 customers, 400 assets required and the number of customers. That's obviously a factor as well for a number of the US of As.

But the asset-related costs will be tied to the specific assets required to serve it.

MR. SHEPHERD: And part of the reason why you are doing that is because you can't actually allocate the shared costs because in order to allocate the shared costs, you'd have to know what they were.

MR. ANDRE: I mean, we know that they are everything over and above the incremental costs, that's how we've...

MR. SHEPHERD: But you don't know what the total cost is to serve the OPDC or PDI customers without any adjustment factors. You don't know that number.

MR. ANDRE: It's a cost -- I mean, you can't know that number. I mean, we certainly know the incremental costs that are required, OM&A and capital. We know the incremental costs that are required to serve the acquired utilities.

But in terms of the total costs, the only way to get that is to go through the cost allocation process.

MR. SHEPHERD: Okay. So can you provide for the Board -- you have already provided the CAM for 2030 with the adjustment factors, right.

Can you provide the CAM for 2030 without the adjustment factors, treating those customers in PDI and OPDC just as if they were the same as any other customers in any other city; density, everything else. Can you do that run?

MR. ANDRE: No. I mean, the density factor we don't have. We haven't run a study to look at what that density -- you know, what that density factor should be for each of those communities, like PDI and Orillia.

MR. SHEPHERD: I am pretty sure you answered that question already. I am pretty sure you told us they're both in the urban class.

MR. ANDRE: They're in the urban class, but the specific -- that density factor construct that we use for some of our other classes couldn't easily be applied. I don't know how I would apply that to the -- right now, how I would apply that to the acquired utilities.

MR. SHEPHERD: I thought it was binary. You either met the test or you don't.

MR. ANDRE: What is binary?

MR. SHEPHERD: The density factor. You are either in the class that has the higher density or you are not. Right?

MR. ANDRE: Yes. But what you were saying is run it without the adjustment factors, and you're saying put them into your urban classes?

MR. SHEPHERD: Yes.

MR. ANDRE: So that will get you closer to what the Board had asked us to do, which was make sure that you charge them their costs to serve.

MR. SHEPHERD: Yes.

MR. ANDRE: But as I said, even the urban and general service energy and demand classes, there is still an element of averaging. But something that I haven't mentioned which is even more important is the whole minimum system and PLCC adjustment.

For Hydro One, that drives a very different allocation of costs to the residential versus the general service demand class.

MR. SHEPHERD: I understand.

MR. ANDRE: And right now, by keeping them as separate classes with the adjustment factor applied to assets, we're able to maintain that split so that the existing customers don't see a big jump.

If we were to bring them into the Hydro One classes, you would see that big disparity in the general service because we would be applying Hydro One's minimum system and PLCC adjustment.

MR. SHEPHERD: Well, you would also be increasing the percentage of your customers that were in the urban classes, which would fundamentally affect your other classes, right?

MR. ANDRE: Yes. If you group them together, yeah, you would be changing the complete results of the model.

And it's not -- you know, the Board -- something that just sort of dawned on me is that the Board in their consolidation handbook, Mr. Shepherd, makes it very clear. On page 18 of that book, they say a utility has the ability -- when you have an acquisition, you can either put them this into one of your existing classes or create a new rate class to put your acquired customers into.

And I think the goal is whatever best reflects the costs to serve.

So our view is that creating a new rate class where you accurately identify the assets required to serve them is the best way to achieve that.

MR. SHEPHERD: So are you refusing to provide a copy of the -- or a run of the cost allocation model that treats the customers of OPDC and PDI the same as legacy customers with similar characteristics? Are you refusing to provide that?

MR. ANDRE: Yes.

MR. SHEPHERD: We know you can do it. The question is will you.

MR. ANDRE: Yes. They would be similar and they would not accurately reflect the costs to serve those acquired customers as our proposal does.

MR. SHEPHERD: So are you refusing to provide it, yes or no?

MR. KEIZER: Yes, we are refusing to provide it.

MR. SHEPHERD: Okay. And so then I am on SEC 40. page 4, and this is, I think, for OPDC.

So in 2018, you paid a million dollars to -- more than a million dollars to Hydro One or its affiliates for operations and maintenance services. Can you tell us about that?

MR. HURLEY: I can speak to that. That's a bit misleading. That is actually our total operations and maintenance costs that we incurred in 2018.

Table 3: Meter Reading Weighted Average Costs in 2018 and 2021 CAMs (Sheet I7.2)

Meter Reading Weighted Average Costs

2018 CAM		from I7.2																	
UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST							TOTAL
0.5%	3.9%	52.8%	13.2%	13.0%	11.9%	1.4%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%							100.0%
2021 CAM		from I7.2																	
UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd	TOTAL
0.5%	3.8%	52.6%	13.1%	12.9%	11.9%	1.3%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.1%	0.0%	100.0%

2.2.2 Density Factors (CAM Sheet E2)

No density adjustment is required for the six new acquired rate classes, as these classes are not distinguished based on density. The value "1" has been input in the 2021 CAM sheet E2 for the six acquired rate classes. These factors for all Hydro One existing rate classes remain unchanged from the factors used in the 2017 model.

Table 4: Density Factors in 2021 CAM (CAM Sheet E2)

UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd
1.000	1.900	4.800	3.600	2.400	2.200	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

2.2.3 New Acquired Rate Class Allocator Adjustments

All costs associated with serving the customers of the Acquired Utilities in 2021 have been added to the 2021 CAM. Six new rate classes have also been added to the 2021 CAM to accommodate the rate harmonization of the acquired utilities in 2021. All inputs to the 2021 CAM have been reviewed to ensure that the model is appropriately assigning costs to the Hydro One existing and the new acquired rate classes. In addition, three adjustment factors were developed and included in the 2021 CAM to ensure that the costs allocated to the six new acquired rate classes appropriately reflect the cost of serving the customers in these rate classes. These adjustment factors are described below.

Fixed Assets Adjustment

An adjustment factor has been applied to the amount of gross fixed assets ("GFA") in USofA accounts 1830 to 1860 to align the costs allocated by the CAM to these USofA accounts with the amount of GFA specifically required to serve the new acquired rate classes. The amount of GFA that should appropriately be allocated to the new acquired rate classes is estimated from the GFA in these USofA accounts for the acquired utilities prior to acquisition plus the in-service additions to these accounts up to 2021. The total GFA that should appropriately be assigned to the new acquired rate classes also takes into consideration that a portion of Hydro One's bulk distribution assets associated with serving customers in each of the new acquired rate classes should also be allocated to these classes. The amount of bulk distribution assets assigned to the new acquired classes was determined using the same proportion of bulk assets assigned to Hydro One's other customer classes not directly served by the bulk system.

Assets in all other USofA fixed asset accounts (e.g. distribution station assets, land, buildings, general plant, etc.) are considered to be commonly shared among all classes served by Hydro One. The amount of these common assets normally allocated to all rate classes using the cost allocation principles underlying the CAM are not adjusted.

The GFA adjustment factors are shown in Table 5. The adjustment factors are applied to the GFA in USofAs 1830 to 1860 as shown in rows 437-507 of the 2021 CAM's "E2 Allocators" tab. Hydro One proposes to apply these same factors in future runs of the CAM.

Table 5: GFA Adjustment Factor

GFA (USofA 1830-1860)	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.495	0.362	0.190	0.660	0.688	0.378

The amount of GFA not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Given the Board's CAM methodology, the appropriate allocation of GFA to the new acquired rate classes is critical for driving the allocation of the majority of distribution O&M costs, other than customer-related costs (e.g. billing, collections, meter-related expenses). The allocation of O&M costs, in turn, is a key driver of most administration and general costs.

Net Fixed Asset ("NFA") Allocator Adjustment

The NFA and NFA ECC allocators in the CAM's "E2 Allocator" tab are also adjusted to reflect the GFA adjustment for USofA's 1830-1860 as described above. GFA values assigned to the new acquired rate classes are translated to NFA values based on the relationship between total GFA and NFA determined from rows 112 to 116 in the CAM's "O6 Source Data for E2" tab. The NFA adjustment factors that have been applied are shown in Table 6 below.

Table 6: NFA and NFA ECC Adjustment Factor

NFA and NFA ECC	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.531	0.446	0.350	0.689	0.730	0.495

The amount of NFA and NFA ECC not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Depreciation Cost Adjustment

A depreciation adjustment factor is applied to the depreciation assigned by the CAM to USofA accounts 1830 to 1860 for the new acquired rate classes. The depreciation amounts assigned to the new acquired rate classes as shown in "Sheet 7 Amortization" of the CAM are reduced by the same GFA adjustment factors discussed above in order to reduce the depreciation amount assigned to the new acquired rate classes consistent with the reduction in the GFA for those USofA accounts.

The depreciation amount not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Table 7 shows the unadjusted depreciation amounts compared to the adjusted amounts for each rate class shown in row 2016 of the "O4 Summary by Class & Accounts" tab of the CAM.

Table 7: Adjusted Depreciation Amounts to Reflect New Acquired Rate Classes

Deprecation USofA 5705	UR	R1	R2	Seas	GSe	GSd	UGe	UGd	St.L	Sen.L	USL	Dgen	ST	AUR	AUGSe	AUGSd	AR	AGSd	AGSe
Unadjusted	22.4	75.0	138.7	27.3	40.8	45.7	6.0	9.7	3.3	1.5	0.6	1.0	14.9	2.5	0.9	1.8	7.0	1.7	3.1
Adjusted	22.7	76.1	140.7	27.7	41.4	46.3	6.1	9.8	3.4	1.6	0.6	1.0	15.1	1.6	0.5	0.9	5.3	1.4	1.8

MR. SHEPHERD: I am asking why your savings are lower than they were when you got approval. I am asking you to undertake to provide details of what changes caused them to be lower; can you do that?

MR. ANDRE: Yes, sure, we will undertake to do that.

MR. SIDLOFSKY: JT3.20.

UNDERTAKING NO. JT3.20: TO PROVIDE DETAILS OF THE CHANGES THAT CAUSED SAVINGS TO BE LOWER THAN WHEN HONI GOT APPROVAL

MR. SHEPHERD: My next question is on the same interrogatory response; this is page 3 of that response in F. So we were looking at the rate base allocated to the six acquired rate classes, and it looks like it totalled 361.5 million. And you said yes, it does, but that's not the right number.

So maybe you could just explain this answer and why the number that appears to be in the cost allocation model is not the right number for rate-making purposes.

MR. ANDRE: Right. So the $361.5 million figure comes from the 01 sheet of the cost allocation model. And what that represents is the amount of assets that would have been or were allocated to those classes prior to the application of the adjustment factors that Hydro One has adopted.

The adjustment factors, in terms of being able to incorporate it into the model, Mr. Shepherd, the easiest place to do that was in the allocaters tab. So it's in that tab where we make the adjustments -- I guess it's E 6 allocators tab. It's in that tab where we show the adjustments to the gross fixed assets after the application of the adjustment factors. And that doesn't translate into the numbers that come into the 01 sheet. It goes and gets these numbers from another tab where that adjustment wasn't reflected.

So in terms of the costs that are allocated by rate base, like net income, interest costs, PILs and all of that, that allocation is based on the 173.6 million in rate base, not the 361.

MR. SHEPHERD: Excellent, thank you. And my next question is still in the same interrogatory response. This is in attachment 1, and I have two questions on that.

The first is -- we heard the other day that you have zero capital productivity -- Hydro One has zero measured capital productivity. Did you hear that.

MR. ANDRE: No. To be honest, Mr. Shepherd, I haven't heard that testimony.

MR. SHEPHERD: Will you accept, subject to check, that your witness said that?

MR. ANDRE: Okay.

MR. SHEPHERD: I am looking at these lower capital spend for the acquired area and I am thinking, well, if this is not because of productivity, then doesn't this mean you're investing less in their systems?

And I -- there's probably a good explanation; I am just trying to understand.

MR. ANDRE: Well, like I say, you know, if that question had been put to panel 2 -- I expect that yes, if they are spending less, Mr. Shepherd, we now had the utility's integrated for, you know, a year, a year plus, and I would imagine they have better information on the status and the performance and the state of those assets.

So I would expect that the capital reflects the latest information they have about the need of the assets in the acquired utilities.

MR. SHEPHERD: I was asking more a question, and this is presumably not you -- I am sorry, the information said all the acquired questions were of this panel, so that's why I am asking you.

MR. ANDRE: Sure, no problem, Mr. Shepherd.

MR. SHEPHERD: Otherwise I would have asked the last panel.

What I am trying to understand is whether this means that the emphasis or the prioritization of the customers in the acquired areas has been reduced if you are spending less. Or is that not a fair conclusion?

And if that's outside of your area, just tell me.

MR. ANDRE: No, like I said, this reflects what our asset management group now believes the assets in these three acquired utilities require to maintain a safe reliable system.

But, yes, it does -- it does represent a change, but this is the latest information on what we believe these assets require.

MR. SHEPHERD: All right. The next question I have is recent acquireds.

MR. SHEPHERD: My question is -- this appears to be unfair to the old ones, the old acquireds, because you are giving this special deal to the new ones. And that may be because the deal for the old acquireds was unfair.

MR. QUESNELLE: Mr. Shepherd, now you are definitely going back to what the Board determined. I think if you pose your questions as to the acquireds -- what's the comparison doing for us, as far as understanding whether or not the direction is involved the issue in this case?

MR. SHEPHERD: Why don't I go there, and then I think you’ll see that the questions I was asking were critical.

Right now, you're proposing to allocate $41.2 million of costs. And the way -- what you did to respond to the Board is you said, okay, first we are going to reduce it from 60 to 46, wait that's not enough because now we’ve got the Orillia decision. Let's reduce it another 5 million because of the distribution stations, ah, that's still not enough. So now we have to reduce it by having those customers at 80 percent, or I think it's 83 percent, revenue to cost ratio just to keep their rates below what they would have paid otherwise.

Isn't that what you ended up doing? Because otherwise, you can't -- Hydro One can't get its costs low enough so that the costs to serve these customers are below what they would have paid. You can't, right?

MR. VEGH: Again, Mr. Shepherd is now creating a narrative around how these costs were allocated. If he has questions around how the costs were actually allocated, he can ask those questions.

But so far it's been a bit of a speech about how he believes what was motivating Hydro One's activities.

MR. SHEPHERD: Well, maybe my friend Mr. Vegh hasn't done as much cross as some other people, because one of the things you do in cross is you put a narrative to the witness and you say isn't that true, and that's what I just did.

MR. ANDRE: I am happy to answer the question. And I would start, Mr. Shepherd, by saying, you know, you went through -- you started here and then I think you mentioned, and then the Orillia decision came along and you thought, okay, the costs were too low.

I believe during the technical conference we had specific discussion around that, and there's an interrogatory where you asked about that. And I specifically responded that the Orillia decision had nothing to do with the move to eliminate the distribution stations.

When we looked closer at the costs that were being allocated to the acquired utilities, what we noticed was that the amount of distribution stations that were being allocated was significantly higher than the actual distribution station asset costs for the acquireds. And we looked at that and said, does that seem right?

And when we looked at the operation of the acquireds, we thought, okay, the distribution stations really do provide more of a local service. I mean, in the future there may be some feeders that go outside the -- outside the acquired utility service territory. But right now, they provide a local service, very similar to the poles and the wires and the transformers that are within those acquired utilities.

So that's the driver for making that change. It had nothing to do with the Orillia decision. And what we arrive at, the 41 million, is a cost that we believe fairly captures two things: It captures the incremental costs. So if you go back to JT3.18-19 and you reference the 25.6 figure, I think you correctly pointed out that figure represents the only the incremental costs associated with acquiring the utilities.

The 41.2 that we end up allocating to them captures not only the incremental cost, it captures the fact that there’s upstream distribution facilities that are now being used to serve the acquired utilities. There are common shared facilities, things like operating centres, service centres, call centres, the meter services shop, our head office building, our IT and billing systems, those are all shared facilities that now we are allocating a share of those costs to the acquired customers per the Board's methodology, and we believe it's appropriate that they share in those costs and that's where you end up with the 41.2 million.

MR. SHEPHERD: And so the bottom line ends up being that your costs go up by 25.6 to serve these people, but you think that they should pay another 15.7 -- 15.6, sorry, as their share of the common costs, which basically reduces the rates for everybody else, right?

MR. ANDRE: Yes, that's right.

MR. SHEPHERD: Because otherwise, everybody else would have to pay.

MR. ANDRE: That's correct. To the extent we don't recover a share of those costs from the acquired customers, we'd be recovering from the other rate classes, that's right.

MR. SHEPHERD: And the thing that happened between March and December is -- aside from the Orillia decision which you say has no bearing -- is that somebody had the bright idea to go look and see whether this was right?

MR. ANDRE: Yes. I mean, we were looking at those, you know, in preparation for the upcoming interrogatories, in preparation for the hearing. I mean, like we were looking at, you know, are these numbers correct.

MR. SHEPHERD: And so the people in Smiths Falls, for example, they pay the full amount of all these things. There's no adjustment for them, right?

MR. ANDRE: Yes, that's correct.

MR. SHEPHERD: And the people in Trenton, and the people in Thorold, they all pay the full -- I am trying to understand why, aside from the fact that the Board is getting tougher with you about acquireds, I am trying to understand why the cost allocation to these acquireds is fair and the cost allocation markedly different for the old acquireds is also fair. Which one is no longer fair?

MR. QUESNELLE: Mr. Shepherd, I think Mr. Vegh made an objection to that line as to whether or not the original acquired costs are fair. Those are acquired entities now. They are customers of Hydro One, and have been for twelve years.

I recognize -- I think it's valid to have the comparison of the methodology and point to the differences. But at this juncture, I think the evidence that has been given is that there was a conversation and there were Board decisions back in 2006.

MR. SHEPHERD: Mr. Chairman, if Mr. Andre answers my question that the current cost allocation is fair, then that's the end of it. By implication, the old one is unfair, but you're right, there's nothing we can do about it.

But if his answer is neither of them is fair, or there's a balance, or they’re fair in different ways, then I think this Board should hear it because that relates to these acquireds.

MR. QUESNELLE: In that context, Mr. Andre.

MR. ANDRE: I think the allocation to the three acquireds that we have now follows the Board's underlying principles that are in the cost allocation model. There are certain costs that are allocated based on number of customers and weighted number of bills, and that is the same as it always has been.

And then on top of that, we've adjusted -- we have made an adjustment to what the model would normally allocate to be consistent with the direction that the Board has provided with respect to setting rates for these three acquired classes as part of their MAAD decision.

MR. SHEPHERD: I wonder if you could turn to Exhibit K10.8, which is the materials from the Orillia motion. And I am looking at page 31, which is part of the Niagara-on-the-Lake analysis.

I am not going to ask you to agree with the analysis; I know there's lots of things you disagree with in it. But I am going to ask you about one statement in here. It's the last two bullets on page 31 -- does do you want to wait to get it up on the screen?

MR. ANDRE: I have it. It's not up on the screen; I don't know if we want to wait to bring it up on the screen.

MR. SHEPHERD: You can read those two bullets while we are waiting for it to get up on the screen, page 31 of K10.8. Sorry, page 31 of K10.8. There you go. And right at the bottom of the page, you see those last two bullets? So basically they have stated two sort of basic underlying rate principles, and I am going to ask you whether you agree with them. The first is, if ownership changes but the acquired service territory is merged with a lower-cost service territory then rates in the acquired territory should fall.

And then the second -- the last bullet is, if ownership changes but the acquired service territory is merged with a higher cost service territory, then the rates

to continue into the future.
MR. ANDRE: Yes, that's the assumption we've made, and we have indicated that we would potentially revisit those allocation factors, but, you know, in the long-term there may be a need to revisit that, but right now that is the assumption that is built into the process that we've adopted.
MR. SHEPHERD: Well, you just said that going forward you are not going to have the information. How are you going to revisit it if you don't have the information?
MR. ANDRE: I think people raise the point that in 40 years after all of the assets have been replaced, you know, is it still appropriate to use those adjustment factors, and we concede that once all of the assets have been replaced, and that happens over a very long period of time, that it may be necessary to revisit it. I can't tell you right now what we would do. Certainly in the near-term, you know, in the next five, ten years, we believe the adjustment factors as proposed in our application would be appropriate.
MR. SHEPHERD: So what you are proposing to this Board is that, going forward, if you add distribution stations -- or indeed any of those assets, anywhere in the province -- these acquired customers are going to bear some of the cost?
MR. ANDRE: That's exactly right. And, sorry, just let me finish -- and in the same way, if we happen to need a distribution station within Woodstock because their load

is growing or a new auto plant sets up or -- then that cost would be shared among all of the other Hydro One customers, so it works both ways.

MR. SHEPHERD: So these costs -- this whole category of costs is going to be socialized going forward between all of your customers across the province?

MR. ANDRE: Yes, that's correct.

MR. SHEPHERD: All right, except that these customers pay a lesser share than your legacy customers?

MR. ANDRE: They would pay the -- so the adjustment factors would apply to whatever rate base exists in the future; that's correct.

MR. SHEPHERD: So -- and this -- this adjustment doesn't apply to any other customer, so, for example, the 92 utilities you've applied so far -- you've acquired prior to this time, they all had the same issue, but you didn't adjust for that and you're not going to; you're not proposing to.

MR. ANDRE: That's correct.

MR. SHEPHERD: And so if you spend a million dollars on a station in Ancaster, then they'll all pay, except these three utilities, the customers of these three utilities, which will pay about half or so?

MR. ANDRE: The -- yes, that is an outcome of the adjustment factor approach, would be that they -- the acquired utilities would get a share of whatever growth happens, you know. I would state again that if there was a station that was built specifically for Woodstock or

Norfolk or Haldimand, they would too only get a 60 percent share of that cost of the station.

MR. SHEPHERD: And this problem, this problem is an artifact of postage-stamp rates, right? It only exists because of postage-stamp rates?

MR. ANDRE: Yes, I mean, the socializing across a utility like Hydro One that serves the whole province, and so we have one rate for a particular class regardless of where in the province you are, if that's what you are referring to postage-stamp rates, then I would say, yes, that is an outcome of postage-stamp rates.

MR. SHEPHERD: And the difference between these acquireds and the previous acquireds or your legacy customers for that matter, the difference between them in terms of treatment, which sounds -- you will agree it sounds on the face of it it isn't very fair -- is the result of the Board saying, no, these guys -- these three at least, you can't ask them to pay more than their fair share of the cost to serve them, right? Which is the first time you've heard that.

MR. ANDRE: That is the direction we were given in the MAADs decision and that's the direction we're following.

MR. SHEPHERD: Mr. Chairman, that's probably a good time to take a break.

MR. QUESNELLE: Yep. Thank you, Mr. Shepherd.

Ms. Anderson has a question.

QUESTIONS BY THE BOARD:

MS. ANDERSON: Sorry, I just have one clarification.

rebasing period. And the Board in EB-2017-0049 says that you are required to apply the same cost causation analysis to both legacy or acquired customers, right? That's what it says?

MR. ANDRE: Yes, they set an expectation in terms of distinguishable cost causation analysis, yes.

MR. SHEPHERD: You are not proposing to do that in the case of OPDC or PDI, right?

MR. ANDRE: No, I disagree. I think what we are proposing does have -- does recognize the distinguished cost causation associated with both OPDC and PDI, in that for those two service areas, we know specifically the amount of assets, local assets required to serve those utilities.

So we have that piece of information. Our proposal with respect to the adjustment factors is akin to a direct allocation of those fixed asset costs to those -- to the acquired classes, which is certainly permitted by the Board. Navigant had indicated that that is an appropriate way to allocate costs.

And then every other cost, so all of the OM&A including shared OM&A is then allocated you know, using the Board's model which follows the cost allocation cost causation principles embedded in the cost allocation model.

MR. SHEPHERD: So what you are attempting to do, your allocation of principle for PDI and for Orillia is local assets serving that area are directly allocated, right?

MR. ANDRE: Correct.

MR. SHEPHERD: And then everything else that flows from that allocation is also adjusted, right?

MR. ANDRE: No. So once you identify the local assets, then everything else -- so the allocation of, you know, all of the A&M costs and all of the costs that are outside the 1850 to 1820, so all of the OM&A costs, including shared costs -- would then be allocated per the Board's cost causation principles --

MR. SHEPHERD: Yes, aren't some of those costs allocated based on rate base?

MR. ANDRE: Yes. And so rate base would have been -- to the extent that rate base would have been impacted by the adjustments you make to the allocation of assets required to serve that area, then, yes, that -- so identifying the assets required to serve an area has an impact on gross fixed assets, it has an impact on net fixed assets, it has an impact on depreciation.

So those factors are there. But then A&G costs and net income costs and interest costs, all of those are driven by either the gross book value of assets or the net book value of assets, and that's done using the Board's cost allocation principles.

MR. SHEPHERD: But they will be lower if your direct allocation is lower than your standard allocation, right?

MR. ANDRE: I think we've been very clear to say the standard allocation in this case, what it would do is it would allocate to those service areas Hydro One's average costs based on the relative peak of that service area, relative to the rest of Hydro One.

MR. SHEPHERD: Yes.

MR. ANDRE: And it would allocate Hydro One's average costs, and Hydro One is a largely rural utility, so the allocation of Hydro One's average costs without any adjustment is -- wouldn't result in the appropriate or -- it wouldn't accurately reflect -- which the Board tell us they want us to do -- it wouldn't accurately reflect the costs to serve those specific service areas.

MR. SHEPHERD: Right. So where I am going with this is the Board was very clear if you are going to apply it to the acquireds you have to apply the same rules to the legacy, so why are you not directly allocating the capital costs to serve the people in Brockville and in Smiths Falls and in Ancaster?

MR. ANDRE: Because for those areas, Mr. Shepherd, we don't know the specific amount of fixed assets associated with serving just those areas.

MR. SHEPHERD: And why don't you know that?

MR. ANDRE: Because we track all assets. Our financial system tracks all poles used within the distribution system, all transformers used within the distribution system. It doesn't have a geographic breakout, you know, for a particular community.

MR. SHEPHERD: You have a GIS, right?

MR. ANDRE: We do.

MR. SHEPHERD: And your GIS will tell you how many poles and what wires and what transformers and everything, even in some cases the vintage of those things, right?

MR. ANDRE: It will tell us numbers, but it won't tell us how much of the costs that are associated with -- you know, that are from our financial database are actually associated with those specific assets.

MR. SHEPHERD: So then when the Board said you have to apply the same rules to legacy as to acquired, you are basically saying, we can't, so we are not going to. Is that right? Because we just don't have the information.

MR. ANDRE: I think I have been very clear that we are applying the same rules. So the Board permits direct allocation where that is possible, and all of the allocation of OM&A costs and shared costs follow the exact principles that are underlying the Board's cost allocation model.

So I think we are following the cost causation principles.

MR. SHEPHERD: But you are not directly allocating to legacy customers. You are only directly allocating to acquired customers, right?

MR. ANDRE: Because we have the information that will let us accurately identify the costs of serving that service area within which the acquired customers are located.

MR. SHEPHERD: I am not saying that you are ignoring what the Board is telling you. What I am saying is the Board told you to do something and you're saying, we won't do that because we can't. Isn't that right?

MR. ANDRE: No. I disagree. I think the cost causation principle that we're applying for the acquired classes is not applicable to those specific communities that you referenced.

MR. SHEPHERD: All right. If you are willing to take an early lunch, I think that might be helpful.

MR. MILLAR: Okay. Why don't we do that. Let's come back in one hour.

MR. SHEPHERD: Yes.

--- Luncheon recess taken at 12:22 p.m.

--- On resuming at 1:29 p.m.

MR. MILLAR: Good afternoon, everyone. I would like to get us started again.

Mr. Keizer, has there been any progress with respect to the issues you were going to have a look at over lunch? These were with relation to some of the undertakings Mr. Shepherd was encouraging.

MR. KEIZER: I don't believe that I had specific ones that I was considering over lunch. Mr. Rodger may have --

MR. MILLAR: I'm sorry, I think that's right. It was Mr. Rodger.

MR. KEIZER: We did with respect to the update we did orally this morning -- sorry, with respect to the update that I did this morning, we did do a paper update. So we have distributed that to parties as well. But I don't think I had any particular...

MR. MILLAR: You're right. Mr. Rodger, were there any discussions?

Comparison of 2030 Costs Allocated in EB-2018-0270

Class	***Allocated Costs***	***# Customers***	***Cost/Customer***
UR	$121,580,909	261,362	$465.18
AUR	$5,370,979	13,850	$387.80
UGe	$29,973,096	19,046	$1,573.72
AUGe	$1,744,685	1,544	$1,129.98
UGd	$39,265,034	1,772	$22,158.60
AUGd	$2,462,920	180	$13,682.89

Source: Ex. I-1-9 Attach 3
Allocation - Sheet O1, line 40
Customers - Sheet I6.2, line 23

Comparison of 2030 Costs Allocated in EB-2018-0242

Class	*Allocated Costs*	*# Customers*	*Cost/Customer*
UR	$121,452,732	261,362	$464.69
AUR	$14,111,869	35,211	$400.78
UGe	$29,642,792	19,046	$1,556.38
AUGe	$4,077,833	3,925	$1,038.94
UGd	$38,589,389	1,829	$21,098.63
AUGd	$4,806,102	403	$11,925.81

Source: Ex. I-1-48 Attach 3
Allocation - Sheet O1, line 40
Customers - Sheet I6.2, line 23

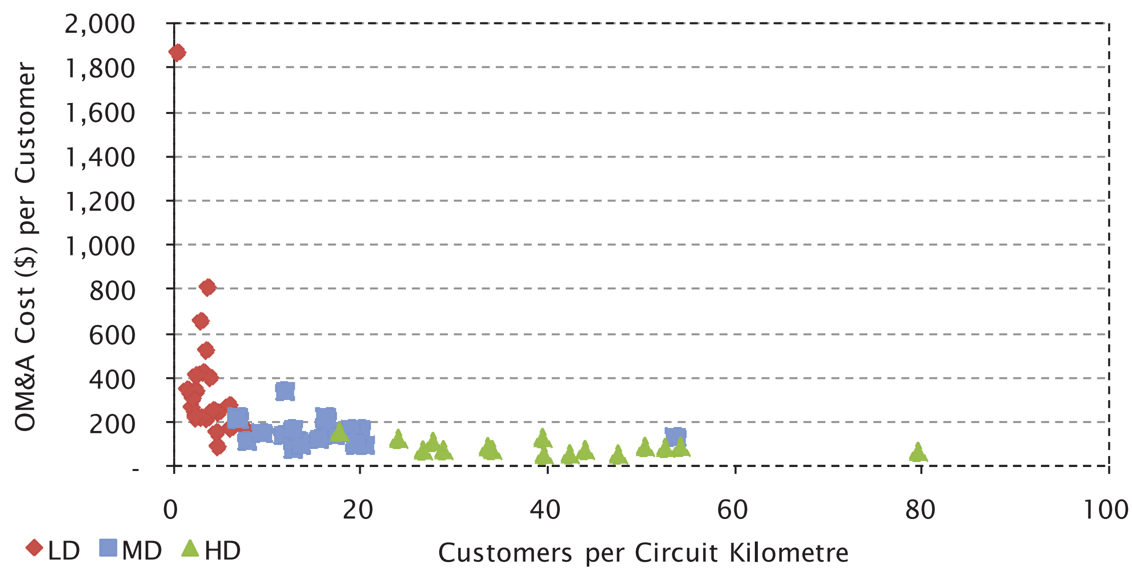
Figure 59: High-Density Sample Area Results

Operating Area	Sample Area	OM&A	Asset Intensity
Dryden	HD1	77	8,323
Essex	HD1	126	5,076
Kingston	HD1	57	2,882
Newmarket	HD1	130	9,037
Owen Sound	HD1	58	4,700
Perth	HD1	76	7,740
Sudbury	HD1	77	4,631
Timmins	HD1	69	2,709
Essex	HD2	157	4,451
Newmarket	HD2	87	3,773
Perth	HD2	113	7,136
Sudbury	HD2	90	4,946
Timmins	HD2	91	4,905
Newmarket	HD3	91	2,265
Sudbury	HD3	56	6,176
Newmarket	HD4	75	5,151
	Average	89	5,244

Source: LEI and PNXA analysis

Additional Scatter Plots

Figure 60: Relationship between OM&A Costs and Customer Density (per circuit kilometre)



Source: LEI and PNXA analysis

as it is, Mr. Shepherd, there are no plans and there have been no discussions about reducing the number of classes. These six classes have been created. We hope to use them in the future potentially to merge others as there's another response that says they may go into that, we may need to create new classes, so that part of it is as it is.

The reference to part D was simply, you know -- yeah, I am not sure why we even referred you to part D, because I think that first sentence gives you the full response, doesn't it?

MR. SHEPHERD: All right. You could read it as, well, we didn't look because we didn't have to. Or you could read it as, we know there were no discussions, but even if there were we wouldn't give them to you.

MR. ANDRE: Yes. So I can confirm that for this response it's the former.

MR. SHEPHERD: Okay, thanks.

And then the second question on that response is that you have said, and you have said this in other places too, in other proceedings too, that -- and indeed, other utilities have said this about harmonization, that you are going to keep these six classes separate until there's no material difference in the costs to serve those classes. And I am trying to understand, if they are integrated into your system, how is the cost to serve ever going to converge? Can you just explain how that happens?

MR. ANDRE: The -- I understand -- I understand the point that you are making, and I would agree that, you know, given the use of the adjustment factors they will always get less of a share than -- of certain costs than other classes.

So the convergence is not likely. But I guess, I mean, you know, the Board could make decisions about -- about, you know, for example, the move to all fixed rates.

If it turns out that the all fixed residential rate for one of these new acquired classes, you know, is within a dollar or $2 of one of our other classes, is there a need to maintain two separate classes.

So it's really more of a, we don't know what policy changes may come and what they might do to the classes, so it's a catch-all to say it could happen, but I agree that I wouldn't see that happening in the foreseeable future, and I can't see what would drive -- I can't give you an example of something that would drive us to end up with the same rates.

MR. SHEPHERD: There's not a natural thing that happens that converges costs; right? This would have to be something unusual for the costs to converge?

MR. ANDRE: The only thing I can think of, I mean, you know, if all of the assets -- in 40 years, when all of the assets -- when there's been a turnover, complete turnover, of the assets that are associated with serving these acquired utilities, presumably all of these brand-new assets would have been put in at the Hydro One cost, as opposed to the cost that the acquired utilities spent in putting in those assets.

UNDERTAKING - JT2.1

Reference:

Undertaking:

To provide an explanation of the nature of the difference between the board's model and Hydro One's cost allocation model, and the impact applied to this process; if in evidence, to provide the reference.

Response:

As clarified on page 12 of the transcript, the undertaking was to clarify the impact on the results from the cost allocation model due to differences in the Peak Load Carrying Capacity ("PLCC") assumptions within the model.

Hydro One's cost allocation model applies PLCC values that are specific to Hydro One's conductors and transformers. These values are based on a Minimum System Study originally approved by the OEB in EB-2008-0187, with further updates approved by the OEB in EB-2013-0416. Hydro One's specific PLCC values are 1,154 watts for conductors and 2,939 watts for transformers.

The PLCC values used in PDI and OPDC's cost allocation models (as filed in EB-2012-0160 and EB-2009-0273, respectively) are the default values established by the OEB in 2006. The OEB cost allocation model's default PLCC values are 400 watts for both conductors and transformers.

Exhibit Q, Tab 1, Schedule 1, page 23 of Hydro One's last distribution rate application (EB-2017-0049) included a discussion on the impact of using different PLCC values in Hydro One versus Acquired Utility cost allocation models. As noted in Exhibit Q, Tab 1, Schedule 1, use of higher PLCC values results in a shifting of allocated costs from residential to general service classes.

The table provided below shows the impact on the 2018 Hydro One cost allocation model[1] as a result of applying different PLCC values (Hydro One specific PLCC values and default OEB PLCC values.)

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[1] EB-2017-0049, Draft Rate Order Exhibit 3.1 filed on April 5, 2019

	Using HONI's PLCC Values		Using OEB Default PLCC Values	
HONI Rate Class	**Allocated Costs ($M)**	**Revenue to Cost Ratio**	**Allocated Costs ($M)**	**Revenue to Cost Ratio**
UR	$ 87.1	1.08	$ 94.3	0.99
R1	$ 285.0	1.09	$ 310.4	1.00
R2	$ 530.1	0.97	$ 570.1	0.90
Seasonal	$ 100.0	1.09	$ 114.1	0.96
GSe	$ 166.3	0.99	$ 147.5	1.11
GSd	$ 156.0	0.89	$ 101.2	1.37
UGe	$ 22.5	1.01	$ 18.5	1.22
UGd	$ 31.0	0.91	$ 20.7	1.36
St Lgt	$ 11.0	0.93	$ 12.6	0.81
Sen Lgt	$ 5.7	0.97	$ 5.7	0.96
USL	$ 2.8	1.23	$ 3.0	1.15
DGen	$ 6.3	0.58	$ 6.4	0.58
ST	$ 54.8	0.96	$ 54.0	0.97
Total	**$ 1,458.5**	**1.00**	**$ 1,458.5**	**1.00**

Tell me whether my math is right. If I just is divide 1.057 by 1.0431, I get the impact, right?

MR. ANDRE: You get which?

MR. SHEPHERD: I get the impact on the --

MR. ANDRE: Yes, you are right. Yes, that percentage change is how much the commodity would change, yes.

MR. SHEPHERD: All right. So then I want to go to Exhibit I56-SEC -- let's use 99, and I am going to the spreadsheet which is 02, okay?

MR. ANDRE: Okay. I think these were provided as spreadsheets, so you night not necessarily have it. It depends on the question Mr. Shepherd has. Should Erin pull that up?

MR. SHEPHERD: Yes, yes, 99-02. You will be happy to know that I am rapidly reaching the end.

And when it comes up, I am looking at the GS 50 to 99 tab.

MS. McKINNON: Nothing seems to be working on my computer at the moment, so I will bring it up momentarily.

MR. ANDRE: I have a hard copy of that, so I can certainly follow along with the question if no one else may be able to.

MR. SHEPHERD: I will ask the question and you may be able to answer off the top of your head anyway, if I know you.

I am looking at the Woodstock bill comparison and the distribution has gone way up, but then the transmission costs go way down. And so, for example in this customer with 177 kilowatts of demand, the sample customer you are using, their transmission charges go down from $892 a month to $596 a month, a 33 percent reduction. And it appears to be all entirely driven by a reduction in the unit cost.

And that's true for all three of them, although the difference in the case of one of them is quite small. I wonder if you could just explain why this happens and why this is -- I looked for an explanation and couldn't find one.

MR. ANDRE: Yes, I don't know if there is an IR response that has an explanation to that, but I can certainly help you, Mr. Shepherd.

The RTSR rates that the acquired utilities were charging their customers, the last time they were sort of rebased would have been at their last cost allocation model. So Woodstock, when would that have been? 2012 or '13, somewhere around there.

MR. SHEPHERD: Yes, '11 or '12.

MR. ANDRE: And then from then on under the IRM, they just used the Board's RR, revenue requirement work form, which all it does is it looks at the change in transmission charges and then bumps up everyone's RTSR rates as necessary to recover what the forecast transmission charges are going to be in the future.

When we do it in 2021, we are now looking at and we are using data that comes from Mr. Alagheband's shop in terms of meter data for the actual customers, either smart meter data or interval meter data, and looking at the contribution of this class to the peaks. And what we are finding with the more current data is that these general service customers are contributing less to the peak -- and remember the peak is what transmission charges are based on -- than what was assumed they were contributing to the peak back when the utilities were calculating those rates.

So I think the explanation is something as simple as they were using data from 2012, 2013, on that relative contribution to the peak. In 2021, we are now using the latest data available to us on the contribution of this class to the peak. And the reality is -- and to that I can't speak. I don't know if general service customers either had been better at implementing efficiencies, or better at avoiding the peaks for other reasons, ICI reasons for example. But for whatever the reason is, the latest data shows that they are contributing less to the peak, and therefore by contributing less to the peak they are attracting a smaller amount of the share of transmission charges.

MR. SHEPHERD: So that's what I thought. And -- but this comparison appears to imply that the rates, if they had not been acquired, would be that much higher. But what your explanation is, is in fact that the transmission costs would have gone down anyway no matter who owned them; right?

MR. ANDRE: I don't know what the approach is for these acquired utilities in terms of updating their load shapes. I mean, they seem -- you know, if they continue to use the revenue-requirement work-form approach then it wouldn't have changed.

All we can comment on is the rates that they were paying at the time of acquisition, and if those rates were escalated, then -- and actually, in the case of Woodstock here you can see that the escalated rates for Woodstock actually dropped. We said back in 2014 they were $902, and now in 2021 the escalated rate is actually only 892, so we did show a bit of a drop, but it's not related to them having adopted different load shapes, but I can't comment on what the utility would have done with respect to the transmission charges that it applied to its customers.

MR. SHEPHERD: Would it be correct to understand this difference is as Hydro One -- I guess because you have more resources and you have more expertise in the area of rates, you took a more thorough approach to figuring out what they should pay for transmission and in effect corrected what the acquireds had been charging to a more appropriate level; is that fair?

MR. ANDRE: It's the same approach, yeah, that we use for all of our rate classes. Whenever we file a cost-of-service application we revisit the contribution to the peaks and therefore the amount that should be paid for transmission for all of our rate classes, in this case the acquireds included.

MR. SHEPHERD: All right. That's all my questions, thank you.

MR. SIDLOFSKY: Thanks, Mr. Shepherd.

UNDERTAKING - JT1.2

Reference:

Undertaking:
To provide the T2 S1S for 2017 and 2018 for OPDC.

Response:
Please see attached OPDC T2 Schedule 1's for 2017 and 2018.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2017-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 .... 1,215,676 A

Add:

	Line	Amount	
Provision for income taxes – current	101	59,000	
Provision for income taxes – deferred	102	239,000	
Amortization of tangible assets	104	1,187,017	
Charitable donations and gifts from Schedule 2	112	12,500	
Non-deductible meals and entertainment expenses	121	8,250	
Other reserves on lines 270 and 275 from Schedule 13	125	691,777	
Reserves from financial statements – balance at the end of the year	126	1,028,618	
Subtotal of additions		3,226,162 ▶	3,226,162

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Deferred debit CGAAP adjustment - liability increased for de	694,000
	Total of column 2	694,000

	Line	Amount	
Total of column 2	296	694,000	
Subtotal of other additions	199	694,000 ▶	694,000
Total additions	500	3,920,162 ▶	3,920,162 B

Amount A **plus** amount B .... 5,135,838 C

Deduct:

	Line	Amount	
Gain on disposal of assets per financial statements	401	92,985	
Capital cost allowance from Schedule 8	403	3,119,665	
Other reserves on line 280 from Schedule 13	413	927,473	
Reserves from financial statements – balance at the beginning of the year	414	693,922	
Subtotal of deductions		4,834,045 ▶	4,834,045

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Actual Repayments C GAAP Liability	4,000
	Total of column 2	4,000

	Line	Amount	
Total of column 2	396	4,000	
Subtotal of other deductions	499	4,000 ▶	4,000
Total deductions	510	4,838,045 ▶	4,838,045 D

Net income (loss) for income tax purposes (amount C **minus** amount D) .... 297,793 E

Enter amount E on line 300 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2018-12-31

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- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,178,041	A
Add:				
Provision for income taxes – current	101	169,000		
Provision for income taxes – deferred	102	-140,000		
Amortization of tangible assets	104	1,222,768		
Loss on disposal of assets	111	59,399		
Charitable donations and gifts from Schedule 2	112	12,200		
Non-deductible meals and entertainment expenses	121	10,000		
Other reserves on lines 270 and 275 from Schedule 13	125	927,473		
Reserves from financial statements – balance at the end of the year	126	2,056,618		
Subtotal of additions		4,317,458 ▶	4,317,458	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Deferred debit CGAAP adjustment - liability increased for de	693,000
	Total of column 2	693,000

Total of column 2 ▶	296	693,000		
Subtotal of other additions	199	693,000 ▶	693,000	
Total additions	500	5,010,458 ▶	5,010,458	B
Amount A **plus** amount B			6,188,499	C
Deduct:				
Capital cost allowance from Schedule 8	403	3,089,640		
Other reserves on line 280 from Schedule 13	413	1,828,473		
Reserves from financial statements – balance at the beginning of the year	414	1,028,618		
Subtotal of deductions		5,946,731 ▶	5,946,731	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
	Total of column 2	

Total of column 2 ▶	396			
Subtotal of other deductions	499	0 ▶	0	
Total deductions	510	5,946,731 ▶	5,946,731	D
Net income (loss) for income tax purposes (amount C **minus** amount D)			241,768	E

Enter amount E on line 300 of the T2 return.