

ONTARIO ENERGY BOARD

FILE NO. **EB-2024-0115** Hydro Ottawa Limited.

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EB-2024-0115

THE ONTARIO ENERGY BOARD

Hydro Ottawa Limited

Application for electricity distribution rates

and other charges beginning January 1, 2026

Technical Conference held in person and virtually from 2300 Yonge Street, 25th Floor, Toronto, Ontario, on Wednesday, September 24, 2025, commencing at 9:30 a.m.

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DAY 3

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MICHAEL MILLAR Board Counsel

JULIA NOWICKI

MARGARET DEFAZIO Board Staff

NARISA JOTIBAN

HELENA WANG

TIARA FEARON

DALIANA COBAN Hydro Ottawa Limited

JONATHAN MYERS

CLEMENT LI Building Owners and Managers Association (BOMA)

TOM LADANYI Coalition of Concerned Manufacturers and Businesses of Canada / Energy Probe Research Foundation

MICHAEL BROPHY Community Action for Environmental Sustainability (CAFES) and Pollution Probe

LAWRIE GLUCK Consumers’ Council of Canada (CCC)

MARK RUBENSTEIN School Energy Coalition (SEC)

JANE SCOTT

MARK GARNER Vulnerable Energy Consumers’

BILL HARPER Coalition (VECC)

ALSO PRESENT:

LIANNE CHARTRAND Hydro Ottawa Limited

SHAYNE THOMPSON

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Wednesday, September 24, 2025

--- On commencing at 9:30 a.m.

M. MILLAR: Good morning, everyone. This is Day 3 of the Hydro Ottawa technical conference. Before we get to Mr. Brophy and his questions of panel 2, Ms. Coban you had a preliminary matter.

PRELIMINARY MATTERS

D. COBAN: Yes, good morning. Just a minor clarification we wanted to put on the record. In her exchange with Ms. Augustine yesterday regarding the battery energy storage program, this can be found at pages 94 to 95 of the transcript from yesterday. Ms. Gillis noted that, subject to check, the $20,000 annual maintenance costs for the BESS units were not included in the $2.8 million non-wire solution line. Ms. Gillis has gone back and verified the statement and would like to clarify that this amount is, in fact, included in this referenced budget. Thank you.

M. MILLAR: Thank you, Ms. Coban. Nothing further?

D. COBAN: That's all, thanks.

HYDRO OTTAWA LIMITED – PANEL 2, RESUMED GENERAL PLANT DISTRIBUTION SYSTEM AND PLAN INVESTMENTS AND RELATED OM&A AND STAFFING WORKFORCE, CUSTOMER ENGAGEMENT, BUSINESS PLANNING, CORPORATE GOVERNANCE AND OTHER REVENUE

ANGELA COLLIER

ANDREW WILLIS

JOSEE LAROCQUE

TREVOR FREEMAN

DONNA BURNETT VACHON

LOUISA YEUNG

M. MILLAR: Okay. Mr. Brophy, over to you. I have you down for 25 minutes.

EXAMINATION BY M. BROPHY

M. BROPHY: Yes, thank you. I think that should do.

Good morning, my name is Michael Brophy and there were certain questions from CAFES Ottawa from panel 1 that were referred to panel 2, so those are the ones. You might have heard some of them on the panel 1, but I will go through them with you here. Great. Okay. So, the first one that was referred to panel 2, we are talking about 1-CO-9 and the specific portion that they wanted panel 2 to talk about was in the evidence 1-4-1, attachment E. So I can wait until you pull that up, and if we just go to page 59 of that to start, that would be great. And just while that's coming up, so this was in relation to some of the outage numbers. I will just maximize this so I can see. So is it page 59 of the, of the report? There, that's the one, thank you. Perfect. Okay. So, you will see on that page, the reference to Hydro Ottawa outage numbers based on customer survey results and it indicates that the, on page 59, that the Ottawa Hydro results are higher than the Ontario and national averages based on those results. So, the first question that panel 1 couldn't answer and referred to you is -- so, just to get oriented on Appendix E of 1-4-1, the information in that appendix, that's from a national survey and also then compares results to Hydro Ottawa customers; is that correct?

T. FREEMAN: Good morning, Mr. Brophy. Yes, that is correct. This was a survey commissioned by the Canadian electricity association now known as Electricity Canada. Hydro Ottawa participated in that, so our customers were surveyed and benchmarked against national results.

M. BROPHY: Okay, thank you. And then on page 60, so the next page of Appendix E, I saw that it indicates that only 23 per cent of Hydro Ottawa customers had no outages in the past 12 months; is that correct?

T. FREEMAN: Just for clarity, that's the self-reported metrics from customers. So 23 per cent of respondents indicated that they had not had an outage in the past 12 months. For our actual outage data, and I believe you had this exchange with panel 1, that's our SAIDI and SAIFI numbers, but 23 per cent of respondents indicated that they had not experience an outage.

M. BROPHY: Okay, thank you. And I guess that's where I ran into some issues with panel 1, because they had SAIDI and SAIFI, which they knew quite a bit about, they didn't know much about this appendix, per se, and I was comparing it trying to rectify between the two because it seems to tell a bit of a different story. So, are you in a position to be able to shed light on the difference between these survey results, based on those outage numbers reported by customers and the adjusted and unadjusted SAIFI results that were reported in CO-9; is that something you can do?

T. FREEMAN: I can certainly speak to the survey results and what they are indicative of and how that relates to the SAIDI and SAIFI numbers, I think you were provided some of that information yesterday. But, so as I mentioned this was a national survey that did also survey our own customer base, Hydro Ottawa customers, as well, as you will see, in the data general population. So that's people that live in the Ottawa area that may or may not be an actual Hydro Ottawa account holder, that's the dark blue bar there. And so this is, again, self reported experience of outages. This survey was conducted in Q4 of 2023, and so just for context, in 2023 we -- at the end of 2022 we experienced the -- an ice storm in December 2022, another ice storm in April 2023, as well as several extreme weather events throughout the summer of 2023. So we would expect that customers responding to this survey would indicate that, yes, they did experience outages. That doesn't necessarily -- this doesn't impact our SAIDI and SAIFI numbers, that's based on actual system performance and the stats around that.

M. BROPHY: Okay. And we went through with panel 1 the adjusted numbers where some of the data is removed for the two categories and then the raw numbers there, and they agreed to provide some extra info on that. So, okay, thank you. panel 1 had said insurance is panel 3, so I am assuming that's correct and not panel 2, unless you tell me otherwise. And, similarly, load forecast is panel 3 and not panel 2, so I am saving those questions that were referred to panel 3, unless you tell me you are anxious to answer them.

A. COLLIER: That is correct.

M. BROPHY: Okay, thank you very much. I just want to make sure I don't miss a panel, because we can't go backwards.

A. COLLIER: Understood.

M. BROPHY: Okay, thank you. So the next questions that were referred to panel 2 is in relation to 1-CO-12, and that's provided a table related to the Ottawa retrofit accelerator program. And panel 1 gave some general information related to, you know, the response in CO-12 but referred discussion of some of the table to this panel. So I will just make sure we have got it up here, yes. Okay, yeah, that's the one. So, the areas that they referred to your panel were, you will see in 2024 the reported results. So, you know, zero energy savings identified and then energy savings achieved. It just indicated that you didn't have that data yet. So I guess the question is: When would that data be available?

T. FREEMAN: So, we will take them line at a time. So the first line, energy savings identified, the reason it's zero for 2024 is because the identification of these savings are as part of carbon pathway studies that are funded by the program. The number in the first line, 56, indicates that that number of studies started in 2024 but none of those completed in 2024, so there were no savings identified. All the savings identified from those 56 studies would be included in the 2025 number, because that's when the study would be finished.

M. BROPHY: Okay. So would it be fair -- so you've got a 2024 and 2025 number against energy savings identified, would it have been fair just to put the one number against both, because that's the savings that came from 2024 and 2025?

T. FREEMAN: It could be presented that way. We were specifically asked to break it out by year, so we wanted to keep to what the question was. I will note that not all of those 69 studies identified in 2025 were necessarily completed by the time we responded to this IR, and so that number that you see under 2025 does not include all the savings that may be identified from those studies, just the ones that have been completed or were completed at the time.

M. BROPHY: Okay. And then the row below it, which is energy savings achieved, when would that information be available?

T. FREEMAN: So just to clarify that statement there, this program is specifically funding carbon pathway studies to identify savings, so think of it as an energy audit that also looks at carbon savings. The program doesn't actually fund or support the implementation of those measures from a financial perspective. Some of those measures that were identified in the audits may be implemented in the short-term or the medium-term or long-term, or may not be implemented at all. Our team is continuing to work with those customers, but reporting on that measure is not part of this program. So it won't be a reported metric as part of the program, and it's not something that we will be specifically funding.

M. BROPHY: Okay. So do you have visibility on where the results would have been achieved, or are those in other programs that you don't -- aren't able to link back to these surveys or these audits?

T. FREEMAN: We may have visibility through the support that our team provides, through our key accounts teams. Some of these customers are key account customers, so we have an ongoing relationship with those customers, through our CDM or EDSM team. For example, if the measures identified in the study qualify for incentive funding, our EDSM team could help connect those customers with that incentive funding. So we may get line of sight into that. But there isn't a direct, necessarily, correlation between the studies here and this program and how the customer chooses to implement that.

M. BROPHY: Okay, so would you be able to undertake to provide two things; one is any updates to the numbers. I know you noted that this was as a point in time and there might be additional results specifically for energy savings identified, but if anything else is updated, sure. And then the second would be kind of on a best-efforts basis an idea of the energy savings achieved based on what you just described, and if you need to note that there may be additional savings that aren't tracked, you know, because they are occurring in other programs, feel free to add those notes just so that people don't think it's understated.

T. FREEMAN: We can undertake to provide updated numbers based on what you see in this table, I would say to the end of August. I can check with the team. We should have August data. In terms of providing actual projects implemented, I don't think it's possible to provide a correlation necessarily between this specific program and measures implemented, because those measures could be implemented for a number of different reasons. They may have been identified in this program, they may not. There isn't a direct correlation, necessarily, so I don't think it would be a correct presentment of the data to show you projects implemented moving forward through the other programs, if that makes sense.

M. BROPHY: Okay, fair enough. So, yeah, I will take that undertaking for the update.

M. MILLAR: The undertaking is JT3.1.

UNDERTAKING JT3.1: Provide update to the numbers and energy savings achieved to August

M. BROPHY: Okay, thank you very much.

Okay. The other question that was referred to this panel, and I think because it links to governance, was related to 1-CO-1, and the response to 1-CO-1 discussed the relationship between Hydro Ottawa and its shareholder, the City of Ottawa. It also discussed the presentation Hydro Ottawa provided to the city council, I think the big one was June 25th, 2025, on the details of this application. So the presentation, June 25, 2025, was that the only presentation to council in the past year related to this application by Hydro Ottawa?

A. COLLIER: Good morning, Mr. Brophy. The presentation that you're referring to to city council in June of 2025 is our normal AGM presentation, it's not necessarily specific to this application. We do have to go in front of city council once annually as part of the AGM to present results corporately, which includes Hydro Ottawa Limited and all affiliates.

M. BROPHY: Okay. Great. I think I saw that labelled that way on the agenda, and then also on the City of Ottawa they have the recording, and then it's posted on YouTube, and I think it was fairly long, probably maybe an hour or even more than an hour, on going through the details of the application. So, you know, it looked like -- or it was largely focused on details of the application, at least from the recording that was made of the presentation.

So do you know, was that presentation filed yet?

A. COLLIER: That presentation has not been filed as part of this proceeding, mainly because it occurred after we filed this evidence.

M. BROPHY: Okay. So can you provide a copy of the presentation?

A. COLLIER: We can certainly provide a copy of the presentation. I would just like to add it is a Hydro Ottawa Holding Inc. presentation, so there are elements of the presentation that do not pertain to Hydro Ottawa Limited or this application in any way.

M. BROPHY: Fair enough.

M. MILLAR: That undertaking is JT3.2.

UNDERTAKING JT3.2: Provide a copy of the presentation given to the City of Ottawa

M. BROPHY: And I guess while we are on the topic, because there was a -- a large portion was on the Hydro Ottawa application, which is under Hydro Ottawa Limited, but you also mentioned the parent holding company, and there is elements in there. So I guess that's the normal way to report up to council, it's not visibly just from Hydro Ottawa, it -- they don't have direct visibility then into what's going on at Hydro Ottawa the utility, they only get what comes through the holding company; is that -- is that correct? Or -- or is there a bypass that the utility can go right to council and provide info, not going through the holding company?

A. COLLIER: There is no bypass mechanism that I am aware of. And if you look at every annual AGM in every June at city council, it is always Hydro Ottawa Holding Inc. presenting the results of the prior year. Obviously, for Hydro Ottawa Limited, Hydro Ottawa Holding Inc.'s largest subsidiary, the rate application and our application is a substantial update that is provided this year, and if you go back five years ago it would have been the same at that time. But, yeah, there is no other mechanism.

M. BROPHY: Okay, okay, thank you. Those were all the questions that were referred to this panel, so I am done. Thank you for the answers.

M. MILLAR: Thank you very much, Mr. Brophy. I think up next we are back to OEB Staff and Ms. Jotiban.

EXAMINATION BY N. JOTIBAN

N. JOTIBAN: Hi, everyone, Narisa Jotiban. I just would like to start with, if you could please pull up Excel spreadsheet, Attachment 1, Staff 1, please. Could you please go to Appendix 2K. If you please go to cells M14 to M16. Here in these cells show the variance, variances between the 2024 rate year versus 2024 actuals for the employee, for the table, employee cost. So the variances here are the difference between the actuals and the forecast for management positions, non-management positions and total.

So now you notice that the updated actual number for management positions is 14 positions hired, and the forecast. And the updated actual number for non-management positions is 17 positions lower than forecast.

Would you be able to explain whether the updated 2024 actual for management and non-management positions have any impact on the forecast numbers for 2025 and 2026?

L. YEUNG: Hi, this is Louisa Yeung. Could you please repeat your question, please?

N. JOTIBAN: So basically, I am just trying to understand whether the updated 2024 actual management and non-management positions would have any impact on the current forecast for 2024 and – sorry, on the forecast for 2025 and 2026?

Because originally, if you are looking at cell K14, for example, management position for the forecast shows 133. And then the 2025 forecast shows an increase by two positions, to 135, and then to 141 in 2026. But because the actual actually came in higher, so now 2025 forecast is actually -- the number of positions is lower than the actual. And also 2026, number of positions for management, also is lower than the actual for 2024.

So I am just wondering if, based on the updated actual, are you going to -- do you have any explanation whether, like, are these the variances due to retirements, that's why you need to hire some positions that are overlapping? Or for other reasons? Or are you going to be updating the 2024 -– sorry, 2025 and 2026 forecasts?

L. YEUNG: Thank you. So let me explain the actual to budget variance for 2024, first. So, yes, you are correct that 2024, the management FTE is higher than the bridge year forecast, and is offset by a decrease in non-management.

The reason why is because of due to retirement, overlap, and then also some of the positions that acting by non-management, so they are non-management but acting on the management position. So this is a transition year in 2024. We don't expect that type of variance to continue in 2025 in 2026.

N. JOTIBAN: Okay. Thank you for the explanation. That's very helpful.

Moving on, I would like to ask if you could pull up exhibit 4-1-2, page 53, and starting from line 6. Here, Hydro Ottawa provided an explanation for the cost increase of $1.7 million in 2026, under the information management and technology. So the explanations says that the $1 million increase is due to increased compensation cost and five incremental positions required for cloud computing, cyber security and data and systems integration and program management.

Now, could you please pull up the response to 4-Staff-150? Could you quickly scroll to the response in part (e)(i)? I thank you. So here, Hydro Ottawa provided details of the work and responsibilities for the five new positions under this program for 2026.

Could you please scroll down a little bit, to part (e)(ii)? A little bit more, please. Yes. So here, the response, Hydro Ottawa stated that the main driver for hiring other five positions in 2026 is to support the grid modernization program.

Could you please explain further how you determined that these five positions are required in 2026, based on the implementation schedules and resource requirement for the grid modernization program?

A. WILLIS: Hi, it is Andrew Willis. Yes, I can explain that. Our grid modernization program is predominantly associated with lots of new technology and increasing IP-enabled assets on our grid. And so we need to bring in some additional resources for cyber security to make sure that the attack surface, that it is growing, is managed well and that we safeguard our assets.

We know we are going to be putting in some cloud solutions and technology, so we need cloud engineers to help us make that transition. We need program managers, because we will be executing a number of critical projects that require cross-functional collaboration, and grid technology engineers, obviously, to support many of the process changes and to manage the technology in the business.

N. JOTIBAN: So these are all scheduled to be implemented in 2026?

A. WILLIS: Yes. We have a number of positions in 2026, and none in 2025.

N. JOTIBAN: Sorry, I am referring to other grid modernization projects that are going to be implemented in 2026. Is that why you need to hire another five positions in that year?

A. WILLIS: The grid modernization program is a journey, and we are – we need to ensure - it is starting in 2026; some of that work has already started. And we want to make sure that we have the resources in place to ensure our success.

N. JOTIBAN: So could you please explain if any of these positions are not filled as planned? What would be the impact on the implementation of grid modernization projects?

A. WILLIS: Well that, that would be speculating. However, it would introduce a level of risk at a time that we would like to avoid.

N. JOTIBAN: So would that mean that the projects, some of the projects would be delayed?

A. WILLIS: I would be speculating, but as we would not have the resources and staff available to ensure our success, be it managing the technology, ensuring that we can cover all the cyber security aspects, running programs, yes, they could potentially result in delays if we don't have those resources available.

N. JOTIBAN: Okay. Thank you, very much, for the explanation, I appreciate it.

Could you please pull up 4-CCC-47. Would you please go to page 2, table B.

So the table shows the subscription cost under information management and technology program. It's forecast to increase by 1.3 million in 2026 compared to the previous year and that accounts for about 78 per cent of the total increase under this program. Could you please provide how much of that 1.3 million increase is due to new subscriptions and how much is due to the price adjustments from existing subscriptions?

A. WILLIS: Give me a moment to confer with the panel. Thank you.

A. COLLIER: Hi, can you repeat your question? Sorry.

N. JOTIBAN: Would you be able to provide how much of the 1.3 million increased from 2026 versus 2025 in Table B, how much of that is due to the new subscriptions and how much is due to the price adjustment from existing subscriptions?

A. COLLIER: I don't think we have this level of detail in our accounting system to break that out. I think if you refer to our inflation exhibit you'll see that, certainly, price is a key driver of some of these increases that we have experienced, but also the number of technology and subscriptions. So it's a mix but it would be very difficult to kind of break out vendor by vendor and invoice by invoice what -- to get that view that you're asking for.

N. JOTIBAN: Okay. That's okay, thank you so much for your response. Could you please go to the updated 1-SEC-27? This is a question that I asked panel 1 already and they were able to provide some more information. And could you please go to page 11, Table E? Yes. And this table here shows a description of each productivity benefits initiative and methodology that support the calculation. Now, you could please just scroll down a bit further to page 12, initiative 3.2.6, satellite imaging for vegetation management. Here. The last two sentences in the methodology column on page 13 states that savings are calculated as the difference between the forestry maintenance budget and what the budget would have been without the overstory efficiency. Expected efficiency is 15 per cent in 2026, and 20 per cent from 2027 to 2030. So yesterday panel 1 was able to respond to my question on why the expected efficiency in 2026 is lower than the other forecast years, but I have a follow-up question that I would like to ask panel 2. Would you be able to explain assumptions used to derive the expected efficiency? How did you come to derive, to come up with the numbers of 15 per cent in 2026 and 20 per cent; what are the information and assumptions you used to derive these numbers?

L. YEUNG: Hi. The percentage of efficiency came from a business case that our business team that, that review all the details with the vendor as well that comes up with calculate with that percentage.

N. JOTIBAN: Can you explain a bit more? Like, for example, are they -- I would just like to know what are the information, besides that it's a business case, some other, are there some kind of costs that are used to derive these numbers?

L. YEUNG: Just one second, let me confer, please. Sorry about that. So, subject to check, to my knowledge that this is based on the vendor experience from what they are seeing provided to others and in also in addition to our internal review.

N. JOTIBAN: So the vendor's experience is that quantitative?

L. YEUNG: So the percentage is provided through that business case.

N. JOTIBAN: Okay. Okay, thank you. I appreciate your response. So I would like to ask a little bit more on this, if you could please pull up an Excel file titled Updated Attachment 1-SEC-27A? If you could please go to Row 51? This one shows -- the information in Row 51 is the reactive tree trimming spend, and if you could please maybe scroll to the right a bit more. So from column I to M, those are the years starting from 2026 to 2030. So, I used the data for the reactive tree trimming spend for the period of 2026 to 2030 to calculate a year over year increase in reactive tree trimming costs and noticed that the annual increases are quite lumpy. For example, in 2027, that would be cell J51, the increase is 14 percent higher than the reactive tree-trimming spend in 2026. And then for 2028, the year-over-year increase is 4 percent, 5 percent increase in 2029, and then it increases quite a bit to 15 percent in 2030.

So I am wondering if you would be able to explain how you determined the reactive tree-trimming cost, since the increases seem to be large in some years and smaller in some years? If you can explain the large increases in 2027 and 2030 compared to the other forecast years?

L. YEUNG: Yes, you are right that the increases year over year is a bit lumpy. And this is explained in CCC 38, so the contract expires in 2026, and we are prepared for a new contract to begin, and also, that contract is expected to last until 2030. So that's one reason, is because of the contract renewal.

The second reason why is because the amount is calculated based on the total contract cost, and the total contract cost also that there are some information provided in CCC 38 that it is based on the cycle trim, and they have a three- to five-years plan that each year planned to be divided, not necessarily evenly. It depends on how it falls in our grid. So that's why that each year it may not be evenly spread in terms of our costs.

N. JOTIBAN: So would you say that in 2030 the increase of 15 percent, that's due to maybe the cycle?

L. YEUNG: I would say a combination of both due to the contract renewal and also the cycle trim.

N. JOTIBAN: Okay. Also the contract renewal is also happening in 2030.

L. YEUNG: Correct. This is our assumption.

N. JOTIBAN: Okay. Thank you. That's very helpful.

Now I would like to move on to my next question. Could you please pull up the Excel spreadsheet 4-SEC-72A. I already asked panel 1 this question, and they said it's better suited for panel 2. Please refer to Row 14, engineering and design program. The total cost increase in this program is 6.3 million, and it's broken down by category on the right: Inflation, labour, new IT, and other.

Now, if you could please go to Exhibit 4-1-2, page 39, line 17. Starting from line 17, this is an explanation for the cost increase of 6.3 million in 2026 under the engineering and design program. I was trying to cross-reference and noticed that the cost breakdown in the Excel file appears to be inconsistent with the explanation in Exhibit 4.

So in the Excel file, the labour cost shows an increase of 1.5 million for 2026, but the Exhibit 4 explanation in line 22, it shows -- sorry, it shows other compensation costs of 2.2 million. And also, the cost increase in the Excel file due to inflation is 0.3 million, but in this exhibit here on page 40, lines 5 to 6, that the cost increase due to inflation is 1.1 million. And also, the Excel file shows 1.6 million in other category, but there is no explanation in this exhibit. I am not sure if that is due to the way you are trying to break down the cost in the Excel spreadsheet by certain categories, that's why the numbers aren't consistent with the explanation. So would you be able to provide why the numbers in the Excel spreadsheet do not match with the explanations in Exhibit 4?

L. YEUNG: Yes, I can. So SEC 72, that Excel file is originated from Exhibit 4-1-2, page 6. So maybe we don't need to go there, but in there there was a footnote in the bottom showing that the labour costs in there represent compensation net of capital allocation recovery. So in Schedule 4-1-2, the 2.2 million represent the gross composition cost increase year over year versus the Excel file that is composition cost net of labour recovery. So that's why it's a lower amount. It's 1.5 million. So hopefully that explains the first item.

N. JOTIBAN: What goes in the other category in the Excel file that comes up to 1.6 million?

L. YEUNG: So the Exhibit 4-1-2, page 6, again, that table is to -- is a cost driver table. It is -- the design for it is to provide another view of our OM&A costs started with the inflation line. So that is based on the OEB inflation parameter over the OEB-approved OM&A cost, and that table is to -- the nature of it is to capture all the main items other than inflation. So we try to separate it from there versus in the 4-1-2 inflation is blend into all other items. So that is like a slightly different view.

So in terms of your question about what that other, inside that 1.6 million, I am hoping that between the two evidence, CCC 43, the cost breakdown will provide you some idea of what is included in there, and also the Exhibit 4-1-2, page 40, it talks about the grid modernization costs, those are included in that 1.6 million.

N. JOTIBAN: Okay. That's very helpful. Thank you very much for the explanation.

Would you please pull up Exhibit 4-1-1, page 10. I already asked panel 1 this question, and they said it's better suited for panel 2. Here Hydro Ottawa stated that population growth and electrification are driving a significant increase in its OM&A cost and affected the programs as shown on this page. That includes customer billing, customer and community relations, underground locates, maintenance-related programs.

Would you please identify which OM&A programs on this page are affected by increased electrification?

Could you maybe just scroll down a little bit more?

I am assuming that some of them are affected by population growth and some are affected by electrification? Or are they all affected by both drivers?

A. COLLIER: Yes. So on this page, the programs are identified in the bold, so customer billing, customer and community relations, engineering design, those are also programs at the JC level.

But what this is trying to drive at is obviously growth and electrification as a driver is causing an increase in our assets and our CAPEX, which is causing an increase in our head count, as panel 1 would have alluded to, as well as maintenance-related programs. Under engineering and design, there is complexity in the long-term planning for electrification. All of that is causing increased costs, both in terms of people as well as these other items. Underground locates has to do with increased work, as well.

So it's very hard to, you know, precisely tie numbers to each driver because you have costs and people serving multiple drivers. But this page that you have pointed to here are the main factors driving that increase.

N. JOTIBAN: Okay. Thank you. Would you please go to 1-DRC-1, page 3? Starting from line 7, Hydro Ottawa stated that:

With an increase in electrification, Hydro Ottawa's OM&A costs will also increase.

And it stated that:

“With increased electrification and EV penetration, Hydro Ottawa will be utilizing a new CRM, or customer relationship management, which will streamline EV connection requests, automate workflows, enhance customer service, improve project intake, boost agent productivity, and track performances. These investments are designed to yield productivity and operational effectiveness gains.”

My question is given that an increase in electrification drives OM&A cost higher, and from reading this it seems that a new -- the new CRM would help the organization achieve efficiency gains by utilizing it.

So is there any effect on OM&A costs associated with electrification by utilizing the new CRM?

A. WILLIS: Hi, it is Andrew Willis. Our CRM system is a foundational system for Hydro Ottawa. We have automated our service desk on that system, we have automated our field service, we are managing all of our customer intake for many OEB programs, right? - and our key accounts team.

So as we automate this, we are getting a number of productivity and efficiency gains that are being driven by programs related to electrification. I would say the CRM is one component of that. And we have had the system since 2018 and are continuing to evolve that system and drive efficiencies throughout our organization and to drive increased intelligence on our grid and customer experience.

N. JOTIBAN: So would the utilization of this CRM lower any OM&A costs associated with electrification? I understand that you have productivity benefits identified in exhibit 1 for capital, but I am just wondering if there's any cost savings that could be realized that's associated with increased electrification by utilizing a new CRM?

A. WILLIS: I believe there are. We are actually in the process of building a roadmap for our CRM program moving forward in 2026, which is looking at people, process, and technology as a result of all of the transformation and electrification. And, at that time, we should be better positioned to understand those savings.

N. JOTIBAN: Okay. Also at this time, you will not have any information or would be able to identify where the cost savings could be reflected in OM&A?

A. WILLIS: Let me speak with my panel. Thank you.

Other than what we have identified in the productivity, we haven't quantified our savings yet on the CRM program. But certainly, with the level of automation that we have put in, we avoid having to hire new staff, we avoid having to manage customer intake via email. We are enabling skills-based routing workflows, so there is a number of benefits there. But I don't have any OM&A savings to share at this time.

N. JOTIBAN: Okay. Thank you, very much, I appreciate it.

Now I would like to move on to my next question. Could you please pull up 4-Staff-172? Could you please refer to line 10? This is a reference for a web page that contains a news article that OEC and Envari Holding Inc. announced their equal ownership of Teraflex Limited earlier in 2025. My question is: Did TeraFlex do any work for Hydro Ottawa since the announcement?

A. COLLIER: Yes.

N. JOTIBAN: And will Teraflex be doing any work for Hydro Ottawa in 2026?

A. COLLIER: Currently Teraflex is on probation with Hydro Ottawa Limited due to some safety violations, so that will depend on the resolution of those issues and whether they successfully win any further proposal work.

N. JOTIBAN: So, if they did some work -- do some work for Hydro Ottawa previously, could you please update Appendix 2N to reflect the work that Teraflex did for Hydro Ottawa? Because I don't see it in that table in Appendix 2N.

A. COLLIER: Sorry, can you -- can we pull up the table and what you're referring to specifically?

N. JOTIBAN: What year did Teraflex -- is it -- sorry, I mean it has to be 2025. So would that -- if you go to the year 2025. So would this table, if you scroll down a little bit more, already capture any work that Teraflex provided to Hydro Ottawa?

A. COLLIER: Just give me a second to confer with my colleague. Okay. So, 2N is corporate cost allocations, so there is no corporate cost allocation between Hydro Ottawa Limited and Teraflex. So I think your question is really about 2H.

N. JOTIBAN: Oh, okay. Sorry.

A. COLLIER: And what I would say to that is because the acquisition of Teraflex occurred after all of the financials and forecasting for this application, 2H does not reflect any potential work that Teraflex would do for HOL. And, at this time, given the safety violations, it would also be quite difficult to forecast until those are resolved and without knowing what future work they would win.

N. JOTIBAN: And what about the actual?

A. COLLIER: The actual, the acquisition -- the actuals are all correct, because they weren't an affiliate prior to all the actual data that you have in 2H.

N. JOTIBAN: Okay. Thank you. And another question is the pricing methodology for services provided by Teraflex. In Exhibit 4 I only see pricing methodology for services provided by Hydro Ottawa Holding Inc. Do you also have updated pricing methodology for services provided by Teraflex?

A. COLLIER: Again, in 4-2-1, this is about shared services and corporate cost allocations, so Teraflex would not be part of that exhibit. Any work that they would have done in the past for Hydro Ottawa Limited would have been prior to them being an affiliate and their pricing would be the same as any other contractor.

N. JOTIBAN: Okay. Okay, thank you. I appreciate that. Now, my last question. Could you please pull up 6-Staff-187, Part B, Response? Thank you. So Table A and Table B show the reconciliation of the balances in accounts 4375 and 4380 from Appendix 2H, which is Other Revenue tab in Chapter 2 appendices, and the total price and then cost for the services in Appendix 2N which is Corporate Cost Allocation tab. If you look at Table A, we asked Hydro Ottawa to reconcile the numbers between the two appendices and Table A shows that they are reconciled. But for Table B, it looks like the balances in account for the 3A from Appendix 2H, they are not equal to the annual -- the total annual cost for services in Appendix 2N, and the variance is identifying as the weighted average cost of capital. Would you please explain why they don't reconcile and how the weighted average cost of capital is related to the variance in account 4380?

L. YEUNG: So Table A is the revenue, so between 2H and 2N they are reconciled to each other.

N. JOTIBAN: Yes.

L. YEUNG: Table B is our expenses. The difference is because of weighted average cost of capital. So when Hydro Ottawa provides services to the affiliates, we charge, in addition to the direct cost, we charge in addition the weighted average cost of capital, so that to get the full cost charge to the affiliates. And weighted average cost of capital is not being recorded in 2H because that is not the direct cost, is not the typical direct labour or services, so that's why it's not a part of 2H.

N. JOTIBAN: Okay, thank you for your explanation. I have no further questions, thank you.

M. MILLAR: Thank you, Ms. Jotiban. I think Ms. Wang is next, if she is there. There we go.

EXAMINATION BY H. WANG

H. WANG: Yes, thank you, Michael. Good morning, panel. This is Helena Wang from the OEB. Before I start, I would actually like to clarify the question that Narisa just asked. Could Hydro Ottawa please provide a USoA account that the way average costs are recording?

L. YEUNG: Hi, Ms. Wang. We cannot provide the USoA, because it wouldn't be recorded in a USoA for that weighted average cost of capital.

H. WANG: All right, thank you.

L. YEUNG: No problem.

H. WANG: So I would like to start with the updated Chapter 2 appendices attached to 1 Staff 1. If we could go to the Chapter 2 appendices, please. Thank you. In Tab 2BA for 2021 to 2025, could we please scroll down to year 2023. In cell E218, Hydro Ottawa reported a total PP&E addition of 86.81 million in cell E218 for 2023; do you see that? This amount is different from the number reported in table E filed in response to 1 Staff 1.

Now, if we -- could we please go to 1-Staff-1 on page 7. So table E on this page -- thank you. So in this table, the fixed-asset total additions of 92.514 million is reported for 2023. Could you please explain the difference?

A. COLLIER: I think we would have to take that away to look at that.

H. WANG: Thank you.

M. MILLAR: So I think that's an undertaking, and it's JT3.3. Ms. Wang, could you repeat what the undertaking is for?

H. WANG: Okay, so can you please provide a reconciliation of the table E fixed-asset total addition for 2023 reporting in table E what the total PP&E addition reported in Tab 2BA for 2023?

M. MILLAR: Thank you.

UNDERTAKING JT3.3: Provide a reconciliation of the table E fixed-asset total addition for 2023 reporting in table E what the total PP&E addition reported in Tab 2BA for 2023

L. YEUNG: Sorry, just a second. Lianne, can you bring up the other evidence, please? I just want to take a closer look at this number.

Sorry, never mind, I think better take an undertaking. Sorry about that.

H. WANG: That's okay. Thank you.

Now, can we please go back to the Chapter 2 appendices, please, Tab 2BA for 2026 to 2030. That's a different tab. Thank you. Can we please look at the net fixed assets for 2027 in Row 155. If you could please click on the opening and closing. So D155. So if you click on D155 and G155. You have to click both cells together to get the average calculation. Thank you. So you will see that the average is 2.259 billion, according to Tab 2BA, and if we could please go to the updated 2027 revenue requirement work form attached to 1 Staff 1.

L. CHARTRAND: Sorry, can you repeat that reference, please?

H. WANG: Right. 2027 revenue requirement work form attached to 1-Staff-1. Thank you. And if we could please go to the data input tab. And you will see the net -- the net fixed-asset amount reported here does not match. You don't have to pull it up, but the net fixed asset of 2.266 billion reported in this work form does match what was originally filed. So it appears that the 2027 revenue requirement work form wasn't updated as part of 1-Staff-1. Do you agree?

A. COLLIER: Could we defer this question on the revenue requirement work form to panel 3, please?

H. WANG: Okay, all right, thanks.

Moving on -- sorry, let me just mark this. Can we look at the rate base reported in the 2027 revenue requirement work form. If we move to Tab 4, rate base -- thank you. The calculated rate base is 1.701 billion; do you see that? And if we could go to the 2026 to 2030 PILs work form attached to 1-Staff-1, the Tab A data input sheet, and scroll to the right a little bit, you will see that the rate base reported for 2027 here is 1.698 billion. This is different from the amount we just looked at in the 2027 revenue requirement work form.

A. COLLIER: Yes, so any questions on PILs or the revenue requirement work form would be panel 3.

H. WANG: All right, thank you.

Could you please undertake to provide a copy of the 2024 audited financial statements?

A. COLLIER: Yes, I was just checking to see if we had already provided it, but provided that we haven't, we can certainly undertake to provide the audited 2024 HOL financial statements.

H. WANG: Thank you.

M. MILLAR: JT3.4.

UNDERTAKING JT3.4: Provide the audited 2024 HOL financial statements

H. WANG: Now, can we please go to 2-CCC-19, part A on page 2. Thank you.

So here, Hydro Ottawa stated that contributed plant is only included in the capital contribution line and is not considered growth capital, as the contributed plant consists of in-kind contributions or non-cash assets. And Hydro Ottawa further explained that this methodology is applied across all capital programs.

Could you please clarify that the gross capital here is specifically referring to the gross capital line in the table in the exhibit 2-5-6?

A. COLLIER: Sorry. This question was labelled as panel 1, so we haven't reviewed it. But maybe if you could repeat your question again?

H. WANG: Right. So in CCC's question, they referenced exhibit 2-5-6, page 9 to 10. There is a Table 2 in that question – sorry, in that reference. And then Hydro Ottawa provided explanation of the items in that table.

So I am just asking if you could clarify that the gross capital mentioned in Hydro Ottawa's response is specifically referring to the gross capital line in that table? Maybe it would be helpful if we could go to exhibit 2-5-6, please? On page 9. Thank you.

So this is the table here. And you will see that there is plant relocation and upgrades, gross, contributed capital, and contributed plan.

So I am asking if your response is specifically referring to the gross capital line in this table.

A. COLLIER: So subject to check and discussion with panel 1, contributed plant is not in the gross line in this table.

H. WANG: Okay, thank you. You don't have to pull it up; I am just going to read it out that the OEB Accounting Procedure Handbook, effective January 1, 2012, Article 430 provides directions regarding non-cash contributions received.

And on page 425, the OEB Accounting Procedure Handbook stated that:

“When contributions in aid of construction are received in the form of services or properties, the value of the contribution should be recorded in the applicable asset accounts, 1606 to 1990, and defer revenue account, 2440.”

Could you please confirm if Hydro Ottawa's accounting treatment for contributed plant, specifically in-kind contributions or non-cash assets, is in line with the OEB Accounting Procedure Handbook?

A. COLLIER: Could we take that as an undertaking?

H. WANG: Sure.

M. MILLAR: That's JT3.5.

UNDERTAKING JT3.5: Confirm that Hydro Ottawa’s accounting treatment for contributed plant, specifically in-kind contributions or non-cash assets, is in line with the OEB Accounting Procedure Handbook

M. MILLAR: And Ms. Wang, just while I have you, we will be looking to break for our morning break within the next five minutes or so. So if you could just find a natural spot to break your questioning, we will take our break after that.

H. WANG: I think we can probably just break now; I am done with this question, if that's okay.

M. MILLAR: Yes, of course. The undertaking was JT3.5. Why don't we break now until, I guess, 11:11 or so.

And just for people's notes, Ms. Nowicki and I will be sort of switching in and out today as your hosts. I think she will be joining us after the break, and them I will be back at some time as well. So we will see you all in 15 minutes.

--- Recess taken at 10:56 a.m.

--- On resuming at 11:11 a.m.

J. NOWICKI: Ms. Wang, please proceed.

H. WANG: Thank you. This is my last question, I think this question mainly is probably for panel 3, but some elements of the question I could get some help from panel 2 if possible. You don't need to pull it up, I would like to reference a recent OEB accounting order issued on April 30th, 2025, for the establishment of a deferral account to record impacts arising from implementing the electric vehicle charging rates. On a high level, the accounting order directs that electricity distributors whose OEB approved 2026 distribution rates become effective on January 1st, 2026, are to make the EVC rate available to eligible customers on January 1st, 2026. Could you please confirm that Hydro Ottawa is to make EVC rate available to eligible customers on January 1st, 2026?

A. COLLIER: Yes, that is a panel 3 question.

H. WANG: Okay. To your knowledge, could you please confirm if there is any implementation costs are included in the bridge year 2025 or and/or test year 2026 as part of the OM&A, the implementation costs related to the EVC rate?

A. COLLIER: Just a second. I am not aware of that. I don't know whether the answer is yes or no, to be clear.

H. WANG: All right, thank you. I can confirm that again tomorrow with panel 3, then. Thank you.

A. COLLIER: Thank you.

H. WANG: I have no further questions for panel 2, thank you very much.

J. NOWICKI: Thank you, Ms. Wang. So I believe we are still with OEB Staff for our panel 3 and Ms. DeFazio. I think we need a few minutes, Ms. DeFazio isn't in the room at the moment. So, perhaps we can pause for two minutes before Ms. DeFazio comes online. Thank you.

--- Brief pause taken.

J. NOWICKI: Apologies for the delay, I will pass things over to Ms. DeFazio to continue with OEB Staff questions for panel 2.

M. DEFAZIO: Hello. Are we on?

A. COLLIER: We can hear you.

EXAMINATION BY M. DEFAZIO

M. DEFAZIO: Excellent, thank you. Okay. Can we please pull up 2-Staff-77, please? This IR we discussed the conversion of bulk metering buildings to multiple customer metering or suite metering buildings, which is a program Hydro Ottawa has. Just a question about the impact, could you please explain the impact of these conversions on Hydro Ottawa's OM&A expenses?

A. COLLIER: Sorry, Ms. DeFazio, that would have been a question that should have been posed to Panel 1.

M. DEFAZIO: They told me to ask you.

A. COLLIER: Hmm.

M. DEFAZIO: Are you guys metering?

A. COLLIER: No, the metering expert was on panel 1.

M. DEFAZIO: Okay, then. We will move on. Could we please, then, go to Exhibit 4, Tab 1, Section 1, attachment A? And in Exhibit A, page 13. Thank you. So, here we see the OM&A expenses for the EAM project and they're approximately -- well, $1.2 million in 2026 and the expenses decrease over the forecast period. The OM&A section does not show, as it's not required, yearly expenditures for OM&A programs. Are there any other OM&A programs you're aware of that would follow a similar pattern, with the decreasing cost over the test period?

L. YEUNG: Hi, Ms. DeFazio, this is Louisa Yeung. We do have other projects such as CRM that is in Exhibit 4-1-1A, attachment A, page 20, showing that the cost is actually increased by 0.5 million in 2027. So, as you can see, that 2026 we have budgeted 0.7 million, but it's going up in 2027. And in addition to that we also have AMI, which is in Exhibit 2-5-7, page 138. So for this project the OM&A started as 0.7 million but it goes up to 2 million by 2030.

M. DEFAZIO: Thank you. Are you aware of any programs that would go -- other programs similar to the EAM that would go down over the forecast year period?

L. YEUNG: I don't have that on top of my head.

M. DEFAZIO: Thank you. Just one more question. Follow-up to 2-Staff-87, the interrogatory. So in this interrogatory response, Hydro Ottawa provided a number of agreements with Hydro One for CCA -- or, sorry, CCRA, as well as some of the -- a number of invoices. If we go to the IR Excel attachment for 1-Staff-1, and Tab 2AA, please, and scroll down towards the bottom of the sheet, we will see the general plant. Up just a little bit, please, and keep going. Two more lines. Oh, maybe three. There we go. CCRA.

So OEB staff attempted to take the invoices provided in 2-Staff-87 and reconcile the amounts in 2AA, and we were -- we didn't even get close. We were totally confused. So I was wondering if you could clarify how the amounts were placed into 2AA, if it was through some other method of payment, then what was recorded by invoices, or if you could reconcile the invoices to 2AA.

A. COLLIER: Yes, thanks, Ms. DeFazio. Luckily, we have an ERP system to do all these calculations for us. But what I will do is I will maybe walk you through one example of how you can do that with the evidence that we have on record, and we can go from there. So if you remember this number that you're seeing on the screen, I guess in cell B47, which -- CCRA for 2021 of 16.9 million. I will now ask Lianne to pull up from Schedule 2-5-5, Table 34, I think. I don't have the page. Oh, I think you passed it. Yes, okay. So if you scroll down a bit to the total. So Ms. DeFazio, if you remember the number from your 2AA exhibit, you will see that this total matches, so that's how at least you know which project the CCRA payments relate to. So I will take the largest project, so we will take the Cambrian MTS, which is the second row in this table, and if we remember the number 16 million, 16.056 million. Now if we go back to the IR 2-Staff-87, attachment B, which -- and on page 17. Okay. So this table, this milestone payment -- milestone date table, if you could just scroll up a bit, Lianne. Okay. So you'll notice that the last four rows of this table are 2021, which is the year in question. If you add up those four numbers, you'll come up with 16.763 million. That, however, as per the top of the table, includes HST, but as you know, we don't record HST in the CCRA program, because we get that back from the government. So if you remove HST from those four numbers, you come up with 14.8 million. But then, because Cambrian was a very large project, we then apply AFUDC, or allowance for funds used during construction, so that is how you go from the invoice to the CAPEX amount in 2AA.

M. DEFAZIO: Okay. Thank you. So what we have -- what we are looking at right now is a contract, not the actual invoice? So we had attempted to do it using the invoices only. So if you had a schedule payment in a contract, there -- we could assume that that payment would have occurred?

A. COLLIER: Absolutely, yes.

M. DEFAZIO: Okay. Thank you very much. That is all my questions.

A. COLLIER: No problem.

J. NOWICKI: Thank you, Ms. DeFazio.

If there are no further questions or clarifications for this panel, I believe that concludes panel 2. Thank you very much for your time. Up next we have panel 3, and I will pass it on to Ms. Coban to introduce the panel.

D. COBAN: We will need to complete the panel switchover, so we need about 20 to 30 minutes to get their technology all set up. So if we could break to make that happen.

J. NOWICKI: Okay. So it's 11:28 now. If we come back at 11:50 or 12:00, would that be sufficient time?

D. COBAN: Yes, I will -- we will aim for 11:50, but I will be back online with an update if for some reason we have having technical issues.

M. GARNER: It's Mark Garner from VECC. I am just throwing out, is there any efficiencies in simply taking an early lunch and coming back at 12:30, or sometime like that, and then we save some time? So I just throw it out and...

D. COBAN: Just give me a moment, Mr. Garner.

We have already made lunch arrangements based on the schedule, so it would be difficult to accommodate that.

M. GARNER: Okay. I just wondered. Okay, thank you.

J. NOWICKI: Okay. So let's take a break now, in that case, until 11:50, and we will come back, and if, Ms. Coban, your team needs more time, then we can reassess then.

D. COBAN: Sounds good, thank you.

J. NOWICKI: Okay, great. So we will reconvene at 11:50. Thank you.

--- Recess taken at 11:29 a.m.

--- On resuming at 11:50 a.m.

HYDRO OTTAWA LIMITED – PANEL 3, RATE FRAMEWORK, COST OF CAPITAL, PAYMENTS IN LIEU OF TAXES, BENCHMARKING, LOAD FORECASTING, WORKING CAPITAL, COST ALLOCATION, RATE DESIGN, DEFERRAL AND VARIANCE ACCOUNTS AND REGULATORY COSTS

APRIL BARRIE

CUC DUONG

MEGHAN FEE

NEIL TEJWANI

M. MILLAR: Good morning again, everyone. We are going to continue now with the beginning of panel 3. Mr. Myers, could I ask you to introduce your panel?

J. MYERS: Sure. Thanks, very much. So I will turn it over to our panel starting with Ms. Barrie, to introduce themselves and their titles, as well.

A. BARRIE: April Barrie, director of regulatory affairs.

C. DUONG: Good morning. It's Cuc Duong, manager of rates and revenue.

M. FEE: Good morning. It's Meghan Fee, manager of regulatory policy and compliance.

N. TEJWANI: Good morning. It's Neil Tejwani, treasurer.

J. MYERS: Thank you. And the panel is now available for questions.

M. MILLAR: Thank you, very much. Mr. Harper, I will turn it over to you. And, between you and Mr. Garner, you have 90 minutes.

EXAMINATION BY B. HARPER

B. HARPER: Yes. With any luck, we won't require all that time. I would just like the start off by saying my name is Bill Harper. I am a consultant for VECC.

Whoever on the panel is dealing with load forecast, you will be happy to hear all my questions in that area were filed in writing. So my questions today will be dealing only with the areas of cost allocation and rate design.

And in that regard, can we start off by turning to VECC-53? Can you scroll down to the response? According to this response, Hydro Ottawa records $1.3 million of costs of the energy transition, customer strategy and innovation group in the USofA 5510. And then directly allocates the costs to the various customer classes. Correct?

C. DUONG: Hi, Mr. Harper. Yes, that's correct.

B. HARPER: Would it also be correct to say that you are also proposing that these costs will be included in tab 02 of the cost allocation model, where various benchmarks are calculated for the service charge in each customer class?

C. DUONG: If I can defer that for a second? Sorry, Mr. Harper, could you repeat your question?

B. HARPER: Sure. I think you are also proposing to include these costs which you directly allocated in each of the customer classes in the cost allocation model tab 02 calculations, where you calculate various benchmarks for the service charges for each of the customer classes.

C. DUONG: Yes, that's correct.

B. HARPER: Okay. Now, the response then goes on to state that this group is responsible for managing your key account customers, including consultations regarding your non-wires solutions programs and initiatives.

Now I assume that managing these consultations regarding your non-wires solutions programs is not the only -- is only one of the activities that this group's involved in. Would that be fair to say?

C. DUONG: Sorry, if we can consult? Thank you.

So this group does more than just the non-wires work.

B. HARPER: So I guess maybe if you could outline for me now what else they're responsible for? Or, if you feel more comfortable with it, maybe there's some internal documentation that you have as part of your documentation of your organizational structure as to what the responsibilities of this group are which you could undertake to file?

C. DUONG: I can explain briefly what this group does. So they are the key accounts team that mostly oversees two main directives, which is to help and address our larger customers in terms of any question they have on their rates and their consumption needs and stuff.

As well, they are involved in carrying out efficiency saving programs, as well, with our key accounts -- our key account customers accounts.

B. HARPER: So they would be responsible for -- I don't want to use the word delivery, but sort of facilitating the delivery or assisting with the delivery of the CDM programs that your larger customers are undertaking or looking to undertake. Would that be fair?

C. DUONG: That would be fair, yes.

B. HARPER: That would also apply to, say, the upcoming EDSM programs that, you know, are likely to be initiated under the IESO's new framework that was introduced in January 2025?

C. DUONG: That would be fair. If I can also take a break for a second? Thank you.

Hi, Mr. Harper. We do have a reference that explains what this group does as well. So if we can go to Schedule 4-1-2, page 46? And just from a clarification standpoint, this team also provides EDSM for all customers, not just the key account customers.

B. HARPER: EDSM, okay.

C. DUONG: Mm-hmm.

B. HARPER: Okay, fine. I am sorry, I hadn't caught this when I was rereading through it. So this should be fine and be sufficient for my purposes. Thank you, very much.

Maybe now if we could go to exhibit - I guess it's Schedule 7-1-1, table 4. Here, you provide the meter-reading weighting factors that you are proposing to use in your cost allocation model for each of the years 2026 through 2030. And I would just like you to maybe keep in the back of your mind that the relative weights are roughly 20 to 1 in approximate terms.

Now, I would just like to understand, is the meter reading -- is your meter reading done by Hydro Ottawa? Or is it actually done by a third party?

C. DUONG: It is done internally.

B. HARPER: So all of the meters are read internally, then. Because there was some reference when you were talking about how the weighting factors are developed to both third party and internal costs. So what types of third-party costs would be involved in your meter reading, then?

C. DUONG: I should clarify, Mr. Harper. So it is read internally. However, there are additional, we call it “bucketization” of some of our meter reads. And we do use external contractors to help with that.

B. HARPER: Would the bulk of the meter reading costs as they are totalized for purpose of the cost allocation, would the bulk of those be in your internal costs? Or would the bulk of them -- what proportion is made up of sort of the third-party costs?

C. DUONG: I would have to look at our evidence to exactly tell you what proportions are internal versus external.

B. HARPER: Okay. Well, maybe we can just put a pause on that and see whether I need to pursue it further.

C. DUONG: Yeah.

B. HARPER: Now, when you are billed by your third-party providers for that, and I guess they would have a methodology for billing you. Do they bill you on a per customer basis? Or if the customer has more than one meter, do they bill you on a per meter basis for that totalization or for that, I guess, bucketing, for want of a better verb?

C. DUONG: Subject to check, of course, they bill us monthly. And whether it's based on volume or not, I am unsure of that.

B. HARPER: Is that something you could undertake to look into for me and determine?

C. DUONG: Yes, we can.

B. HARPER: Okay, thank you very much. I guess we need an undertaking number for that.

M. MILLAR: Yes, that's JT3.6.

UNDERTAKING JT3.6: Provide information on third-party meter reading billing procedures

B. HARPER: Thank you.

Could we go to VECC-52(b)? And scroll down to, right there, that page right there that's great. Now, you remember I asked you to remember the ratio of 1 to 20 from the previous evidence. When I look at this and I look at the relative weights, the relative weights here just seem to be more in the order of 1 to 5, and I was wondering if you could reconcile the numbers you gave me in this response with the numbers in your original evidence, and tell me what the difference is, which one's correct, and in your view which one of the two for cost allocation model purposes we should be using?

C. DUONG: Hi, Mr. Harper. So this Table C and potentially an update that's maybe in 1-Staff-1 would be the values we have used in our cost allocation model. The other ratio that you were referring to was directly more with the metering cost itself, but this meter reading includes other other costs.

B. HARPER: Right. Because if I actually look at the cost allocation model itself and what you filed, I think the ratings were 1 to 20 in there. Maybe we can just call up the cost allocation model you filed for 2026 with the original application. I am going by memory, I may be wrong, but I just wanted to check before I leave this. Oh, it would be the cost allocation model which would be one of the Exhibit 7, maybe exhibit Attachment 7A, maybe. All right, okay. Maybe if we go across to Tab I7.2. And if I scroll down we see a weighting of 1 for smart meters, if we scroll down more we see a weighting of 20 for the interval meters. And this is where, from your response you just gave, I think you told me it should be 1 to 5 if I'm not mistaken? Or roughly whatever the numbers were in the VECC interrogatory response; is that correct? And if you want to go away and look at this further and come back to me and get back to me by way of undertaking that's fine, too.

C. DUONG: Thank you, Mr. Harper. The 1 -- so what we are looking at here, as you have noted, is a 20 to 1 ratio that was noted in your first table that you've referenced. The other second table mentioned is relating to the ratio for, I believe, the meter capital account. But we can take an undertaking to reconcile that for you.

B. HARPER: No, because if we go back and look at the response to VECC-52B, it was dealing specifically with meter reading weighting factors. If you look at both the question and the response, it wasn't meter capital. This one was dealing with meter reading. That is what was confusing me, so maybe you do want -- maybe what you gave me here was the capital weighting instead of the meter reading weighting and you can check and see whether that's the case?

C. DUONG: So one was just the vendor weighting only.

B. HARPER: Okay. So, which one was the vendor weighting only?

C. DUONG: We can take the undertaking just to reconcile that for you, Mr. Harper.

B. HARPER: Okay, fine. Thank you very much, that would be fine. If we can get an undertaking number for that?

M. MILLAR: Yes, JT3.6 -- pardon me 3.7, JT3.7.

UNDERTAKING JT3.7: Reconcile which was vendor weighting only

B. HARPER: Okay. Now, I would like to look at what the costs you're proposing to include in the SSS administration charge. So, if we could first to Schedule 8-3-2, page 3. If you scroll down a bit, you have listed a number of budgets of incremental cost items that you have included in the charge. And one of the costs you have included in the first bullet is the cost of processing the Ontario electricity rebate. What I was wondering is: Is it only standard service supplied customers that are given the rebate or customers that are served by retailers; do they also receive the rebate?

C. DUONG: It's all customers that receive the rebate that qualify for it.

B. HARPER: Right. Then I guess, then I guess why would it be reasonable to assume the processing costs just in the SSS admin, as opposed to including it in a cost that would be paid for by all customers, including retailer customers?

A. BARRIE: Mr. Harper, it's April Barrie speaking. So, how we looked at the SS charge which is different than the retail service charges, retail service charges are very specific in terms of saying the only charges we are allowed to build into those rates are incremental to what otherwise would be there. So, the Ontario energy support program would be already something that all customers get, and as a result should not be included in the retail service charges. However, the SSS charge doesn't have a similar item and the Ontario energy rebate program is not specific to distributor charges only. So I do feel like there is a disconnect in terms of what is allowed in each of the two different charges.

B. HARPER: I appreciate there is a disconnect. I thought what you were trying to identify here, because the SSS admin only, is only applied to customers that take standard service supply, it is not applied to customers that are served by retailers; correct?

A. BARRIE: What we are -- so you are just wondering if the actual costs of the program related to also the retailer charge is in here?

B. HARPER: No, no.

A. BARRIE: For those particular customers only or for all customers?

B. HARPER: Well, what I was struggling with was the fact that what you say here is you identified specifically the incremental costs of processing the Ontario electricity rebate, and I assume that's the incremental cost of electricity rebate for all customers in the province -- for all customers, sorry, that are served by Hydro Ottawa and that those incremental costs are going to be included in the charge that is only levied against standard service supply customers, it will not be levied against customers served by retailers; correct?

A. BARRIE: That is correct.

B. HARPER: And I guess I was wondering, since the rebate is paid out to everybody and therefore, therefore it would seem reasonable that the costs of processing the rebate should be paid for by everybody. And I am not suggesting it would be included in the retailer charge, I am suggesting it should be included in a charge to all customers, as opposed to just SSS admin customers. And that is what I was struggling with.

A. BARRIE: So, that's -- sorry, that is what I was trying to say. Like, if I was to design these two rates myself, you would need a charge that all customers should be paying. The retail service charges are designed in a matter that just picks up the incremental costs for retail services whereas on the assumption and basis that all customers have the ability to become a retailer. However, the SSS charge has not been designed in the same fashion that, and it is not, therefore -- it doesn't pick up just the incremental costs. So there isn't another charge for just retail customers to be captured within.

B. HARPER: No, but I guess you could include -- the costs are included in your overall cost for the utility, and therefore if they aren't recovered specifically through the SSS admin charge, they will be recovered through your general cost allocation to all customers. And since all customers get the rebate that seemed to be the more reasonable way. But this is a matter of argument, I think, I think you have confirmed what I was interested in confirming and we can pursue the rest of the matter later on, if I can put it that way.

Similarly, if we look at the second and the third bullets, I wanted to understand the difference between, one, the wholesale market settlement activities mentioned in the second bullet and the monthly settlements with the IESO and the Hydro One mentioned in the third bullet. I want to understand what's the difference between those two different settlement activities?

C. DUONG: Hi, Mr. Harper. So, the second bullet refers to the settlement with the IESO for the difference between the market pricing and the fixed prices for those customers --

B. HARPER: Okay.

C. DUONG: -- fixed price customers. And the third bullet is relating to settling the payments to our embedded service providers, which is IESO, Hydro One and our embedded generators.

B. HARPER: Okay. Now, staying with that third bullet, am I correct that the settlements with the IESO are for both commodity and transmission charges?

C. DUONG: That's correct.

B. HARPER: And does the IESO bill retailers separately for the transmission charges for the customers they serve, or are you billed transmission service charges for all customers in your service area, regardless of whether they are a standard supply service customer or a retailer customer?

C. DUONG: That would be correct. It's in the latter.

B. HARPER: Okay, okay. I won't go any further than that. I just -- I understand. And similarly, when it comes to Hydro One, I assume the settlement charges you're referring to there are settlements for things like your low-voltage expense you have to pay them?

C. DUONG: That's correct.

B. HARPER: And, again, Hydro One bills you for low-voltage charges for service for all your customers in your service territory, not just the SSS admin customers; correct?

C. DUONG: Correct.

B. HARPER: Okay, fine. Now, maybe if we could go to VECC 66D. And I think maybe you covered all this. You talk about the working capital allowance, and the working capital allowance is made up of working capital associated with commodity, global adjustments, transmission, low-voltage charges, and regulatory charges. Now, the regulatory charges include, if I understand correctly, such things as the wholesale market service charge and the triple RP?

C. DUONG: Triple RB, yes; that's correct.

B. HARPER: And again, for customers who contracted with retailers, you charge them the wholesale market service charge, the triple RP charge, so -- don't you?

C. DUONG: Those customers that are retailers?

B. HARPER: Yeah, that are served by retailers. They don't pay you the wholesale market service charge and the triple RP charge; correct?

C. DUONG: If I can reframe your questions --

B. HARPER: Sure.

C. DUONG: -- to ensure I understand your question. Are you saying do we charge our retailer customers -- sorry, do we charge our retailers the costs of both -- well, for all commodity costs? So costs of power, we call it, which is listed there as commodity, global adjustment, transmission, low voltage, et cetera?

B. HARPER: No, I wasn't speaking about the commodity, because I understand the retailers are responsible -- I think are responsible for -- you know, they're dealing with the commodity side. What I was dealing here was specifically with the regulatory charges; i.e., the wholesale market service charge and the triple RP, and whether those specific charges, which I believe are tariffs on your rate schedule -- do you bill those to customers that are served by retailers?

C. DUONG: Yes.

B. HARPER: Okay. That is really what I was wanting to contract for. Now, but I think we have just touched upon the fact that, you know, you don't charge customers that are served by retailers for the commodity, though, do you?

C. DUONG: That's correct.

B. HARPER: Okay. Now -- and so that your cost of power that you pay for the IESO, that would not include any commodity costs associated with deliveries that were made to retailers -- retail customers; correct?

C. DUONG: Actually, Mr. Harper, let me correct my last statement. The -- so customers who are retailer customers pay, of course, their commodity at the retailer pricing.

B. HARPER: Right.

C. DUONG: Then we settle with the retailers the difference between that retail pricing and the, what we call true cost of power, the market commodity cost. So inherently, we do charge our retailer customers commodity as well.

B. HARPER: Okay, fine. Except you have a -- and I guess going back to the previous conversation I think I had with Ms. Barrie, if I can correct this correctly, part of that whole cost and process of settling with the retailers, that is part of what is theoretically picked up through the retail service charges?

C. DUONG: That's correct.

B. HARPER: Okay, fine. I think I have got the answers I needed on this one.

Could we go to Schedule 8-2-1, page 3. Yeah, I think this should be fine. Now, it's the bottom half, it's the last paragraph on the page, and -- or the second-last paragraph now that it's on the screen. If I understand correctly, Hydro Ottawa is billed on a gross basis for line connection and transformation connection charges by the IESO. And based on 2023 results, that adds an additional $1.35 million to Hydro Ottawa's UTR charges; correct? At least that's what I understand from that statement there. Is my understanding correct?

C. DUONG: Correct.

B. HARPER: Okay. Now, could we go to Environmental Defence Number 34. Scroll down to part (a). I believe it's part (a). I am sorry, I didn't make a note to myself as to which part it was, but I believe -- or -- oh, could you scroll down a bit more? I apologize for this. I didn't make a note to the fact. But I think in part of this response it basically states that Hydro Ottawa bills your RTSR charges on a net load basis; am I correct on that?

C. DUONG: That's correct.

B. HARPER: Okay. And that -- but that net load basis would include the recovery of gross load billing adjustments, such as the 1.35 million that we just talked about for 2023; correct?

C. DUONG: Correct.

B. HARPER: Can we go to Environmental Defence 36. Here in the response you state:

“Hydro Ottawa is not proposing any rates – to charge any rates on a gross load basis in this rate application. Hydro Ottawa supports the use of gross load billing for RTSRs where appropriate.” [As read]

And I guess I was struggling with the fact that, since the IESO bills you on a gross basis and those costs are included in the costs you must recover from customers, why you don't consider it appropriate to apply the RTSRs on a gross load basis?

C. DUONG: Well, the current rate design for the billing of the RTSR is based on the net basis. We have not had the opportunity to collect information, sufficient information, to charge these RTSRs based on the gross load basis.

B. HARPER: Well, I would assume that, in order for the -- in order for you to calculate something like the $1.3 million adjustment that's required to adjust on the UTRs, that requires you to calculate what the implications of the gross load are for the UTRs, and so why wouldn't you also have it if you are looking at applying it on your RTSRs?

C. DUONG: If I can take a moment, Mr. Harper.

Thank you. So currently, our generators that are -- we are incurring costs on a gross load basis are not creating stranded assets in our distribution grid.

B. HARPER: That wasn't the question I asked you. I asked you about the -- you said you couldn't do it because you didn't have the information to do it, and I guess I was asking why that information wasn't available.

C. DUONG: So for clarification of my last statement is, if we were to charge all customers on -- based on a gross load basis, we would have to understand all customers' gross load basis, which is beyond these customers that incur -- we incur gross load costs on. So --

B. HARPER: I guess as a subset, though, would it not be reasonable to charge just those customers that are -- that are triggering you to have to pay the IESO on a gross load basis, charge those -- apply the same criteria that the IESO applies in identifying where gross load billing is appropriate, apply that same criteria in your RTSRs, so it wouldn't be all customers, it would just be those same customers that are triggering you to incur something like the extra 1.35 million that you incurred in 2023?

C. DUONG: One could design such rates based on that, but going back to the earlier conversation of, we would require more analysis to understand if these embedded generators are creating any stranded assets in our territory. And currently, we do not believe they do.

B. HARPER: Well, I guess when we get down to whether that's an appropriate criteria or not is a matter of argument. So I guess we will leave it at that for now. Thank you, very much.

Can we go to Schedule 7-1-3, page 3? Here, you talk about your current standby charge and your current standby charge billing methodology. And you list three examples.

In the first example here, you indicate that under your current standby rates, when the generation is on all month, the standby billing demand is equal to the contract quantity.

And I was just wondering, does this apply even if the generator is operating at less than its nameplate rating for some or all of the month? Like, regardless of what level the generator is operating at, if it's operating all month, the billing demand is equal to the contract demand quantity? I just want to understand how the current methodology works.

C. DUONG: As well, could we, Mr. Harper, refer to IR 1-CCC-2? That also provides further examples on how the standby charges would work. I am not sure, Mr. Harper, if you had a chance to review this, as well.

Sorry, this is a wrong reference. It is 7-VECC-61. And sorry, Mr. Harper, if you could repeat your question?

B. HARPER: Yeah. I guess what I was struggling about, this is not dealing with your proposal but dealing with the way you apply your current standby rates, which I think is what was being dealt with on page 3, how billing is done under the current standby rates.

But I was wondering, under the first example, the first example was when the generation is on all month, more or less the generator is operating all month. And what I was wondering about in the example you had was a generator that was 800 kilowatts, and the contract demand was for 800 kilowatts, I believe.

And I was wondering whether that methodology, which is you bill using the contract demand value, applies even if -- the generator may be operating, but let's say it's an 800-kilowatt generator. It may be operating – the operation would be varying, going up and down during the month, so that sometimes during the month, it's operating at 50, sometimes it's operating at 800.

Would you still bill at the 800 value, even if it was operating at something less than its full nameplate rating during the month?

C. DUONG: And if you're speaking to the proposed, current proposed --

B. HARPER: I am speaking to the current --

C. DUONG: Current, current, sorry. Okay.

B. HARPER: The current.

C. DUONG: Because they have contracted, they have a contract for 800, that plays into the calculation of how much we would charge them standby on.

B. HARPER: Okay. So I think that the answer to my question is yes.

C. DUONG: Yes.

B. HARPER: Regardless of the level, even if they weren't operating at their full level, they would be billed based on the full contract quantity. That is all I was wanting to understand.

C. DUONG: Which mostly, because it's a reserve capacity of 800.

B. HARPER: Yeah, okay.

Now if we go to page 5. And I guess you are dealing here with the same -– no, sorry, page 5 of Schedule 7-1-3. I apologize. Go to page 5 now.

And here, you are applying that same Example 1, but under your proposal, your proposed standby rate, if I am not mistaken. Correct?

C. DUONG: That's correct.

B. HARPER: Okay. And here I guess, if I understand correctly, rather than -- the billing demand now will not be the contract quantity; it will be the contract quantity minus 500 kilowatts. And what I was wondering was why this change in the determination of the billing quantity under this example, where the generation is not all month? Why have you now changed, so you are subtracting 500 kilowatts from the contract quantity?

C. DUONG: It's because we wanted to create a fair playing field of standby charges across generators. As you would know, generators that are under 500, we do not charge a standby on. So we wanted to ensure that those generators -- or those customers with generators greater than 500, that they do not get billed a standby charge on the first 500, just to so-called even the playing costs of -- field, of charging these customers in general.

Sorry, let me summarize that again: So you have an embedded generator that's 500 or lower, we do not charge a standby charge on. But then you have a customer with embedded generation that is above 500; for the first 500 generation, we wanted to ensure that the two customers are treated equally.

B. HARPER: Oh, okay. Fine. And that would be, I guess, even though you are actually supplying – no, that's fine.

Now I guess I just want to, under the example here, on the first one, if the generation was -- let's assume the nameplate rating was 800 kilowatts, but the customer had decided to only contract for 400 kilowatts of standby. I would assume that what would happen is I take the 500, I divide it by some -- I take the 400, I subtract the 500, I would get a negative number. So there would be no billing demand, and the customer would have no billing demand in that case, if he was on all month.

Am I correct in how that would have worked, if the contract was actually less than 500?

C. DUONG: It should be correct. Having said that, it really depends on the peak that we capture when the generator is on versus the peak when the generator was off. So you are saying --

B. HARPER: No, we are still in Example 1 --

C. DUONG: One.

B. HARPER: -- where the generator is on all month. And in that case, if the generator is on all month -- like, I just want to make sure I understand how this works, you know, before I make any conclusions about its reasonableness, to be quite honest with you.

So that if the generator is on all month, the nameplate rating is 800 kilowatts, but they have only contracted for 400, which I assume they are allowed to do, then, if they were on all month, I assume the billing demand would be zero?

C. DUONG: Correct.

B. HARPER: The billing demand would be zero. Is that correct?

C. DUONG: That's correct.

B. HARPER: Okay, fine. Like I said, I just wanted to understand how it runs.

Now could we go back to page 3? And I guess I would like to turn to Example 3 now, to make sure I understand how all that works.

And this is again under your current standby charge. And this was the example that got a little bit confusing to me and I must admit, as you will have seen, I have some written questions on this to clarify some of my understanding of some of your examples. But I just want to understand how I think it works in general. And as you indicate here:

“Under the current standby rates, if the generation is on for only part of the month, and the standby billing demand is equal to the contract quantity less the difference between the peak when the generator is off and the peak when the generator is on.”

Have I got that correct?

C. DUONG: Could I defer for a second, please? Mr. Harper, I am just explaining why I am going offline here. I believe there is an IR that explains there was a correction that was made in Example 3. I belief it was a Staff question.

B. HARPER: Yeah. I know it explained the number. I was talking more about the general methodology. My question didn't include any numbers. I was just understanding, I think, because I think you explained in the IR response that the billing demand was something slightly different, because when you worked through the math in the example it came out slightly different. But I just want to make sure I understand the general approach was you take the contract demand and you subtract from that difference between the peak when the generator was off, you know, that less the peak when the generator was on; and that is how it's calculated currently?

C. DUONG: Correct.

B. HARPER: Right. Now, again I guess I am just curious because, I guess you know, customer can operate in different ways and to some extent sometimes the generation is tied in with their load. And so, in this example, how would the example work if the peak when the generator was off was actually less than the peak when the generator was on? I assume the part in brackets there would be, the second part would be negative, and so you would basically, they would be basically be billed the contract demand in that case, if I understand this correctly? Like, you would never subtract a negative number, I guess is what I am saying?

C. DUONG: So, we -- so the values in the bracket, we do subcontract the off value, the values in the bracket.

B. HARPER: Right. So, let's say the off value was 200 and the on value was 400 for some reason you would be subtracting a negative number?

C. DUONG: Yes, which is explained further in the next section called the backup overrun adjustment, and the reason why we do that.

B. HARPER: Okay. But then in that situation you would deem they would have gone into...

C. DUONG: Exactly, backup overrun requirements.

B. HARPER: Well, I guess the fact that the difference is negative doesn't necessarily mean they have exceeded the contract quantity, though, does it?

C. DUONG: No, but the first part of this equation is you take their contract demand, in this example, 3 here is 800 and if they were, in the second part of this formula, into a backup overrun we take up the 800 minus the absolute value of that overrun.

B. HARPER: Okay. I will have to think this through a little bit more. And maybe when you respond to some of my written questions I will also understand it a little bit more, thank you.

Now, if we can go back to page 5 of Exhibit -- of Schedule 7-1-3. And here under Example 3, and I guess I have the same question, because this is how you define the billing demand under your proposal. Not the backup overrun demand, but the standby billing demand under your proposal. And, in this case, you do the same thing, you take the contract -- this is when the generation is on for part of the month and off for part of the month. In this case you start off the same way, you take the contract demand, you subtract the difference between when the peak, when the generator is off and the peak when the generator is on, but then you have now added another step, which is you now subtract the lower of the metered peak -- the metered peak when the generator is on for 500 kilowatts. And I was wondering if you could explain to me why you have added that last bit; why you changed the billing demand by adding that last bit to your formula here?

C. DUONG: Sorry, Mr. Harper, there was a bit of cutting off but I believe I understood your question. So, the proposed adjustment is consistent across all examples of we do, we do not want to charge these embedded generators the first 500 required standby generation, or standby reserve. However, I believe this is the one where there was the IR that corrected the formula and --

B. HARPER: Yes, the 250 should be 350 if I recall correctly. That's right, yes.

C. DUONG: That's right, yes.

B. HARPER: Yes. Okay. Okay, I think that's it. Now, finally, this is my final question on the area of standby rates you will be pleased to know. Finally, your current standby rates, like your 2025 rate, is approved on an interim basis if I am correct; right?

C. DUONG: Correct.

B. HARPER: And your standby rates have been approved on an interim basis for a number of past years; is that correct?

C. DUONG: That's correct.

B. HARPER: Can you tell me when they were first approved on an interim basis, what year that was?

C. DUONG: Certainly, subject to check, I believe it was in 2003.

B. HARPER: Okay, that's fine. So it's been quite a while, let's put it that way.

C. DUONG: That's right.

B. HARPER: Now, you are proposing that your new standby rate would be effective January 1st, 2026?

C. DUONG: Correct.

B. HARPER: Going forward? However, I haven't seen anything in your evidence in your proposal as to what will be done if anything regarding the interim rates, the past rates, you know, the interim approval of your current rates. Are you, like you know, often when you get new rates you -- I guess, maybe what I am struggling with is -- I guess you could have proposed that those interim rates you made final as they were, you know, the same as they were approved on an interim basis. Or you could go back and say, now that we are looking for final rates, for final approved rates we are going to go back and we want to adjust the rates that were only approved on an interim basis in the past. And I haven't seen either of those two sort of options going forward as to how to treat this interim rate approval to date in your application, and I was wondering if you had given any thought to that or what your proposal was in that regard?

C. DUONG: Yes, so if we can go to the top of this schedule, Lianne? I believe we made that statement of we wanted to -- we are proposing to finalize our current existing --

B. HARPER: Okay, okay, okay. So, I am sorry, I must have read this through this quickly. So, you are proposing that the rates that have been in effect since 2020 -- sorry, I forgot the year. The rates, the historical rates that have been in effect, you are looking to have those finalized on a final basis as they were approved on an interim basis?

C. DUONG: That's right.

B. HARPER: Okay, fine. I think I got that correct now. Okay. I just have one final topic area here, which -- and that has to do with -- and this was actually dealing, in part, with some questions which referred the panel to you from Panel 2. And this has to do with the net metering program. And, as I mentioned to them, in reviewing the documentation regarding Ontario's net metering program I couldn't find any reference to there being any limit on the size of the generator that could participate in the net metering program. And so, I am not aware of there being a sort of, at a provincial level, any limit on the size of a generator that can participate in your net metering program; do I have that correct?

A. BARRIE: That is correct.

B. HARPER: And you haven't -- have you established any limit from your perspective on the size of a generator that can participate in your program?

A. BARRIE: No, as the regulation states at any size, so we have not gone against the regulation.

B. HARPER: All right. Now, when I look at the regulation itself it does, however, make some mention of the fact that the expectation is that the generator will be generating electricity primarily for the generator's own use. You're aware of that?

A. BARRIE: I am aware of that.

B. HARPER: And I guess that I was just wondering, is there any -- what is the criteria, test, or I guess -- how does, how does Hydro Ottawa test or make sure or satisfy itself that that aspect of the generation, of the regulation, has been satisfied when they are looking at an application from a net metering customer, from a potential net metering customer? Let's put it that way.

A. BARRIE: So, the onus is on the customer to ensure that they are sizing their generation to be self-sufficient and the regulation itself ensures that that happens by having the clause in there that it's not a cash value credit, and as a result the customer can use within the year any credits that up from over-generation and future bill. However, after 13 months that generation credit expires. So Hydro Ottawa reviews accounts on a regular -- through an automated process and once the customer has reached that threshold then those credit will be eliminated.

B. HARPER: Right. So, it's more on a -- I guess because the credits are to a large extent done on a, on a volumetric basis not on an kilowatt -- not on a capacity basis, and so that as long as the volume of embedded generation does not -- what would kick in is if the volume of the embedded generation exceeded the customer's own usage, that's really what you are looking at. As opposed to it from the capacity that a customer requires versus the capacity of the nameplate rating? I think that's my understanding of what you are telling me, then.

A. BARRIE: Well, it would be following the regulation, and because we don't know what the customer needs are and what they may be sizing their generation for in the future, it's up to them to ensure and understand, and we do provide education on that, that if they oversize their generation then they will not -- then they will lose the dollar credits.

B. HARPER: Now, the next thing I have is just a quick clarification. If we go to Schedule 8-4-2, page 1. And just scroll down on Table 1 here. You show your sort of current 2025 approved net metering charges being $15. Now, if I actually go to your approved tariff schedule for 2025, which I think you can find in Attachment 8-5-1B, at page 10, the value referenced here is $16. Now, I assume the $16 is correct and not the $15 in the table on page 1 from the exhibit?

C. DUONG: It appears that way, Mr. Harper.

B. HARPER: Okay, fine.

Now do I understand that you're proposing to remove the net metering service charge from your tariff schedule effective January 1st, 2026?

C. DUONG: Yes, Mr. Harper, that is our current proposal.

B. HARPER: And in order to get a sense of revenue involved, I am going to ask you if you could provide me a calculation of the annual revenue that Hydro Ottawa would receive during the upcoming IR term if the 2026 monthly service charge was set at a value equal to that 2025 charge of $15, escalated by the OEB's approved inflation factor, so that would be your 2026 charge you would be using for reference, and subsequently for each of the years '27 through 2030 was increased by the 2.1 percent you have used elsewhere in your application, and then those rates were applied to the forecast number of residential and commercial net metering customers in each of the years 2026 to 2030.

I am just trying to get a sense of what's the quantum of revenue that's involved in this proposal to remove the charge. And so I am just asking if you were willing to undertake that calculation and provide it to me?

C. DUONG: If I can just take a moment, thank you.

A. BARRIE: Lianne, could you go back to -- apologies, just so that we make sure we are -- Lianne, can you go back to the original exhibit that Mr. Harper made reference to?

L. CHARTRAND: Mr. Harper, could you repeat that reference, please?

B. HARPER: You mean the original exhibit, the 8-4-2, page 1, the table --

L. CHARTRAND: Yes, please.

B. HARPER: -- in it with the $16 charge?

L. CHARTRAND: Thank you.

C. DUONG: Hi, Mr. Harper. Yes, we can do that calculation for you. Having said that, as you can see in Table 1 here, we have explained the cost of supporting these customers are less as we have more efficiencies during this rate period, so we will be basing that calculation on the rates that we have calculated here.

B. HARPER: It will be on starting with the $16, because that's the approved rate for 2025; correct?

C. DUONG: However, as noted in this schedule, we do have additional efficiencies in the costs to support these customers, and therefore we believe it would be more appropriate to use the calculation using these rates -- or calculating the calculation based on these rates.

B. HARPER: Based on -- I am sorry, based on which rates? I am only talking about the net metering charge. I am only talking about the net metering charge, which is the one you are proposing not to continue on your tariff schedule as of January 2026, and I don't believe the schedules -- I believe you provided schedules to support the costs underpinning the first three rows in that table, but I don't think -- if I am correct, I don't recall seeing any -- because you weren't proposing any rate for 2026 going forward, there wasn't any costing schedule for the net metering. Am I correct?

C. DUONG: You are certainly correct, Mr. Harper. But I will just take a moment to confer. Thank you.

Thank you. So you are certainly correct that we have not provided additional information on the proposed rates for the net metering for '26 to '30, because we were proposing to not charge at that rate. Having said that, we can certainly calculate the additional revenue that we would have earned off of net metering customers, either basing it off of the approved rate of $16 and then escalating, as you mentioned, to 2.1 percent. However, we still believe that the costs of support, the net metering customers, have gone down, and it is quite similar to what we would believe how we supported the microFIT customers.

So in our response to you we can certainly provide the $2 based on those two proposed rate values.

B. HARPER: Well, if you would -- I guess, if I'm understanding, if what you're saying is you will do it the way I asked and then if you think there is another way that is better you will also do it that way, I am perfectly willing to see -- I am perfectly willing to see the two, so if that is my understanding of what you are proposing you would do as the undertaking, that is fine by me.

C. DUONG: Yes, thank you.

M. MILLAR: The undertaking is JT3.8.

UNDERTAKING JT3.8: Calculate the additional revenue that would have been earned off of net metering customers based on approved $16 rate and escalating to 2.1 percent

B. HARPER: Okay. And I think that is all of my questions, I believe. Mr. Garner now has a few questions for you.

M. GARNER: Yes, and Mr. Millar, with a bit of quickness and maybe a slight delay of lunch, I might be able to finish, and then we can go for lunch.

M. MILLAR: So we would like to finish around 1:00, Mr. Garner. Happy to give you a few minutes past that, but we don't want to sit too much past that.

M. GARNER: Okay. I leave it in your hands.

EXAMINATION BY M. GARNER

M. GARNER: So I have really just three things to cover, and the first one is -- and let me just bring up the interrogatory. It had to do with the formula, and it had to do -- I'm sorry, I am just finding it -- the cost of power change you made in the formula for this upcoming custom IR. And one of the changes you made is to adjust the cost of power component, and that was in interrogatory 1-VECC-3. And I asked you, I think, a question, that really kind of what I got was a repetition of the evidence, and I think that's really because my question was badly put.

What I was trying to really understand in -- you have made this change from the last formula where you didn't make a working capital adjustment based on power, and I was trying to ascertain why you said you said, well, because we have electrification, which I take it is a larger forecast that you built in. But I was trying to understand the materiality of all of that, and I am wondering, did someone somewhere ask you, what's the material difference if you were to simply follow the methodology you had the last time? And I am wondering if you could help me with that. Did you make a calculation yourself to understand the materiality of this change? From the last formula, I mean?

C. DUONG: Hi, Mr. Garner. So no one has asked us for that calculation, and we have not put anything on record for that.

M. GARNER: Well, can I ask you, would it be -- if -- would I be right to use this method myself? So I looked at 1-Staff-1, which just has a summary of the rate base, and if you bring that up, 1-Staff-1, page 16 of 51, and I just looked at the working capital number in there, and you'll see there is a number of, for 2026, of 79,540, and my assumption -- you can correct me, and that's why I am asking if I am wrong -- my assumption was that under the previous formula the way it would have worked is that 79,540 would have been embedded for the whole period of the plan. Under the new formula, as you see in the following columns for '27 through '30, there is an increase in the working capital amount based on the changes in the load forecast, and that, therefore, works through to an adjustment in the amount of revenue requirement you have. So have I got that right so far?

C. DUONG: That's correct.

M. GARNER: So the difference, would it be -- would I be right to run this method -- or maybe you could run this method -- I would basically say the difference is the difference between 79,540 and all the subsequent numbers, multiplied basically by the weighted cost of capital for those numbers. That would give me the kind of incremental revenue that I am gathering through this change in the formula.

Would that be methodically sound, so to speak?

C. DUONG: If I can take a moment to defer. Thank you. Mr. Garner, could you repeat your question, please?

M. GARNER: So I was trying to, again, understand the materiality of the change in the formula which now adjusts the working capital for the change in the load forecast. And so the way I was trying to determine a numeric value of that, in dollars, was I took the difference between your 2026 forecast for working capital, 79,540 as shown in table O, and in each year the incremental or the variance in each year from that number.

I then basically said, well, that's the increment in working capital the formula provides, and then I multiplied that number by your weighted cost of capital in order to get a dollar figure for the revenue requirement adjustment that's falling out of the change in this new formula.

C. DUONG: Yes. So that's sound, yes.

M. GARNER: Okay. So when I did that math – and maybe you could just do that math and then confirm with me in an undertaking that that is the incremental change of the new formula for working capital, versus had you applied the old formula to your CIR. Just so that when we get to it, we don't have to argue about what the numbers are. I have done it and the numbers seem like the difference is in about $1 million, $1.5 million.

But I would rather you do it and then show it back to me and say yes, that's the number, in case I am doing it wrong.

Would you undertake to do that?

C. DUONG: Certainly, yes.

M. GARNER: Okay. So the undertaking, Mr. Millar, in a pithy way is to undertake to show the annual and total incremental revenue requirement associated with the change in the formula for working capital allowance. And I leave it at that, because we went through the way I would do it; I leave Hydro Ottawa to determine if that's the correct way.

M. MILLAR: The undertaking is JT3.9.

UNDERTAKING JT3.9: Show annual and total incremental revenue requirement associated with the change in formula for working capital allowance

M. GARNER: Thank you. Can you just tell me, do you recall when the last time or, if ever, did Hydro Ottawa do a lead-lag study to determine its own specific number to apply for working capital? I mean, it's using 7.5, the Board’s default.

But has Hydro Ottawa ever done its own lead-lag study to determine the number for that?

C. DUONG: Yes. The last time Hydro Ottawa did a lead-lag study was in its 2016 application.

M. GARNER: Do you recall what that resulted in? Do you have a memory of that?

C. DUONG: We would have to refer back to the 2016 evidence.

M. GARNER: Could you just include maybe that in the undertaking, and we will just add that to the undertaking, and just include in the number that was last filed?

C. DUONG: Sorry, if I can just take a moment.

M. GARNER: Okay. If you can find it quickly, that's fine.

C. DUONG: Thank you. So the 2016 evidence result shows a higher working capital allowance than OEB's working capital allowance.

M. GARNER: But do you know the number, like, what it came up with?

C. DUONG: No, I do not remember the number. I would have to --

M. GARNER: Why don't we just include it in the undertaking? It seems simple enough. It's probably very close there and I don't want to take up too much time.

C. DUONG: Okay.

M. GARNER: Would that be okay with you?

C. DUONG: Sure.

M. GARNER: Okay, thank you.

So I am going to move on from there quickly, and I want to then go to issues on deferral account. And this one is a carryover from panel 1. And you may have, if you are following the transcript, heard.

I was trying to understand, this is to do with the CCRA proposed variance account. And I was trying to figure out how in the account the numbers that were used as the marker, the variance marker, which is found at 9-SEC-87. You will see table A, 9-SEC-87.

And in that table, you will see a row saying “CCRA symmetrical”, and then “test years.” And there is I guess what I am calling a marker, and the marker for 2026 is $7 million -- these are in thousands, but anyways -- yeah, $7,697,000, and then $7,642,000, et cetera, et cetera.

So I looked at those numbers and I said I don't understand how do those numbers, how were those numbers derived from the table that shows the forecast for CCR payments? And that's at 2-SEC-56. And that showed, for instance, $18 million in 2026, $1.3 million in 2027.

And so I was just trying to understand, how are those numbers related? How did you get there? I don't understand that.

C. DUONG: I am just going to take a moment to review the two tables as you have referenced.

M. GARNER: Thank you.

C. DUONG: Sorry, Mr. Garner. The other reference was SEC-56?

M. GARNER: It's up on the screen.

C. DUONG: Okay.

M. GARNER: That one is the -- I think, I just have to find it now myself, again. But, yeah, the one was at SEC-87, and the other one I think is at SEC-56. Yeah.

C. DUONG: Thank you. So the table that you see here in 2-SEC-56, these are CCRA payments. So the timing of the actual payments was the other table, I forget the exact reference; it's relating to the additions of CCRAs. So there is a timing delay between your expenditure and your actual additions of CCRA.

M. GARNER: Okay. But maybe this is a better way, another way to ask the same question because I am still a bit confused: At 9-SEC-87, in 2026, the amount of $7,697,000 is what, a payment that you expect from Hydro One in that year, or a calculation of a marker for the variance, based on something else?

Is that an actual-year forecast of an actual payment from Hydro One?

C. DUONG: The amount for 2026 in the other table would be, I will call it, the in service of that CCRA amount, whereas -- so it could relate to previous payments that were made in 2025. But then I will call it in service, or capitalized, in 2026.

So, again, the difference in these two tables is the timing of the actual payment versus when the related stations are energized. And, therefore, it is related CCRAs that are capitalized.

M. GARNER: And that's where I struggled, because the numbers are so different. So for instance in the first table, where you are doing the variance accounts, it's 2026 and 2027, and you have similar numbers. But, of course, if you go to the actual CCRA other schedule, it goes from $18 million to $1.3 million in those two years, do you know what I mean?

So the actual numbers that are showing up in that table are significantly different. But when I look at this table, they are not significantly different; there is more of a pattern. And the significant difference shows up in 2030.

And are you saying that's kind of what's happening, is the $1.3 million is actually showing up in 2030 as something? Or they don't seem to match in any fashion in that way.

C. DUONG: If I can take a moment, thank you.

M. GARNER: Mr. Millar, I have one question after this. I am not sure how long that is going to take. The other one I think will take at least 10 minutes, maybe 15. So it's up to you, whether you want to stop for lunch or not, after this.

M. MILLAR: Yeah. If you are going to be 10 minutes or more, I would suggest we break for lunch after the answer to this question.

M. GARNER: If that's what you would like to do. I can do my one question and then when we come back, and then move on with the other people...

M. MILLAR: Sorry, Mr. Garner, you have one more question and then 15 more minutes?

M. GARNER: No, no. After this -- after this question -- after we're dealing with this question I have one more question, which may take up to 15 minutes.

M. MILLAR: Okay. So, let's finish this one off and then we'll break for lunch.

M. GARNER: Okay.

C. DUONG: Thank you. So there is two answers I wanted to mention as the values you see here in Table A, and I am not sure if you have already seen it, they do match to the capital asset continuity schedules that have been admitted in this application --

M. GARNER: That's how I find -- okay -- yeah.

C. DUONG: Sorry. It's certainly subject to check, and certainly we can do that reconciliation for you, but as you mentioned before I took the time for the break, is that the payments that you see in the other schedule, they do get capitalized more later on in the years here so that, therefore, you do see an increase in the capitalization of those earlier payments during this period of time.

M. GARNER: I think I understand what you're saying. You are saying is: To really understand this I have to go to the continuity schedule and look at that?

C. DUONG: Well, the continuity schedules is at a summarized level but, yes, these values here will tie to the capital assets continuity schedules that have been filed.

M. GARNER: Okay. Well, let me -- I've been told that we should take lunch now. I have one more thing to follow after lunch, and let me just think about that over the lunchtime. But I think I understand what you are telling me.

M. RUBENSTEIN: Sorry, I was wondering if I could just add a follow-up because I had a similar question here. Is it possible to provide the Table A in 2-SEC-56 on an in-service additions basis? And if the number in that table does not reconcile with the information that was provided, I believe in 9-SEC-87 that Mr. Garner took you to, that you could explain why not?

C. DUONG: Hi, Mr. Rubenstein. Yes, we can do that.

M. GARNER: Maybe that can be an undertaking, and I think that would definitely then clarify it a lot more. So I think that's an undertaking?

M. MILLAR: Yes, I'm sorry. JT3.10.

UNDERTAKING JT3.10: Provide 2-SEC-56, Table A on an in-service additions basis and if the numbers do not reconcile to explain

M. GARNER: Okay. Mr. Millar, it's 1:04. If you would like me to come back after lunch for my last question, I will do that.

M. MILLAR: Right. Thank you, Mr. Garner. We will break until --

M. DEFAZIO: It appears that we have lost Mr. Millar.

M. GARNER: I thought it was me for a minute.

M. DEFAZIO: Who is not in the office -- oh, there you are, Michael. We lost you for a moment. Could you repeat what you said about breaking?

M. MILLAR: Oh, I am sorry if you lost me there. Break until 2:05, and just reminding people that Ms. Nowicki will be taking over again after the lunch break.

M. GARNER: Thank you.

J. MYERS: Thanks very much.

--- Recess taken at 1:04 p.m.

--- On resuming at 2:05 p.m.

J. NOWICKI: Good afternoon. Welcome back to Day 3 of our technical conference. We will be resuming with questions from VECC to panel 3. So, Mr. Garner, whenever you're ready.

M. GARNER: Thank you, Ms. Nowicki.

Welcome back, panel. As I promised, I only have one question left, and it actually isn't from VECC, it was -- it's 1-SEC-17, and it has to do with the tariff impact deferral account. And I -- as a preface, I couldn't understand how the account works and I couldn't figure out a question to ask you about how the account works, and my friends at Schools cleverly just asked you how does the account work. But when I asked you -- when I read the response, I have to admit I was left even more perplexed, and let me give you an example as to why, and it's, for instance, in the response. If you go to page 2 of 3 of that response, it says right there:

“As an example...”

In the first paragraph, second line down, I believe:

“As an example, overhead transformers costs increased by 25 percent due to USA tariffs.” [As read]

Well, that just caused me to be perplexed, because a tariff off of the US is a tariff on stuff coming into a country. The tariffs that affect you are tariffs for stuff that comes into our country; right? That's the cost of a tariff. The US isn't putting tariffs on items it's exporting, it's putting tariffs on items it's importing. And so I was first of all just paused by that and going, okay, so what do you mean? Are you -- I don't understand. And then when I went down and looked at the rest of the answer, I still couldn't really understand what you're asking -- the question really is asking you is like, well, how do you figure this out? If a tariff would have to be a tariff put on by the Canadian government, right, that would be a tariff that would have a cost to you, otherwise prices may rise on things that you are importing, but whether they are due to a tariff or whether they are due to multitudes of other impacts is unknowable.

So maybe you can help me with, how does -- how does this account actually work? When you say there is an invoice that identifies a tariff, exactly what do you mean?

A. BARRIE: So, hi, Mr. Garner. So the particulars about the invoice and that part was panel 2, but what I would say from -- that I can answer is that we were saying only things that were identified on our actual invoices would be recorded into this account. We wouldn't be doing some kind of calculation to come up with the amount in order to work with the variance accounts. But the other mechanism is exactly how the invoices should look and everything like that would have been a panel 2 question.

M. GARNER: But how is that verified? So I am a US -- you buy something from me in the US and it's now 25 percent more, you are using that example, there is obviously no tariff on that item coming into Canada from the US, because US doesn't -- it's the Canadian government that's charging the tariff, so -- if there is a tariff. And so that -- someone can easily claim this price is up because of US tariffs; i.e., the input costs are more expensive in the US and the cost has gone up, but claiming that doesn't make it true, on an invoice or otherwise. So how would you demonstrate to an auditor if this account gets audited? How do you intend to demonstrate the veracity of a claim on an invoice that comes, say, from the US that -- well, first of all, it's -- first of all, how is it a tariff item if it's coming in from the US, since the US doesn't charge the tariff, the Canadian government charges the tariff, so don't you have to say only things that have a Canadian government taxed tariff on them and is identifiable by that tax can be put into the account? Is that what you are trying to say?

A. BARRIE: So I don't believe that is the situation. However, yeah, so what we have just brought up is a response to -- and I was just going to make reference to that, in 1-SEC-17, we do have an amount already indicated that we have the ability to record and track this. Again, panel 2 would have been the better panel to speak directly to this. And I -- other than saying I know they have worked it through, they know they have a way to track it, they believe it would be auditable -- I was here more to speak with how the mechanisms of the actual account would work.

M. GARNER: Well, given you are in the regulatory, you will have to speak to how it works, in the sense of the veracity of the balances, but I take your point. If it's panel 2, it's panel 2.

But let's go to that $5,433. Can you produce that invoice to demonstrate to us what was the basis of including $5,433? Can you show us what you looked at that said that is what goes into this account? Because I am having a hard time comprehending --

A. BARRIE: So I don't know if it's -- I haven't personally seen the invoice, and I don't really know what's on it and if there is any confidentiality things. What I could undertake to do is to provide a better example of, like, in terms of the line of the questioning that you are asking, and then explain that piece of it. But I don't want to -- I don't know what all makes up that 5,433, so I don't want to undertake something I am not sure what I am agreeing to.

M. GARNER: Well, I am certainly happy to take an undertaking that better explains how you are actually -- how you are actually identifying increases that are related to tariffs, since a tariff is only charged by the Canadian government, the federal government, not -- an American government tariff doesn't get charged to a Canadian. But I am still -- I still go back to the 5,433. I am not interested in identifying the party. You can redact the party's name, you can redact everything on it. What I am interested in seeing is exactly on the bill how does one say, okay, this is tariffed in the sense of, we are going to capture it in this account? So I would ask you to go back and reconsider whether you can provide the invoice redacted with any company name or that in order to demonstrate -- show us an example of how this would work? I mean, I am happy also to take a better -- if you feel you can provide a better explanation, but as I am reading this response I am just totally perplexed at even the way you are using the word "tariff", because US tariffs don't actually impact us. Right? They impact Americans, and Canadian tariffs impact Canadians. So it's just not clear to me what you are doing with this account.

A. BARRIE: I am just going to consult for a second. I will be back.

So I don't feel comfortable providing more, just because I said I am not the expert in terms of understanding how exactly it was thought through, and I can provide you a better explanation if maybe particular words are missing within how we have explained it.

The other piece I am not sure with that $5,000 is if it's one or multiple invoices. So I can go back to look into what that is, but I don't have those details. So I will just say I might be able to provide an example of an invoice. I don't know that it's going to say 5,433 or if that's more than one invoice.

M. GARNER: Well, if you would -- the undertaking I would like is not -- as you say, there may be more than one invoice, but the basis would be an actual transaction, not a made-up transaction, since it's the actuality of it that I am struggling with. And so I would ask for that undertaking, and Mr. Myers, I mean, if it's a refusal at the end when they look at it, you can explain the refusal to do so. I understand that. But I would still ask for the undertaking to provide redacted if necessary for confidential or commercial reasons the name, for instance, of the party or whatever, but would show us how that invoice qualified for the account.

J. MYERS: Yes, and I think you said earlier that you are also willing to accept a summary of it, if not the actual document; correct?

M. GARNER: No, I am not sure what I said. I think what I said was if Hydro Ottawa was also willing -- I heard them say that we can give you a better explanation -- I said I am happy to accept an explanation they feel is more clear. But I think I am sticking to the idea that the -- it's an actual transaction invoice, so it's not a theoretical one, it's actually showing me what it is. That's saying is, here is the line. If you read this line, it says this, and this is how we bucketed it into that account. Right?

J. MYERS: I think what Ms. Barrie is saying is that if we can do so, then we will. And if it has to be redacted, then we will explain why that's the case.

M. GARNER: Or if you refuse, you can just --

J. MYERS: That's right.

M. GARNER: -- you know, outline the refusal.

So with that, Ms. Nowicki, maybe we can have an undertaking if that's --

J. NOWICKI: Yes.

M. GARNER: Okay.

J. NOWICKI: So that's JT3.11.

UNDERTAKING JT3.11: Show reason invoice qualified for the account, redacted if necessary

M. GARNER: Those were all of my questions. So, thank you, Hydro Ottawa, thank you, panel, Ms. Nowicki.

J. NOWICKI: Thank you, Mr. Garner. So up next on our schedule we have SEC. And we have you down for around 60 minutes.

EXAMINATION BY MR. RUBENSTEIN

M. RUBENSTEIN: Thank you, very much. I have some questions and then my colleague, Ms. Scott, will have some questions.

I do want to follow up on the -- with respect to 1-SEC-17, because I had similar questions. And I also maybe incorrectly thought that they were appropriately fully for this panel.

As I understand the account, and I think Mr. Garner was getting at it or at least how I understood it, and you can correct me, at least for example -- sorry, the example that was set out in part (b), is that this account would capture the scenario that it's talking about where, for example, you purchase a transformer from the United States. The United States has levied tariffs on everybody, lots of -- and the input costs have increased of the necessary materials to build that transformer, and that increases the cost. Do I have that right?

A. BARRIE: That is my understanding of how we plan to record that. Yes.

M. RUBENSTEIN: All right. And I think there was some struggle and we were trying to get it, at that question, is how do you know what the costs are, because even a -- for example, if an input price, there is a tariff on steel of, depending on where the country is, 25 or 50 per cent, not all of that may be passed on into the end-use cost.

And I took from some of the things that you said in the response, as well as in your response to Mr. Garner, that, well, it would have to be itemized on the bill you get. Did I get that right?

A. BARRIE: That is correct.

M. RUBENSTEIN: Well, then can I ask you to help because, in part (c), you say:

“Hydro Ottawa is actively engaging with its suppliers to ensure that, where possible, costs related to global tariffs are itemized on the respective invoices. In the event that the supplier is unable to report the impact of global tariffs on its invoices, Hydro Ottawa may apply alternative methods to identify the impact of these costs, if any. For example, long-term supply contracts typically include a price adjustment clause, allowing for annual contract escalations in accordance with published price indexes. Cost increases in excess of those contracted benchmarks may be attributable to global tariffs and would require additional support from the vendor.”

So can you explain to me, it seems you actually may also do something different, if you don't have itemized costs. So can you help me?

A. BARRIE: Again, that was more intended for panel 2, so I don't know exactly how the invoice would look. But we had been looking, and I know as part of those discussions was that we would have contracts, right? So if a vendor or - and I am just throwing that out there, was 3 per cent, and they come back to us and say we actually need 4 per cent due to increased tariffs, and we would have to have those conversations. And there would need to be some kind of validation of that.

But that would have been a better conversation to have with panel 2, as they have more of the supplier relationship.

M. RUBENSTEIN: So, Ms. Barrie, ultimately you are going to have to - you will seek to dispose of the account. There is going to be a number of costs in that account. I am just trying to understand how you foresee this working.

Every single different entry we are going to have to go through and look at the invoices to sort of verify what process the company undertook to, I guess, estimate the impact of the tariff, because it wouldn't be explicit?

A. BARRIE: No. The thought wouldn't be that. This account would need to be audited on an account-by-account or, sorry, invoice-by-invoice basis as part of clearing the account. But that we would put that in the type of groups, so that we would have, these dollars are associated with invoices that have been able to have very strictly indicated that this is a price increase due to tariffs. If it was related to the change as I noted in the other example, that being inflationary, that would be a different grouping.

A third grouping, of where it just couldn't be assessed at all, would not even show up in the account.

M. RUBENSTEIN: All right. Could I ask you to update the balance of the account as of, I guess, the latest information you have, by the end of September?

A. BARRIE: Yes, we can do that.

J. NOWICKI: That will be undertaking JT3.12.

UNDERTAKING JT3.12: Update the balance of the customer account as of Hydro Ottawa’s latest information by the end of September 2025

M. RUBENSTEIN: Can we move now to 1-SEC-16? So, in this interrogatory, we ask you about the proposed large-load revenue variance account. And in part (a), we asked you to explain how Hydro Ottawa defines large load for the purposes of the variance account. And essentially you take us to a table in Schedule 3-1-1, table 8. So maybe we can go to that.

So the table shows the kilowatts that I presume would be the baseline for the account based on various customer categories. But it still doesn't actually explain to me how you have defined large load for the purposes of this account. Is it all incremental load in the GS, general service, 50-and-above category? Can you help me?

A. BARRIE: So it would actually be for customers who, through these requests, have moved from other rate classes into the large-use category.

M. RUBENSTEIN: Okay. So this would be customers who are in GS under 50, and they are now moving to a larger class?

A. BARRIE: It would be customers lower than the large-use class. So it would be all three of those categories. So what this particular table is trying to demonstrate is the movement to the large-use category.

So we have had a number of requests that it is going to move customers due to increased use from a lower commercial class. So anything above 50 and, prior to the large-use class, and that their requests have resulted in that their load will become a new large user account.

So if you look at, for example, I don't know if this is helpful or not, but if we go to Schedule 3-1-2? I hope we can scroll down; I am looking for the historical customer account table. Keep going. So there is another one; maybe it's the next table, I am not sure.

But if you can see here that we have our large-use historical customers - there we go. From 2021 to 2025, there is only 11. And if you look at our history prior to 2021, you will see that number has gone up, fluctuated a little bit, otherwise. But it's mainly been 11 for a number of years.

If we now go to Schedule 3-1-1, there is a similar table. There you go. Thank you. You can see we start in 2026 with 11 large users and, by the end of 2030, we have 14. So it's to capture those incremental, large-use customers.

M. RUBENSTEIN: So then just to be clear, the definition is just the change in large-use customers, the revenue from those large-use customers?

A. BARRIE: Just a moment, sorry. So just to clarify, it would be the incremental load. So we wouldn't be including the load that the customers already have, but the difference between what we have forecasted for these customers, that increased load for these customers, versus what the incremental load turns out to be.

M. RUBENSTEIN: All right. And what happens if there is a new, an additional large? So imagine in 2027, there is a 13th large-use customer that was not a customer of Hydro Ottawa before. Would that be included in that account?

A. BARRIE: Yes, that would also be included in that account. Just to be clear, this account is to work in both directions. So if the loads don't come on as we anticipate, then we would record the revenue that was lost as a result of the customer not becoming a large use customer.

M. RUBENSTEIN: Well, what about an existing large use customer that shuts down or transfers to a lower rate class; would that also be recorded?

A. BARRIE: That is not captured in this account. That is not captured in this account.

M. RUBENSTEIN: Thank you very much. Can we go to 1-Staff-6? And if we go to the next page, table -- so back up. As I understand the question you were asked, what essentially would this look like if you were doing a price cap as compared to your proposed custom IR framework, what's the difference in the amount; do I have that correct?

A. BARRIE: That is correct.

M. RUBENSTEIN: Am I correct that you, and maybe I am incorrect but you will let me know, that you did not include in the calculation of the price cap scenarios the increase in the billing determinant growth which you forecasted, the load growth essentially?

A. BARRIE: Do you mean in the HOL proposed line or the cohort line? Because the cohort line, just to be clear, would just be an incremental based on the base year, that is how we've calculated it. So typical costs of service where you would just rebase in '26 and inflate after that which would be the lines titled cohort. And the other ones would line up with HOL proposed, so it would include the change in the load forecast determines --

M. RUBENSTEIN: Sure, but if you are trying to show the difference between your proposal and the price cap, price cap would obviously include the I minus X adjustments in every year, but you also include additional revenue from load growth; right? From the increase in the billing determinants, it didn't seem you included that component in the price cap part when you are doing that scenario.

A. BARRIE: Just a moment, I just have to consult. So I haven't actually completed an incremental one in the past, but looking at -- historically I don't remember seeing the calculation where it increases the billing determinants over the five-year period.

M. RUBENSTEIN: Well, if you're doing --

A. BARRIE: You would take your base and you would -- and you would use the original load forecast and you would, and then you would inflate the rates.

M. RUBENSTEIN: No, I understand. But if we are trying to figure out how much money at the end of the day the company would get under price cap versus under your proposal, the rates increase by the I minus X. But you --

A. BARRIE: Okay, sorry. I understand the question, yes.

M. RUBENSTEIN: -- there's a billing determinant growth. So I was wondering --

A. BARRIE: Okay.

M. RUBENSTEIN: My assumption -- I don't believe you have done that, and I would ask you to do that based on the billing determinants that you are forecasting over the next five years.

A. BARRIE: No, that was not understood as being the question. No, that has not been calculated in Table A.

M. RUBENSTEIN: Can you do that?

A. BARRIE: I can do that, yes.

M. RUBENSTEIN: Okay.

J. NOWICKI: That will be JT3.13.

UNDERTAKING NO. JT 3.13: Determine how much money Hydro Ottawa would receive under price cap versus under Hydro Ottawa’s proposal based on billing determinants Hydro Ottawa is forecasting over next five years

M. RUBENSTEIN: Now, there is a number of -- lots of questions, lots of IRs you have been asked about the various -- about affordability, and rate increases and so on. And we would like to have a better sense of Hydro Ottawa's rates, how they have changed over time. So we have asked you to provide, by way of undertaking, a table that shows for each, for each year between 2012 to 2025 actuals, and in the proposed 2026 to 2030 show for each rate class: A, the distribution monthly service charge; B, the distribution volumetric charge for that class; C, any fixed DVA riders that would be considered in the OEB subtotal A category under their bill impact model; and D, the volumetric DVA riders that would be considered under the subtotal A and B bill impact model; is that something Hydro Ottawa can do?

J. MYERS: Sure, Mr. Rubenstein. This is something you already filed or you are asking now for this undertaking?

M. RUBENSTEIN: I am asking for this undertaking.

J. MYERS: Okay, I am not sure if the panel understood that. Do you need that to be repeated?

C. DUONG: Sorry about that, the other camera was off. We can do that, it is just a concern with the timeline required to complete the calculation.

M. RUBENSTEIN: Well --

C. DUONG: Not necessarily like it's -- no, not giving a week to just deal with this one, there is a lot of other questions we are also dealing with.

M. RUBENSTEIN: I am okay if this takes a little longer.

C. DUONG: Okay.

M. RUBENSTEIN: That's fine, but I do think it's important information.

J. NOWICKI: So that will be JT3.14.

UNDERTAKING JT3.14: Provide table that shows for each year between 2012 to 2025 actuals, and in the proposed 2026 to 2030 for each rate class: A, the distribution monthly service charge; B, the distribution volumetric charge for that class; C, any fixed DVA riders that would be considered in the OEB subtotal A category under their bill impact model; and D, the volumetric DVA riders that would be considered under the subtotal A and B bill impact model

M. RUBENSTEIN: Thank you very much. Can we go to 1-SEC-3? This is -- and I am looking at the updated version which you filed on September -- when was it? Not that long ago, the date there, September 12th. And if we scroll down -- so in that we had asked you a question with respect to number of studies for you to provide. And in your response you say that you've, given that these materials were not directly relied upon in this proceeding, Hydro Ottawa has only listed these studies in reports at this stage. More notably, as some of studies contain sensitive information to the organization, Hydro Ottawa has requested only studies that are necessary to complete the record be requested; do you see that?

A. BARRIE: Yes, I see that.

M. RUBENSTEIN: So, can I ask that Hydro Ottawa provide the following studies: One, the customer capability assessment; two, the grid modernization strategy and roadmap phases 1 and 2; three, the grid modernization key performance indicator development; four, review of Copperleaf predictive analytics value framework. Now, I believe three and four have already been agreed to provide in an earlier panel, but just for completeness. Five, Hydro Ottawa AMI 2.0 business case deliverables benefits assessment and value drivers; six, AMI 2.0 business case final report; seven, a fleet process study; eight, a jurisdictional research and analysis, as I understand, related to inflation; and then nine, peer group analysis, but that one only if it is different from what is provided on the record, i.e., if they are different peer groups, or metrics, or some other type of analysis because I believe my understanding from reading it that's -- it seems to be what you may have already been providing on the record, so that's the caveat for that.

A. BARRIE: So, just I will take a moment.

D. COBAN: Mr. Rubenstein, relative to Table A, I haven't done the concordance but are you basically asking for everything in Table A; is there anything you haven't asked for?

M. RUBENSTEIN: Yes.

D. COBAN: Okay.

A. BARRIE: Yeah. So, I appreciate, I think, the larger ones that we are of concern about putting on the record were included in the list. However, some of them I am not as familiar with, so I will undertake to consider the ones that you have requested. I know for sure there are certain ones we can, I just -- so I can take that back.

M. RUBENSTEIN: Sure.

D. COBAN: The undertaking, just for clarity on this one, will be to consider to provide the studies that Mr. Rubenstein referenced in the lead up to the question and, if we can, we will. And if we can't we will provide a rationale for why it cannot be provided.

M. RUBENSTEIN: Thank you very much.

J. NOWICKI: So JT3.15.

UNDERTAKING JT3.15: Consider providing studies Mr. Rubenstein referenced in the lead up to the question and provide them, if possible, or provide a reason why not

M. RUBENSTEIN: Can we now go to 1-SEC-11? And here we asked you for some supporting calculations for Table 3 and 4 that's in the evidence in Exhibit 1-3-1. And you've referred us to 1-Staff-8. But if you go to 1-Staff-8, all you do is provide a breakdown of the tables by year, but not the underlying calculations. So maybe we go to 1-Staff-8, and we go down. So can I ask you to go -- to respond to the question as originally posed, and you can break down – 1-Staff-8 may be easier and may be better, but if you're able to provide the underlying calculations, and also this should be updated for the IR updates that was filed on Monday with respect to the productivity tables. Is that something you can do?

A. BARRIE: Just for clarity, are you just looking for basically table A and table B but in Excel format?

M. RUBENSTEIN: No. In the original evidence you essentially --

A. BARRIE: Sorry, can we go back to the original question, again, then, sorry, Lianne.

M. RUBENSTEIN: Yes.

L. CHARTRAND: Can you repeat the reference number, please?

M. RUBENSTEIN: If we can go to 1-3-1, Table 3 and 4. So in Table 4 is the one that I am most interested in. You provide a capital-related revenue requirement based on the savings in Table 3.

A. BARRIE: So then are you looking for -- basically, if I look to the revenue-requirement schedule, the lines, like, that are typically shown in OM&A? Like OM&A, rate base, like, that kind of line item --

M. RUBENSTEIN: Well, it's only capital-related revenue requirement, so that, but it would also -- what assumptions are you using for depreciation, how have you come to those numbers, and --

A. BARRIE: Okay.

M. RUBENSTEIN: -- the capital-related revenue requirement, and then you broke it down. But the caveats would be, first, this number is slightly out of date, as some updated numbers were provided on Monday in your -- updating the number of SEC interrogatories with respect to the productivity, so presumably, these numbers would also be slightly different.

A. BARRIE: So the updated calculations were provided in Excel format in that undertaking as well, so is there more detail you are looking for in there as well?

M. RUBENSTEIN: Sorry, the Excel spreadsheets, those -- they don't provide a revenue -- you are here providing the revenue requirement and in implication those tables --

A. BARRIE: So you want the transition from those to this. Okay.

M. RUBENSTEIN: Yes, as well, if you can do it, on a per initiative basis.

A. BARRIE: The revenue requirement on a per initiative basis?

M. RUBENSTEIN: Yes.

A. BARRIE: Yes, we can to that.

J. NOWICKI: So that will be JT3.16.

UNDERTAKING JT3.16: Provide revenue requirement on a per initiative basis

M. RUBENSTEIN: And this is with respect to '26 to 2030. In 2 SEC 24 that was filed, you provide the 2021 to 2025 productivity savings, but what you have not provided, we would ask you to provide it. And you can see the -- this is the revised information here. Yes, you are showing the '21 to 2025. Can you provide the revenue -- the capital-related revenue-requirement impact related of those savings over that five-year period?

A. BARRIE: Sorry, can you repeat the question?

M. RUBENSTEIN: Sure.

A. BARRIE: Is it basically -- to which table again?

M. RUBENSTEIN: So you are showing here $23.6 million in capital expense productivity savings over the '21 to 2025 in the updated table. And I am trying to understand what the -- what the revenue --requirement impact of that is over those five years, because that's a CAPEX number that you're showing, not a revenue-requirement number.

A. BARRIE: Sorry, maybe I am just looking in the wrong spot. I thought you quoted 26 as a number, and I see that --

M. RUBENSTEIN: 23.6. You'll see this at the -- I am looking on the screen, which is 1 SEC 24 in the updated --

A. BARRIE: Okay. 23.6. Sorry, I heard 26, so that was my confusion.

M. RUBENSTEIN: No, that is fine, no problem.

A. BARRIE: Yes, I can do that.

M. RUBENSTEIN: Thank you very much. You will provide the supporting calculations for that when you provide that?

A. BARRIE: Yes.

J. NOWICKI: That will be JT3.17.

UNDERTAKING JT3.17: Provide capital-related revenue-requirement impact of savings over five-year period along with supporting calculations

M. RUBENSTEIN: Can we go to 1-SEC-13. So we asked you in this interrogatory to provide the analysis that Hydro Ottawa has undertaken regarding the specific relationship between, A), change in total customers in OM&A costs; and B), change in system capacity in OM&A costs. And in your response, you are essentially explaining what you are doing with respect to the OM&A growth factor, but I am not sure you answered the specific question. Have you done any -- has Hydro Ottawa done any specific analysis regarding the specific relationship between total customers and OM&A costs?

A. BARRIE: So what we relied on, as we mentioned, is we looked at both the PEG model and the cost allocation model, which are already OEB models which look at those relationships, and we also looked at a forecast of our OM&A spend over the period, and we did an analysis of ensuring that what we have -- those connections appeared to relate. So we didn't, if -- we haven't done our own cost study, like, replicating something like the PEG. What we did was rely on the PEG model, and we looked at the PEG model in terms of the things that we do not feel is being picked up through that model that would show our relationship with our costs.

M. RUBENSTEIN: So when you said a moment ago that you did your own analysis, I just -- I didn't perfectly -- I recognize it's not a PEG-style analysis, but you said you did some analysis. Could you just speak to that for a moment?

A. BARRIE: So we looked at our five-year OM&A costs, and we looked at the result of what our CROF formula was coming to make sure that it aligned and the two did, I guess, make sense. It was our ability to make sure that our CROF formula was coming out with something that aligned with our predicted future costs.

M. RUBENSTEIN: How did you -- what is the basis of your sort of -- sorry, what is the basis of your forecast OM&A costs that you were comparing to the growth factor? Because this application -- obviously, you are only having -- there is only a 2026 OM&A number, so what exactly were you looking at?

A. BARRIE: So we looked at forecasting out costs past the base year in order to see what we thought, in order to estimate forecast costs into the future and what those costs would look like.

M. RUBENSTEIN: Can you provide that?

A. BARRIE: Yes, I can.

J. NOWICKI: That's JT3.18.

UNDERTAKING JT3.18: Provide forecast costs past the base year that were forecast to estimate forecast costs into the future and what those costs would look like

M. RUBENSTEIN: And just similar to the question regarding the specific relationship between total customers and OM&A, was there anything specific outside of what you just said with respect to looking at change in system capacity in OM&A costs?

A. BARRIE: Well, we -- we did, like, a comprehensive review, as you can see in our PEG analysis of trying to look and understand how those cost flows work, as well as, we relied on looking at the cost allocation model itself and how it has many inputs that look at how it drives both per customer as well as per capacity. And that's the analysis we undertook in terms of -- and that's where also we did do and report -- are proposing to use five years' worth of cost allocation, as we see those costs shifting throughout the period.

M. RUBENSTEIN: Okay. Thank you very much.

Can I ask you to lastly go to 1-SEC-14. And we had asked you with respect to your proposed ESM in part (b) with respect to the OEB undertaking review of the TCB model and how that would impact your ESM, because as I understand there is a relationship between your cohort ranking and the ESM thresholds. And in your response you say that you're not proposing to review the total cost benchmarking model, you are not proposing that whatever the outcome of that review would impact your proposed ESM; do I have that right?

A. BARRIE: That is correct.

M. RUBENSTEIN: So do I take it then that review would impact your proposed ESM; do I have that right?

A. BARRIE: That is correct.

M. RUBENSTEIN: So do I take it then when we are looking at where you are in 2030, to compare it to where you are now for the purpose that we would be using the OEB's current model, even though it won't be publishing updates to that model -- it may not. If it changes with new data or has a new model or jettisons the whole idea, it won't be publishing that information.

So what exactly are we going to use in 2030?

A. BARRIE: I am not sure what their model is going to look like, but we do have the predicting model that we can put our own inputs in, and look at the outcome. I know we wouldn't be running it the same way PEG would. I hadn't anticipated that, through the review of the PEG model, it would be a completely holistic change that we probably wouldn't be able to rely on that model in order to consider where or would have been, otherwise.

M. RUBENSTEIN: So imagine it's not a total change, but they do adjust. You know, hopefully, at the very least, we update the data from this, as I understand it, is data up to 2012, and we use more current data.

Is that where we are going to compare? Will we be using that new model? Or is it the model that is in place today, with the data to 2012?

A. BARRIE: The larger concern about using what might come out of the review by the OEB is that we don't know what they might do adjustments for. And we had looked at the PEG model, and there was the one correction for the lines, which we anticipate would be as part of that new model.

However, things like looking at other revenue and impacts on conservation are items that we don't know and can't foresee whether or not the OEB is going to adjust, but we feel that they have had impacts on how the PEG model predicts our costs and views our efficiency. And that's why we didn't want to rely on what may be the outcomes, because there might be other drivers where the OEB, again, sets a model that on average may reflect a certain predictability, but doesn't work for all utilities equally.

M. RUBENSTEIN: Yeah, but that's why I want to be quite specific, because I think - let's imagine the Board agrees or the parties agree to your proposal. I think it needs to be somewhat concrete of what exactly is the comparison point, and I am somewhat a bit unclear.

I understand that if the Board jettisons the model, we can't use it. But I think there is obviously many things that could happen that is short of that, right? -- just simply updating the numbers.

So I don't want to put you on the spot here well, I somewhat am putting you on the spot, but I am happy for you to take an undertaking to provide a somewhat concrete proposal of what exactly the sort of rules that you are proposing to be put in place would be.

A. BARRIE: Yes, I can take that as an undertaking.

J. NOWICKI: That will be JT3.19.

UNDERTAKING JT3.19: Provide concrete proposal of what rules are being proposed to be put in place re ESM model

M. RUBENSTEIN: Just give me a second here, to check my notes. Okay. Thank you, very much. Those are my questions. My colleague, Ms. Scott, will have some questions.

EXAMINATION BY J. SCOTT

J. SCOTT: Thank you. Hello, panel 3. My name is Jane Scott. I am a consultant with the School Energy Coalition.

If we could start with 1-SEC-5? And Mr. Rubenstein touched on this, and I had some further questions. This is the large-load issue. And if you could go down to table A?

And so I did ask, I know that this IR response was directed to panel 1, and I did ask some questions of panel 1 on this. But then I was asking about the relationship of this with the load forecast, and I was directed to panel 3.

But first, because I asked for a definition of large load, and panel 1 said it was for loads greater than 5,000 kilowatts, which was slightly different than what I heard your answer to earlier.

Can I just confirm that large loads, the definition of large loads is the same in the application for planning purposes and for the load forecast purposes?

C. DUONG: Hi, Ms. Scott. So, yes, the two definitions of large load is consistent, which is GS greater than 5,000, or 5,000 and above.

J. SCOTT: But I guess what I heard earlier was it's an incremental load that takes either a new incremental load that becomes large user right away, or takes an existing customer into the large-user category? Is that correct?

C. DUONG: Yes. So when you are referring specifically to a question that Mr. Rubenstein had about what would be put into the large-load variance account, reference there was the incremental 5,000 that would go into the account.

J. SCOTT: Sorry. So does the incremental large load have to be 5,000 or greater?

C. DUONG: Yes. So, for example, if you take our one customer that is already an existing large user, and based on our forecast we believe they will ask us for a greater than 5,000 incremental increase, and if they should materialize that load but doubled it, we will record the difference or the additional revenue requirements into the account to give back to the customers.

If that same customer did not materialize their increase and, in fact, gave us no increase during this period of time, we would record the revenue-requirement deficiencies into this account.

J. SCOTT: Okay. And if you had a customer who is currently a GS less than 5,000, and they added 500 kilowatts and would become a large user, is that considered --

C. DUONG: No. No.

J. SCOTT: No.

C. DUONG: We would not consider that into this account. However, had that same --

J. SCOTT: And it may be, if it's the same for the account. But I am more interested here, for this table A, and for the load forecast. Yeah.

C. DUONG: So, as you may know, that table A is from the DSP, and in clarification on the DSP information. That specific question could be better addressed by panel 1.

J. SCOTT: No, no, no. No, no.

C. DUONG: Having said that, having said that

J. SCOTT: They asked

C. DUONG: No, having said that, having said that, sorry. Ms. Scott, having said that, what we are saying here is -- sorry, just wait a second, please.

We both considered a large-load customer to be any GS greater than 5,000.

J. SCOTT: Mm-hmm.

C. DUONG: For the purpose of planning forecasts and revenue forecasts, should the incremental increase not -- for any GS customer, and it is greater than 5,000 megawatts, most likely will propel them into our LU class, we are proposing in the large-load variance account to calculate the revenue sufficiency or deficiency related to whether they incrementally materialized their load or not.

And that would include, as previously discussed, any new customer that we did not develop a forecast as a larger load customer. A new customer in our territory, we would put that revenue requirement, sufficiency, I guess, into this account as well.

J. SCOTT: Okay. Do we have somewhere a list of, and we are not asking you to identify customers or anything, but breaking down these large loads, you know, one existing large user, plus 5,000, one new large user, plus 10,000, one existing GS greater than 1,500 less than 5,000, plus 6,000?

Do we have that somewhere, broken down? And, if not, can you provide that?

C. DUONG: Ms. Scott, we did have an IR response that, broken out further, the table that we had provided in the revenue load forecast. Let me find that IR. That might provide sufficient information for you.

Having said that, how you first described your request, we do not have that and cannot provide that due to the confidentiality of the customers. So let me just take a moment to find --

J. SCOTT: I think you might be referring to 3-SEC-63, and that was my next question. That's where I am going. It's the attachment, it's actually an Excel attachment; is this what you were referring to?

C. DUONG: No. Just a moment, please.

J. SCOTT: All right. Keep that handy because I am going to come back to that.

C. DUONG: Hi, Lianne. Can we go to 9-VECC-72, please? And then please -- is there -- keep going down. Yeah. So, in this Table A we provided the large load electrification changes from existing class customers that are lower than LU. And then those that then when they become an LU customer it's reflected in the line LU customer. So, I am not sure, Ms. Scott, if this suffices for you to show which customer classes we forecast to have been affected by the electrification, large load electrification, where they become a large user during this test period.

J. SCOTT: So, this is sort of similar to the attachment to 3-SEC-63, though it's not -- the numbers are sightly -- I see, okay. You have broken it out.

C. DUONG: We have broken it out by --

J. SCOTT: All right. Okay. So, let's use this then as an example. Can you explain to me how you went from the listing that was in Table A on 1-SEC-5, to these numbers in Table A?

C. DUONG: So, we have a specific number of customers who have requested a significant large load increase, or capacity increase, based on their needs. Those customers have either signed an offer to connect or were at the time submitting one and which some of them, as you have noted, in the other graph provided by in our DSP that they are the similar customers.

J. SCOTT: So, but so if I look at Table A for 2026, the sum of the offers to connect in the submitted forms is 72.8 MVA. So how, then, does that -- how do you then get to the minus 25 in the one class and plus 118 in the other class?

C. DUONG: Thank you, if I can take a moment to confer?

J. SCOTT: Thank you.

C. DUONG: Thank you. So, when you look at the information that's provided under the planning forecast, that information is based on their forecast and their specific needs, the planning forecast is, as you may have read, is more granular and location specific and it deals with immediate needs from our customers. Some of those immediate needs are aligned with the revenue large load forecast numbers that we have. There are going to be differences between some initial requests from these customers on their capacity needs to when they are expected to materialize in the billing forecast. So the differential, I would summarize it to be, there are capacity requests that have been provided and when we are looking at the impact of those capacity requests in terms of a billing demand forecast we have adjusted it as such for this purpose here.

J. SCOTT: Can you provide an example of one, the one I just -- maybe for 2026 of how -- my understanding is from the planning that was 72.8 MVA connected in 2026. So, what assumptions were made about that load coming in to the load forecast? And maybe that's -- can you provide me with the assumptions that are made?

C. DUONG: So, for example, for that one customer they would provide an X capacity requirement, that's in the graph that you are referring to, but for the purpose of the billing forecast we would be translating that into a billing demand forecast of what we expect their billing demands are. So, for example, if a customer, in the case of the example there, is if they wanted 18,000 megawatts capacity, the planning forecast would have to take that in consideration for investment purposes. However, if we look at the same customer and we translate it to a more billing forecast demand, we would adjust that same customer and incorporate what we believe to be the proper forecast demand for this purpose here. So we do include the same customers, we do the same assumptions on timing, however one translates from a capacity requirement and another translate into a billing forecast.

J. SCOTT: And other than having 12 months -- well, I don't know if you use -- are you using 12 months or are you assuming these come on mid year; what's your assumption in terms of when they come in on, for billing purposes?

C. DUONG: There are specific, I guess I would say it, low profiles for some of these customers where their capacity needs are met, are I guess realized at certain hours in a year where that does not necessarily translate to a consistent billing demand throughout a full 12-month period.

J. SCOTT: So, there is nothing you can provide me that will sort of show me how you have come up with these numbers?

C. DUONG: We can look at your request and under consultation, but, having said that, as mentioned, we only have, I would say, a handful of these large load customers that, given the confidentiality of these customers, it may be hard for us to give you the reconciliation of these two.

J. SCOTT: Okay, if it has to be under confidentiality, then I have signed the declaration, so -- okay. So moving on --

J. NOWICKI: Sorry, Ms. Scott --

J. SCOTT: Sorry, yes, Ms. --

J. NOWICKI: -- shall we mark that as an undertaking?

J. SCOTT: Yes, please.

J. NOWICKI: JT3.20.

UNDERTAKING JT3.20: Provide greater detail

C. DUONG: And Ms. Scott, we can certainly give you an illustrative -- representative, illustrative example of these differences, so that should suffice as well.

J. SCOTT: Well, if that's all you can give me, then that would be fine.

C. DUONG: Thank you.

J. SCOTT: But it would be more helpful to have the actual data.

M. DEFAZIO: Hi, Jane. Do you mind if I jump in on a couple questions related to the billing thing?

J. SCOTT: Please do, Margaret, yes, Ms. DeFazio.

M. DEFAZIO: Thank you.

These customers -- so this has been good. This has really cleared up a lot of questions that we had, but -- so these customers, they would be at least in the large user category, because they have to have a delta of 5,000 kilowatts, so they are going to be at least 5,000 kilowatt customers. They receive bills monthly; correct?

C. DUONG: That's correct.

M. DEFAZIO: So let's say we are in January of '26 and one of these customers has increased their load from 6 to 12. Is the -- how are you going to calculate the variance? Are you going to compare January '26 to January '25 and calculate the variance, or are you going to compare January '26 to the last three Januarys averaged, or some other method? How are you going to calculate what the variances would be for these large accounts? Many of these, I assume, have some seasonal component to them.

C. DUONG: So we would be comparing the comparable seasonal month, so in your example there it would be a comparison of January to January.

M. DEFAZIO: To the previous January?

C. DUONG: To the previous January; that's right. To establish the increase. So then it would be compared to what we have already forecasted for these customers.

M. DEFAZIO: Right. And your forecast for the customers coming online that would result in a debit to the account instead of a credit, would that forecast be -- the forecast you have for them coming online or increasing it would be done by month, so monthly debits or monthly credits could be calculated?

C. DUONG: That's correct. So further -- sorry --

M. DEFAZIO: I am just curious how we are going to review the account when it comes time for disposition.

C. DUONG: Sorry, if I can consult for a second; thank you.

So what we would be proposing is to summarize this information at a certain level where you can review the calculation, so it would be at a customer class level. We can certainly provide any [indiscernible] dates of what was forecasted to what was actual, but of course we would not be able to provide customer-specific-level information.

M. DEFAZIO: Could you provide that by month at this time so that when it comes time the audit it we have what you have projected at this point in time?

C. DUONG: We can.

M. DEFAZIO: Could you do that by undertaking, please?

C. DUONG: Yes.

J. NOWICKI: That will be JT3.21.

UNDERTAKING JT3.21: Provide forecasted compared to actual by month

M. DEFAZIO: Thank you. I will return the mic to Ms. Scott.

J. SCOTT: Thank you.

Related to 1-SEC-5, you have provided a table in 2-CO-21. And that showed under the inquiries, which my understanding are not included as large loads, but they have -- one of them is data centre?

C. DUONG: Yes.

J. SCOTT: And if you just go down a bit you will see the line -- there is a table below there -- yes. Yeah, data centre there, yeah.

Now, in -- it's actually in Exhibit 9, where you say you have received data centre inquiries but they were not forecast as part of the equation, are these the numbers you're referring to, or is there something in addition to this for data centres?

C. DUONG: Could you provide the exact reference?

J. SCOTT: Exhibit 9. And I apologize. I have the PDF only. PDF 25.

C. DUONG: Lianne, if you can move to the reference. Could you, sorry, again, repeat the reference?

J. SCOTT: It's probably in 9-1-3. No, it's -- as I said, I only have the PDF, and it's page -- PDF page 25, but let me...

C. DUONG: On your PDF, the top right may have the reference information.

J. SCOTT: Yeah, I don't have it in front of me. I would have to pull it up. It is page 15 of 43, in that second full -- that first full paragraph, “furthermore.”

C. DUONG: Is this the correct page, Ms. Scott?

J. SCOTT: Yes, it starts:

“Furthermore, has also more recently received data centre enquiries that are not forecast as part of this application.” [As read]

C. DUONG: That's correct.

J. SCOTT: So my question is, is that -- this in addition to those shown on 2-CO-21, table A?

C. DUONG: So not in addition. If you go back to the other reference, the listing of data centres are under the inquiries stage.

J. SCOTT: Okay.

C. DUONG: Yes. So those are referring to the same thing, yes.

J. SCOTT: Okay, thank you.

If we could go to 3 SEC 63B, Table A. Yes. So this is the reclassification of the net customer movement. First of all, can you -- do you have an explanation for why the numbers in 2024 are so different from the previous historical numbers?

C. DUONG: So in Hydro Ottawa we undergo a customer reclassification annually. As you noted here and as noted in this table, the 2024 reclasses have significant changes. As you can see in 2024, the small commercial class have grown in size and therefore has been moving back to the GS classes. This is a reflection, if I can speculate, it's because of, if you look at 2021, for example, and due to probably COVID and economic shutdowns, a lot of our commercial customers had moved from a higher GS greater than 50 class and went down to small commercial class, and I guess it has taken them up to 2024 for them to bring their business back in line and have -- move them back from small commercial class to a GS greater-than-50 class.

J. SCOTT: My understanding is you incorporated those adjustments in 2024 into the load forecast.

C. DUONG: That's right. And we wanted to reflect their proper customer class for the load forecast, moving forward.

J. SCOTT: Okay. But did you make any forecast for new customer – like, in 2026, for customer reclassification in future years?

C. DUONG: No, we have not in the sense of done anything in addition to what is reflected in -- so table A, for example, has shown some customer movements from the last 2021 to 2024 period. And, of course, previous to that, we may have or would have other customer reclassifications that are embedded in our historical trending.

The historical trending customer classes would be one input to where we believe our customer classes are moving forward, as well.

J. SCOTT: Okay, thank you. If you just scroll down on that question, part (c)? We did ask about the fact that there was no adjustment for the general service greater-than-50 classes regarding electrification, or increased electricity use because of changes in heating or heat pumps.

So my understanding is for general service less than 50, you do make an adjustment for heating electrification?

C. DUONG: That's correct.

J. SCOTT: And for greater than 5,000, you're making an adjustment, too; that's your large-load requests?

C. DUONG: That's correct, with the caveat that those large-load requests are large-load requests. We don't know if it's due to specific electrification needs or not. They have asked us for significant increase in their needs; it could be based on, due to electrification, it could be due to other purposes.

J. SCOTT: Okay. And you can't break those out?

C. DUONG: Yeah. That information is not necessarily always provided to us from our customers.

J. SCOTT: Okay. I am still not sure why the decision was made not to put any -- in that middle class, why they didn't, for various reasons, are not affected. And it doesn't quite jibe when I look at your, you know, the reference scenario for the planning work. It talks about general service electrification for heating. When you look at your customer satisfaction, your questionnaire, you call it satisfaction survey, people interested in moving into heat pumps definitely probably will consider electrification.

I am just wondering why there is that gap between the two, for those classes, specific classes?

C. DUONG: Yes. Leanne, could you move to Schedule 3-1-1, and section 7.1.2, but more specifically in other places as well, we do provide explanation on why we believe the other GS classes may not have electrification needs in the current test period. There are many factors that affect their electrification needs; it is explained in this schedule.

My understanding as well is from the planning load forecast, they have, as you know, the decarb study, which gives them additional information on where their building capacity needs are. But their planning, actual forecast investments for the next, for this test period, is specifically geared towards the immediate customer needs, not necessarily a layer on top, the decarb planning forecast.

J. SCOTT: And I don't have the reference to this, but there is somewhere where you talk about the surge, and it talks about the surge in public sector electrification.

So what you are saying, that's only happening if it's in the large-user public sector, of buildings that are in the large-user class?

C. DUONG: We did mention in here that there is interest in electrification in the federal sector. Some of those have been incorporated into our large-load request, so they have – they are customers, existing customers that are below the large load, the large-user class, that we have forecasted to be a large-load customer during this rate period.

We have also explained that some of those electrification needs are only possible based on further funding, which we then explain may not come about during this test period. And therefore, we have then explained that we have not forecasted a generalization of GS customers to electrify their load, if the funding is not there.

J. SCOTT: Okay. My last question, if we could just turn to 8-SEC-85, and down to the table below.

If you could provide how you arrived at the forecast of these numbers for unprocessed payment charge and the reconnect at meter, regular hours and after regular hours?

A. BARRIE: Ms. Scott?

J. SCOTT: Yes?

A. BARRIE: Are you just looking for the theory behind how we came up with the numbers, like, what are the driving factors?

J. SCOTT: The driving factors that, why it's going down and how you determined how far these were reduced.

A. BARRIE: So if you are looking for the driving factors behind the unit numbers then, yes, we can do that.

J. SCOTT: Okay. Thank you. Those are my questions for panel 3. Thank you.

J. NOWICKI: Thank you, Ms. Scott. I will just mark that last undertaking as JT3.22.

J. SCOTT: Yes, thank you.

UNDERTAKING JT3.22: Provide how Hydro Ottawa arrived at forecast of numbers for unprocessed payment and the reconnect at meter charge during regular hours and after regular hours

J. NOWICKI: Okay. And then up next, we have CAFES Ottawa. Mr. Brophy, I see you are on the screen. We have CAFES down for around 10 minutes. So I think we can go through your questions and then, after, we will take our afternoon break.

EXAMINATION BY M. BROPHY

M. BROPHY: That sounds great. Initially, I think we had about 30 minutes allocated, but I think I will only need 10 minutes, so we just asked it to be targeted for 10 minutes.

By the way, Michael Brophy; I think you had been watching earlier. Some of the questions we had asked in other panels had been referred to this panel, and then I had one other question as well, which I will start with.

And you were just talking with SEC about 2-CO-21, and the table related to the data centre enquiries that are there. So you can pull it up if you want, or I can just ask the question. Yes, that's the table, exactly. Okay.

So you provided that information. And then above it, in part (a), the response. You said there are four categories that you are using: inquiry submitted load form, signed off, offer to connect and then connected.

So for the information that's in table A related to data centre by year, can you provide the breakdown of how many customers each of those numbers represents? I don't want any names or confidential information, but just the number.

And then if you can also indicate for each of those amounts, by year, which of the four categories it fits into from part (a)? So inquiries, submitted load form, signed offer to connect, or connected, is that something you can do?

C. DUONG: If I can just take a moment, thank you.

M. BROPHY: Okay.

C. DUONG: Hi, Mr. Brophy. So, as you may know, this is a panel 1 document. We can undertake to provide that information, but I -- we cannot guarantee that the information you are asking for is available. But we can certainly undertake for that.

M. BROPHY: Okay, yeah. Best efforts is fine, thank you.

J. NOWICKI: So that will be JT3.23.

UNDERTAKING JT3.23: Provide inquiries, submitted load form, signed offer to connect or connected

M. BROPHY: Okay. Terrific, thank you. The next question relates to 2-CO-14D. And this is an insurance-related question that was referred to this panel by another panel. So, the response to CO-14D indicates that Hydro Ottawa has storm insurance related to distribution facilities, buildings and operation centres, among other things. And then Hydro Ottawa indicated that there was no damage leading to any insurance claims from the Derecho event in 2022; is that correct?

N. TEJWANI: Correct.

M. BROPHY: Okay. So, I know through a lot of the material and discussion through the technical conference Hydro Ottawa spent a lot of time highlighting the 2022 Derecho event, and it just seemed a bit off that there was no damage that resulted that could have been recovered. So I am just wondering, can you help me understand that apparent paradox? I would have thought that such an event would have caused damage that could have been recovered through insurance.

N. TEJWANI: Sure. So, under commercial insurance policies Hydro Ottawa's property insurance policy at the time and its current commercial insurance policy, the only poles and wires that are covered are 1,000 feet of ingress and egress into a substation. Hydro Ottawa was fortunate in the May '22 Derecho that the substations, administration buildings and operation centres did not sustain damage that would justify an insurance claim.

M. BROPHY: Okay. So it was just from the limiting of certain categories in the insurance that ended up not applying, I think is what you said?

N. TEJWANI: That is correct.

M. BROPHY: Okay, thank you. And then the last area of question was related to, we were talking -- there is a few IRs, but one of the ones we were talking on panel 1 about was BOMA-8, and it relates to EDSM potential. I won't go through the broader EDSM programs, but one of the questions that we asked panel 1, and it was referred to this one, is: Does Hydro Ottawa have information on what the maximum potential is in its service territory for all energy efficiency programs?

C. DUONG: Hi Mr. Brophy. If we can take a moment to confer?

M. BROPHY: Sure.

C. DUONG: Hi. So, I am not sure if this will provide you what you need, but we certainly calculated our EDSM savings based on IESO targets and our portion of those savings. And those targets are forecasted by the IESO, whether that is a reflection of the maximum potential in Ottawa or not we cannot make that kind of comment. But, as noted here, the IESO had targeted a 3,000 megawatts of savings over their current framework and we have used that information as well as the percentages, as noted in this response, to calculate what our expected EDSM savings are.

M. BROPHY: Thank you, and I think I understand. So you have taken the targeted numbers, based on the IESO information, panel 1 mentioned that you're participating in the stream 2 work and there might be additional local program savings that come from that. So, you know, that would be on top, but it sounds like you didn't have those numbers right now --

C. DUONG: So, sorry, I should clarify. So, there are -- so this 3,000 megawatts is targeted savings from the IESO program, which would include some local initiatives in there. And in addition, as you mentioned, there are some Stream 2 savings and programs that we have included in our forecast as well.

M. BROPHY: Okay, thank you. So, I just want to use one example of an EDSM program and see if we can get, you know, some information, given that you don't have kind of an assessment for all maximum energy efficiency programs, you are using the targeted numbers from IESO. So, IESO's EDSM has a program which is included in residential, and maybe small commercial as well but let's just talk about residential for a minute, where Hydro Ottawa customers can move forward with up to a 10-kilowatt solar panel and battery combination and it gets incented through the program. And do you know what that would equal in annual energy and peak demand reductions if a customer were to implement that?

C. DUONG: I'm sorry. If you can repeat that question? Thank you.

M. BROPHY: Sure. So, just using the EDSM program that relates to the 10-kilowatt solar panel and battery combo for the incentives that are available to Ottawa hydro customers; can you tell me what that would equal for a typical residential customer in annual energy and peak demand reduction, if they were to install that?

C. DUONG: I believe in our calculation of the additional savings there is the program relating to additional solar panels on -- but it's the commercial solar panels. And we have incorporated that billing, or savings, in our load forecast. But it sounds like you are specifically asking about residential solar panels; am I correct?

M. BROPHY: Yeah, I was using the residential as an example, so are you familiar with the residential application?

C. DUONG: Yes, but we have not done a separate calculation.

M. BROPHY: Okay. So I was going to ask for an undertaking to provide some information and it would probably make sense just to put it all into one. And I understand we could slice and dice this a lot of different ways, so I just picked one scenario and then it's quite easy to prorate off of that once we get that. So, can you provide the following information, and you can include any assumptions and the basis for your calculations as well, just to make sure that that's clear: What the annual energy and peak demand reduction would be if all eligible Hydro Ottawa customers implemented the 10-kilowatt solar panel and battery combo where there's incentives through the EDSM program; is that something you can do?

C. DUONG: Sorry, before I could respond to that, I wanted to make it clear that, as you may know, in our current territory there have been supporting programs in the past to support residential customers to put up solar panels on their roof. The impact of those programs have been reflected in our historical loads, which, of course, have been provided, information on our load forecast going forward. And you are thinking that if, under your scenario, if all residential customers, the remaining residential customers, the remaining residential customers, also install solar panels, what would that look like in terms of a load forecast change, it would be a significant undertaking for us to do. We do not have information on whether our current residential customers have a solar panel or not. There would be a lot of assumptions made there to do this calculation.

M. BROPHY: And to make it simple, you can just assume that there were ho historical, because I understand it might be some work to go and find out who has them already, so just assume there aren't any, and then apply it to your customers, and then we can sort out later the difference between that and who already has it, but that, I think, would relieve you from trying to sort out who already has solar panels, it would just be assumptions and math then.

D. COBAN: Mr. Brophy, I just kind of challenge the relevance of that if we are not able to get a clear picture from what is already embedded versus what would be incremental. Like, how is this information going to be of assistance to us in this process if that is an inherent sort of limitation to looking at the data.

M. BROPHY: Sure, no, that's a great question. So as I mentioned earlier, the 100 percent assumption, without having to go back and figure out who already has solar panels, is an easier calculation using information that you'd have readily available. So it was just put forward as the simplest calculation. We could have said 50 percent or 1 percent, you know, it's -- it can be prorated either way later, but, you know, certainly, if we use 50 percent as an example, you know, 50 percent of the residential customers in Hydro Ottawa's service territory don't have solar panels, so you know that, you know, 75 percent don't, right? So, you know, you can get to a reasonable assumption following it. So I just picked the 100 percent because it's the easiest math you can do, but we could use 50 percent or whichever number you would like to use, and then proration is simple enough.

A. BARRIE: So I guess I am also trying to understand, like, what we are using this data for, because, like --

M. BROPHY: Sure.

A. BARRIE: -- obviously, 100 percent of our customers are not moving to solar panels in the next five years and during this rate term. The IESO has not even put that much funding in probably for the entire province to do that for all of Hydro Ottawa's customers. We also are -- just to explain our customer residential class a little bit as well, it includes, you know, customers that are in bulk meter buildings, which, none of them would be eligible to do this. It also includes customers that could be in a triplex or a six-storey, as long as they manage to still be considered residential. So you also added the world eligible, which would remove a significant number of our residential customers, so I am just wondering if maybe I understood better what you're trying to achieve as an outcome, maybe we could understand what would or would not be possible.

M. BROPHY: Sure, sure, yeah. So having that information provides what's possible if it were to be undertaken in comparison to the current embedded IESO targets that you talked about earlier. And the reason I mentioned in the undertaking request that you can put in assumptions, so say you had a 100 percent number for residential and there were certain ones that came out, so then it got you down to some other number. I am just asking that you state that number, and so if you were to, you know, take best available information on residential numbers and applied it, you know, I am happy to live with whatever conditions you end up putting in the response that indicate the adjustments that you had to make. It provides a directional potential number using one of the programs in relation to what the targets are that were included in the plan.

D. COBAN: Mr. Brophy, I am still struggling with the request. It seems like a fair bit of work, and what we are looking at is a hypothetical in terms of what's possible versus what we are here to evaluate is what's probable and likely to happen and has been assumed for the purposes of setting rates, so I am just struggling with the level of effort that seems to be involved in your question and the kind of probative value of looking at it from a, you know, hypothetical, what's possible perspective.

M. BROPHY: Okay. So why don't we deal with it this way: Why don't you use 10 percent residential -- of your residential customers, and do the math based on that, and I don't want to get into argument, that's not the purpose of the technical conference, but, you know, what's in your plan versus what's possible or in the interest of customers within your service territory is a matter of debate, and so I don't want to get down that rabbit hole, but I am happy if you wanted to use 10 percent customer numbers for that calculation.

A. BARRIE: And, sorry, so what -- so now I get the start -- like, if we said 10 percent of customers, and then what do you want us to do based -- after that, if you could repeat what your request is?

M. BROPHY: Yeah, okay, sure. So if you take 10 percent of your residential customers and you were to implement the assumptions of the 10-kilowatt solar panel and battery combo incentives that are available, you can take -- they both have incentives, but they can be applied together -- and you applied that to your -- to 10 percent of your residential customers, what is the annual energy and peak demand reduction that would result from that?

A. BARRIE: So is this a billing peak demand or a capacity peak demand?

M. BROPHY: Well, ideally capacity would be best, but if one is easier for you to determine, then you pick, and you can indicate what you have used.

A. BARRIE: Well, it's just, it's very different if you assume they are throughout our service territory. 10 percent, the impact on -- because you would have to do that at a station level and not -- so it's just, I am not quite sure how we would do that, and that would be -- would have been a discussion for panel 1 to be able to say on a capacity, so I am not even sure the level of difficulty for them to do such a calculation. And is it assumed to be done, like, on a net metering kinds of basis so that their battery and solar combination results in them doing no more than offsetting their own load? So in other words, I would have to have a large enough customer that this 10-megawatt solar panel is useful --

M. BROPHY: Yeah. So currently -- I am probably not familiar with all the program details, but currently, net metering is not applicable to that program, so it would be --

A. BARRIE: Right. So --

M. BROPHY: -- normal time-of-use -- time-of-use rates.

A. BARRIE: Correct. So I guess my concern is, like, with the net metering program, customers can take advantage of using that credit throughout the year, whereas with the 10, under the current program they lose that credit in the current year, right -- or in the current month, sorry, not in the current year. They use it, so at any point in time if they over-generate, it just kind of displaces into the grid. So am I building it off their lowest peak in the 12-month period --

M. BROPHY: Well --

A. BARRIE: -- in order to not -- because if they build it off their highest peak the majority of the year currently at least being summer peak you are going to look at the majority of the year they would have too much generation.

M. BROPHY: Yeah, so they would have high --

A. BARRIE: Potentially.

M. BROPHY: -- they would have the highest generation in the summer, which is also the highest peak. And then any excess goes into the system, which then benefits system peak demands as well.

A. BARRIE: So you want to see, then, what the impact is mainly on our highest peaks of the year?

M. BROPHY: Correct. And you can do it at a system level if that's easier.

A. BARRIE: So I just don't know how possible this is, so -- just because it's not something I would be calculating. So I can undertake to ask this question, but I can't really undertake to provide an answer.

M. BROPHY: I understand. Best-efforts basis is fine. And noting the assumptions, of course, because you could apply different assumptions, as we talked about. Okay. Terrific.

J. NOWICKI: So that will be JT3.24.

UNDERTAKING JT3.24: Show impacts on highest peaks of the year with assumptions considered

J. NOWICKI: And, Mr. Brophy, I note we are at 3:46. I think we should take our afternoon break at this time. I am not sure whether you have any more questions.

M. BROPHY: That was the last one. Thank you very much.

J. NOWICKI: Okay, thank you, Mr. Brophy. So we will return at 4:01 and resume questions for panel 3 with CCC. Thank you.

--- Recess taken at 3:46 p.m.

--- On resuming at 4:01 p.m.

J. NOWICKI: Welcome back. We will be continuing questions for panel 3 with Mr. Gluck for CCC.

EXAMINATION BY L. GLUCK

L. GLUCK: Thank you. Good afternoon. My name is Lawrie Gluck and I am a consultant for the Consumers Council of Canada.

If we can please go to 1-CCC-2, part (d), please? If we could just scroll down a bit?

In this response, you provided four tables labelled table A to D that provide different treatments of certain aspects of the revenue requirement relative to Hydro Ottawa's proposal.

And can you advise whether these tables reflect the updated revenue requirement and are directly comparable to the revenue requirement shown in table B in the response to 1-Staff-1, please?

C. DUONG: Hi, Mr. Gluck. Certainly, subject to check, I believe they might be based on the original submission.

L. GLUCK: Thank you. Would it be possible for you to undertake to update them to reflect the updated requested revenue requirement?

C. DUONG: Certainly, subject to check, if they were not done based on the 1-Staff-1 update, we would do that.

L. GLUCK: Thank you.

J. NOWICKI: That will be JT3.25.

UNDERTAKING JT3.25: Update tables to reflect updated requested revenue requirement

L. GLUCK: Thanks. If we could go to table D, please?

And here, I had asked for you to take the property tax line out of OM&A. And can you explain what forecast you were using to inflate the property taxes in the years 2027 to 2030, given that I would expect that they wouldn't be inflated by the custom revenue OM&A factor, now that it's out of the OM&A bucket?

C. DUONG: Hi, Mr. Gluck. Let me just take a moment to confer, thank you.

L. GLUCK: Sure.

C. DUONG: So what I can say to you is that these property tax values were based on the forecast that was done for this test period. However, the underlying assumptions that were used to calculate these values, annual values, may be best to have been asked of panel 2.

L. GLUCK: Okay.

C. DUONG: But they are based on certainly existing property values -- property taxes, and then adjusted for a certain assumption.

L. GLUCK: Okay. But it would be, can I take it, and maybe you don't know the answer and I should have asked panel 2, but is it fair to say it's not the growth factor anymore, but it's the expected increase for property taxes, directly?

C. DUONG: That's correct.

L. GLUCK: Okay, thank you. Can we go to part (p) of the same response, please? Part (p), please, so it should be down. Thank you.

And I know you have had a number of discussions about the large-load variance account. But I am interested in a very small portion of it that I don't think was discussed today. And in the third sentence in this response, you describe the revenue requirement-related part of the true-up.

And can you speak to the net of the return on equity-related capital contribution would be trued up? Can you explain what that is?

C. DUONG: Mr. Gluck, so the sentence you mentioned that starts with the revenue requirement impact, and then it would be adjusted for the capital contribution true-up. So these large-load customers have requested significant systems expansions that are subject to the EC model. And the calculation to ensure that their additional requested load may either be recovered through future rates or, if not, they would request an initial capital contribution to that process, undergoes an eventual true-up to actual materialized load during the connection horizon.

And when and if their loads do not materialize or shall their load not materialize, we could request for additional capital contributions. And therefore, we did not want to recuperate that capital cost as well as receive additional revenue requirements if we did not factor that into our calculation for this large-load variance account.

So basically, we did not want to double-dip on the revenue requirements relating to these large-load customers not materializing.

L. GLUCK: Just to make sure I understand: So I think you were using an example where they, a customer, does not materialize, like they don't end up connecting?

C. DUONG: They connect, however they may not realize the load that they originally had requested from us. So we would have built our equipment capacities based on their initial request. And hypothetically, for example, a customer is asking us for an additional 10 megawatts of load and they were going to give it to us during the 2026 to 2030 period annually.

However, if they do not materialize that load, we would then be requesting a capital contribution from them.

L. GLUCK: And that capital contribution would flow into this account? Is that what you are saying?

C. DUONG: It would be reducing the revenue requirement needed from this variance.

L. GLUCK: Got it. Okay, thank you. Can we go to the chapter 2 appendices filed as a response to 1-Staff-1? And if we could go to sheet H of that, please?

C. DUONG: Sorry, could you clarify which tab? Is it Appendix 2H?

L. GLUCK: Yes, the other revenue. Yeah, thank you.

And if we go down a bit and look at the interest and dividend income row? I think it is a bit below that. Yeah.

And if you go all the way to the right, scroll to the right of this, the last, that last row is year-to-date 2025.

So my understanding is that, year to date, you have generated $192,000 of interest income? Is that correct?

N. TEJWANI: Yes, that's correct.

L. GLUCK: And my understanding for 2026, you forecast zero interest income?

N. TEJWANI: Yes, that's correct.

L. GLUCK: And can you explain the basis for that forecast?

N. TEJWANI: Earlier this year, there was a favourable operating cash flow variance due to lower than expected global adjustment. So Hydro Ottawa Limited found itself with positive cash balances for portions of the month before it needed to pay its monthly IESO bill. So that's the source of the interest income revenue.

However, in keeping with the deemed capital structure, we try to avoid carrying positive cash balances.

L. GLUCK: Okay. And when you do have short-term cash balances, you obviously earn interest on that. Is that right?

N. TEJWANI: Yes, sir.

L. GLUCK: Okay, thank you. Can we go to 9-SEC-87, table A, please? And, if we go to the bottom of the table, just where the grand total is shown. Am I correct that, based on your proposal, the entirety of the proposed capital additions for the 2026 to 2030 period are, with the exception of the PILs contribution, is subject to either symmetrical or asymmetrical deferral account treatment?

A. BARRIE: Yes, that's correct, in that it has been for -- it's in the current period as well.

L. GLUCK: Currently the entire, all additions are subject to --

A. BARRIE: Yes, and the majority is asymmetrical.

L. GLUCK: Okay, thank you. And can we go to 4-Staff-138, Table B, please? Panel 2 took me to this table to show an updated version of the cost per locates inclusive of 2024 actuals, and I did not ask this of them and I should have: Can I ask that you please undertake to provide the number of locates, average cost per locate, the total external locate cost and the inspections line for the 2016 to 2030 period, please?

A. BARRIE: Sorry, can you repeat that?

L. GLUCK: Sure. In summary it is to expand this table from 2016 to 2020, and to fill the same information but we wouldn't need the EVA line because there was no EVA during that period.

D. COBAN: And, Mr. Gluck, just for my understanding, why are we reaching back before the prior rebasing? We are really here to just deal with the historical years, the most recent five years since we last rebased.

MR. GLUCK: Yeah. The importance of the previous period with respect to the locates is to see -- to give the Board an understanding of the growth of the costs associated with locates that occurred prior to the introduction of the relevant legislation. And that would have come in place in 2022, I think, the bill was passed and then the account started in 2023. So, to understand whether locate costs were increasing at a pace higher than the OEB's inflation rate it would be -- you would need a little bit more information, a little bit more historical information than just 2021.

A. BARRIE: So my concern with taking that undertaking is no in order to facilitate the work that we did in order to record this variance account, it's several vendor invoices that have to be monitored and accumulated on a monthly basis, it's not insignificant work. Like, this is not stuff that I can just pull out of the ERP. Like, the dollar amount I can, but to get to the average cost, like, that's -- I am not even sure we have, like, that might be data entry from invoices kind of thing to be able to achieve that, which would be a lot of work.

L. GLUCK: Well, we do think it's important in terms of supporting your request for disposition of the GoCA account, and the manner and the methodology you used to calculate it, so we are requesting that information.

D. COBAN: And can you point us to any OEB guidance that requires that kind of historical baseline for this? It just does seem like we are sort of introducing net new requirements relative to what the OEB has established in its accounting order and policy on it.

L. GLUCK: I don't know that there is any Board guidance in terms of, you know, how far back you have to go. But you do have to prove -- or I shouldn't say that. I would expect that you would have to show that the baseline you are setting to which you're viewing the variance, that that is directly driven by the bill, it would require you to show, or in my view it should require you to show, the growth of locate costs up to the introduction of the bill.

A. BARRIE: As part of Hydro Ottawa's request we are strictly focusing on the increase in the locate cost, so I'd -- and so, I am just wondering would the charge per, like, rather than getting back all the volumes there, if there is something in a smaller value that we -- or data, especially even doing one year's worth is significant amount of work to gather, to go all the way back to '16 monthly invoices for several vendors. That's not -- we certainly don't have it in Excel format, it would be on an invoice itself and grabbing all that data individually.

L. GLUCK: Would it, if we went back to 2019, add two years, so 2019 and 2020, would that be a more reasonable request in terms of the amount of time that it takes?

A. BARRIE: So, it's obviously more reasonable because it's smaller. I just -- it's not me that would have to do that work, so I can undertake to take it back to see how much effort that would be, it's just I know it's not insignificant.

L. GLUCK: Okay. I would appreciate you -- best efforts.

J. NOWICKI: So that will be JT3.26.

UNDERTAKING JT 3.26: Provide the number of locates, average cost per locate, the total external locate cost and the inspections line for the 2016 to 2030 period

L. GLUCK: Thank you. And this is my last question, and if we can go to 1-Staff-1, at page 44, please? And if we go down before the table, please? So, here Hydro Ottawa notes that for a number of Group 2 deferral and variance accounts the 2024 year-end balances have now been included in the disposition proposal. And I just wanted to check to see whether -- have you provided anywhere in any of the IR responses or otherwise the details supporting the amounts that have now been added to those accounts for 2024 year-end? And just -- I would just use the capital variance sub-accounts as an example for those accounts in Exhibit 9, Tab 1, Schedule 3, you have Tables 12, 13 and 14 that are supportive of the disposition request, but those end in 2023. So is that something that's been provided on the record in support of all the additional accounts that the 2024 amounts that have now been added to these accounts?

A. BARRIE: Just one second, please. No, they have not been put on record in the detail you are referencing in Exhibit 9.

L. GLUCK: And is that something you could do for the accounts that you have updated?

A. BARRIE: Yes, we can.

L. GLUCK: Thank you.

J. NOWICKI: That will be JT3.27.

UNDERTAKING JT3.27: Put on record details supportive of the disposition request

L. GLUCK: Thank you very much. Those are my questions.

J. NOWICKI: Thank you, Mr. Gluck. Up next we have BOMA. Mr. Li? Please go ahead.

C. LI: Hi, can you hear me?

J. NOWICKI: Yes, we can hear you.

EXAMINATION BY C. LI

C. LI: Great, okay. Good afternoon, everyone. My name is Clement Li, representing Building Owners and Managers Association Ottawa, or BOMA Ottawa. As it turns out, I only have one question for this panel today, which is a follow-up question to one of our IRs, BOMA number 3. I have already asked panel 1 this question yesterday, but Ms. Coban suggested that it would be more appropriate for panel 3 to handle this question, so here we are.

So, let's put BOMA-3 on the screen. In part B, our question was to ask you to explain the difference, or the significant difference, among the compound annual growth rate, or CAGR, derived in the reference that I listed in my IR, reference 1, 2 and 4. I understand why a planning load forecast will always be higher than a revenue load forecast, in terms of the absolute KW or kVA. In the planning load forecast it's based on extreme conditions, extreme weather, worse coincident peaks and all that, and then in the revenue load forecast it's the most likely scenario, and of course there is a difference in terms of the absolute value of the forecast.

And I also heard the exchange earlier this afternoon between you and Ms. Scott on the electrification and large load requests. So I get it. There should be a difference. But what you did not explain or I did not understand, I did not follow, is that, why the growth rate difference is so significant. For context, in reference 1, the CAGR is 7.8 percent over the period, and in the same period, in reference 2 and 4, in both cases they are less than 1. So there is a pretty big difference.

So when I went through your response, I don't think -- or at least in my mind, I don't think you really answered my question, you just basically pointed me to a few places in your evidence and give me the -- so here they are, the assumptions and methodology in these sections.

And I read them. And I still could not understand the significant difference in growth rates.

So what would be really helpful is, I am asking for undertaking, is if you can give me a summary table, say three columns, one for each of the reference, reference 1, reference 2, and reference 4, and I am suggesting that you can have different categories, basic forecast assumptions, like commercial floor space, forecast population demographics, housing start -- the economic stuff, right? And I assume they should be common for all cases, but if you can list it, that will be great so I know they are common.

And of course then you have, like, CDM or EDSM assumptions for each of the category, not category, each reference, and then of course then the big one, electrification, activities, EV penetration, large load requests like data centre, customer switching the load from fossil fuel to electricity. I guess this is the category that I really expected there would be some differences or lacking among the three forecasts that will contribute to the difference in growth rate.

So -- so far I guess what I am talking about is the CAGR for the whole period, but in this summary table it would be really great if you can do that too, is to actually do a year by year, like '26, '7, '8, '29, '30, comparison among the three columns, so that I can actually clearly see the drivers or the assumptions that you listed that contribute to the significant difference in growth rate among the three cases, so that is the request for undertaking.

A. BARRIE: So I am just going to take a moment to consult, and I will be right back. Thank you, Mr. Li.

C. LI: Thank you, sure.

A. BARRIE: So I think we can undertake to provide more details and try to reconcile it for you better between the two. It can't be done on an annual basis. Lianne, if you could scroll back up. What was provided in those buckets in this chart, is you can see those deliberate dots in these reference scenarios for the decarbonization study was done on a five-year basis.

C. LI: Fair enough.

A. BARRIE: So I couldn't reconcile on annual basis --

C. LI: Fair enough.

A. BARRIE: -- there's just no annual basis on which to do that --

C. LI: Fair enough. If you can do it, like, for the entire period, that would be fine too, that's fine.

A. BARRIE: Yeah, and just so you -- like, we can try to -- I am not going to be able -- necessarily be able to go to the -- down to the 100 percent level of some the items that you have laid out, but to the best efforts, we can try to pick some of the major ones that we think will help explain to you the differences between the two. And it's certainly not going to -- like, I am not going to get a number at the end of the day that balances. Like, I am not going to be able to fill in all those gaps with, this is exactly if you add like, 1 plus, you know, 1 plus 1 plus -- and then you keep going, I am going to get to 5. It's not going to work that way.

C. LI: I am not asking you -- just to clarify, I am not asking you to give me every single factor, but I would appreciate if you can give me the big one -- the key ones, so that we say, okay, so this is a big one. Like, understand, you don't have to give me every single thing, and I understand you are not going to be able to reconcile 100 percent, but to give me some idea, what are the things that drives the difference, that's the key information that I am looking for.

A. BARRIE: So we can undertake to try to provide a more detailed level to help you understand those differences.

C. LI: Yeah. Thank you.

J. NOWICKI: So that will be JT3.28.

UNDERTAKING JT3.28: Provide year-by-year comparison of CAGR for 2026, 2027, 2028, 2029 and 2030

C. LI: That's it. It's quick. I don't have any more question. Thank you.

J. NOWICKI: Thank you, Mr. Li.

So up next we have Energy Probe. I see you on the screen, Mr. Ladanyi. We have you down for 15 minutes.

EXAMINATION BY T. LADANYI

T. LADANYI: Thank you. My name is Tom Ladanyi. I am representing Energy Probe and also CCMBC, but my questions will be all on behalf of Energy Probe. First I want to touch on something that was discussed this morning, if I got it right. So in March of 2025, the OEB issued its decision on EB charging, EB-2023-0071. And I understand from what was said this morning, if I caught it right, that you will be implementing this in 2026. Is that right?

A. BARRIE: I don't think they were clear this morning about if we will be implementing it in 2026, but we do have a requirement to do so.

T. LADANYI: Yes, thank you.

Now, in that OEB decision -- I am just going to read part of it to you. It says:

“Implementation, cost deferral, and variance account, the OEB will establish a deferral account to allow electricity distributors to track the revenue-requirement impacts of their incremental and material costs of implementing the EBC rate in a deferral account.” [As read]

And then it goes more into description. So you don't have this deferral account yet. You will be establishing this deferral account?

A. BARRIE: So we do not have that account as of yet, so we would have to determine if we think the cost is going to be material enough to request it.

T. LADANYI: Are you actually working on implementation right now, or you are not even started?

M. FEE: Hi, Mr. Ladanyi. Yes, we are actively working on implementation, and we will be implementing it for January 1st.

T. LADANYI: But you are not currently in 2025 tracking those costs?

M. FEE: I am not aware of the costs. I am sure there is a costing somewhere for the estimates for the changes to the system that will be required. However, the last that I was aware, they are not significant.

T. LADANYI: Thank you.

Now, can you turn to Exhibit 7, Tab 1, Schedule 3, page 6, Section 6, please. Can we have that on-screen? Right. So you can see Section 6, consideration of future distributed energy resources. Now, in the second sentence there it says:

“Embedded behind the meter distributed energy resources, BTM DERs provide benefits to the system as a whole. However, additional distribution...”

If you can go to the next page, please, so we can scroll up so we can see the wording. Right.

Okay:

“However, additional distribution resources are needed to ensure the resilience, reliability, safety, and power quality of the electric grid system, while ensuring the DERs are served effectively. The costs associated with the customers with BTM DERs can differ significantly from those without. BTM DERs are often operated to address individual customers' non-coincident peaks, and have intermittent effects on the grid's operating resources, thus requiring deployment of LDC resources to monitor and actively address any resulting voltage issues or related mechanical wear to the system.”

Now my first question related to this is do you have an estimate of these costs, incremental costs that you are talking about here for the 2026 test year?

C. DUONG: Hi, Mr. Ladanyi. Are you specifically talking about a certain type of DERs? Or, in general?

T. LADANYI: That's actually a really good question. I am glad you asked me that question, because I think that the evidence in this case is very confusing about what are DERs, and what should we be talking about.

Because in the section on - another section on DERs, I am not going to go to it now, DERs are defined as being - could be for example a gas turbine or it could be a reciprocating engine, a large one for some commercial establishment. Or it could be a small rooftop solar unit. So you have everything in there.

So I don't know what you mean here. They are all behind the meter. You can tell me what you actually have in mind, with this evidence.

A. BARRIE: So in the particular evidence that you have referenced, Mr. Ladanyi, that's the standby service charges. Yesterday, and I believe the day before when you were referencing the bill in settlement, it was related more to our microFIT fit, and larger generation charges. So we do treat those differently.

T. LADANYI: Sure.

A. BARRIE: Like with the standby generation charges, those costs flow through the cost allocation model, and they are built off of that level of detail. So just like other rates, it is the outputs of the cost allocation model, whereas our microFIT fit and larger generations, we do more of a cost study specifically for the charges related to those.

So I could bring you to the evidence where the more detailed costs analysis has been done and is submitted as part of those ones.

T. LADANYI: Well, you can just give me a reference; you don't have to bring it to me.

A. BARRIE: Yeah. So it's within Schedule 8-4-2. The attachment PDF to those have the detailed costs for additional billing agents, settlement functions, accounts receivable/payable. We billed those costs off of looking at the microFIT approved rate from the OEB, and we picked up similar costs.

So if you look at that, I will say you are not going to see all grid-related costs related to those, as we did mimic the microFIT rate class charge.

T. LADANYI: Yeah. So microFIT as I understand it was a program to connect, for example, large wind farms or large solar farms which were at the one location; they were actually not distributed throughout the system.

So I am not sure that they are actually applicable in this case, but maybe you think they are actually the same. So you wouldn't call those things DERs. They are all in the one location; they are not distributed throughout your system.

A. BARRIE: So we do consider them DERs. So the microFIT is less than the 10 megawatts. And then our fits is above, and then our larger ones are even larger size generation. So we have one --

T. LADANYI: So would the large -- go ahead.

A. BARRIE: Sorry. I was just going to say so, in the PDF attachment that I reference, and it's attachment A, it has the costs analysis for all three of those.

T. LADANYI: I will have a look at that, thank you.

Do you have a benefit-cost analysis of the impact of BTM DERs on the Hydro Ottawa distribution system? Because in the paragraph I just read you, you mentioned benefits. Do you have a benefit-cost analysis?

A. BARRIE: Just give me a moment to consult.

On record, we have the BCA for the Kanata North region, specifically. I think that's Staff-67.

T. LADANYI: Thank you. I will look that up.

A. BARRIE: Yes. It's part of Staff-67.

T. LADANYI: Thank you. So do BTM DERs create a revenue deficiency for Hydro Ottawa?

A. BARRIE: So we look, similar to like the evidence I have just provided, Hydro Ottawa had looked at introducing generation charges as part of our 2016 rate application. And within those charges, we were trying to recover specifically the costs related to additional billing and settlement, as I mentioned, designed off the similar charges of the OEB generic microFIT charge.

So as a result, those capture those types of costs. However, they do not capture costs past those. So you don't allocate a portion of your distribution grid, for instance, to any of these, to the generators, specifically.

T. LADANYI: Sorry, why would you do that?

A. BARRIE: Because we based the charges on a similar fashion as the OEB did in their proceeding. It would be EB-2009-0326.

T. LADANYI: Thank you, I will look up that. It's 0036 is it? Is that what you said?

A. BARRIE: 0326.

T. LADANYI: 0326, thank you.

A. BARRIE: Yes. It's called distribution rate from embedded micro generation.

T. LADANYI: Yes, yeah. Well, we can have a debate whether it's that. Certainly my position is that it's not applicable in this case, but that's subject for argument.

So can you please turn to page 2 of the same exhibit? It's exhibit 7, tab 1, schedule 3, page 2, section 3. And this is called current standby rates and rate structure. Right there, thank you.

And I can just read you a sentence out of this, which is kind of the second sentence from the bottom of the first paragraph:

“The standby rate structure is based on the customer's requirement for reserve capacity under the standby arrangement, and the standby charges ensure that the standby customer pays their fair share of Hydro Ottawa's infrastructure and operating costs to support the standby service. These standby charges also provide a source of funding to support upgrades and investments in technologies to handle increasing distributed energy resource penetration.”

And then you say:

“Hydro Ottawa does not charge load displacement generation with nameplate rating of below 500kW, which supports the development of smaller DERs across Hydro Ottawa's service territory.”

So as I understand this evidence, the customers with DERs with nameplate rating of 500kW, and above, pay a standby charge, but the customers below that do not pay it.

So who actually pays the fair share of these costs for the customers who are below 500kW?

A. BARRIE: Just for a point of clarification: Even with standby rights, it's only those customers who do request standby backup. Now Hydro Ottawa does monitor customers who have the behind-the-meter generation that's larger than 500, to ensure that they are not relying on the grid and not contracting for back-up generation.

However, we do see variability just naturally over the year between all of our customers. And so some of them may be just reducing peaks for instance to help support their portion, in reducing their portion of the global adjustment. However, they do not necessarily impact the charges that we charge for distribution.

T. LADANYI: Yeah. So I see actually two classes of customers, ones that are large customers who would be participating in the ICI, industrial conservation initiative that I mentioned a couple of days ago, and the other ones would be small customers who might have rooftop solar; it could be an aggregation of small customers that an aggregator of rooftop solar has.

Now further on in this evidence, so if you just go back to exhibit 7, tab 1, schedule 3, page 7? Exactly, back to page 7, and we are.

So you will see here, you can see it right there, from 2019 to 2023, almost 300 new renewable DERs were connected to Hydro Ottawa's distribution system. Of these newly connected DERs, 88 percent were 10kW or under.

What is the significance of 10kW?

A. BARRIE: The significance of 10KW is that they would be considered a micro generator, so that can be a mix of customers who are taking advantage of the net metering program, in which case some of them are residential customers and those residential customers are fully fixed. The fact that they have generation on the roofs doesn't adjust the costs they pay into the distribution system. Others could be the microFIT generators in which we do have that specific charge we referred to earlier. And then we could see some within the other rate classes, but they may not always be something we're aware of, though. If they are behind the meter and they are not at meter at is the point. I think Mr. Ladanyi may have -- his camera froze at least.

J. NOWICKI: Mr. Ladanyi, are you there?

T. LADANYI: I am back, I think Rogers did something against me. I think they are scheming against me, I am not paranoid. Anyway. So, what I was saying is: So the difference, really, is what is a micro generator? And I think the difference is that you might charge them less administrative cost for connecting them, that's probably the reason but I don't want to give evidence on your behalf.

A. BARRIE: No, the micro generation just means it's below 10 megawatt. It's a defined category of generation types.

T. LADANYI: Okay. So were there, during the same period 2019 to 2023, were any non-renewable DERs added? So these would be the ones that were mentioned elsewhere in your evidence, these would be, for example, landfill sites or bio gas or whatever; was any like that added?

A. BARRIE: Would you include batteries to that?

T. LADANYI: Well, you know, yes actually. On that list you had batteries as well. The answer is yes and you had photovoltaic, and batteries and combinations thereof.

A. BARRIE: So the numbers I personally see, I just see it by size and number of type of meter, I am not sure the makeup of the types of generators. I think we may have -- just give me a moment. Let me see if I can see if we put that on the record. I'm sorry, I looked quickly I am not finding the reference where I thought we had put something on the record, but I am not clearly finding it.

T. LADANYI: All right. I will accept it's there, I am sure I will be able to find it. I just have one more question and you will be happy to know that after that that's going to be it. So in the same exhibit, you say with the continuation of the 500-kilowatt threshold for load displacement generation to qualify for standby charges, this ensures standby charges are not a disincentive for most generation projects. Why should there not be a disincentive for generation projects that increase revenue deficiency?

A. BARRIE: So, we do believe customers supporting the reduction on the infrastructure is a benefit to all customers when you don't have to build all new load. The 500 was established for standby customers also in terms of efficiency. If you start -- it can create a lot of effort to be monitoring and for all of these different individual customers. And, as I mentioned earlier, customers on the whole seasonally can fluctuate. So just pinpointing specifically those that do have backup generation that fluctuates their load, we don't want to look at that as a --

T. LADANYI: I think I lost you.

A. BARRIE: Oh, are you back?

J. MYERS: Mr. Ladanyi?

T. LADANYI: I am right here.

A. BARRIE: Sorry, I am not sure where I trailed off. But I was speaking to the fact that load customers can have seasonality and Ms. Duong was talking about that earlier, and we don't look at standby for customers that are below that 500 threshold, one, for efficiency purposes, but also there is that seasonality which is load customers that can fluctuate throughout the year. And we do believe that that's a reasonable threshold to create.

T. LADANYI: Since you mentioned standby, I keep thinking about the 300 new DER customers you added, like, if just -- and you said they were 10 megawatts or under, if you just do simple arithmetic that is going to be like 3,000 megawatts. Would not that place certain demands on you to have standby capacity to deal with these customers when they are not generating? For example, if they are all solar customers in the evening they can't generate anything, so you have to have assets on standby to provide electricity to them. And maybe some might have batteries, but let's assume they don't. Wouldn't you have to have something on standby? Like, what I am trying to explain is they are actually a bigger problem for you, or going to be as big a problem for you as larger customers who you are charging a standby charge?

A. BARRIE: So, in terms of monitoring and being able to maintain the grid, that's far beyond my expertise and I wouldn't want to go into assumptions on that. But what I can say is, from a rate standpoint, we continuously review and monitor how customers are using our grid in a different manner and ensure, try to ensure at least, causality principles. And, as a result, as those items continue to change and shift we will adjust as we feel accordingly. We need to as well, to ensure safe, reliable grid for our customer base.

T. LADANYI: So, is there any chance that you might actually lower the actual 500KW threshold at some time in the future, if there is a very, very large number of new small DERs in your system?

A. BARRIE: As indicated, we would always be monitoring to ensure that how we're charging our customers is done in a reasonable manner. If that would mean lowering or increasing that threshold, then we would do so.

T. LADANYI: Okay, thank you. These are all my questions.

J. NOWICKI: Thank you, Mr. Ladanyi. So, up next we have OEB Staff. Ms. Coban, does Hydro Ottawa have a preference? We can get started on some of OEB Staff's questions today or we can wait until tomorrow to go through Staff's questions. I think, if I am calculating correctly, we would be able to have time to go through all of OEB's Staffs allotted time before the lunch break tomorrow.

D. COBAN: Maybe just give me one moment, I am just going to confer. One second. Okay. I am advised that Hydro Ottawa's preference is to resume tomorrow with OEB Staff.

J. NOWICKI: Okay. Thank you, Ms. Coban. So, that will conclude Day 3 of our technical conference. Thank you to our panelists and our participants for your time today. And we will resume tomorrow with OEB Staff's questions for Panel 3. Thank you.

--- Whereupon the proceeding adjourned at 4:51 p.m.