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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 Monday, September 22, 2025, commencing at 9:43 a.m.

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DAY 1

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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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Monday, September 22, 2025

### --- On commencing at 9:43 a.m.

M. MILLAR: Good morning, everyone. Welcome to the multi-day technical conference for Hydro Ottawa application its EB-2024-0115. My name is Michael Miller, I'm OEB counsel and your host for the next couple of days along with my cocounsel Julia Nowicki. I'm joined today by a number of Board Staffers who will be in and out. I will just introduce Margaret DeFazio right now, who is the case manager. What we will do is -- actually, Tiara, could I ask you to begin with the land acknowledgement? Thank you.

# Land Acknowledgement

T. FEARON: Good morning, everyone. The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many Nations, including the Mississaugas of the Credit, the Anishinaabeg, the Chippewa, and the Haudenosaunee and Wendat peoples. This area is now home to many diverse First Nations, Inuit and Métis people. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit. We are grateful for the opportunity to gather and work on this land and recognize our shared responsibility to support and be good stewards of it.

M. MILLAR: Thank you, Ms. Fearon. I'm going to start with appearances for which I will do a roll call. I think that's the easiest way to do it. And then I understand there's some minor preliminary matters and then we can get right to the witness panel. So could I begin with you, Ms. Coban?

# Appearances

D. COBAN: Certainly. Good morning, everyone. Daliana Coban, external legal counsel for Hydro Ottawa. I will also put in an appearance for Mr. Jonathan Myers who will be joining as for Panel 3. And with me today from Hydro Ottawa we have April Barrie, director of regulatory affairs. We also have Lianne Chartrand, executive assistant and Shayne Thompson, supervisor regulatory compliance and projects. They're going to be working together behind the scenes to pull up all of our evidence references so we can follow along. And in that regard I just wanted to remind the parties to please reference the evidence by exhibit, tab, schedule or IR number, not the PDF page numbers, so that we have a clear and consistent transcript on the record of those references. Thank you, Mr. Miller.

M. MILLAR: Great. Thank you, Ms. Coban. I just have a list so I am going to go through it and if you are here please enter an appearance. Building Owners and Managers Association?

C. LI: Good morning, everyone. Clement Li here, representing Building Owners and Managers Association, Ottawa.

M. MILLAR: Thank you, Mr. Li. Coalition of Concerned Manufacturers and Businesses of Canada?

T. LADANYI: Good morning, everyone by name is Tom Ladanyi. I am representing the Coalition of Concerned Manufacturers and Businesses of Canada.

M. MILLAR: Good morning. Next up I have Community Action for Environmental Sustainability.

M. BROPHY: Good morning, everyone. My name is Michael Brophy and I'm appearing on behalf of CAFES Ottawa and then also I'll be representing Pollution Prove, so you don't have to cover that one again. Thank you.

M. MILLAR: Okay. Thank you, Mr. Brophy. Consumers’ Council of Canada?

L. GLUCK: Good morning, Lawrie Gluck on behalf of Consumers Council of Canada.

M. MILLAR: Mr. Gluck. Distributed Resource Coalition? I think that is Daniel Walmer if he's joined us. I'm not sure if he is on the call. Okay. I will move on. I have Energy Probe next but that's you again, Mr. Ladanyi?

T. LADANYI: Yes it is, again. Tom Ladanyi, again, I'm also representing Energy Probe and in this proceeding since I representing two intervenors I will split my time between them. My questions are only going to be on behalf of Energy Probe.

M. MILLAR: Okay. Thank you very much. I have Enbridge down. I'm not sure if they are in the room or not. Mr. McMahon, are you there? Okay, I will move on.

Environmental Defence? Mr. Elson, are you there? Again, some people may be joining us later in the day because they are later on in the schedule.

School Energy Coalition.

M. RUBENSTEIN: Good morning. Mark Rubenstein, counsel for the School Energy Coalition, and I am joined by my colleague SEC Consultant and Jane Scott.

M. MILLAR: Thank you, Mr. Rubenstein. VECC, Vulnerable Energy Consumers Coalition? I saw you there, Mark.

M. GARNER: I'm just trying to get myself to work, sorry. Mark Garner appearing for VECC. And with me, I believe, is Mr. Harper, Bill Harper also.

M. MILLAR: Great, thank you. That's all I have on my list. Have I missed anybody? Okay. With that I will turn it over to Ms. Coban. I think there was a preliminary matter you wanted to address?

# Preliminary Matters

D. COBAN: Yes, just one matter to put on everyone's radar: That in the course of preparing for the TC we identified a need to correct the calculations that were presented in IRs 1-SEC-24, 1-SEC-25, 1-SEC-26 and 1-SEC-27, and these updates were filed through RESS earlier this morning and circulated to all the parties.

And I also just want to clarify that the witnesses on Panel 1 can answer any questions about the initiatives noted in these IR responses that pertain to distribution system planning, construction and operations, but any questions regarding the calculations, including the updates that were filed earlier today should be directed to Panel 2.

M. MILLAR: Okay. Thank you very much. Would you like to introduce your witness panel?

# HYDRO OTTAWA LIMITED – PANEL 1, OPERATIONS DISTRIBUTION SYSTEM PLAN

Laurie Heuff

Margaret Flores

Guillaume Chretien

Kristopher Lelliott

Jenna Gillis

Shawn Carr

Steve Hawthorne

D. COBAN: Certainly, thank you so much. So, as we noted in the letter that was filed on September 8, we've got Panel 1 here to speak to distribution system capital and operations investments including any project level details, staffing details, productivity initiatives and performance metrics related these areas of Hydro Ottawa's business. And I now like to just take a moment to ask each panelist to introduce themselves by name and title and we will start off with Ms. Laurie Heuff.

L. HEUFF: Good morning, everyone. Laurie Heuff, I'm the Vice-President of Distribution System Planning and Asset Management for Hydro Ottawa. I will pass it over to my colleague, Margaret Flores.

M. FLORES: Good morning, everyone. My name is Margaret Flores, and I am the manager of assets. I am going to pass it to my colleague Guillaume.

G. CHRETIEN: Good morning, everyone. Guillaume Chretien, I am the Manager, IT Planning and Programs for Hydro Ottawa. And I will pass it on to Kris Leliott.

K. LELLIOTT: Good morning, everyone. Kristopher Lelliott, Director of System Operations and Grid Automation. I will pass it on to my colleague Jenna Gillis.

J. GILLIS: Good morning. Jenna Gillis, Director of Distribution Engineering and Asset Management. I will pass it over to Mr. Carr.

S. CARR: Good morning, everybody. My name is Shawn Carr. Director of Customer Strategy and Innovation. And I will pass it to my colleague Steve Hawthorne.

S. HAWTHORNE: Good morning, everyone. My name is Steve Hawthorne and I am Director of Distribution Program Delivery at Hydro Ottawa.

D. COBAN: So that concludes our panelists, Mr. Miller. Over to you.

M. MILLAR: Great, thank you so much. Mr. Rubenstein, I'm going to pass it over to you. We are slightly behind schedule because of our technical issues. I will remind everyone we have some very full days, so I know it is a challenge but we need to all do our best to focus and get through this as efficiently as possible.

So, Mr. Rubenstein, it's 9:51 and I'm turning it over to you.

# Examination by M. Rubenstein

M. RUBENSTEIN: Thank you very much. I will be asking questions first and then my colleague Ms. Scott will also ask questions for the Panel. I was wondering if we could first pull up -- but let me just give the Panel a roadmap of what I'd like to talk about first, and then I have questions on a number of interrogatories that are very specific to those interrogatories. But at first there is a couple of interrogatories that really get to the capital planning process and I sort of want to have a discussion to clarify, at least for me, an understanding of how it works.

It may be best if we start at 2-SEC-42. And in part A we had asked you for the Copperleaf outputs of the prioritization process and in the response you provided that for 2025 and you say that you have not completed it for 2026; do I have that correct?

J. GILLIS: Good morning. It is Jenna Gillis. Yes, that's correct. It is not yet completed for 2026.

M. RUBENSTEIN: Now, if I go to SEC-41, if we go back into interrogatory, here you're talking -- in part A you're talking about the capital planning process, and you discuss in the first phase that you started with nearly $2 billion in capital projects for the given period, and then you had a second phase which involved reprioritization optimization process which established a new capital target of approximately 1.2 billion; do you see that?

J. GILLIS: Yes, I do.

M. RUBENSTEIN: So I just want to make sure I'm understanding the relationship between those two, the interrogatory SEC-42 and the statement here in SEC-41, because I read it that in SEC-42 that you haven't done that sort of process in the Copperleaf system for 2026, but it appears here, as I understand it, that you did some sort of reprioritization optimization process to get you from the 2 billion to the 1.2 billion over the five-year period. So can you help me reconcile it? What am I missing?

J. GILLIS: Yes, just give me one moment, I'm going to pull up the reference for you.

Okay. Thank you. So the referenced IRs are speaking about different processes. So the way that we undergo our staged is, first, we undergo a program optimization process and review, and the second is a program -- sorry, pardon me, a project level optimization. So the referenced IR SEC-41 is referring to the overall program and capital expenditure plan optimization process, whereas SEC-42 is referring to our annual project level optimization. So they are different processes. Within the first -- yeah, go ahead.

M. RUBENSTEIN: No, go ahead, I apologize.

J. GILLIS: No, so I was just going to add that level of clarity, that once we have the program level set on an annual basis, we then go through and provide an optimization.

M. RUBENSTEIN: So let me start with the program level process, which is what you're addressing, I believe, in SEC-41. As part of that process, is it a version? Have you determined for each program and each project value scores and so on, and are you running it through the Copperleaf optimization process that gets you from the 2 billion that 1.2 billion for either all the projects or a subset, or programs and projects?

J. GILLIS: So at that level we are not running all of the programs and projects through the Copperleaf prioritization process. I'd like to point you to Schedule 254, section 3, the planning process, it begins on page 4 of Schedule 254. Thank you. And its just starts in section 3 there.

So this section here talks us through the overall broad capital expenditure planning process and how it starts, first with the setting of the corporate priorities and objectives, integrated with the customer preferences, overall strategic planning.

So if you go down to figure 1, which is on page 6, this provides an illustrative of this global process, so if you take a look at the beginning, we start with the inputs that form together to come up with the referenced corporate memorandum that provides the overall guidance for setting of that first budget that you referenced, that $2 billion budget.

So using the inputs, Hydro Ottawa through its business strategies, you can see is that layer in purple, were given the direction to go and come up with all of the program-level spending required for the five-year period, and that was the reference, $2 billion, I believe from SEC-41. From there we went through a second layer of optimization, where we reset the baseline at the $1.2 billion threshold to come up with the overall capital expenditure plan. Once that capital -- yes, go ahead.

M. RUBENSTEIN: Yes, so my question is really getting at how you get from the 2 billion to the 1.2 billion.

J. GILLIS: Yes, for sure, I can --

M. RUBENSTEIN: I understand the inputs to the --

J. GILLIS: Okay. Perfect. Yeah, for sure. So essentially what happened is within these business strategies each of the groups individual for the strategies and the investments went back and did a reprioritization and an analysis based on reducing the overall capital expenditures, as well as the operating and maintenance costs, so it was within each of the business representatives and the experts on the specific assets of the categories that they were looking at to rerun their own individual processes to look at decreasing costs and coming up with alternatives, and those alternatives in some cases are represented within the material investment plans, which are Schedules 256 through 259.

M. RUBENSTEIN: So as I understand it, you did not use the Copperleaf optimization system to get you from a long list of $2 billion projects to a shorter list, still long list, but a shorter list, of $1.2 billion.

J. GILLIS: That is correct, because the Copperleaf optimization is used on the annual basis for the project prioritization for the annual output.

M. RUBENSTEIN: Okay. Thank you very much. That is helpful.

Can we go to 2 SEC -- back to 2 SEC-42, and maybe we can open up the attachment. It is an Excel spreadsheet.

L. CHARTRAND: Mr. Rubenstein, I don't have an attachment for SEC-42.

M. RUBENSTEIN: I do. I'll -- \_IR\_@\_2SEC42A.

L. CHARTRAND: My apologies. I have found it.

M. RUBENSTEIN: No problem. So as I understand what this file is, as we had asked for it, this is the optimization process used for the purposes of 2025; correct?

M. FLORES: This is Margaret Flores. Yes, that is correct.

M. RUBENSTEIN: And I just want to understand what exactly is it optimizing? So presumably, as I understand sort of how these systems work, is there a larger list of projects that then it is selecting from, or is it just optimizing within the list of projects, you know, ordering them, essentially, from the highest priority into the least, and it is just a prioritization process?

M. FLORES: So the Copperleaf optimization module is used to optimize projects under system renewal and system service. There is a larger set of projects, especially for pole renewal, as well as cable renewal and other distribution assets, and it optimizes the actual locations where we're going to be replacing poles, cables, or other distribution assets.

M. RUBENSTEIN: All right. But that's not shown here, right? All you're showing is the ones that I guess are -- were selected to be done this year?

M. FLORES: That's correct.

M. RUBENSTEIN: What was the constraint put on Copperleaf to get you to this list?

M. FLORES: So for different distribution programs we will use the OEB-approved budget and constrain this and that.

M. RUBENSTEIN: Can you please provide the full list that was used?

M. FLORES: Yes, we can do that.

M. RUBENSTEIN: In the same format?

M. MILLAR: So I will mark that as Undertaking JT1.1.

M. RUBENSTEIN: Now, if we scroll --

M. MILLAR: And Mr. Rubenstein, could you just repeat what the undertaking is?

M. RUBENSTEIN: Sure. I'm not sure exactly what the technical term here is, but it is the full list of potential projects that the 2025 Copperleaf optimization process used.

M. MILLAR: Right. Thank you, JT1.1.

UNDERTAKING JT1.1: TO PROVIDE THE FULL LIST OF POTENTIAL PROJECTS THAT THE 2025 COPPERLEAF OPTIMIZATION PROCESS USED.

M. RUBENSTEIN: If we can just scroll over, and just so as I understand what this -- sorry, back to the spreadsheet. And just so I make sure I am reading the table correctly, the whole value is the sum of columns G through -- and maybe we can scroll over. Further over, sorry. It is G through T, which as I understand would be all of the values or the benefits between G through S. And then the investment cost at T.

Do I have that correct?

M. FLORES: That's correct. It includes all the benefits, the risks that we are mitigating with the project, as well as the total cost for that project.

M. RUBENSTEIN: Now I know that you have filed the guides to the Copperleaf process, and they are confidential. And I am just going to ask you to do this by undertaking, both, so it is probably best to do it by undertaking, but also so we don't need to go in, in confidential.

I have reviewed the underlying documentation and it's very unclear to me how that total investment cost is calculated. So I was wondering if you could, using the information on this table, pick, you know, a simple and a more complex -- and if you can run through the math of how the total investment cost is calculated for the purposes of the Copperleaf process. Is that something you can do?

M. FLORES: I believe we have an example of that. Let me just go through the IRs. We have done one. Give me one second.

M. RUBENSTEIN: I know there is some simple -- like, this is -- you know what these mean, but when you get to the -- I don't want to say anything, but it is a little bit more complex as I understand from reading the confidential material. But…

M. FLORES: I will like to point you to 2-Staff-59 part (c), page 4. Actually, page 5, where we show the project value calculation.

Is this what you are referring to?

M. RUBENSTEIN: No. I apologize, it is all confidential in the reports. But all I will say is the cost is -- it is a lot more complicated, how it is calculated, how you get from the cost, what the inputs are to the cost, to the total investment score. And I was wondering if you can run a couple of mathematical examples, because it is very unclear from that, and how you have got to your -- the numbers here.

M. FLORES: Leanne, can you show page 7, please? Is this what you are referring to?

M. RUBENSTEIN: So, for example, using your example there of the St. Joseph Boulevard, the negative 2,330 value score for total investment cost?

M. FLORES: Mm-hmm?

M. RUBENSTEIN: Which is you have a version of that in the spreadsheet for all of those, it is not clear how that number is derived based on –

M. FLORES: Okay. That would be based on the estimated cost of the project.

M. RUBENSTEIN: Yes, but how? It's not just the numbers of the project, right?

M. FLORES: Yeah. It will be based on the total number of poles that will need to be replaced under that project.

M. RUBENSTEIN: Well...

M. FLORES: Are you looking for the actual estimate of that project?

M. RUBENSTEIN: Well, I would like you -- and maybe, just again, easiest to do this by undertaking: If you can pick a simple or a complex project from the list in 2-SEC-42, and how you get to the total investment score? Because even if you just look at the table in the following columns, where you have project costs, there is no -- sometimes it's easy, sometimes it's not. And it is a bit unclear how it is done.

So I would ask -- and if you take a look at the confidential parts, it reads that it is a much more complex process.

MR. FLORES: Okay.

MR. MILLAR: Okay. So we will mark that as JT1.2. And again, Mark, could you give us the pithy summary?

M. RUBENSTEIN: Sure. Using it to provide the math behind the total investment cost in 2-SEC-42(a) with reference to the methodology.

M. MILLAR: Okay. JT1.2.

D. COBAN: Sorry, I just want to clarify: JT1.2 is only relating to an example of a project, right? You are not looking for that across the board? I believe you noted several times you are looking to just see a demonstrative example.

M. RUBENSTEIN: If you could do a simple and a complex? And by simple and complex, I mean the inputs are simple and the inputs are complex.

L. HEUFF: Mr. Rubenstein?

M. RUBENSTEIN: Yes?

L. HEUFF: Can I please clarify, sorry? So the total investment cost in this case is quite literally just the budget that was estimated. It's a high-level, level-A budget that was estimated, and that is what is input. And the total dollar value in the exhibit is what is input as the total investment cost.

Are you looking for us to provide a Level-A, high-level -- what we call a Level-A story, like, so it is top-level estimate that hasn’t been highly refined yet by a projects manager?

Are you looking for us to provide those assumptions that get put in, just to -- I am just trying to further understand exactly what it is that the exhibit is for.

M. RUBENSTEIN: Well, maybe you can help explain, because when I look, it appears -- and because I don’t have the -- I am only just looking at the spreadsheet.

L. HEUFF: Yes.

M. RUBENSTEIN: It seems that you are taking the 2025 project cost, right? -- and then dividing it by, yeah -- it is dividing it by a thousand to get to the value score. Correct?

L. HEUFF: Correct, correct.

M. RUBENSTEIN: With some rounding, let’s call it some rounding differences, although -- but then, it is not entirely correct for all of them. Some of them are not.

So you can see, for example, I'm looking at -- there is a pole renewal at Dagmar, phase 1. It is a project cost for $950,000, and it is $910,000, so it is a bit more than rounding. It is also unclear to me, you have some post-2025 costs. Are those not included? Is it only the 2025 costs?

And the reason I pause is when you look at the documentation, it appears that this actually is supposed to be much more complex. And it is just not clear to me, that.

And since we are not -- this is not confidential, 1 can’t -- I don’t want to speak to it anymore.

L. HEUFF: I believe my colleague, Ms. Flores, can provide a bit more information so that we can ensure that we are answering your question correctly.

M. FLORES: Yes. There are some projects where it wouldn’t be -- it wouldn’t align. Like in the case of the St. Joseph Boulevard, phase 1 pole renewal, because there might be some projects that extend over a year period. And the total value of the project is measured over the total cost of the project.

So if there is a project that runs for two years, then the total cost for 2025 would not be shown in that table.

M. RUBENSTEIN: But is that a simple way? Are you saying it is simply the total cost of the project, divided by a thousand? That is the -- over however many years?

M. FLORES: Yes.

M. RUBENSTEIN: Okay. And is not in that present value calculation or anything? It is just a one-year project?

M. FLORES: A net present value is done based on the benefits and the mitigated risk. So your overall value would be a net present value.

M. RUBENSTEIN: Okay. Can I ask now -- maybe we can use that example, right there. So for this St. Joseph Boulevard phase I project that you are showing on the screen as an example that had -- as I am seeing, has a positive net benefit of about 9,000 value points. Correct?

M. FLORES: Correct.

M. RUBENSTEIN: And do I understand then because this is a project, it only gets the -- at the initial stage, when we were talking about moving from the $2 billion to the $1.2 billion, would this exist? Would you be utilizing any of this information to get to, to determine which of the projects would get you to the more narrow spending proposal?

M. FLORES: Yes. Individual pole renewal projects will go through this process, once the budget has been approved.

M. RUBENSTEIN: I understand, on an annual level. I am just trying to understand at the --

M. FLORES: At the program level for OEB submission –

M. RUBENSTEIN: Yes.

M. FLORES: -- it wouldn't go through this process. We are not using Copperleaf portfolio.

M. RUBENSTEIN: Put aside the Copperleaf optimization process. Would you look at this information? Even though it may not be a formal optimization, but would you see a list of all the projects and say, okay, well we have to get down to some budgets and these are the best ones to go?

M. FLORES: Not for the program level optimization.

M. RUBENSTEIN: Now as I understand, and this is referenced in a number of places in the evidence, that for programs they each have a MIP, material investment plan, and is that an annual process or is the MIP set out for the whole planned term?

M. FLORES: Material investment plans are set out for the whole term.

M. RUBENSTEIN: And is there a -- no, go ahead.

M. FLORES: I was going to say for program level definitions what we are using from Copperleaf, it is another module which is called predictive analytics and that help us determine programs under the system renewal investment category.

M. RUBENSTEIN: Okay. So, let's finish the MIP and I will not hear about that. Is there any material difference between what is included in a MIP and then what's included in the supporting information for each of the programs in Exhibit 2, Tab 6, Schedule 7?

M. FLORES: No, that the 257 is the material investment plans.

M. RUBENSTEIN: Okay. So that is the MIP?

M. FLORES: Mm-hmm.

M. RUBENSTEIN: So, going back to your point about predictive analytics, does it, as part of the predictive analytics process, does it -- as I understand, you are doing somewhat of a similar thing where you are taking a look at the risk reduction and risk against off a couple of a number of values. Are you then calculating similar things as what you are seeing --

M. FLORES: Yes, but at that --

M. RUBENSTEIN: -- in this figure on the screen?

M. FLORES: It is similar, but it is not at the asset level, not at the project level. And it is mostly -- it mostly has risks at the project level using the Copperleaf portfolio optimization. We have benefits and risks that in the Copperleaf analytics we have mainly risk values that are part of the value framework.

M. RUBENSTEIN: So, for example, let's use poles. That's an asset category as a class. Are you running -- when you mean -- can you help explain what exactly the output of that process is?

M. FLORES: Yes, I would like to point you to Schedule 251, figure -- give me one second. Sorry, let me go back to Staff 59, page 4. And here's where we show the value calculated at the asset level. So basically what we did is we run the aid to help us determine, and constrain, to help us determine the needs of the system in the persistent renewal programs and we determine a number of -- a number to replace all of the assets in poor and very poor condition. That number was high and impractical and it wouldn't allow for customer affordability. So, we looked at three different alternatives which I describe in Schedule 257. One to maintain the cost, and the second one for short risk mitigation and another one for long term risk mitigation.

We used the information from PA which predicts the degradation of assets over time, as well as helps us look at the changes in age demographics and the risks that we are mitigating with each of those options. At the end the assessment was done at the entire overhead asset classes level, so it helps us determine the number of poles, the number of switches that we wanted to replace. In the case of overhead assets the decision was to go with the long term option, the long-term mitigation option, which would allow us to improve the condition of the assets and also meat the education criteria set out in the material investment plan.

M. RUBENSTEIN: So, just to be clear, when you're talking about the asset level when you are doing this you are talking about the individual asset level? You know, a pole on this street is this age and this condition, et cetera?

M. FLORES: That's correct. Mm-hmm.

M. RUBENSTEIN: Okay. And when you're sort of taking that up to the high-level and making a determination between the cost contained in short-term and long-term risk mitigation the definitions, was there a specific definition, like we need a reduction in risk and how X equals cost containment, a reduction in risk, your comparative risk of Y is short-term risk mitigation; or is that just, you know, there was judgment that you used to determine the categorizations?

M. FLORES: No, there wasn't.

M. RUBENSTEIN: Sorry, there wasn't judgment or there wasn't a specific --

M. FLORES: There wasn't a specific constraint that we applied. We looked at each individual asset type and there are the overhead class and determine the right level of investment including the requirements to meet the modernization targets and the resiliency initiatives. And it an effort to maintain reliability and improve the resiliency of the system for major weather events.

M. RUBENSTEIN: And at the high-level when you are making a determination, I understand, you know, we see this in the various programs you will see the number of assets you are doing and the cost and a description of the difference between each of the three categories, but is there a numerical answer that you looked at that shows anything that when you were comparing the different outcomes besides cost, you know, total value, value per dollar spent; what was the output that you were looking at when you were making a determination?

M. FLORES: We were looking to meet the evolution criteria set out in the material investment plan. So there were different things that needed to be considered. Our value strategy or our asset management strategy, it's based on risk mitigation, project optimization as well as maintaining the performance of the assets.

M. RUBENSTEIN: I understand.

M. FLORES: So all of those had to be considered.

M. RUBENSTEIN: I understand, but was there some quantitative outputs? Besides cost, obviously. What were the quantitative and number of assets replaced, but in terms of the risk, what were you looking at to make a determination about the relative risk of each of those proposals? What is the output that you would be looking at out of the process?

L. HEUFF: Hi, Mr. Rubenstein, it is Laurie Heuff. Say just in general there was not a specific qualitative value that was applied at any point in time on any individual asset. It would have been an engineering judgment, it is individual subject matter experts who are reviewing the data and making judgements as to what level of risk is acceptable within each one. They were reviewing various aspects such as the total useful life and the asset condition. They weren't just looking for what would happen even necessarily up to 2030, but they were looking even beyond and trying to ensure we were able to balance the replacement rates. They were looking at different aspects such as availability of contractors or the number of volume of assets that would need replaced, so there was a number of factors that were considered but I wouldn't say that there was any specific calculation that was applied or a metric that was applied. It was much more done based on engineering judgment, along with total cost, obviously, which was one of the main driving factors.

M. RUBENSTEIN: And so, even though as I understand, you, for each asset, you do calculate a net value? And this is the intervention value, I guess, you are showing on the screen which has at an asset level. You didn't roll that up to look at the cost containment, short-term risk mitigation, long-term risk at mitigation, what were the differences in the value that we were getting at Hydro Ottawa from each of those?

M. FLORES: Yes, so Copperleaf would have given us an output based on the different alternatives that we were evaluated. I don't have the number. I don't think we have an IR with those numbers, but we do have it if you look at each of the specific asset types.

M. RUBENSTEIN: Well, can I ask that you -- it's less about asset type. It's more about by program type, right, because you show in each of the programs or each of the reliability system renewal programs, being stationed over and underground, you're showing the various alternatives and which of the three you've taken, I think an overhead, it's long-term and the other two is short-term.

Are you able to provide for each of those the...

M. FLORES: Yeah, we would have it at each specific asset type, and we could roll it up to the asset class that would align with the material investment plan. Now, keep in mind that we have mentioned that our asset risk framework is still evolving, so we are monitoring the output annually as additional information is added, and it will become more accurate.

M. RUBENSTEIN: Okay. Well, can I ask you to provide that at the asset level, and then also you could do the roll-up?

M. FLORES: Yes.

M. RUBENSTEIN: And that's for each of the various three program alternatives for each of the three programs that this is applied.

M. MILLAR: Okay. I have that is JT1.3. I still have 1.2 marked, Mr. Rubenstein.

M. RUBENSTEIN: Oh, then either 1.2...

M. MILLAR: Sorry, say again?

M. RUBENSTEIN: I don't think we need 1.2.

M. MILLAR: Okay. So should we call this one 1.2?

M. RUBENSTEIN: Sure.

MR. MILLAR: Okay. And could you repeat what the undertaking is?

M. RUBENSTEIN: I will try. It is the -- I think it's called under Staff 59 the intervention value or the net value, is how I'm reading it, at 254, page 73, at the asset level and also then at the program level for each of the three alternatives, being cost containment, short-term risk mitigation, and long-term risk mitigation, and if it is possible in each of those of you are able to break it down by those various value scores at the aggregate level, obviously, for each of the asset categories, so we can see what the change in reliability risk is, financial risk, safety risk, environmental risk, and the replacement costs.

M. MILLAR: Okay, that's JT1.2.

UNDERTAKING JT1.2: UNDER STAFF 59 THE INTERVENTION VALUE OR THE NET VALUE, AT 254, PAGE 73, AT THE ASSET LEVEL AND ALSO THEN AT THE PROGRAM LEVEL FOR EACH OF THE THREE ALTERNATIVES, BEING COST CONTAINMENT, SHORT-TERM RISK MITIGATION, AND LONG-TERM RISK MITIGATION, AND IF IT IS POSSIBLE IN EACH OF THOSE TO BREAK IT DOWN BY THOSE VARIOUS VALUE SCORES AT THE AGGREGATE LEVEL FOR EACH OF THE ASSET CATEGORIES, SO WE CAN SEE WHAT THE CHANGE IN RELIABILITY RISK IS, FINANCIAL RISK, SAFETY RISK, ENVIRONMENTAL RISK, AND THE REPLACEMENT COSTS.

M. RUBENSTEIN: Thank you very much. Can I ask now we go to 2 SEC 39. And this is -- there is an attachment in part A where you provide the asset health index guidelines.

And as I understand for most of the assets, one of the conditions is asset age, and then for each asset it may be weighted differently. Do I have that correct?

M. FLORES: Yes, that's correct.

M. RUBENSTEIN: Are you able to provide a revised asset condition assessment results by asset type that removes service age as a condition?

M. FLORES: I don't think that is possible. Our asset condition assessment framework includes each, and it has been reviewed by a third party and confirmed that we have a robust asset condition assessment framework, so at this time I wouldn't say that's possible.

M. RUBENSTEIN: Well, sorry, there's a difference of you don't like it versus is it not -- this is just a technical question. Is it something you can do?

M. FLORES: Let me confirm, please. I will have to take that away, but I will have to review it with the technical authority to confirm whether that's possible or not.

M. RUBENSTEIN: I'm going to ask you to do that and, if you can do it, please do it.

M. MILLAR: So I'm hearing that's an undertaking. JT1.3.

UNDERTAKING JT1.3: TO PROVIDE A REVISED ASSET CONDITION ASSESSMENT RESULTS BY ASSET TYPE THAT REMOVES SERVICE AGE AS A CONDITION.

M. RUBENSTEIN: Yes, thank you. Can we go to -- sorry, one second here. If we go back to the interrogatory itself, and in Part B we had asked if Hatch had done any other work for the company over a period of time, and you provide in Part B a list, a lengthy list, of information that they've done for you. One of the things I understand that they've did, if you see this on the next page -- and maybe this is what was discussed earlier -- they did a review of the Copperleaf predictive analytics framework. Do you see that?

M. FLORES: Yes, they help us through the implementation of PA.

M. RUBENSTEIN: So let me just back up just so I understand what they did. They simply helped you through it. Did they provide an assessment, areas that you should improve, or areas that -- there be a works? Was there any sort of report that they issued at the end, or...

M. FLORES: They reviewed the inputs to the value framework. I believe we have submitted the report. I will have to confirm, but we did get a report confirming that our value framework was robust.

M. RUBENSTEIN: I don't think -- I may have missed it if it is on the record, so can I ask you to provide it or at least point me to where it is if I missed it, because there is a lot of documentation. I know there is a Hatch review of the asset curves, but not this one.

M. FLORES: I will need to take a look and get back to you on that one.

M. MILLAR: How would you like to proceed with this? Shall we mark it, or...

D. COBAN: Why don't we just take it away at the break and see if we can provide you that reference without taking another undertaking, and if we need more time we can do an undertaking.

M. MILLAR: Okay. Sounds good.

M. RUBENSTEIN: One other thing on that is that it talked about grid modernization, key performance indicator development. Do you see that?

M. FLORES: Yes.

M. RUBENSTEIN: And as well, I saw a reference to that in the grid -- or in the grid modernization strategy which you filed as response to 2 Staff 57. It talks about the references, developing KPIs. Can you just speak to what exactly are you doing with respect to the KPIs? Have they been developed?

J. GILLIS: Yes, so with working through Hatch we developed a number of different categories that we would want to monitor through the grid modernization roadmap and achieving of objectives. Right now we have a set of preliminary KPIs, and we are still working through the process to make sure that we have all of the data inputs to validate those assumptions and ensure that they are going to provide value going forward.

M. RUBENSTEIN: And can you provide those initial KPIs?

J. GILLIS: For the ones that we have ready, since some of them are still under development, I can provide you the intended KPI, but not necessarily the results for all of them. Are you just looking for the list of KPIs?

M. RUBENSTEIN: Yes, and maybe how you are calculating them. I understand the results are maybe to come.

J. GILLIS: Yes, I can take away to take a look at what we have available to be provided with respect to the grid modernization KPIs.

M. RUBENSTEIN: Thank you.

M. MILLAR: Is that an undertaking?

M. RUBENSTEIN: I believe so.

M. MILLAR: We'll mark that as JT1.4.

UNDERTAKING JT1.4: TO PROVIDE WHAT IS AVAILABLE WITH RESPECT TO THE GRID MODERNIZATION KPIS.

M. RUBENSTEIN: And with respected to Hatch, its involvement, were they just assisting you, or did the provide you with a report that looks at, you know, maybe, you know, suggestions, the jurisdictional scan? What was their involvement?

J. GILLIS: Their involvement was supporting us through basically looking at our grid modernization roadmap and supporting us through understanding kind of some industry benchmark KPIs that would be available and looking at our availability of data to help us suggest a set of KPIs that could be used, so they provided us with an initial set of reference KPIs for contemplation within the grid modernization steering committee and roadmap.

M. RUBENSTEIN: Can you provide that?

J. GILLIS: Yes. That would be the same thing that I am looking to provide you under JT1.4.

M. RUBENSTEIN: Okay. I think it -- at least I heard it to be slightly different. It is one is Hatch provided you with some initial work and some -- I guess some benchmarking or -- I don't mean benchmarking; I guess best practices. I forget exactly the language you just used. And then I thought you are providing me what your preliminary KPIs that you are going forward with. Maybe I misheard you.

J. GILLIS: Yes.

M. RUBENSTEIN: So that sounds like two different things. We can do it, the same undertaking, but it seems to me those are not exactly the same.

J. GILLIS: Sorry, I am just going to clarify: I think the witness has been clear that this work is in development, Mr. Rubenstein. So I think we are having a bit of a hard time -- I am, anyway -- differentiating between your two different requests, given that it is all sort of work that is under review at the moment.

M. RUBENSTEIN: Okay. Well, I am going to ask for what Hatch provided you. And then, if you've moved forward with anything, you can explain which -- if you are doing anything or you plan to do anything differently than what they have provided with you, as a preliminary list? Maybe that is the easiest way to go forward.

D. COBAN: Does that sound reasonable?

J. GILLIS: Yes, that is reasonable.

M. RUBENSTEIN: Thank you.

M. MILLAR: Okay. So we will mark that then as JT1.5.

L. HEUFF: I think that's 1.4, Mr. Millar.

M. MILLAR: Is that still part of 1.4?

L. HEUFF: It is a clarification on 1.4, yes.

M. MILLAR: Okay. Thank you.

M. RUBENSTEIN: Can we go to 2-SEC-43? As part of this interrogatory, we had asked you to provide a copy of the latest version of all significant capital program and project execution report documents that are regularly produced monthly, annually, et cetera?

And I see from the last paragraph of your response, you refused to provide that information on the basis:

“Without the context of the presentation and detailed discussions that occurred at the meetings between stakeholders, these materials are not probative to deciding the issues in this proceeding.”

Do I have that correct?

S. HAWTHORNE: This is Steve Hawthorne. Yes, that is correct.

M. RUBENSTEIN: Maybe we could just back up for a second: As I understand from the response, you do have a monthly and quarterly capital portfolio status update that goes to the executive management, and a quarterly version that goes to the Board? Do I have that correct?

S. HAWTHORNE: That is quite close. Let me take a minute, and I can walk you through the various steps, if I may?

M. RUBENSTEIN: Sure.

S. HAWTHORNE: So, on a monthly basis, the individual project managers receive actual expenditures on individual projects. The financial forecast and projects statuses are then updated and reviewed with their supervisor. That is then submitted into a monthly program review, generally aggregated into the various type of projects that we have.

The program review is a meeting between various stakeholders at the supervisory and manager level. That output is then fed into an aggregated portfolio review which consists of members between the manager and director team.

In those meetings, we review overall health, status, change request, resourcing -- the types of figures we need, requisite to review the overall status of the portfolio.

That is then further submitted to our monthly business alignment meetings between the director and manager team.

M. RUBENSTEIN: What is in the monthly business alignment, I guess -- I don’t know what it is, a memo, presentation, some sort of document that is provided? What is it showing?

S. HAWTHORNE: So the output to the monthly business alignment meeting is an overall status of the capital expenditures and additions projections relative to the Hydro Ottawa board-approved values. And then at the portfolio meeting, we are reviewing the projected capital expenditures and additions relative to the OEB-approved values, as well as the Board-approved values.

M. RUBENSTEIN: And does this, monthly, show the execution of capital projects in terms of, I assume, just costs and schedule?

S. HAWTHORNE: They review the status in terms of general cost, updates that are relevant to the various tiered level of a reporting that are pertinent to that particular team: trade staff, availability, both internal and external, as well as general risks at the program or portfolio level that we deem relevant and may disrupt the ability to perform that program or the ultimate portfolio.

M. RUBENSTEIN: Sorry. In your view, that information is not really relevant?

S. HAWTHORNE: Pardon me?

M. RUBENSTEIN: And so going back to the interrogatory response, maybe I am just confused. I am not sure how that -- why is that not relevant?

D. COBAN: I am just going to step in, because we are dealing with a matter of relevance. I think what you have here on the record, Mr. Rubenstein, is our refusal, which is predicated on the fact that in order for you to be able to review these materials in a meaningful manner, you have to have the context of the discussions that happen at these meetings.

Mr. Hawthorne is here and able to speak to you about this process. But I think the materials, without that discussion, is why we believe this is irrelevant and why you have the refusal here.

M. RUBENSTEIN: And am I correct -- maybe you can tell me, here. Insofar as projects are over budget during the term plan, you are seeking to put that in the rate base this year, correct? The full cost of all the projects up to 2025 that was spent?

S. HAWTHORNE: Yes. That's correct.

M. RUBENSTEIN: And in my understanding, it is above what was approved in the last proceeding. Do I have that correct?

S. HAWTHORNE: Yes, that is correct.

M. RUBENSTEIN: And so understanding and actually seeing the monitoring or what the company does to manage its projects through this reporting process, I understand, Ms. Coban, you are saying that that -- because we are not in the meetings, I guess, we shouldn't see what -- this sort of a documentation?

D. COBAN: Correct. I think it would be difficult for you to glean the process from just, you know, a presentation where you don't have the context of the discussions that happen among the subject matter experts.

M. RUBENSTEIN: Okay. Well, I am still going to ask you to provide the information. Again, I do think it is relevant. And if you had provided it today, we could have maybe have that context.

D. COBAN: We are going to maintain our refusal. We will consider it again at the break, Mr. Rubenstein. But, for now, we will maintain the refusal.

M. RUBENSTEIN: Okay. Just going back to the process, Mr. Hawthorne, you are comparing the budgets at -- sort of at the aggregate level. Is it against an annual budget, or is it against the board-approved budget?

What is being compared against, here?

S. HAWTHORNE: We compare it against both.

M. RUBENSTEIN: So I take it then, because you are saying that, that the annual budget is then different than the board-approved budget?

S. HAWTHORNE: There are circumstances where they may differ and circumstances where they would be the same. Yes.

M. RUBENSTEIN: So, for example, let's take the last five-year plan, the 2020 to 2025 plan. There's obviously Board-approved budgets. Were there annual -- in each year, either at the highest aggregate level to the -- let's call it the program level that you are seeing in all the appendix 2As and through the evidence. Was there a difference between the Board-approved and the annual budget?

S. HAWTHORNE: Yes, generally speaking.

M. RUBENSTEIN: Can you provide the annual budget for each of those years, like the Hydro Ottawa annual budget for each of those programs for each of those years?

S. HAWTHORNE: Yes, we can undertake to provide that.

M. RUBENSTEIN: Thank you, very much.

M. MILLAR: That is JT1.5.

UNDERTAKING JT1.5: TO PROVIDE THE ANNUAL BUDGET FOR EACH OF THOSE YEARS, 2020 TO 2025, FOR EACH OF THOSE PROGRAMS

M. RUBENSTEIN: Can we go 2-SEC-44? And we asked you to provide some information with respect to asset-condition demographics in a single table. And maybe we can go to appendix B? And it is an Excel spreadsheet.

And as I understand what this is showing, as requested, is it showing your forecast asset condition based on the proposed plan, correct, for each of the three major system renewal programs? Do I have that right?

M. FLORES: That's correct, that's correct.

M. RUBENSTEIN: And so we see, for example, for the overhead system, you are showing it again. That's the proposed long-term risk-mitigation strategy. Correct?

M. FLORES: Correct.

M. RUBENSTEIN: Are you able to provide a revised version of this table showing what they would look like against the various -- the other two alternatives, for each of them?

M. FLORES: Yes, we can do that. We show it in graphical -- in graphs in 257, but we could do the same for this.

M. MILLAR: That is JT1.6.

UNDERTAKING JT1.6: TO PROVIDE AN UPDATED VERSION OF THE TABLE AT 2-SEC-44, APPENDIX B, SHOWING THE OTHER TWO ALTERNATIVES

M. RUBENSTEIN: Okay. Thank you, and now I just want to make clear, as I am looking at when the question asks you with respect to the proposed program I just want to be clear what is included in that and what is not included in that for the purposes. Does that take into account all of the work that's being done in all programs or just those that are -- so for example, the plan work you're proposing to do, for example, in the overhead program.

So let me just let me give you an example. When you are showing the change of poles, is that just based on the work that is being done in the overhead program or does that also take into account reactive work, you know, replacing poles that you may have to do in some other programs?

M. FLORES: It will take into account all the work that we do under system renewal.

M. RUBENSTEIN: So, system renewal only?

M. FLORES: That will include corrective renewal.

M. RUBENSTEIN: Okay, thank you very much. But it wouldn't take into account any work that you may have to do in a system access or system service program?

M. FLORES: That's correct.

M. RUBENSTEIN: Okay, thank you very much. Now, can we go to the evidence, can we go to 25, Schedule 4, page 220? And if we just look at that figure 71, I want to make sure I understand the figure. Am I correct that what it's showing is for 18 of Hydro Ottawa's planning regions it shows -- do I have that right; that is what each of those, at the bottom, that is what you were looking at here?

J. GILLIS: Yes, that's correct. That is our planning regions.

M. RUBENSTEIN: And it is showing the existing -- and so, what I am seeing here is the capacity you expect to need for the peak load in 2030 and then in 2035?

J. GILLIS: Yes, that's based on our planning forecast.

M. RUBENSTEIN: And LTR is today; what is that?

J. GILLIS: LTR is the limited time reading of the station, which is the planning capacity summed for the region.

M. RUBENSTEIN: Now or when you did this analysis?

J. GILLIS: Just let me confirm with you what has been included in there, if that is including the plant or not. Just give me one moment to look at the evidence. So that's the current available capacity but also including Piperville and Hydro Road additions, new stations.

M. RUBENSTEIN: And, as we mentioned, the 2030 and 2035 sum, that's the planning forecast though not the IRP forecast load; correct?

J. GILLIS: I am just rereading the evidence to make sure I don't misstate. Yes, that's correct.

M. RUBENSTEIN: Okay. I'm going to ask you to undertake to do the following: First, can you provide this in tabular format in the figure. And second, I would like you to add two additional things for each of the planning regions. One is essentially the sum of, I guess, 2025 or 2024 what the latest you have with respect. And the other thing is what will be the, I guess, the LTR capacity if the OEB, at the end of the -- by 2030 if the plan as you proposed is approved?

L. HEUFF: So, I would say could you please confirm the first part of what you are asking? I was confused by that request. The very first piece you were saying if by 2030 what we will have; can you confirm what you mean by that?

M. RUBENSTEIN: Sure. Well, sorry, there's two parts. I'm asking for two additional pieces of information so the first is: You are showing essentially what the planning work, the planning forecast load, is in 2030 and then in 2035 and I'm interested, first, in either 2025 or 2024, whatever the last piece of information you have is. And then the second part is to understand what the actual capacity will be by, say, 2030 if the plan is approved with all the proposals that you have in the application.

L. HEUFF: So, I believe the 2030 piece is what is in the orange bar, which you are already requesting, that is what the capacity will be in 2030 as a result of the investments. But the 2024, what you are asking for is the part A would be -- what you are looking to understand is what the bars would look like for current state of installed capacity? Which would be, I believe, the LTR so I'm not sure I'm completely understanding --

M. RUBENSTEIN: Maybe I misunderstood that. That is probably that I misunderstood. This is not showing what the actual planning forecast of the peak demand is in these planning regions in 2030 and 2035; it's the actual capacity?

L. HEUFF: I will have Ms. Gillis confirm, but I believe that's correct.

J. GILLIS: If you just scroll up above figure 71 quickly, you can see that figure 71 compares the megawatt forecast for 2023 and 2035 with current available capacity, including Piperville and Hydro Road station for the 18 planning regions considered.

M. RUBENSTEIN: Yes, that's what I thought you said. So it's not the sum of 2030 and sum of 2035 is showing the planning load, not the forecast capacity available?

J. GILLIS: That is correct.

M. RUBENSTEIN: So then back to my request.

J. GILLIS: Yes. So, when you asked for the sum of '24 or the latest values we have are you looking for weather corrected actuals or are you looking for what was provided in our forecast?

M. RUBENSTEIN: I guess it is whatever the same type of -- however you're doing the 2030 and 2035, which I assume is weather corrected. I don't know.

J. GILLIS: Yes. So, sorry, what I'm looking to clarify from you is: Are you looking for actual load or are you looking for forecast?

M. RUBENSTEIN: I guess actual would be the best. I'm just trying to find out where we are. Look, unless you may be the better person to tell me what is the best way to do it. I'm trying to understand where we are today; right? You're showing 2030 and 2035 and I'm trying to find out where we are today in 2025. So if that's based on the planning load for 2025, sure.

J. GILLIS: Okay. That information is provided on each of the regional levels in a different graphical format within the application. You are looking for it consolidated on a single figure, like that in 71?

M. RUBENSTEIN: Yes.

J. GILLIS: Sorry, I'm just going to take a moment to confer to make sure that we have this all. Just give me a moment. Okay, thank you.

I just want to make sure that we are capturing accurately what you are looking for. So, you're looking for the latest available actual load in the by-planning region and then you're also looking to compare that to the planned capacity included by 2030 based on the planned investments we are undertaking?

M. RUBENSTEIN: Yes.

J. GILLIS: And then you're also looking for the forecasted load growth in 2030 and 2035?

M. RUBENSTEIN: Well, I thought that was already on the table?

J. GILLIS: Correct. I just want to make sure that that's what you would like to see consolidated on a single figure.

M. RUBENSTEIN: Yes.

J. GILLIS: So in that instance there is four values you would like to see by planning region?

M. RUBENSTEIN: I think there would be five values, I'm adding 2.

J. GILLIS: Okay.

M. RUBENSTEIN: And in tabular form.

J. GILLIS: And in tabular form.

M. RUBENSTEIN: Yes.

J. GILLIS: Okay. So I'm going to just repeat back what you said. So we are looking to have in tabular format and in graphical format by planning region the 2030 and 2035 forecast, the latest actuals, as well as the planned capacity at the end of 2030, as well as the current capacity within the system as demonstrated in figure 71?

M. RUBENSTEIN: Yes.

J. GILLIS: Okay.

M. RUBENSTEIN: Okay. Can I ask you to go to 2 Staff 72. And if we can go down to the second page. This is Part A. You provided a table or figure for staff. Do you see that?

J. GILLIS: Yes.

M. RUBENSTEIN: And the Y axis is megawatts, but in the -- where it is explaining what each of the colours are, the legend, actuals, and weather-corrected are in MVA?

J. GILLIS: Yes, I see that on the graph.

M. RUBENSTEIN: Are you assuming a one-to-one power conversion ratio, or you have -- what have you used here?

J. GILLIS: I would have to clarify for you. I'm not sure if that's just a typo or if it was a numerical error.

M. RUBENSTEIN: Can I ask you to do that, and then can I also ask you to provide this table in a tabular format?

J. GILLIS: Yes, I can take a look to see what we have available.

M. MILLAR: We will mark that -- Mr. Rubenstein, I'm worried I missed an undertaking related to figure 71. These are separate undertakings; is that correct?

M. RUBENSTEIN: Yes.

M. MILLAR: Okay. So the first one related to figure 71, I believe, is JT1.7.

UNDERTAKING JT1.7: TO HAVE IN TABULAR FORMAT AND IN GRAPHICAL FORMAT BY PLANNING REGION THE 2030 AND 2035 FORECAST, THE LATEST ACTUALS, AS WELL AS THE PLANNED CAPACITY AT THE END OF 2030, AS WELL AS THE CURRENT CAPACITY WITHIN THE SYSTEM AS DEMONSTRATED IN FIGURE 71

M. MILLAR: And this one is 1.8. Could you repeat what the undertaking is for?

M. RUBENSTEIN: This is for -- this one? It's two parts. One is to provide the figure A from 2-Staff-72 in the tabular format, and then the second is to clarify or to understand, are the actuals and weather-corrected information actually provided in MVA instead of megawatts, and if not, is there a power conversion that was used?

M. MILLAR: Okay, thank you. That one is JT1.8.

UNDERTAKING JT1.8: TO PROVIDE THE FIGURE A FROM 2 STAFF 72 IN THE TABULAR FORMAT, AND TO CLARIFY WHETHER THE ACTUALS AND WEATHER-CORRECTED INFORMATION ACTUALLY PROVIDED IN MVA INSTEAD OF MEGAWATTS; AND IF NOT, IS THERE A POWER CONVERSION THAT WAS USED.

M. MILLAR: And Mr. Rubenstein, we are looking to take our morning break around 11:00, so I would just ask you to find a break in your question --

M. RUBENSTEIN: This is as good a time as any.

M. MILLAR: Okay. Why don't we take our morning break, and we will return -- probably about 15 minutes. Yes, so that will bring us back, let's say, at -- yeah, 11:11. We will do it by the minute. Thank you, everyone.

### --- Recess taken at 10:57 a.m.

### --- On resuming at 11:13 a.m.

M. MILLAR: So back to you, Mr. Rubenstein.

M. RUBENSTEIN: Well, let me go back to Ms. Coban and the witness panel. But I understand during the break they were going to find me a reference or provide an undertaking to provide the predictive analytics review?

D. COBAN: We are still looking for that reference, Mr. Rubenstein, so will get back to you after the lunch break.

M. RUBENSTEIN: Okay. Now, I am not available after the lunch break. So I would much appreciate if we can do this by way of undertaking.

D. COBAN: It sounds good. If we have a reference, then we will put that under the undertaking response; if not, then we will consider your request.

M. MILLAR: So that is JT1.9. And, Mr. Rubenstein, I have forgotten what that was about, because it was a while ago.

M. RUBENSTEIN: Yes.

M. MILLAR: So if you could repeat it?

M. RUBENSTEIN: Same with me, but my recollection was I had asked for the evidence, the Hatch had undertaken an analysis or review of the predictive analytics inputs process, some review of something to do with that. And I had asked for a copy of the report or review.

M. MILLAR: Okay, JT1.9.

UNDERTAKING JT1.9: TO PROVIDE EVIDENCE THAT HATCH HAD UNDERTAKEN AN ANALYSIS OR REVIEW OF THE PREDICTIVE ANALYTICS INPUTS PROCESS

M. RUBENSTEIN: Thanks. Again, I just want to clarify something on JT1.5. This was the annual budgets which would have been -- I just want to be, just to make sure you understand what I am thinking you are going to provide, just to make sure we are on the same page here: It is essentially the annual budgets for each of the five -- the Hydro Ottawa annual budgets for each of the five years on each of the programs.

So it would essentially look like an appendix 2AA, but instead of the actuals, it would be the annual budgets.

S. HAWTHORNE: Yes, that's my understanding.

M. RUBENSTEIN: Sure. Can I ask now that we can go to 2-SEC-50? And in this interrogatory, we had asked you to -- where cost of replacements are determined by a unit cost calculation, to provide the unit cost details and how they are derived? And for each of them, when you are talking about the determination, they all essentially read exactly the same. As I understand what you had done is you have taken an historic analysis of historical spending, and then you say:

"To account for unforeseen challenges and cost escalations, a risk factor has been included in all programs. Additionally, an average annual increase has been incorporated to address the rising future costs of equipment and materials."

Do you see that?

S. HAWTHORNE: Yes, I see that.

M. RUBENSTEIN: Can you help me, explain how much is this risk factor?

S. HAWTHORNE: Yes, I can provide some context around that. So the risk factor is really meant to identify site specific or anomalies within each individual asset type.

So if we take station switchgear, for example, we apply a general unit rate to the number of switchgear or cells that are going to be replaced based on the sites that have been selected.

Now, once we review the individual sites that are selected, at a preliminary stage we go through and review the specific details of that site.

So, for example, to replace the switchgear, one may need to remove a wall or install a door and, at another site, one may not need to do that type of scope.

And the particular risk factor is really around identifying site-specific details such that the cost per project can be aggregated to a cumulative unit rate.

M. RUBENSTEIN: Okay. I will say that back to you, or at least how I understood, and you can tell me. So am I clear then? So, for example, let's say the $620,000 station switchgear renewal project, right, at the first one there?

Assuming you are doing more than one of Those, and you are doing a number of them, do I take you start with the historical spending, and so that may be some amount less than obviously the $620,000? Correct? That is stage one?

S. HAWTHORNE: Yeah. We look at historical spending and then, depending on program, it may or may not be less than what is stated on the page.

M. RUBENSTEIN: Okay. And so if you take that number, and then you look at the types of projects you are planning to do and then make a determination against that historic average, if there are -- as you used as your example, they are more complex, less complex, what the makeup is. And then you add some additional amount to that, to get to a higher unit cost?

S. HAWTHORNE: No. Using the example of station switchgear, we go through and identify, site by site, the per unit cost. And the number that is listed on the page is the average unit cost for station switchgear, for example.

So individual sites may be more or less, depending on constructability challenges.

M. RUBENSTEIN: When you apply the unit -- for the purposes of this application, where you have proposals with respect to obviously spending, are you applying a uniform unit cost for the -- for when -- to those programs? Or do you start with some unit costs and then what you are saying is then you will make adjustments to it, with respect to the complexity?

So, for example, using the switchgear, is every station switchgear -- I mean, at least the switchgear -- it is $620,000 per unit, plus I guess there is some annual inflationary amount. But -- or is it done differently?

S. HAWTHORNE: So staying with switchgear, individual projects again will have specific unit rates associated with them, the end of the process I described. And then the number of $620,000 per unit is the average after that exercise that I described is completed.

M. RUBENSTEIN: Okay. So you are going backwards in some sense to get me this number, right? You are going back and determining what is all the switchgear costs and dividing it by the number of switchgears? It is not the other way around, where you have a per switchgear cost that you are then uniformly applying to all the projects?

S. HAWTHORNE: That's correct. And again, noting that the starting point is using those historicals and dividing by the number of cells or units per site, we then work up to a new number.

M. RUBENSTEIN: Okay, thank you. Can we, in the next page, you have “pole renewal.” Do you see that?

S. HAWTHORNE: Yes, I see pole renewal.

M. RUBENSTEIN: And you have $27,500 for pole, and then $60,000 for undergrounding, you said?

S. HAWTHORNE: Yes. That's correct.

M. RUBENSTEIN: Can you help me: What is the undergrounding with respect to a pole renewal project?

S. HAWTHORNE: Yeah. So –

M. RUBENSTEIN: Those are overhead?

S. HAWTHORNE: Within the pole renewal program, we have included a specific 50 poles to be undergrounded as part of that overall program. And that $60,000 per pole represents the cost to transfer those assets underground. So effectively remove the poles and install underground, based on 50-metre span lengths.

M. RUBENSTEIN: Okay. Thank you. That makes much more sense.

Can I ask you now to go to 2-CCC-26? And here, you were asked to provide certain unit cost information specific. And if we can go table A, on the next page?

Do you see you are providing -- and it is about halfway down the page -- you are showing a cable renewal, you are showing $735,000. The historical amounts are $735,000 for a kilometre of cable replacement unit costs.

Do you see that?

S. HAWTHORNE: Yes, I see that.

M. RUBENSTEIN: Can I ask you now, just keep that number in mind? I just want to compare it. Can you go to 9-SEC-90? No, sorry, not that one; it is the wrong reference. Sorry, 9-SEC-89.

And in this interrogatory, just to give you the background, we had asked you to provide with respect to the performance outcome accountability mechanism that was in place for the last term, the metrics and the outcome.

If we go to the second page, one of them is “underground cable replacement cost, dollars per kilometre.” And those numbers -- sorry, metric 5, I apologize -- just scroll down a bit.

And those numbers are obviously markedly different. So can you reconcile what I assume were -- they are not the same, for the comparison, obviously.

But what's the difference?

L. HEUFF: Mr. Rubinstein, if you will recall the last time when we did this, this is only a subset of the cost. I can’t remember which specific US of A is taking into account.

My colleague, Mr. Hawthorne, might be able to more directly provide you the US of A, but it is not the total project cost; it is specifically looking at just the cable conduit cost itself, I believe, whenever we refer to these numbers. Whereas the other number you were referencing was actually the total project cost divided by the kilometre length, whereas this is just a specific component.

M. RUBENSTEIN: Okay. And the component is just a physical cable? Is that...

L. HEUFF: I believe so, I would have to confirm.

M. RUBENSTEIN: Your memory may be better than mine, Ms. Heuff.

L. HEUFF: I'm sorry?

M. RUBENSTEIN: Your memory may be better than mine.

L. HEUFF: It is just the cable, I just can't remember specifically which component number it is under the US of A, which is what we could confirm if you are looking to understand.

M. RUBENSTEIN: Okay. No, I'm just trying to understand what the difference was. Thank you very much.

Can we go down to 2-SEC-45A? And this was with respect to the 1898 & Co resilience report. I think you had it up on the screen. If we could just go back to the IR. Thank you. And we had asked you in this response, in Part B sorry, with respect to the 26 economic projects for certain pieces of information and if we scroll down to the next page, you provided some of that information, but what is not included in this is which projects Hydro Ottawa is planning to do?

M. FLORES: That's because the selection of these specific projects will go through the annual project selection process. So we're going to look at this projects and then score it against our value framework and that's how the final project selection will be done.

M. RUBENSTEIN: And so, you haven't made a determination if you will do any of these projects; right?

M. FLORES: No, we will do some but it will go through the annual optimization process.

M. RUBENSTEIN: Can I just understand the second -- if you do the projects which -- where would they -- which programs?

M. FLORES: It will go under the resilience program, which is part of the system and service investment category.

M. RUBENSTEIN: All right. But the total -- in that line item there is a budget for every year, just to be clear, and that's the budget that you will use and then you will, I guess, select the highest value projects from that?

M. FLORES: We will need to do all the detailed planning assessment of those projects and we're doing a portion of the projects on an annual basis, spending, planning review, and confirmation of more accurate estimates.

M. RUBENSTEIN: Okay. You are talking about using your optimization process that we've discussed, obviously, the various value metrics that you use for that, scores. As I understand, the report though looks at some other things that I don't think are currently part of your value framework. So can you explain how those are going to mesh together?

L. HEUFF: Yes. So, Mr. Rubenstein, hopefully I can help provide a little bit of clarification. So if you'll note in Exhibit 258, under the distribution enhancement section, there is a resilience bucket that we have allocated funds towards. So at this point in time we know that the projects that we will consider are going to come from the ones that were recommended by 1898 & Co. However, on an annual basis we will do the project scoring following our value framework that is identified within the Copperleaf module that we had referred to and we walked through earlier this morning, and we will score them against our own framework.

So, the 1898 evaluation that was done was to provide us, essentially, a short list of projects that have a positive benefit-cost ratio from their scoring methodologies. However we're going to, again, do it against our own value framework on an annual basis to confirm which projects should actually specifically be done.

M. RUBENSTEIN: Okay. And will you revisit the ninth -- the 1898 methodology? So let give you an example; right? Let's just use the first project, well, maybe that's the hardest. But if we go to the least -- has the lowest BCR, it is based on a project cost. If your design turns out that it is more expensive, right, and so that the BCR goes and drops below 1, is that project now eliminated from consideration or would you still do it in the context of if it meets your benefits analysis?

L. HEUFF: So, if you review the projects that are in this list they are done exclusively or predominantly based on resilience benefits. However, when we put a project into our Copperleaf value framework it's also considering other benefits, it could be from observability through grid modernization or some of the other value frameworks, it could also provide additional capacity. So, the score of the project could actually go up or if you think these poles happen to be at end-of-life, and they also have a high-level of failure likelihood and a high-level of risk, the overall comprehensive, the total project value, could actually go up and score higher as a result of the other ones that wouldn't have been contemplated when 1898 & Co did their actual evaluation. Their evaluation was done specifically on the resilience value which we've now incorporated a resilience value into our Copperleaf module, however the project itself could have a lot of other values that it provides to our system and that would be taken into consideration as well when we are doing the individual project scoring.

M. RUBENSTEIN: I'm just trying to figure out what this list of projects really -- at the end of the day, you're going to do some resiliency projects and is it just you're going to do it anyways and if it fell on this list we're going to put it in the resilience bucket of spending and if it's not it is going to go in the, you know, underground bucket of spending?

L. HEUFF: So, we would put it in this list and this list is what we would work off of when we are doing the resilience values. However, the resilience project listing, however we're still going to score the project to ensure that it has a positive value within our Copperleaf model before we execute on it. So, we won't execute on a project that has a negative Copperleaf value.

M. RUBENSTEIN: But you could still have a negative BCR value if updated?

L. HEUFF: Potentially, I mean, it would be -- we would have to walk through one in specifics to see, but it is potentially you could have a negative resilience but a total overall value in considering other factors within the system.

M. RUBENSTEIN: Okay. But will you update this BCR analysis based on further information or that's the list and it is what it is; that you are using your process to determine if it is going to go forward or not?

L. HEUFF: I think it's probably too pre-emptive to say specifically what we would do down the line if we saw that there would be value from updating the list or if there's changes or new considerations that need to be taken into account that we believe that we would need to glean further value from updating it, it is possible that we would do an update to this list.

M. RUBENSTEIN: Well, less of an update but more about a re-updating the numbers. So, for example, you have a lot of projects at the 1.2, 1.3. You know, this is, obviously, done on a preliminary cost assessment goes maybe be much higher, right, and that drops those below 1?

L. HEUFF: Yeah. So, exactly we would -- if the cost came back when we go into detailed design and the value went from say, for instance, the one that said a million 16 currently if it came up at $6 million on the overall value doesn't make sense anymore, then it would drop itself down in the list and it wouldn't be prioritized any longer. We wouldn't necessarily do it against -- we wouldn't ask 1898 to do it against theirs. It would provide that same output within the Copperleaf value framework. If the value went to $6 million the benefits of doing the project would actually become negative and it would drop off our list as well.

M. RUBENSTEIN: I'm sorry, and did Copperleaf not provide you with the tools to do the updating yourself or you would actually need them to do it?

L. HEUFF: Sorry, so we do our own value framework. We would input --

M. RUBENSTEIN: Sorry, I misspoke. With respect to the 1898 methodology, I'm talking about updating. You've mentioned you don't know if you would go back to Copperleaf -- but, sorry. 1898. My question was: I'm assuming that they didn't provide you with the ability to update this analysis?

L. HEUFF: No, I don't believe they did.

M. RUBENSTEIN: Okay, thank you. Can we go to 2-SEC-51? And in Part C, this is with respect to AMI 2.0, we had asked you: Have you completed the competitive procurement process and entered into a contract, if not what's the basis of the cost estimate? And in your response you say:

"The basis of the cost forecast for the rate period was developed with internal and external support, including historic spend and internal estimates of foundation capital and operating expenditures to achieve the proposed tenure deployment. The forecast cost basis estimates but are not limited to existing unit metres, ITOT systems installation, maintenance and labour costs."

Can you provide a little bit more detail exactly then? I know you're sort of talking at a high-level, which is understandable, I'm just trying to get a better sense of how you're actually developing the cost estimate. You're talking about external support. Is this from quotations or other costs or similar deployments in the sector? Can you help me with how the numbers were determined for the purpose of this application?

K. LELLIOTT: I appreciate the question. So when we talk about internal and external, we did have some external third-party support that helped us to understand the basis of unit meter costs and the costs for deployment across the ten-year period, so again, the basis of that cost forecast in the interrogatory shows that we know our internal cost of our current metering fleet and our current requirements to sustain that program, as well as what it would take to deploy while working with the third party to validate some of those costs to bring it forward for the OEB.

M. RUBENSTEIN: Okay. And when do you expect to have an RFP? When do you essentially expect to have, you know, the actual Copperleaf costs? When do you expect to have sort of more hard costs, and what your expectation would be?

K. LELLIOTT: The expectation is to follow the process that we talked about, having -- in question C about procuring that external technical partner. Then from there we will be able to go to market for an RFP in the very near future, leading to our first deployment of those metres with those more realized costs.

M. RUBENSTEIN: Sorry, is the date -- I don't mean a specific date, but month or year, what are we talking about here?

K. LELLIOTT: That that would be in 2026.

M. RUBENSTEIN: Okay. Can we go to 2-Staff-62. I just want to make sure I understand your response here.

You were asked in part A to provide the probability of a failure of a poor wood pole in Hydro Ottawa's system, and on page 3 of the response you provide such a formula with a set of numbers. I just want to clarify it.

Am I correct that what you are forecasting us 7.4 percent of poles in very poor condition will fail in any given year? Is that how I read that correctly?

M. FLORES: Yes. That's correct.

M. RUBENSTEIN: All right, thank you very much.

Can we go to 2-Staff-67. And this is the -- with respect to the non-wires customer solutions program, and in Attachment A you provide the BCA analysis, and there is a supporting spreadsheet, which does essentially the mathematical calculations, and as I understand for the benefits, for the quantification of benefits, you talk about -- you are utilizing the annual marginal distribution costs essentially avoided.

As I understand, you've estimated using an average distribution capacity cost for 100 MVAs using historical averages, and I won't pull you to the spreadsheet, but you are calculating -- as I read it, you're calculating -- it's $78.6 million for 100 MVA? Does that sound about right?

J. GILLIS: It sounds about right, but I'd like to pull up the specific values in the spreadsheet to confirm.

M. RUBENSTEIN: Sure.

J. GILLIS: Make sure that we're talking about the same thing.

M. RUBENSTEIN: No problem.

J. GILLIS: Can you please go to the tab labelled "program assumptions" at the top of the page in column C, row 2?

M. RUBENSTEIN: And in the explanation of it in the written attachment, the document, you say it's a estimate using average distribution capacity costs using historical actuals.

Can you help me understand how? What historical average do you use? What's the calculation? How exactly you got to 78.6 million?

J. GILLIS: Yes. So I don't have the exact calculation handy, but essentially what we did is we looked at the three different layers that go into the construction of a 100 MVA station, which would be the station cost itself, the distribution cost in order to unlock that capacity, as well as any of the transmission or what we referred to as the CCRA costs, and so we looked at a comparable of 100 MVA stations that we have forecasted and have done historically and developed averages in those three areas, which sums to the 78.6.

M. RUBENSTEIN: Can you provide the supporting calculations by way of undertaking?

J. GILLIS: Yes, I can go back and take a look to see if that is something that we can provide.

M. MILLAR: JT1.10.

UNDERTAKING JT1.10: FOR THE BCA ANALYSIS IN 2-STAFF-67, ATTACHMENT A, TO PROVIDE THE SUPPORTING CALCULATIONS.

M. RUBENSTEIN: All right. Those are all my questions, and my colleague has got his questions as well. Thank you very much.

J. SCOTT: Thank you. Can you hear me okay, Michael?

M. MILLAR: I think you are coming through loud and clear Jane.

# Examination by J. Scott

J. SCOTT: Oh, thank you very much. Okay. My questions are all for panel 1, according to the IRs, but some of them are 1 and 2, so -- 1, 2, and 3, so if there is a need to pass them off to those panels, please let me know.

Can we start with 1-SEC-5 and table A. So this was for the large loads to be connected, and we just want to make sure we understand that we are reading it correctly, so if I understand correctly, it's the signed offer to connect and the submitted load summary form that get used for load forecast purposes and for the BBA purposes.

M. FLORES: I can respond in respect to the load forecast purposes for planning. Yes, that's what we have used.

J. SCOTT: And that's a signed offer or submitted load summary form as of current?

M. FLORES: This would be up to 2024.

J. SCOTT: Up to 2024. Okay. So -- and then for instance in 2025 the 13.9 MVA and the 7, what that is saying is, based on what you had at hat point, 13.9 and 720.9 MVA is either expected -- is expected to be connected.

M. FLORES: It would be the year that it comes on. It might be a more gradual increase in the actual forecast.

J. SCOTT: Okay, because that sort of leads to my next question. So my assumption then was that the next year, for instance, the 47.9, the 13.9 was included in that 47.9, or is it absolutely new load?

M. FLORES: The 13 is included in the 47.9. That's correct. It's incremental.

J. SCOTT: And what's included in here in large loads is a new load above a certain value. And what is that value?

M. FLORES: 5 MVA.

J. SCOTT: So it is like a large user. Okay.

M. FLORES: Yes.

J. SCOTT: So I was trying to -- I want to understand the relationship between this and the table that was given in 3-SEC-63-A, which is part of the load forecast -- on the Excel spreadsheet, sorry.

Right. So if we go back to 2025, that 20.9, how does that then get translated into the number that's included under the 2025 kilowatts for electrification and large load?

L. HEUFF: I would have to refer you to panel 3 for the responses to that.

J. SCOTT: Okay.

L. HEUFF: Panel 3 would be better positioned to respond.

J. SCOTT: No, that's fine.

There was a related to 2-CO-21 --I don't think we have to pull it up -- table that showed a breakdown of the numbers that are shown in that table A, and there some data centre load included on that, but -- and this may be a panel 3 question, as well. Exhibit 9 stated that you had more data centre inquiries and they were not forecasted as part of the application.

And my question was do you have those additional data centre loads?

L. HEUFF: These are specifically requesting with respect to the revenue load forecast. Then that would be for panel 3, and what they have included in their forecast.

J. SCOTT: Okay, we will save it for there. Okay.

At 1-SEC-24, table D, this is the efficiencies for OM&A. Again, we just want to make sure we understand what we are seeing here. So, for instance, fleet pooling, how I read that is there is an initiative that's going to start in 2026, the pilot program, and that's going to save in this case $100,000 off what would have been the cost without this pilot program.

L. HEUFF: So the application of the financials would be better responded to by panel 2, specific -- if there are any specifics, there's a number of them that panel 1 can speak to, the specifics of what's included within the projects themselves.

But the actual calculations and how they were applied would be better positioned for panel 2.

J. SCOTT: Okay. Maybe then we could look at 4-SEC- 72? Again, this says a panel 1 and 2, so I am not sure.

And this is looking at the $6.1 million increase in testing, maintenance and inspection. And there is an Excel spreadsheet that goes with that.

L. HEUFF: Depending on the specific Question, this might be something that can be answered by this panel. We do have what was included within the testing, inspection and maintenance budget itself would be following this panel.

J. SCOTT: So I will continue. And, if not, I will ask it of panel 2.

So we had asked for the breakdown in here of the $6.1 million. And it is given here that $4.6 million is this proactive distribution maintenance. And “other” is $1.8 million.

Can we get an explanation, what is in that -- sorry, $1.4 million -- what is in that $1.4 million? And maybe before you answer that, and then I, if I cross-reference that to 4-Staff-134, which asks the same sort of question, if you scroll down to the table. And it provided an increase. It explained $5.6 million of the $6.1 million, and said that the -- this was sort of the incremental cost with this, the new maintenance testing and inspection.

And so I'm trying to cross-reference those two. So this one is --

L. HEUFF: So I was just trying to -- yeah, just trying to make sense of the specific numbers that you are providing that you are trying to reconcile.

Can we just walked through that again, please?

J. SCOTT: Yes. So in 4-SEC-72, the Excel has proactive distribution maintenance, $4.6 million, and “other”, $1.4 million. And in the Staff question, it breaks down the $5.6 million into sort of new initiatives, and says the other $0.5 million is just a general increase.

L. HEUFF: I think we are going to have to take that one away, to be able to provide a response.

The other one is more -- like the table, the Excel spreadsheet? -- was from panel 2, versus the way that it has been presented here. So we will need to take it away to reconcile the two numbers.

J. SCOTT: Okay. And maybe if you do that -- well, I am also looking for -- we had asked, and you don't have to pull it up, but 1-SEC-9, which referred to 2-Staff-56, and this was why the maintenance spending had not decreased with the increase in asset replacement.

And so, though there is an explanation there about how, yes, you are replacing more assets, but you are not replacing as many assets as you really should be, so you are going to increase this inspection, testing and proactive maintenance.

And I understand that. But what I am looking for is because you are replacing more assets than you were replacing in the past, there must have been -- well, is there? And if you can quantify it, what the decrease in the maintenance is, all else being equal?

L. HEUFF: Sorry, I am trying to follow the line of questioning. What you are trying to understand is as a result of the replacement, the maintenance costs themselves are not reducing? Is that what you are…

J. SCOTT: Yes. And my understanding is you are saying that no, they are increasing because you are doing all this proactive, new work.

But the total, the total increase of $6.1 million, what we would like to see is, was there a decrease, and then this added proactive work, and what that decrease was.

L. HEUFF: There was not a decrease. There is an IR related to this that is already responded; specifically, I think it was the 2-Staff-56 you had referred to before.

J. SCOTT: Yes.

L. HEUFF: Let me just pull that one up, please.

J. SCOTT: And that is the one where you explain about how you are not doing as much as you would like to have been doing in terms of replacing.

L. HEUFF: Yes, and at paragraph 3:

“Consequently, not all high-risk assets are slated to be replaced through the period, and that our risk renewal strategy relies heavily upon condition maintenance inspection.”

So we are not removing -- the assets that are going to remain in place are still very high risk, and there are a lot of deteriorated assets that are remaining in place. And the incremental investment is so that of the ones that are heavily deteriorated, we can increase the inspection frequency of those assets.

We did provide, also, within that, a table that actually also provides within the summary of the enhancements that we are looking to be making. If you turn to exhibit 4.12 on page 12, table 5?

So the increase -- so the reduction that would have been seen as a result of the assets that are being removed, or the higher volume of assets that are being removed are being offset by the increased cycle frequency that we are planning to put in place in order to mitigate against the incremental risk that is remaining as a result of the high deteriorated assets remaining in the system.

So the specifics of what we are looking to do from an enhancement perspective is in the second column, that 2026 to 2030 program enhancements. And those are the -- this is what is essentially offsetting what would have potentially been seen as a decrease.

J. SCOTT: What do you have -- can you quantify that decrease?

L. HEUFF: I don't know that we are able to. We can take it away and bring it back to the subject matter experts to request whether it's possible.

J. SCOTT: Okay. If you could include it in that undertaking then?

M. MILLAR: So, the undertaking is JT1.11.

UNDERTAKING JT1.11: TO QUANTIFY THE DECREASE.

J. SCOTT: Thank you. In the table in 4-Staff-134, if we could go back to that one and go down to, I think, it is the next page that shows the 1.8 million. Just down a little bit further. Yes. The 1.8 million overall distribution exploring opportunities. Could you talk a bit about how you came up with a budget of 1.8 when, like, you are exploring opportunities; how did you arrive at that forecast?

S. HAWTHORNE: Hi there. This is Steve Hawthorne. So, in order to arrive at that forecast, we looked at specific areas in which we wanted to enhance our overall testing, inspection and maintenance programs in a general sense. And there is a specific IR that actually talks about the types of work that we would be undertaking, if you bear with me one moment and I can pull up the reference, and within that, based on those scopes, we estimated incrementally what that cost would be for one year. Yes. So, if we go to 4-SEC-71 part B, we look at the incremental enhancements that we're proposing with that $1.8 million and the types of work that are proposed to be included.

J. SCOTT: Yes, I saw that it just didn't quantify anything to go from this to 1.8 was unclear how you actually got to that number.

S. HAWTHORNE: I understand. So, based on similar and ongoing scopes where we've looked at things like analytics or using data to improve our programs, we provided those estimates.

J. SCOTT: Can you provide any of that information? Any...

S. HAWTHORNE: I will have to look and see if we can provide any of that information based on how those estimates were put together.

J. SCOTT: Okay.

M. MILLAR: That is JT1.12.

UNDERTAKING JT1.12: TO PROVIDE SUPPORTING DOCUMENTATION FOR THE $1.8 MILLION FOR INCREMENTAL ENHANCEMENTS IN 4-SEC-71 PART B

J. SCOTT: Thank you. 4-SEC-66, and this may be better for the financial panel, but this is where we asked for actuals to June and then we asked for an updated forecast for the end of 2025, and the answer was that that wouldn't be ready until October. And so, my question was when in October would that kind of information be ready when you are filing the undertakings?

L. HEUFF: That would actually be better suited for Panel 2 as a question. They're responsible for the forecasting.

J. SCOTT: Okay. 4-SEC-77, and this does say witness Panel 1 and 2, so I understand. And this actually asked about the new positions and it referred us to 4-Staff-159, which actually may be the better one to pull up. So, most of the remainder of my questions are about determining how many staff positions are available. Are these something that are better in Panel 2 or are there some that you can address here? Or...

L. HEUFF: We can address questions related to this specific position and how the number of positions were determined for any of the individual head count that are related to Panel 1. So, for the most part I can point you in table A that would be metering, engineering and design distribution operation.

J. SCOTT: Okay. Well, if we could just scroll down in that IR response. Stop, stop, stop. At the equation at the top of that page. Okay. So, the answer says because of what the SEC question had asked for, the new positions, the 22 in engineering and design and the 43 in distribution and operations, the how Hydro Ottawa determined the number of new positions. And we were referred to both the workforce planning strategy, but also this formula. So, for this formula the units would be what?

L. HEUFF: I'm going to pass it over to my colleague, Mr. Hawthorne, he should be able to provide you the response requested.

S. HAWTHORNE: The units are either labour hours or positions.

J. SCOTT: My understanding is for the trades -- and how many of the 177 new positions, how many are considered trades?

S. HAWTHORNE: So, with respect to that formula anything listed as direct labour is considered within that formula.

J. SCOTT: Okay. So is this formula done on a job title; on a program, on a position basis; on an all-trades basis; how is this formula done?

S. HAWTHORNE: Yeah, so this formula is prepared on a per trade basis based on a process that involves reviews at various different levels, and then that output is summarized for use within the table in Staff-159.

J. SCOTT: So, can you provide us then for, I guess, then by program, you know, for the positions how, for instance, you -- metering, you determined three positions in 2026?

S. HAWTHORNE: Yeah, and I can walk through the process of how that works. So, workforce planning for trades as were deemed directly where supply happens on a twice a year basis, and for the purpose of this application was also prepared in a 5-year cycle in order to be holistic. So, in that process we essentially look at incremental increases as work programs, as described in the evidence. So, I know you noted some of my references there, but we look at increases in capacity, for example, those increases are then overlaid against the historical performance and needs of that particular trade group. That process involves a review, first at the manager level and then it is then reviewed upwards at director, vice-president and chief level. And the outputs of those individual trades are amalgamated into that overall direct labour line as you've noted on the page in incremental review stages.

J. SCOTT: So, using metering as an example, forecasted labour demand is based -- you are saying in labour hours -- but that's based on a forecast of number of meters to be installed; or is there some --

S. HAWTHORNE: It's a combination of units, labour hours, and financials depending on the specific trade and the historical volume of work and future work that is being performed.

J. SCOTT: So can you provide us with the actual numbers that went into the formula to get the three metering people in 2026?

S. HAWTHORNE: No, unfortunately I'm not able to provide that. As I've stated it's a process review, again, at a multi-tiered fashion where we review the historical financials, labour and, in certain cases, units, not all. And based on, again, those projected increases we prepare what is an aggregated labour hour demand from those process review meetings.

J. SCOTT: But is there not an output of those? Is the output three people in metering?

S. HAWTHORNE: So the output is an aggregated labour hours demand, as noted in the formula. And then from those various reviews we go through and identify what the ideal contracted resourcing needs are to offset that labour demand.

J. SCOTT: So you -- I guess I'm not clear. There are the numbers there somewhere, but you are refusing to provide them? Is that...

D. COBAN: I don't think it's a -- sorry, I'm just going to jump in. I didn't hear a refusal. What I heard is an explanation from the witness in terms of how this process involves various stages of review and inputs.

So maybe the witness can clarify that part of the answer so we can make just sure we've all got a clear understanding of Hydro Ottawa's process, in terms of deriving the metering FTs you are asking about.

S. HAWTHORNE: Yes, and I can add some further --

J. SCOTT: Just to be clear, I am asking about all of the new positions, but using metering as an example.

S. HAWTHORNE: I understand, and I will try another way.

So as a result of the process that I described, there is actually -- there is a consolidated view of the trade workforce requirements, again, that's completed on a twice-a-year basis, and that would effectively be the view of positions that are described for by trade.

J. SCOTT: Well, let me ask my other questions, and we might come back to that.

So for the non-trade positions, which are the other ones, it says where they have their time charged directly to work order an appropriate approach similar to workforce planning for trades was used, so which positions would those be?

S. HAWTHORNE: Yes. So any position that's not listed as directly [voice cuts out] follows the approach written below the labour supply surplus calculation -- or formula, excuse me, so leadership and non-trades.

J. SCOTT: Right. But it also says, but there are some non-trade positions that follow this similar equation approach if they charge time directly.

S. HAWTHORNE: Yes, and I think for the purposes of this, what we mean by direct labour is more synonymous with trades, and for the purposes of how we've used the word direct labour, there can be folks that charge hourly within leadership and non-trades.

L. HEUFF: Would you please divide the reference that you are -- where it is stating that --

J. SCOTT: 4-1-3B, section 3.1.3.

L. HEUFF: Can we just have that reference one more time? I didn't catch it.

J. SCOTT: It's 4-1-3B, section 3-1-3.

Now let's go right at the first paragraph, last line. I guess, maybe let me ask another question. Do you have the forecasted workloads? And are they -- are those in labour hours then?

S. HAWTHORNE: No, we don't have the forecasted workloads in terms of labour hours. That is represented by the positions shown in Staff-159.

J. SCOTT: These are the positions, but the workload, what -- if it's not in labour hours, what is it in then?

S. HAWTHORNE: So it's a -- it depends on the specific position. And, again, we use cost, historical labour hours, if there are folks that charge time, and look at relative effort from historical work programs and the increase in the work programs to project forward the number of positions required.

J. SCOTT: But based on what?

S. HAWTHORNE: Yeah, so it's, again, depending on the number of position -- the specific position at hand, financials, sort of cost, labour hours, units, depending on the individual work program, previous number of positions in all cases.

J. SCOTT: Maybe -- so it sounds very qualitative and not quantitative; would that be safe to say?

S. HAWTHORNE: Subjectively, so, yes, it is qualitative, yeah.

J. SCOTT: Okay. I guess what is misleading is having an equation that -- which is a quantitative presentation.

S. HAWTHORNE: I understand and, again, the equation is meant to determine the final number of trades' positions specifically.

J. SCOTT: Yeah, I understand that, but -- so let's maybe move on to one of the new positions, the utility forestry inspector position, scheduled for 2026. Is this the right panel to ask about that?

S. HAWTHORNE: Yes, it is.

J. SCOTT: Okay. 4-Staff-139-D describes the duties of the new utility forestry inspector position, so my question is, are these new duties?

S. HAWTHORNE: No, for this particular position these are not new duties.

J. SCOTT: So was another position -- so another position was doing this work.

S. HAWTHORNE: Yes, there are existing utility forestry inspectors completing work, and the request is for one additional inspector in 2026.

J. SCOTT: So in this case what would have been the measure of increased workload? Would it have been increased tree-trimming?

S. HAWTHORNE: So in this particular case, effectively the process would have involved a review again starting at the manager level of the existing forestry and vegetation management areas, as well as the relative amount of work that the existing two inspectors are completing to provide quality assurance, as well as respond to existing customer inquiries, based on our projections of where the forestry program is headed, specifically with overstory and targeting hazard trees, in that the existing two inspectors were fully staffed and fully -- a reasonable amount of backlog on a daily basis. It was deemed that an additional inspector would be required in order to ensure that that backlog did not increase further to help and assist with the nature of the changes within the forestry program, moving to trimming within individual cycles, as opposed to mass trimming across that particular cycle with overstory, and then validating data against overstory.

J. SCOTT: Okay. For each of the new positions that are either managers or supervisory positions, can you provide the direct number of reports and also if there are reports under those, for us?

L. HEUFF: Please clarify, Ms. Scott. Are you looking for the existing, or in the future state, the number?

J. SCOTT: No, the new positions that are listed in the 4-Staff-159.

L. HEUFF: So we could provide what we have as a current, and what we can see the future would look like for the programs that I referred to when we began looking at the table A that was referenced initially in Staff 159, we wouldn’t be able to provide the same information for any of the other groupings, as those would be better suited to either panel 2 or panel 3, depending on which ones they are looking for.

The other thing is we don't necessarily have our future organizational structure finalized in all cases at this point in time, especially related to the supervisory positions that would come on in 2027 or 2028. We would be looking to understand what the most reasonable or the -- and the most efficient organizational structure would look like.

So those positions and how many would be reporting to each individual supervisor would be subject to change, depending on what organizational structure we align on when we implement the new positions.

So the bests we could do is provide what we believe it may look like, and what those ratios would look like at a high level. But they would be subject to adjustment.

J. SCOTT: Okay. I am actually mostly looking for 2026, so if you can provide that?

L. HEUFF: Year 2026, we can provide as -- if that is the undertaking, we can provide that, the 2026 supervisor to individual position.

J. SCOTT: Thank you.

L. HEUFF: And do you want the specifics, or just a ratio?

J. SCOTT: If you can provide the positions, yes, that would be helpful.

M. MILLAR: The undertaking is JT1.13.

UNDERTAKING JT1.13: TO PROVIDE THE POSITIONS.

M. MILLAR: Ms. Scott, just a reminder, you are getting close to the end of your time.

J. SCOTT: Yeah. And I think most of my questions can -- I have just got one more. Otherwise, I think most of them are going to be for panel 2, related to panel 2.

Do I have time to ask one more?

L. HEUFF: Apologies. Just on the previous undertaking, just understanding that we are only providing supervisors and the number of positions related to the specific categories that were spoken to at the beginning of the table, and not all of the table.

J. SCOTT: Right. So that was metering, engineering and design, and distribution operations?

L. HEUFF: Correct.

J. SCOTT: And I am not sure if there are any managers in there; they are all supervisors, I think. Yeah.

L. HEUFF: Okay.

J. SCOTT: At 4-Staff-162, it asked about the four new distribution engineering standards, engineer's position. And this was for 2024.

Could you provide the same information that you provided for 2024 for 2026 to 2030 for the five new distribution engineers?

If you could just go down to the response, you will see you did actually provide some numbers there.

S. HAWTHORNE: So I'd like to clarify that the description on the pages specifically clarifying how we arrived at the additional distribution engineering positions in 2024 and the basis for 2026 is different than that as shown on the page. So providing the same description would not be available because the driver and work-program needs have changed, or are perceived to be changing in 2026.

J. SCOTT: Do you have quantifiable information in 2026?

S. HAWTHORNE: Again, we undertook a similar approach for -- if you look at the six different drivers that we have provided for increasing labour needs within 2026, we reviewed existing workload level of effort in the positions today, and inclusive of the 2024 hiring. And depending on the perceived scope changes or additions such as incremental support for maintenance programming or complexity of the load request, we then identify where incremental engineering support would be required.

J. SCOTT: You are saying you don't have this type of information for 2026?

S. HAWTHORNE: We do not have this information for 2026.

J. SCOTT: Okay. No further questions. Thank you.

M. MILLAR: Thank you, Ms. Scott. Mr. Garner, are you ready to go? Or is it you, Mr. Harper?

# Examination by B. Harper

B. HARPER: Actually, I will be starting off. And I guess, yes, we are past the noon hour -- good afternoon. My name is Bill Harper, and I am the consultant for VECC. Both myself and my colleague, Mr. Garner, will be asking questions of this panel.

But before I start my questions, there is a housekeeping matter I would like to address. And that is on September 16, VECC filed a list of written questions which Hydro Ottawa has undertaken to respond to in writing.

And so my question, I guess, it’s to board -- or counsel, is do we need to assign an exhibit number to this list of questions and/or an undertaking number?

M. MILLAR: We don't know that we need to do both, or that there is any magic to it. And I look to Ms. Coban, as well, to see what she would like to do. But we could just mark it as an undertaking.

D. COBAN: I think it would be helpful to mark it as an exhibit, and then the undertaking response can just be to answer to the questions and the marked exhibit.

M. MILLAR: Very good. Okay. So we will call the VECC questions -- what date were they filed, Mr. Harper?

B. HARPER: September 16.

M. MILLAR: September 16, as KT 1.1. And, unless I am mistaken, also the undertaking to respond to the questions from KT 1.1 will be JT1.14.

EXHIBIT KT1.1: VECC TECHNICAL CONFERENCE QUESTIONS

UNDERTAKING JT1.14: TO PROVIDE RESPONSES TO EXHIBIT KT1.1

B. HARPER: Okay. Fine. Thank you, very much.

And so starting off with my questions, my first one has to deal with Hydro Ottawa's response to 2-Environmental Defence-15(a). So if you could turn that up?

And if you scroll down, there is table A, and I guess it is the next page down. And here, you have provided a forecasted cumulative customer connections for the years 2025 to 2030.

And would I be correct in assuming that this includes -- for each year, includes any new connections for residential, general service and large use customers?

UNIDENTIFIED SPEAKER: Yes, that's correct.

B. HARPER: And similarly, would there be any new connections for streetlights, USL or Sentinel customers.

S. HAWTHORNE: Generally, streetlights, yes. Sorry, USL? What do you mean by that?

J. SCOTT: That is your unmetered and scattered load, things -- like, you know, street telephone booths and things like that, traffic cameras.

S. HAWTHORNE: Just one moment. I would like to confer on that, please. Thank you. Yes, confirming that those items would be included as -- in part of the customer connections program volumes.

B. HARPER: And I assume it would also include connections and new generators.

S. HAWTHORNE: No. This number is meant to represent customer connections as described by our customer connection programs, and does not include new generation projects.

B. HARPER: Okay. So it is just related to load customers, then?

S. HAWTHORNE: That's correct, in this particular response.

B. HARPER: Okay. Besides new connections for connecting new customers, does it include anything else?

S. HAWTHORNE: Yeah. This number also includes infill, so that would be upgrades to existing services.

And I would like to highlight that the volumes projected within this table are based on our Salesforce field service system, which is requests that are part of our design intake process for, as you have noted, a new load customer either requiring a new service or an upgrade.

So this is meant to be the number of “projects”, or a number of work packages that are received through that team.

B. HARPER: Right. Would it be possible for you to break the numbers down for each of those years between what we call new customers versus existing customers that are seeking an upgrade and therefore I guess require connection work?

S. HAWTHORNE: We will need to check to make sure that that would be available and, if it were to be available, we could provide that as an undertaking, again, with the caveat that this is based on our tracking system for said request, and noting that within the data can be various anomalies and various requests for individual services that may be double counting or misrepresenting data.

B. HARPER: But I understand it's this connection forecast is the connection forecast that is driving your budgeting for what you have to spend in this area; correct?

S. HAWTHORNE: No, that's not correct. Again, based on -- sorry, not again. But based on what I just described with our mechanism at the project level to track individual projects and potential anomalies with the data we actually use cost as a proxy for volumes within any given year, given that it is very hard to predict the number of projects that we will complete versus those that are in progress.

B. HARPER: But if you are using -- if you have a forecast the forecast must include, not only what you anticipate it will cost, but the volume of connections that you are going to have to be undertaking each year. It seems to me that total cost is a function of cost per connection, which may vary, times that number of connections. So, if this isn't the forecast of what you are assuming is the number of new connections you are going to be doing every year for low connections. For purposes of budgeting do you have a separate forecast for that or you don't forecast that?

S. HAWTHORNE: So, again, we use cost as a proxy within system access and the programs within it to forecast forward what we think the volumes will be. So, the volumes are a derived number in this case and not part of the base calculation.

B. HARPER: And what you have here aren't the derivable volumes then; there would be a separate set of numbers that would be the derived volumes?

S. HAWTHORNE: This is an amalgamation of the derived numbers.

B. HARPER: Okay, so this is an amalgamation. So, maybe just go back maybe if you can, if you can sort of distinguish in some way between new connections and what I would call service upgrades, for want of a better word, is that something you can undertake to go back and look if it's possible to do and provide if it is?

S. HAWTHORNE: I can undertake to see if that can be provided with the caveats that I've noted, and if that is possible to provide we can provide it.

B. HARPER: Maybe if we scroll down to part B?

M. MILLAR: I'm sorry, Mr. Harper, can I mark that as an undertaking or are you still completing the question?

B. HARPER: I think I have a further question which maybe and then hopefully we can roll it all into the same undertaking.

M. MILLAR: Okay, sounds good.

B. HARPER: So, in part B you talked about the number of new connections completed in 2024 and the total is 8,380 when I add the two numbers together. I was wondering if you could give me a similar breakdown similar to what we just talked about for the forecast period for 2024?

S. HAWTHORNE: Again, I can undertake to see if we can provide that because these numbers in part B are based on completed works whereas the forward-looking numbers are aggregated based on the number of requests that we have as a starting point in, say, 2025 and then projected forward using our cost basis. So, again, using cost to drive volumes but, yes, we can undertake to provide to see if we can provide a similar breakout as shown in part B.

B. HARPER: And that would be useful, and if you need to make any distinction between what you're providing for '25 to '30 versus '24 please feel free to do so as part of your response.

M. MILLAR: The undertaking is JT1.15.

UNDERTAKING JT1.15: TO PROVIDE A SIMILAR BREAKDOWN FOR THE FORECAST PERIOD FOR 2024.

B. HARPER: Okay, fine. Thank you. My next question has to do with, could we go to 1-CO-21 part B. Maybe just at the table there. I believe you have already had some discussion with Ms. Scott around this and answered part or some of all my questions, so I just had a couple of brief follow-ups. Now, just to confirm, it's my understanding that for your planning load forecast basically you have included all of the megawatts that are listed here under signed offers to connect and submitted load summary forms?

M. FLORES: That's correct.

B. HARPER: I am correct. And would I be correct that that is a combination of both existing customers that want to increase their load, are talking increasing their loads, as well as new customers that are looking to come on the system?

M. FLORES: Yes, it has combination of both.

B. HARPER: Right. Is it possible for you to break -- and you don't have to break it down for each of the individual, like, subcategories of types, but for each of the totals for the signed offers and the submitted load summaries and breakdown how many new customers, we are talking about cumulative, each year and the megawatts associated with new customers as opposed to existing customers?

M. FLORES: Yes, we can do that.

B. HARPER: Okay. And like I said, you don't have to break it down by individual category because I appreciate that might be getting into some confidentiality issues, but on a total for each category that would be useful, thank you.

M. FLORES: And just to note, only the incremental load here is shown here on the table.

B. HARPER: Right. Yes, no, no, I understand. It was an existing customer, the existing load is not shown on the table.

M. MILLAR: The undertaking is JT1.16.

UNDERTAKING JT1.16: TO PROVIDE TOTALS FOR EACH CATEGORY

B. HARPER: Okay, I think does that does that for that. Can we now go to your response to 7-VECC-61B? Now, I appreciate this question is sort of -- has been assigned to both panels 1 and panels 3, so I assume you'll tell me if the question I ask is better directed to the panel we will be seeing on Wednesday. But here in part B you describe how the distribution infrastructure required to supply a customer with embedded generation differs from that required to supply a customer without embedded generation where they both have the same gross load requirements. And the response identifies additional requirements associated with metering voltage control and generation monitoring and control; have I got that correct?

M. FLORES: Yes. That's correct.

B. HARPER: Okay. And I guess, I was just wondering, the response is a general response. Is there any sort of capacity consideration? Do some of these costs only trigger in when the embedded generation gets about a certain size or do all of these cost categories apply regardless of the size the embedded generation?

M. FLORES: These categories were applied regardless of the size of the generation. For large connections we would have to do the capacity assessment depending on the location of the new component.

B. HARPER: Okay. We will get to that in a few minutes. I guess in terms of these additional requirements can you tell me who pays for the additional requirements; is Hydro Ottawa that pays, or is the customer themselves that would pay for it?

M. FLORES: In terms of bidirectional meter that would be paid by the customer.

B. HARPER: All right.

M. FLORES: Additional protection and monitoring control would be paid by the customer.

B. HARPER: Okay. Now, I guess the one thing I did notice in this response, and I guess you briefly touched on already, was the fact that the response did not identify any difference in how Hydro Ottawa's determination of system capacity needs for a new customer with no behind-the-meter generation and a customer with the same gross load that does have behind-the-meter generation and am I to assume then that, for the purposes of determining capacity needs, it's the gross load of the customer that you use irregardless of whether there is embedded generation that's going to be in place or not?

M. FLORES: Is this for a specific customer location evaluation?

B. HARPER: I guess, in general I guess. If a customer approaches you and says I have a gross load of X megawatts I want to add to the system, does it make any difference to you in that assessment whether or not the customers says and, oh, by the way I'm going to be installing Y megawatts of embedded generation or not?

M. FLORES: It would depend on the size of the generation and the load summary that the customer submits.

B. HARPER: Okay. And with the size of the generation would that be location specific or is there a general size that you apply?

M. FLORES: So, we follow the rules by the DSC to determine the different generation sizes, so from micro, small, medium to large generations. As the generation size increases there is additional assessments that need to be done to ensure the stability of the system.

B. HARPER: Okay, fine. Thank you, I think that's all I need. Okay.

And then can we go to Pollution Probe-12D? Now, again, this interrogatory was assigned to both panels 1 and 3, so I assume you will let me know if my question is better put to panel 3. In the response to 12D you indicate that the mechanism for implementing local initiatives under the IESO's new framework does not exist and that the OEB is currently conducting consultations on it. So, based on this, would it be fair to say that Hydro Ottawa has not as of yet implemented any new local issues for 2025 as envisioned under the ISO's new framework?

S. CARR: Hello, Bill --

[Court reporter appeals]

B. HARPER: I apologize. This is something I've heard before and I apologize for it. Okay. That's fine.

S. CARR: Hi, Mr. Harper. This is Shawn. Just to clarify your question, you're asking whether there are any new local initiatives we have implemented so far in 2025?

B. HARPER: Yes, under what's envisioned, you know, under the ISO's framework that they introduced back in January.

S. CARR: Yes, so we haven't introduced any new initiatives as of yet. We are currently supporting the IESO with the local initiatives that are already in market that were part of the new framework. That said, as part of this investment plan we are proposing a non-wires customer solution program that would involve a collaboration with the IESO to bring new local initiatives into our service territory in a particular targeted area of need, but those wouldn't be slated to begin until 2026.

B. HARPER: Right. And the ones that are in place right now, they were ones that you've implemented under, I guess it would be the '21 to '25 framework that the IESO had?

S. CARR: Some of those local initiatives were carried over from the previous framework, but currently the IESO is offering three different local initiatives in the Kanata North region of our service territory, and they are currently in market.

B. HARPER: And they were introduced in 2025?

S. CARR: It depends on which local initiative you are referring to. They were carryover programs.

B. HARPER: Right. Okay. So they were a carryover from 2024 then.

S. CARR: Yes, that is correct. However, the IESO has also initiated a retrofit adder as a local initiative, and that adder became effective in 2025.

B. HARPER: Okay. And have you had any update on that so far?

S. CARR: So we don't we don't have access to the customer participation. Our role is to support with increasing awareness of these programs. However, once customers apply to participate in these programs, that participation information is with the IESO and their third-party service providers.

B. HARPER: I apologize, I should have remembered that before I asked the question. With this adder, what's -- is there any sort of planned target for savings associated with this new adder program?

S. CARR: The IESO has not shared a particular target for their local initiatives with us at this time.

B. HARPER: Okay. Fine. Thank you, that is all my questions. Thank you very much. I will turn it over to Mr. Garner now.

M. MILLAR: Thank you, Mr. Harper. And just a reminder for Mr. Garner. We're looking to have our lunch break by one o'clock, so if you can find an appropriate spot to break.

M. GARNER: Well, Mr. Millar, if I'm right, I may be able to actually finish my whole thing sometime around 1:00, so it might be a little over, but then you'd be rid of me, so let's see where we are. Thank you.

# Examination by M. Garner

M. GARNER: So good morning or good afternoon, panel. My name is Mark Garner, and I'm also with VECC, and I'm going to deal with a few different things than Mr. Harper did, and the first place I'd like -- and I'm going to be able to shorten it, because Schools this morning touched on a couple of the same issues that I had. So the first place I would like to take you, though, is to 2-VECC-9, and when you pull -- if you pull that up, what you will see is there's about a discussion about -- the question was basically about, I didn't understand or we didn't understand DSP implementation progress that was shown in that table versus what's shown in appendix, and then you explain it in the interrogatory, and that was all fine.

The thing I got a little bit confused at this morning was, the way I read the response was, the response was, well, the table you are looking at, table 7 in -- is using KPIs to basically calculate the implementation progress, as opposed to what Appendix II AB is doing. And I hope I have got that part of the response correct.

Then what confused me this morning was this discussion about the ongoing work with Hatch on KPIs and whether you use them or not, and when I saw this response I thought, well, you do use them, don't you, right now? I mean, you are showing this in this response.

So can you clarify? You are using KPIs now in some fashion?

L. HEUFF: Yes, sorry for the confusion. The KPI progress that was developed with respect to Hatch is specifically around modernization KPIs. The KPI that's on the page here is distribution system plan implementation. It's the KPI that existed from the previous DSP, and it is being monitored and reported.

M. GARNER: Thank you. And that's what I thought. And so that brought me to my next question on this, is, when you're doing the KPI for this on the DSP implementation, I understood in the response why you said you excluded, I think it is emergency work. I understood that. That makes sense to me. I'm less clear about why system access and general plant expenditures get excluded in that KPI. Can you remind me why that is? Even though it says KPIs exclude system access, general plant, and all emergency work. And that's in the first paragraph.

S. HAWTHORNE: Yes, so system access is specifically excluded, given the customer-driven nature of those particular projects, there can be individual load requests that are unknown within any given year that can arise which would disrupt the outcome of that particular KPI.

Additionally, within general plant, that's inclusive of our connection cost recovery agreement, or CCRA program, which has variability in terms of finalized timing and individual costs, as those costs are directly attributed from Hydro One. Therefore, we would be adding potentially error within the KPA, and it wouldn't actually be able to help us drive an outcome.

M. GARNER: Sorry, why couldn't you -- I mean, the CCRA, which is something I want to talk about, why couldn't you just remove that part of -- if it's accounted for in the general plant, it's, I would imagine, not the majority or even significant amount of general plant expenditure is related to CCRA in any given year, is it?

L. HEUFF: My apologies, Mr. Garner. I'd say that the DSP product KPI was developed specifically to track the progress against the operational side of implementation, so what we referred to internally as the sustainment budget, and so the sustainment budget is system service and renewal combined, and it's specifically that identify how we're doing against those plans. General plant is not included in that overall review, and that's why it's actually excluded from this KPI.

M. GARNER: Thank you. And again, that's sort of where I thought to -- is there anything that would preclude one byte from making a KPI metric to general plant, I mean, separately? Is there any methodological impediment to doing that

L. HEUFF: General plant, aside from CCRA, doesn't actually fall within this panel, it would fall within panel 2, so the question to that, that would be a better position for panel 2.

M. GARNER: And I'm happy to ask them, but my question was really about doing it -- and maybe they are still the best people, but what I'm really wondering is, is there is a mechanical problem with doing it, as opposed to, let's say, system access or system renewal. I mean, there may be myriad reasons --

L. HEUFF: Yeah. I don't -- so if you're talking about specifically just adding up dollars and dividing, I mean, we have the numbers available, but really I think what you're more referring to is what's going on within the individual programs and whether it would be appropriate to measure them in that manner.

M. GARNER: Right.

L. HEUFF: And that appropriateness would be better suited to be asked towards panel 2.

M. GARNER: Yeah, fair enough. And I understand where you're going with that, thank you.

Now, the next place I'd like to take the Panel is to 2-VECC-10. And in 2-VECC-10, we asked a question about outages, and given the large capital budget that you were proposing, the issue about planned outages, and the question went to, could there be metrics around outage time and planned outages, and you give a -- I understand the response you give, and it makes sense to me the way you have responded to it, but maybe in the way I'm actually asking that question I should have asked it better.

What I was wondering was, certainly not on all projects, but the way I imagine -- and I could be imagining it incorrectly -- the way I imagine significant projects going forward is, one of the aspects of significant large projects will be a plan, and projects that require customer outages will be -- I wouldn't call them a special project, but they are identifiable in some sense. They are a large project; you have to plan an outage. And so, I was first of all was wondering, are there projects, significant projects, where you do make in the planning of the project an outage schedule for that project?

L. HEUFF: -- projects that have large outages would have a planning aspect to that outage.

M. GARNER: So, is it one of, when you go through these, the planning process, or actually, it is more the implementation of a plan in any year and you are implementing a project, one of the checkboxes so to speak is, “Does this project require an outage?” And then -- is that correct? Let me stop there. Is that one of the questions that would happen on, you know, major projects? Does it require an outage; is that sort of part of the planning questions?

L. HEUFF: So it would be does it require an outage, and there would be also an understanding of for how long and how many customers are impacted, are there any ways to avoid an outage entirely? Those would be the types of questions --

M. GARNER: Right.

L. HEUFF: -- that would be asked during the planning stage.

M. GARNER: And once a plan has been made that decided there needs to be an outage for that project, are there expectations put into the plan as to what that outage is, so that the planning crew have an understanding of what is the expectation for the outage time on the project; does not happen in project planning?

L. HEUFF: Yes, would concern project planning.

M. GARNER: Pardon me?

L. HEUFF: Apologies. That does happen during the project planning.

M. GARNER: Okay. So, my third question on this is: Is it possible in, let’s say 2026, to understand, in your 2026 DSP, to understand where the significant planned outages are going to be in 2026? So if I sat down and we had looked at the whole thing a little differently and I simply said to you is, "for every project which has a planned outage of more than 30 minutes, can you give me a list of all those projects in 2026 that you think will have an outage of more than 30 minutes being arbitrary," you might have a different, you know what I mean, a threshold yourself that you say, oh you know, “We know the largest outages we are planning”?

L. HEUFF: It's not that simple. Unfortunately, it would depend on where the project is within its project planning phase. And at the time, whenever they are actually going to plan it is just before execution, so before the project goes to execution. So some projects, for instance, that might be executed in 2026, the scheduled outage plan might not happen until June. And that scheduled outage plan may change, depending on what the current state of the system is. So, if they have had to take elements offline for other purposes, say there was a station transformer that was out, offline for some reason, and load has been transferred, that outage plan would vary, vary significantly, versus what it would have looked like had you done that scheduled outage, say, six months earlier. So, to be able to actually identify what it would look like a year in advance is impossible. The target is made just prior to, or the expectation in that switching plan and what the outage will look like, is made just prior to execution. And there is the target that is set, or a number that is set and reviewed by all parties at that point in time. And then they strive to achieve whatever they have stated. That is communicated to customers in advance of the outage as well, so there is a customer expectation that is set, so the customers are aware of what to expect for that outage. And then we always strive to meet or exceed the target of timing, of when that outage, how long that outage duration will be.

M. GARNER: Okay? So, is there a way that Hydro Ottawa understands how well or how badly it is meeting the expectation of the outages that it is putting out there: So, as you say, you communicate to customers. Is it part of the assessment process that says we told customers that we would be out for an hour or we were out for 30 minutes, so that is really great. You know, we thought we'd be out for an hour, but we were out for three hours, that is really bad, you know, that kind of stuff. And then something done with that information as in, you know, how can we do this better? Or we did this really great, so how can we learn from it; is that exercise going on somewhere?

L. HEUFF: Yes. So, just to clarify, are you specifically talking on scheduled outages or unscheduled outages or a combination?

M. GARNER: I am talking about scheduled outages. I am very focused on your plan; right? Your plan that you are putting forward --

L. HEUFF: Yes.

M. GARNER: -- and how you are really -- how we can -- customers can be comforted that the utility, in that plan, can minimize outages and is actively working to do that by learning about its outages, by setting expectations and about monitoring those expectations. I am trying to understand how that is done or if it is done?

L. HEUFF: Yes. So, how it is done at this point in time is how I described previously, where we set the expectations with customers just prior to the outage beginning for a scheduled outage. We are always striving to minimize the outage as much as possible through different means of switching, or whatever we are able to do in order to minimize the number of customers who will be impacted by every outage. And then we minimize the number of outage -- the hours that the customer will be out. But the way that we have a process that we set expectations with customers is that we notify them in advance of the outage as to how long the outage duration is expected to take. And then we always strive to meet or exceed it. At this point in time it is not something that is measured or tracked that we could provide any data on.

M. GARNER: Okay, thank you. That's helpful, thank you. The next place I would like to go is 2-VECC-11. And this is going to be a bit complicated because it is not just 2-VECC-11 I am trying to get at in this question. There were a number of other interrogatories by the parties that kind of go to the same issue and, again, I think my questioning may not have been very succinct in what I am really trying to get at in this. And this was really a discussion about -- and I'll have to apologize; I guess my Spanish, the big storms, I guess you call it a derecho? Is that right? My Spanish being worse than my French and my French being terrible, so that's the storm called a derecho you had in 2023 or 2022?

L. HEUFF: Correct, yes. Derecho is the correct pronunciation.

M. GARNER: And what year was that?

L. HEUFF: And yes, it was the storm in 2022.

M. GARNER: In 2022, right. Okay. So, why I am interested in this or why we are interested in this is it seemed to me going through the evidence, going through the interrogatories, that the storm causes Hydro One to take some time to understand what happened and what it can do. And the way I see that is probably best shown in your response to Staff, I think it is Staff-36. And in Staff-36, there is a couple of points. Staff-36, they talk about new standards, and you provide some new standard in Staff-36. We don't have to pause too long on that. And the other one, because I want to show you both of them, the other one is in Staff-41, which is probably more directly about the storm. And in that case, you do two studies, it seems to me, one by Stantec and one by this entity called RSI which, as I understand it -- and I haven't read them in detail, I understand they are basically looking at Stantec, about your vulnerability and the other one about basic climate change. But they are both done in response to the storm; is that correct?

L. HEUFF: Yeah. Also, the original study that was done by Stantec was actually done in 2019 --

M. GARNER: In 2019.

L. HEUFF: -- and it was post-our tornadoes. So we had tornadoes, if you will recall, potentially in 2018, that hit our service territory in September of 2018. So we undertook the Stantec study in 2019. What we did in 2023 after the derecho was an update. So we asked Stantec to go back and review, based on, and we had also had a number of other storms that had happened between 2018 and 2022 derecho, and so we asked them to go back and take a look to see whether any of our -- whether anything should be changed in terms of our application of the improvements that we were making to our system or to the standard. So they did an update to that study in 2023, as a result of the derecho.

M. GARNER: Right, thank you. That is the addendum report; right? That is referred to in there. And thank you for that clarification. And you are looking right at the dates on it, it was 2019. The thing I am trying to then understand is, as I go through the evidence, and I see this at 2-Staff-54 and other places, I am trying to trace and I tried to trace: Where do I see the impacts in the distribution system plan of those reports and the storm. And one place I think I see them by your response is in this distribution enhancement program; is that correct?

L. HEUFF: That's correct. The resilience program, that's within distribution enhancements, is the bucket of money that we are proposing to continue on with storm hardening. Storm hardening efforts were actually undertaken immediately, as of 2023, where we began making improvements to the system to strengthen our north-south lateral pole lines, since those were the ones that showed the highest vulnerability to the high-wind situations. We also updated the anchoring and guying standards, and we began doing some additional anchoring and guying on the north-south laterals, as well. And then the anti-cascading measures, as well, that started in 2023, but the resilience bucket that is proposed for '26 to 2030 does contain the investments to continue on those hardening efforts and, specifically, the strategic undergrounding as well.

M. GARNER: Okay, thank you. And I'm looking at Exhibit 2, Tab 5, Schedule 1, page 104 where it shows the distribution enhancement difference in spending between the historical and the new rate period, and it goes from 28 million to 93 million. Am I correct then to say that's being driven by, let's call it, the storm informed work we have been doing; that's where that $65 million increase over the period is being driven from; is that a fair way of looking at it?

L. HEUFF: Mr. Garner, I'm just waiting for the -- yeah. So the 28 to 93, if you specifically turn to Exhibit 258 there is section 3, Distribution Enhancements 3.5, page 84.

M. GARNER: Yeah, I think I know where you are going.

L. HEUFF: Yeah. So, you can see the distribution system resilience specifically because the distribution enhancements bucket as a whole from 28 to 93 contains a number of different items within it, so you have to specifically look at the distribution system resilience and it would be the spending from '26 to 2030 that is incremental, that is related to the incremental investment as a result of the storm hardening.

M. GARNER: Thank you. You've got to where I was going faster than I could do it. That's kind of where I was going. So, it's really only that line that I am looking at in enhancement that's really the storm part of it, because there is other stuff in there, voltage conversion, et cetera; right? And, conversely, would I be right to say that there is also though system hardening and other kind of storm responsive investments being made in the system renewal area that aren't directly attributable, aren't sort of saying this is directly -- we're not drawing a straight line from this, but we are hardening up stuff in system renewal; would that be correct? So, if you go to, like, in your system renewal budget under Overhead or Underground and you look at the budget increases, is there any of the money --

L. HEUFF: Yeah, I'm trying to -- I don't believe there's anything specifically other than what would be built into the unit costs directly as a result of (inaudible) other than anchoring and guiding increases or the changes to the standards, but they would be built into unit cost. I don't think it's anything material though that I would be able to point to at this point in time.

M. GARNER: Okay, great. That's very helpful, thank you. I think I can then move on. Thank you, that was quite helpful. The next place I would like to move on to was also -- this was touched on by Schools this morning, because it's their interrogatory, but it was something that struck me and I think Mr. Rubenstein asked you directly about this, but it is in 2-SEC-50. And this was about the unit cost and he went through a discussion about the unit cost, and he had the question of his interrogatory which I would have had, too, about the risk factor included in the programs. I was just wondering though, when I look at this table if I -- well, let me just make sure I am understanding what I'm looking at.

If I look at this table and I look at the averages it doesn't matter which one we take, let's just take switchgear renewal. If I take that $620,000, if I look at your DSP and I see, just I don't know what's actually in there. But I see, let's say, 10 switchgear renewals in a year, I would multiply 10 by multiply that 10 by 620 and I would see the budget amount and that equal the budget amount; is that correct?

S. HAWTHORNE: Yes. So, to get the budget amount you would need to take the entire number of switchgear units and multiply by a rate of 620,000.

M. GARNER: Right.

S. HAWTHORNE: And, again, as clarification -- sorry, go ahead?

M. GARNER: No, I was going to say: So it's all inclusive, I was saying there's not other stuff to be added that would give me the whole amount; right?

S. HAWTHORNE: That's correct.

M. GARNER: Okay, thank you. So, if I asked you, and I think if I said to you, can I have the unit cost, take out the risk factor, take out the annual increase that you had even said and give me the unit cost without those two items in it, can you do it; and, I guess, the next question is: Is that a smart thing to do; but can you do that?

S. HAWTHORNE: I'm sorry, I'm not sure I fully understand what you are looking for.

M. GARNER: Well, Mr. Hawthorne, sorry the Staff-620 which you get as you had a discussion this morning about, including a risk factor, and including annual increases to create what I heard was basically a period average. If I instead said, well, don't do a risk factor, leave that out. And then don't do an annual increase, I know that seems odd, like, don't inflate it. I don't believe there's any inflation, and show me that number. Is that -- because that's the number is built from, isn't it; you take an original number and then you say I'm going to add this is my annual average increase and then this is my risk factor. So can you break the number down to show it at it's different levels? Like, I do it just with a risk factor, or I drew it just with the average annual increase.

S. HAWTHORNE: Again, using -- talking specifically station switch gear, the starting point would be the actual unit rate of installed switchgear, and then based on the number of units moving forward and the specific sites in which those units are to be replaced, we consider the site-specific conditions that might affect an individual project and determine a unit rate project level, that's then re-summed and divided by the total number of units to get that average rate. So, I believe I understand your request but I don't think I could easily reproduce what you are looking for.

M. GARNER: Well, let me challenge you on that, and maybe it is my misunderstanding of it. If I imagine the same table with 2 more columns in it, the first column would have the starting point which wouldn't be 620,000 it would be taking, as you say, the historical and then just averaging the historical over the number of years, 4 or 5 years whatever it is, and that would give me one number, let's call it 500,000, then the next column would say, okay, let's now add the annualized increase based on my assumption of what that is. So, that next column would show me 500,000 would now turn into 575, I am just making up numbers, and then the third column would say now I add my risk factor, and so adding my risk factor my 575 now turns into 620. And in that way I understand each step of your -- the impact of each step of your assumptions to get to your new average. Why is that -- it seems to me that's what you are actually doing, so I am kind of wondering why is that not possible to do?

S. HAWTHORNE: Yeah and, again, using station switchgear as an example, when we are talking about considering site-specific conditions that risk factor is really meant to quantify the differences in individual sites. So, what you described isn't actually the process by which we derived the unit rate for station switchgear. So we started with we started with -- pardon me?

M. GARNER: So -- go ahead, sorry. I interrupted.

S. HAWTHORNE: My apologies. So, if we look to CCC-28, table A, that gives the actual proactive replacement cost, for example, for station switchgear in the second row. So the starting point would have been a number similar to that, subject to check my notes as to a specific derivation of that number, and then based on the number of units that we are planning to replace, which equates in this particular period to four specific sites, we will enter into a high-level or Level A estimate, as we call it, of the cost to change the switchgear, or the cells or the breakers at that particular site. And then we divided the sum cost of those 4 projects by the number of units. So, again, there isn't necessarily a specific risk factor that can be applied as you have described.

M. GARNER: Okay. So, are you saying to me that I should look at the number for, let's say we will stay on switchgear, it's a nice example. I should look at the number of 197 and somehow relate that to the number 620?

S. HAWTHORNE: Yes. That's correct. And, again, the 197 is based on projects that were completed within the 2021 to 2024 period.

M. GARNER: So, it would be -- am I being misinformed or misunderstanding to say what was once costing 197 per unit is now, on average, costing 620 per unit as a budgeting mechanism?

S. HAWTHORNE: That's correct. And it's important to understand that switchgear are multiyear projects and the costs and the particular switchgear equipment that was received for the units that were considered within 21-24 actuals the actual PO's for those particular switchgear were placed much earlier in Raid application period through that time. As generally accepted and as stated in the evidence we experience very high levels of inflation, both on equipment but also on outside services and construction costs. It is also important to note that, as I've described, reviewing site-specific conditions in certain instances, completing a switchgear renewal project may actually involve building an entire switchgear lineup while the existing switchgear is operating, and sometimes that can also involve building a building, so the unit rate can be highly variable.

So with that regard --

M. GARNER: Right.

S. HAWTHORNE: -- if we are choosing to replace an entire switchgear lineup, which is inclusive of the breakers themselves, versus doing a rolling replacement, we are in effect moving from 197,000 to the number shown on the previous IR.

M. GARNER: So I should -- you are cautioning me it's not always apples-to-apples that I am comparing with these two things.

S. HAWTHORNE: That's correct.

M. GARNER: Right. Okay. Mr. Millar, I don't have much longer. I think if you give me the benefit of 15 minutes at most, I think I can finish here. I'm happy to come back. It's really in your hands.

M. MILLAR: If it's going to be 15 minutes, we are going to come back --

M. GARNER: I think I can do that. I think I have only two places now to cover, and Mr. Hawthorne, since you are with me on this question, the next one was, you answered this morning, and this was in respect to, Mr. Rubenstein brought you to 2-SEC-43, and the issue about these meetings that happen when you are trying to follow your budgeting of projects that have been implemented and the refusal, et cetera, et cetera, and I understand your refusal, and I'm not really looking to take on Ms. Coban in any way, so I really wanted, though, to take you up on the offer here to discuss this response, and just so that I understand the process for what's happening to -- what's happening when projects are coming in later and over budget, et cetera, so as I understand in reading the responses, there's -- and you correct me -- there is really three types of meetings. There is one meeting with -- I call it -- and you can correct me -- directors and the, what I call the crews, the trades and the crew people, then there's another set of meetings with executive management and directors, and then there is a third set of meetings with executive and board of directors. I might be using the word director wrong for the management teams that are at the project level, but is there sort of three levels of monitoring that are going on, one with ground crew-type people and their managers, one with executives and the people who are in charge of ground crews, and then finally one with the board of directors and executives. Is that correct?

S. HAWTHORNE: It's close, and perhaps if you'd like I can run through the exact sequence of events in the course of any given month and quarter, if that would help. So --

M. GARNER: Yes, and all I'm really just focused on is, what are the types of meetings and who were at those meetings, right?

S. HAWTHORNE: Yes. So the first instance of review -- and perhaps we can pull up the exact IR, just to make sure that we are visually looking at the initial response as well. It's 2-SECC-43.

So on a monthly basis a project manager or system designer will have a cash flow, which is a cost representation of a project status scope and projected plan.

When said project manager receives their actual spend for that particular month they meet with their supervisor to review what that spend versus projected cash flow is and make any adjustments to that individual cash flow for a particular year, as well as for outer years, as we call them, so any year beyond the given expenditure year.

So at that time, if there is a need to adjust the overall forecast above $20,000 or below, the individual project manager or designer will submit, as we call, a change request into our Copperleaf system.

That supervisor then reviews that particular change request and will approve it in Copperleaf. The result of those individual project reviews are then prepared and presented in what's called a program review, which is attended by supervisors and managers, so one level, two levels above the frontline staff that are actually managing projects.

The information contained and the justification for a particular overage is then reviewed within that team and is inclusive of a wide audience, which is not just the project team. It considers our asset planning, our scheduling folks, construction teams, and within that team they deem a particular change to be adequate and justified or not.

The output of those particular program reviews, which are generally distribution stations metering, et cetera, are then amalgamated into a cumulative portfolio review, as we call it.

That meeting is attended by managers and directors and specific supervisors that have a particular scope within our overall project delivered process. Those are responsible for trades forecasting.

So at that third meeting you have two levels and three levels above the frontline staff that are responsible for preparing financial forecasts and delivering on projects. Those folks then review that particular change, and depending on, again, the content and the dollar magnitude of that particular change, it is then recommended for approval or not, and then generally, if approved, contained within the financial forecast for that particular month.

The output of that discussion then goes to a further business alignment meeting, which is a similar but different cross-sectional group of managers and directors that look at the overall business function of the operations team, so to speak, and then the output of that final meeting informs our board and quarterly and monthly reporting.

M. GARNER: That's a lot of meetings. I feel sorry for you. But the meeting I'm really wondering about is, where is the meeting that happens and who is at that meeting, where the annual budget for the utility is brought up and someone says this is where we are at overall, not -- we have a mixture of projects moving around. We are going to be 10 percent over budget this year or we are going to be 5 percent under budget in whatever categories you are using to present that information. What meeting does that happen at, where an assessment -- where basically -- I'm asking this, is, where is the decision made for someone to greenlight what's going to be an overbudget year, when that starts to become apparent? Where is the green light, and where is the conversation that happens about, rather than being over budget, we might rearrange our programs in order to stay within our budget? Where is that happening?

S. HAWTHORNE: Yes, I understand your question, I'm just going --

M. GARNER: And I don't mean at the level of the people who make the -- I'm talking about the people who actually have to say, we have to sign the budget off and go to the board of directors and say we are over budget.

S. HAWTHORNE: Yes, and as I noted, one moment. I'm just going to confer quickly.

M. MILLAR: Quickly, Mr. Garner, while they're doing that. We are at 1:10, and we will need to break shortly.

M. GARNER: I think we agreed on 1:15, but let me see.

M. MILLAR: Well, people will need a break.

M. GARNER: I'm trying to help you, Mr. Millar, but I'm in your hands.

S. HAWTHORNE: Thank you for that. And that meeting happens quarterly, and it's with our executive management team, and it happens through our -- those quarterly meetings and quarterly reporting.

M. GARNER: Okay. Thank you.

The last question I have is -- sorry, I've just got to find it. Sorry, while I am looking, can you just name who's on that executive committee, and position, what positions are in there, the executives are in there, the name of the executive level, like CFO, CEO. Who's there?

L. HEUFF: CFO, exactly, CFO, CEO, COO would be the main relevant parties, and CITO as well. CCO is also at those meetings. That's chief customer officer and chief IT, chief infrastructure technology officer.

M. GARNER: Okay, thank you.

My final question is related to -- and this may be panel 3, so we might be able to do this quickly. In 2-SECC-56, which is basically on CCR payments, if you roll that up you will see a table, and you will see a sum of that table that says -- and I will just pick the number 18 million at 2026 at the bottom is the sum, which I take it is the sum of CCR payments expected to be made to Hydro One in that year, right? And as I understand it, in the new proposal there's an account going to be -- is proposed to basically deal with variances in CCR payments, and what I'm wondering is, how does that $18 million in the years that follow, how do I relate that to, if you go to 9-SEC-87, which is panel 3 -- this is why it might be panel 3 -- if you go -- you see all those numbers, 9, 18 million, whatever, how do I relate those numbers to the table that you see as the benchmarking for that account -- yes, right there, the top line. See the 7,000,697, and then the 762, which, if you look at the response to the IRs, are basically a baseline, it looks, for that variance account.

I just was struggling to understand how does the actual $18 million and 26 1.3 after, et cetera, how do they relate to the 7762108, something like -- how are those numbers related?

L. HEUFF: Yeah, that specifically would be better responded to by panel 3.

M. GARNER: Okay. Well, Mr. Millar will love that answer, so thank you, panel, very much for your responses. You've been very helpful, and Mr. Millar, on to you.

M. MILLAR: Thank you, Mr. Garner. We will take our afternoon lunch break. It is 1:13. We will be back at 2:13.

### --- Recess taken at 1:14 p.m.

### --- On resuming at 2:16 p.m.

M. MILLAR: Good afternoon, everyone. We are ready to continue with the technical conference. Ms. Coban, I think you had a clarification matter you wanted to address?

M. COBAN: Yes. Before the lunch break, Ms. Heuff was having an exchange with Mr. Garner regarding resilience investments, and there was a clarification on her testimony that she wanted to provide.

Ms. Heuff, can I ask you to –

M. HEUFF: Yes, thank you, Ms. Coban.

Yes. So I would like to just turn your attention to exhibit 257, specifically page 68.

So you will note on the line, the second line, we do note there is $9 million incremental within the pole renewal project specifically related to resilience activities. So I did misspeak earlier when I had said that the resilience activities were entirely contained within the resilience bucket. There is this extra $9 million as well that is within the pole renewal program.

M. GARNER: Thank you, Ms. Heuff. Thank you for that clarification.

M. MILLAR: Anything further, Ms. Coban?

D. COBAN: No, thank you.

M. MILLAR: Okay, great.

Mr. Brophy, I am going to turn it over to you. We will be looking to take a break around 3:30, 3:40, if I could ask you to try and find a natural spot in there, if you haven’t finished by then.

M. BROPHY: Sure. And if I get engrained in questions, if you want me to stop, then go ahead.

M. MILLAR: Will do.

M. BROPHY: Certainly.

# Examination by M. Brophy

Good afternoon. My name is Michael Brophy, and I will be asking questions on behalf of Café Ottawa. I had provided over the weekend a heads-up to Board Staff. We had done a reconciliation of the questions in the IRs related to the panels, and similar to what Jane had mentioned for SEC, there are some IR responses that had one, two or three panels noted as contributing.

So my understanding is that the vast majority should fit into this panel, but if the panel needs to redirect me to one of the other panels, then we can go on that, on that basis. So it just means then that we would use more of the time in panel 1, if that is the case, or if it ends up being other panels, then you know that would be reflected accordingly. Thank you.

I also just wanted to note, everyone seeing how efficient it is on bringing up all the exhibits, but I certainly have noticed that and appreciate that. I always want to highlight it, because it's not easy work to do.

Okay. The first question I have is 1-CO-9. And it may be more useful to pull up the actual evidence reference made in that, which is reference 141 attachment E, starting with page 59. So I can wait a minute while that comes up, page 59 of the report. So that is page 59 of 125; is that where we are at? I am on a different page, here.

D. COBAN: We are currently on 141E, page 59.

M. BROPHY: Perfect, yeah. That matches what I have here. Thank you, very much. Okay.

So C-09 provided information related to information from this deck or this report that Hydro Ottawa had filed, and it covered some of the explanation on why the Hydro Ottawa outage numbers outlined in 141, attachment E, were higher than the Ontario and national averages. And then first, just to get oriented for this exhibit which is 141, attachment E, this is a national survey that was conducted that also included comparison information to Hydro Ottawa customers.

Is that correct?

L. HEUFF: The survey specifically is better directed at panel 2. However, I think if you have a specific question, it may still be relevant to panel 1. So if you can keep going with your line of questioning, we might still be able to answer it.

M. BROPHY: Sure, okay. I didn't think we would get this issue of panel 1 versus panel 2 on the first question but, okay, fair enough.

So, okay, I will just repeat the first question them. So first, just to get oriented, the information in 141, Attachment E, that is from the evidence Hydro Ottawa filed, and it's a the national survey that compares results against Hydro Ottawa customers. Is that correct? Or does that need to be answered by panel 2?

L. HEUFF: So the specific details of what is in this would be panel 2.

M. BROPHY: Okay. I will move on to the next one, and I don't want to waste valuable time because it all links to that.

So basically then, panel 2 would then speak to the survey results, and what they mean? Is that accurate? Or is that this panel?

L. HEUFF: That is accurate. It would be panel 2.

D. COBAN: Yeah.

M. BROPHY: Okay, thank you.

D. COBAN: But Mr. Brophy, just so you don't miss your opportunity, I think if you have questions about Hydro Ottawa’s specific reliability performance, the witnesses on the panel can assist you. If your questions are more about the comparison and the methodology that was in the survey, then panel 2 is best to answer.

M. BROPHY: Okay. Thank you. I guess one of the challenges is when you look at 1-CO-9, which is the next IR reference, it relates to the SAIFI reporting, so the outage reporting, which I think is probably this panel. And I was trying to compare the results from the survey done against the adjusted and the raw SAIFI information. So I guess if you can confirm that this is the panel for SAIFI, I can try and ask that, but I don't know if the panel is going to be able to make the comparison comments that I was hoping to get to. Maybe you can just help me on whether that makes sense or not.

L. HEUFF: This is the panel for SAIFI. And we would be the ones that would be able to respond to any questions of any of the data that rolls up to the SAIFI number that is reported within, throughout the DSP. However, the comparisons would not be able to be done by this panel.

M. BROPHY: Okay. Fair enough. So I will try and stick as close to SAIFI as possible, then, for this panel.

So mentioned the reference of 1-CO-9, which also related to outage reporting. And then the reference to the evidence was 253, table 18, which was SAIFI reporting, which was also I think replicated in the response to 1-C0-9.

So maybe what we can do, we will just check the 1-C0-9. Why don't we pull that up, because I think it actually includes all of the -- and then there is a table below in the response -- two tables.

Let me see. I will just double-check the reference again. Again, one second; I may have glossed over the reference. Actually, the table is in 2-CO‑13. Sorry about that.

Okay. Perfect. I don't know if the panel will be able to read it, but if we can get all 4 visuals on the screen that would be ideal or I will start at the top two. So, at the top it has in 2-CO-13 -- it looks like it is just refreshing -- there is a figure A and the response that has SAIDI and SAIFI information and my understanding is that is just a duplicate from the evidence; is that correct?

L. HEUFF: It also includes 2024 actuals in this, whereas the evidence only goes till 2023.

M. BROPHY: Okay. Fair enough, yeah. Okay, thank you. And so, whether it's the one with the more recent updated information or the evidence that didn't include the last year, the SAIFI reporting table is based on a series of adjustments before arriving at the published numbers; is that correct?

L. HEUFF: I believe you are meaning by adjustments do you mean the exclusion loss of supply and major event days?

M. BROPHY: Yes, that's correct.

L. HEUFF: Okay. So, Figure A excludes loss of supply and major event days, whereas Figure B includes loss of supply and major event days.

M. BROPHY: Okay, thank you. And so, can you walk me through the process that Hydro Ottawa uses and to identify and make those adjustments to remove that data from the raw set in Figure B to what is in Figure A?

L. HEUFF: I will pass that over to my colleague, Ms. Flores, to provide a summary of the methodology.

M. BROPHY: Okay. Thank you.

M. FLORES: Yes, we follow the triple R mandate to determine the major event days, as well as the loss of supply and all the different primary causes for outages, so we would use the OEB definitions.

M. BROPHY: Okay. So you don't then have an internal Hydro Ottawa documented process, you are just applying what the triple R requirement is; is that correct?

M. FLORES: We have an internal document process that aligns to the OEB requirements.

M. BROPHY: Okay. And is that filed already?

M. FLORES: I don't believe so.

M. BROPHY: Okay. Can you file that?

M. FLORES: Yes.

M. MILLAR: That is JT1.17.

UNDERTAKING JT1.17: TO FILE THE REFERENCED DOCUMENT.

M. BROPHY: 1.17, thank you. And for those results, in applying those adjustments following the protocol you just mentioned, have you ever had a third party audit done of those adjustments to validate that they are accurate?

M. FLORES: Sorry, just to clarify, the definitions for all the primary causes, as well as the methodology of applied for the major event days classification, it is all in 253, under section 4.4, which is page 39 for major event days.

M. BROPHY: Yes. No, I am aware of that. But I am just asking if you have ever had that process audited or included in any of your third party audits to validate that it's working correctly?

M. FLORES: After every major event date we would send the results from the survey and the event that we are classifying as a major event to the OEB with all the details.

M. BROPHY: And I understand that the data, it goes to the OEB, but has there ever been an audit of that data? I don't think the OEB audits it, but I am just wondering if Hydro Ottawa has ever had it audited?

M. FLORES: No.

M. BROPHY: Okay. Thank you. And just to help to understand the data that's going in for the SAIFI frequency reporting, I will let me give you an example, I think this may reflect a real example but, you know, it's meant to be more hypothetical: So, can you tell me if there's an outage that impacts an apartment building with a thousand units, if the power to the building goes out and is counted in the SAIFI results, is that counted as one customer outage or 1,000 outages?

M. FLORES: It would depend if every unit in the building uses a meter or if there is just a bulk meter for their entire building.

M. BROPHY: Okay. So if it is a bulk meter how would it be treated?

M. FLORES: As one customer.

M. BROPHY: One customer. And then if it's unit metered it would be treated as a thousand outages; is that correct?

M. FLORES: That is correct.

M. BROPHY: Okay, thank you. Do you have any data on which of the multifamily buildings in your service territory that are bulk metered, how many units each of them contains?

L. HEUFF: There is an IR response on this if you just provide us with a moment.

M. BROPHY: Sure.

L. HEUFF: We will point you to it. Just give me a moment.

M. BROPHY: Thank you.

L. HEUFF: Yes, if you turn to 2-Staff-77. Oh, no this is -- I don't think this is the right one. Hold on.

M. BROPHY: If it is going to take you a while you can just provide it later if you need.

L. HEUFF: Yes, we will take it away to provide you with the correct reference, but this has been provided already through another interrogatory that was requested with a very similar request.

M. BROPHY: Okay. Thank you. And is that an undertaking?

L. HEUFF: I can take it as an undertaking to provide the IR.

M. MILLAR: Let's mark that as JT1.18.

UNDERTAKING JT1.18: TO FILE THE REFERENCED IR

M. BROPHY: Okay, thank you. And then, so it sounds like that you have the information that relates to the number of units in multifamily buildings that are bulk metered and, you know, I'll find it in whichever IR response that is.

L. HEUFF: Well, we don't -- the IR response, what it describes is what we do know and the fact that we don't have a complete understanding of exactly how many buildings are -- how many buildings are containing unit milled metering. There are some inferences that are made within the -- and we do attempt to classify it, but there's some inferences that are made within the response.

M. BROPHY: Okay. Fair enough, and I look forward to taking a look at that. So, I think then that tells me what the answer to this question would be, but maybe I will just validate it. So, then if you don't know the number of units in bulk metered multi-residential buildings then it sounds like you wouldn't be able to estimate the impact on SAIFI if you were to count each of those customers; is that correct? Or is that something you could do?

L. HEUFF: No, that's correct. That's not something we are able to do.

M. BROPHY: Okay, thank you. Okay. So, we are on 2-CO-13, on the table. So we had talked about the Figure A which is the SAIDI and SAIFI outage data adjusted for, you know, the adjustments that were mentioned. And then Figure B includes the information, the gross information, before data is removed for upstream outages and major events, I think you've clarified that. So, for Figure B we thought that what you would have been provided is the same format as Figure A with the 5-year average trend included, but it was provided in a different format. So, can you provide Figure B in the same format as Figure A for CO-13?

M. FLORES: Yes, we would be able to provide that. However, it might be not a realistic average due to some of the outliers, as you can see in SAIDI for 2016 and 2022.

MR. BROPHY: And you're reading my mind. Just before Mr. Miller assigns an undertaking number, there's a second part. Can you also provide the apples-to-apples figure B excluding 2018 and 2022, which appear to be the outlier events, so it would be providing Figure B, in the same format as Figure A, and then providing Figure B in the same format as Figure A with 2018 and 2022 data removed. Can that be done as well?

MS. FLORES: Yes, that can be done.

M. BROPHY: Okay, thanks. I think that's probably one undertaking, probably makes sense.

M. MILLAR: And we'll call it JT1.19.

UNDERTAKING JT1.19: (A) TO PROVIDE FIGURE B IN THE SAME FORMAT AS FIGURE A FOR CO-13; (B) PROVIDE THE APPLES-TO-APPLES FIGURE B EXCLUDING 2018 AND 2022, WHICH APPEAR TO BE THE OUTLIER EVENTS, SO IT WOULD BE PROVIDING FIGURE B, IN THE SAME FORMAT AS FIGURE A, AND THEN PROVIDING FIGURE B IN THE SAME FORMAT AS FIGURE A WITH 2018 AND 2022 DATA REMOVED

M. BROPHY: Okay, thank you.

L. HEUFF: Mr. Brophy, I'm able to provide. I did, find the IR response. It's under 2-ED-17, Section C, which does provide the estimate of the unit, bulk metered and unit-metered buildings that we have in our service territory. And a description behind it as to why it's not possible to give them specific answers.

M. BROPHY: I think that's a record on the fastest undertaking response.

M. MILLAR: Yes, so that was that had been JT1.17, I believe, but rather than start re-numbering –

M. BROPHY: 1.18, I thought it was.

M. MILLAR: Pardon me, was it 1.18? Yes, I get yes, I'm sorry, I was marking the new one.

L. HEUFF: No, I think you had it right, Mr. Miller. I have it down as 1.17.

M. MILLAR: And we just gave 1.18, right? Which is the next one.

L. HEUFF: Actually, sorry, I apologize, I am mistaken. Forgive me. It is 1.18.

M. MILLAR: Okay, Mr. Brophy has, has gotten us both. Okay, so I'm not going to start renumbering them, we will just count that undertaking as fulfilled.

M. BROPHY: Yes, okay, no, that's fair. Don't want to start unraveling the undertaking number system.

Okay, so the next question is on 2-CO-14D. The response to 2-CO-14D indicates that Hydro Ottawa has storm insurance related to distribution facilities, buildings, and operation centres, et cetera. But Hydro Ottawa indicated that there was no damage relating to the -- and I'm not going to get my Spanish as good as, the last pronunciation, the derecho event in 2022. So therefore, there was no insurance claims required in relation to the duration of end of 2022, is that correct?

D. COBAN: Apologies, I know this panel, this one does direct as Panel 1. It would be Panel 3 who would respond to any insurance-related questions. Apologize.

M. BROPHY: Okay. Panel 3, thank you very much. Okay, so next question relates to 2-CO-17A, and 2-CO-17A provides information on Hydro Ottawa’s demand forecast and if you put into the Ottawa regional planning IRRP process, the response notes that the decarbonization study reference scenario was used as informing the regional planning process for Ottawa area. And that the reference scenario represents a moderate pace of decarbonization that still meets Canada's 2030 emissions reductions plan and wider 2050 decarbonization goals, but with a more tempered approach in the short term, compared to the policy-guided scenario, which assumes 100 percent electrification. Do you do you see that?

L. HEUFF: Yes, I see it.

M. BROPHY: Okay, thank you. So, just to be clear, before I start asking questions on that, Hydro Ottawa has committed to enabling net zero by 2050, is that correct?

M. FLORES: That's correct.

M. BROPHY: Okay. And your demand forecasting capital plan will deliver on what's needed to deliver on net zero by 2050; is that correct?

M. FLORES: Based on the assessment of the needs until 2030, yes, and the reference scenario does have a target of net zero by 2050.

M. BROPHY: Okay, so your capital plan and forecast is aligned with net zero by 2050, but I do realize that you're just seeking approval to 2030. And then each subsequent plan would then build on that in order to reach the net zero by 2050; is that an accurate statement?

L. HEUFF: I think it's a very complicated answer, Mr. Brophy. I think we'd have to understand a bit more specifically what you're trying to understand.

M. BROPHY: Sure. Well, I think you mentioned that you're already committed to ensuring that the plans deliver on net zero by 2050, so maybe I'll move on to the next question related to this interrogatory.

There's some wording in there where you're proposing to take a tempered approach in the short term. Can you explain what that means?

M. FLORES: Yes, the curve used to come out with the reference scenario was based on that. And a temporary curve, due to the actuals that we were seeing in recent years. That's why we're calling it tempered approach.

M. BROPHY: Okay, so is it correct to interpret tempered as a reduced approach in the short term, but then if you need to have it increased in the medium or longer term, then you would make that adjustment later? Is that is that what that means?

L. HEUFF: That’s generally correct. So, the way the approach that we're taking is to ensure that we're able to connect the customers as the customers have indicated that they require the load. We obviously want to make assurances that we're not overbuilding the system and leaving assets that are stranded.

Essentially what our proposal is as of right now, for 2026 to 2030, is to increment the capacity to the system based on, as we described this morning, the existing offers to connect and the submitted load summaries. We're going to continue to monitor and update our forecast, and we're going to see where we land in terms of the projected scenarios.

When we look at the long term, and when you look at the regional planning that was done, we're leveraging the reference scenario, which is a medium-case scenario, to ensure that we're making asset investment decisions that will allow us to meet those targets, should the electrification continue to grow on that path.

We're also able to pull back so that we don't end up with stranded assets if there is to be a slowdown through policy or through any other economic factors that make come into play.

And so our plan is that if electrification demands it, we will be moving at a pace that will allow us to meet the 2050 target, assuming that's the actual growth pace that happens within the City of Ottawa, yet not overbuild in advance of it, so that we don't end up with stranded assets.

M. BROPHY: Okay, and when I refer to capital plan, I'm not just talking about customer additions, I am talking about everything that's in the capital plan, including the ability to enable DERs and other elements within the plan, and I'm assuming that's what you mean as well, but I just wanted to validate that.

L. HEUFF: Yes, so the decarbonization study is specifically looking at the investments that are required from the capacity perspective. Within that, we are also considering leveraging DERs as the capacity solution in some instances, and we're also considering some non-wired solutions.

So, in some instances, it would be a battery energy storage solution that are, that are proposed, or the non-wires customer solutions programs that are also proposed. And collectively, those are what we're leveraging in order to the capacity needs as part of the limits.

M. BROPHY: Okay, thank you. And when you use the term short-term, what period of time does that mean, generally speaking? The next five years?

L. HEUFF: Generally speaking, correct. That would be the next five years.

M. BROPHY: Five years. Okay. And then maybe medium terms over that period. Okay, thank you.

Just staying on the theme for 2-CO-17, there was a reference in the evidence back to 254, appendix F, page 10, figure 4; I can provide the reference, again, if needed. And it is a comparison graph of the reference versus policy guide scenarios. Yeah, exactly, thank you.

And then I saw in the response that Hydro Ottawa notes that it is not using a planning approach to follow a dual-fuel scenario using fossil fuels, but that you are targeting the reference approach, which I think we just talked about.

And then I also noticed that Hydro Ottawa noted that it considers natural gas as low carbon. Do you recall that?

M. FLORES: Yes.

M. BROPHY: Okay. Do you know, what reference source are you using for the definition of natural gas is low carbon. Is that from some sort of a document? Or is it just a term that you applied?

M. FLORES: Give me a second to review the study.

M. BROPHY: Sure. Or if it's easier, to take it away and answer it in undertaking, that is fine as well, but whichever you would prefer.

M. FLORES: I would like to point you to page 22.

M. BROPHY: Yes, I think it's up on the screen. So sorry, what are you referring to?

M. FLORES: So, in the second paragraph, we talk about the low-carbon fuels such as hydrogen or RNG -- the second paragraph, line 2. So low-carbon fuels are defined as hydrogen or RNG, by the consultant.

M. BROPHY: Okay. So it was just from Hydro Ottawa's consultant; it wasn't from government or a publication; it is just a term that your consultant chose to use. Is that accurate?

M. FLORES: Yes.

M. BROPHY: Okay, thank you. And the reason why it jumped out and I ask is that I think you are aware that Energy Evolution and other policy‑related initiatives that impact your service territory are not treating natural gas as low carbon, and are actually counting on displacing natural gas in order to achieve Net Zero by 2050.

I am assuming you are aware of that. Correct?

M. FLORES: That is correct.

M. BROPHY: Okay. Thank you. So I was just wondering why you would use a different classification for natural gas than is used in those documents, but it sounds like it was just not an intended term use; it was just something your consultant ended up putting in a report. Is that correct?

M. FLORES: Yeah. I would say it was the classification in the way that the consultant made the assumption as to what type of gas mix would be in the system by 2050, by recognizing that in a dual-fuel scenario, that there is some amount of gas that would have to continue to exist if that would be what came to fruition. Right? So we are projecting different potential outcomes by 2050.

We have a plan and a path to get to the policy-guided scenario. However, there is a possibility that through various forms of policy and where things may change along the way, that natural gas would still be in the system. The consultant does make the assumption, however, that the remaining gas would be either hydrogen or renewable natural gas, which they have classified, they have chosen to classify as renewal -- as low carbon.

M. BROPHY: Okay. So actually it is not then natural gas that you are saying is -- or your consultant is saying is low carbon. It was hydrogen or RNG, then, not the actual natural gas. Is that correct?

L. HEUFF: The statement is from these technology adoption assumptions:

“Black & Veatch applied a blended coefficient of performance to convert the amount of energy used by natural gas to electricity, or low-carbon fuels such as hydrogen or RNG.”

M. BROPHY: Okay. Okay, thank you. Thank you, for that.

The next question relates to 3.1-BOMA-8, and that IR response relates to EDSM on potential.

So the first question is does Hydro Ottawa have information on what the potential is in its service territory for all energy efficiency programs?

S. CARR: Hi, Mr. Brophy. This is Shawn Carr. Sorry, can I just ask you to repeat the question, please?

M. BROPHY: Sure, yes, no problem. So I don't think you need the reference, but it was 3.1-BOMA-8. And the question was does Hydro Ottawa have information on what the maximum potential is in its service territory for energy efficiency, or EDSM, whatever you want to call it?

S. CARR: Maybe if I could ask the question a different way: Are you referring to, like, the regional planning process, and whether it takes into consideration all impacts of provincial EDSM?

M. BROPHY: Well, the full potential would include IESO EDSM, which you talked about this morning, and they would have that component.

And then there are other elements that are local that they don't have the knowledge on, so I am just looking at a holistic estimate, if Hydro Ottawa would understand what that potential is?

S. CARR: Yeah. May I just have a moment to confer, please, Mr. Brophy?

M. BROPHY: Sure.

S. CARR: Thanks, Mr. Brophy. So I think there are two parts to your question. I know you were asking about the local achievable potential study, and you were also asking about the load forecast.

So I am just going to begin by answering the first part of your question, and then I am going to recommend that you direct your load-forecast question to panel 3.

But with respect to the local achievable potential study, that is a study that is currently underway by the IESO, and the results of that study for the Ottawa region have not yet been published; we are expecting those results sometime in Q4.

And the purpose of that local achievable potential study is going to be to identify incremental opportunities for EDSM over and above what the IESO has already considered in their load forecast as part of the IRP process.

M. BROPHY: Okay, thank you for that. There was a discussion earlier this morning in relation to the EDSM, I think you call it Stream 2, the local EDSM; do you recall that?

S. CARR: Yes, yes, Mr. Brophy.

M. BROPHY: Just a quick question on that. I was a little confused. So, my understanding is that the local EDSM Stream 2 programs are targeted specifically for participating LDCs to focus on opportunities in their service territory that are not already addressed by the broader IESO EDSM portfolio; is that right or is it something different?

S. CARR: I'd like to first clarify that the Stream 2 process is not yet in place there is currently a regulatory consultation underway in regards to establishing a framework for implementing Stream 2 EDSM. However, as I had indicated this morning, within our investment plan we are proposing to deploy local non-wire solutions in collaboration with the IESO in a targeted region initially of Kanata North. And the details of that program can be found in 2-Staff-67.

M. BROPHY: Okay, thank you for that reference. And I am aware of the consultation that you mentioned, but I think you are likely aware that some of your peer utilities have already signed Stream 2 EDSM agreements and are advancing those programs; are you aware of that?

S. CARR: Mr. Brophy, I would just like to clarify that LDCs, including Hydro Ottawa, have signed an agreement to support the IESO with Stream 1 activities not Stream 2 activities. The consultation for Stream 2 is still underway.

M. BROPHY: And are you saying the local initiatives can't be included in Stream 1; is that your understanding?

S. CARR: Sorry. To clarify as part of the EDSM's new framework the IESO has allocated a budget within their CDM plan for local initiatives. Those local initiatives are intended to address regional constraints identified by the IESO through the IRP process.

M. BROPHY: And does that enable local initiatives identified entities by entities like Hydro Ottawa and their stakeholders?

S. CARR: In collaboration with the IESO, yes.

M. BROPHY: Yes.

S. CARR: But those are IESO led.

M. BROPHY: Okay. So, just to play it back you have an agreement in place with IESO for Stream 1, it allows you to identify, in consultation with stakeholders, local opportunities. You go back to IESO and you say here is the opportunities we think are there and then you fine tune it and then a program is then finalized for delivery; is that the way it works?

S. CARR: In essence. The only think point I would clarify is that it is the IESO that determines where those local initiatives are to be deployed. With input and support from the LDC in which that the program is targeting.

M. BROPHY: Yeah. And would you agree that the Ottawa area is one of the highest priority areas, it seems to always be referenced in all of the IESO DER and previously CDM response; so would you agree that it is a focus, a high focus area for IESO?

S. CARR: Yes, I would Mr. Brophy. Hydro Ottawa has a long history of collaborating with the IESO on local initiatives, going back to 2019 and we've been working with them over the last 3 frameworks to support those initiatives, in a mutual area of need in Kanata.

M. BROPHY: Okay, thank you. The next question relates to 1-CO-12 and that talked about the Ottawa retrofit accelerator program. And thank you for summary table in response to 1-CO-12 providing the details of the program, for the information you have available. And I have read from the response, and I don't want to put words in your mouth, but is it correct to say that Hydro Ottawa is committed to ensuring strong success of the retrofit accelerator program and that those results align with the energy transition needs and the Net Zero objectives?

S. CARR: Yes, I would agree with that statement. We are actively participating and supporting customers on their decarbonization journey and this program is allowing us to provide support and services, as well as external funding for building owners in the City of Ottawa to conduct carbon pathway studies and provide them with a roadmap to decarbonizate their facilities.

M. BROPHY: Yes, it sounded excellent. Thank you. So, the table in the IR response noted that energy savings results for 2024 were not available at December 31, 2024 and I understand that. Do you know when those results would be made available?

S. CARR: Sorry, which results are you referring to?

M. BROPHY: So this would be 1-CO-12, there was a table you provided with the results from the Ottawa retrofit accelerator program.

S. CARR: Yes, sorry and maybe just to clarify: Are you referring to the energy savings identified within that table?

M. BROPHY: Identified and then also achieved, I guess both. It would apply to both.

S. CARR: Yeah, I would suggest directing your question to Panel 2, they would be able to more details on the data found within table A.

M. BROPHY: Okay. Terrific, thank you. I only have one more question on behalf of CAFES Ottawa, and I think it is Panel 2, they would be the one that would talk about governance and coordination between Ottawa Hydro entities and the City of Ottawa; is that correct?

D. COBAN: I think, generally speaking, yes. I think, like, if you asked the specific question you had it could potentially be answered by Panel 1 because there are some elements of coordination that do occur with the participants with Panel 1, but otherwise governance and the City of Ottawa collaboration would be Panel 2.

M. BROPHY: Sure. Okay. Well, why don't I -- I'll ask the question and if I need to ask it again in Panel 2 I am happy to. So, it's in reference to 1-CO-1 and it discussed the relationship between Ottawa Hydro and its shareholder, City of Ottawa. There was, in advance of filing the application, this application we are here talking about, Hydro Ottawa did a presentation to the City Council on I think it was June 25th, 2025; that presentation, has it been filed?

L. HEUFF: That question would most definitely be better directed to Panel 2, Mr. Brophy.

M. BROPHY: Okay. Sure, no problem. Thank you. Okay. So, that's it for CAFES Ottawa questions and then I'm also asking questions on behalf of Pollution Probe so I'm happy to make that shift.

Okay. So, the first question on behalf of Pollution Probe relates to Pollution Probe-7A and that provides detail on how to interpret the numbers in the DER forecast found in 132, figure 7. So, maybe actually that might be helpful to pull up 132, figure 7. That might be the best reference point.

M. BROPHY: That's the one, thank you.

So on this chart can you explain what is driving the non-renewable DER numbers and higher forecast out to 2030? What is that coming from?

M. FLORES: So what we have seen in recent years, some customers are using non-renewable generation for the global adjustment initiatives.

M. BROPHY: So this is your forecast of what incremental non‑renewable generation projects your customers may put in largely to deal with, it sounds like global adjustment; is that correct?

M. FLORES: That's correct.

M. BROPHY: Is that just a -- maybe I will just ask it this way: How did you come up with that estimate? Is it just an extrapolation from the past, or did you do a survey or...

M. FLORES: It's an extrapolation from historical connections.

M. BROPHY: Okay. So you're extrapolating historical. And so the global adjustment has been in place a long time. Customers that are impacted by that that would have an opportunity to maybe reduce those charges, wouldn't it make sense for that to peter off? They'd already have those solutions in. Wouldn't that make sense?

M. FLORES: We still felt that it was important to consider that. As you can see here, the addition -- or the incremental additional capacity from 2024 to 2030, it's about ten mix, and it's not as -- it doesn't have as high growth as per the renewable connections.

So respecting that the growth for renewable connection would be much larger.

M. BROPHY: Okay.

M. FLORES: Especially in terms of count. Maybe not so much in terms of the total capacity, but in terms of connections, number of connections.

M. BROPHY: Okay. And why wouldn't you go out to customers to validate what their plans are so you could hone in on whether that number is real or not?

M. FLORES: That number will vary based on the incentives that are available. So we do know that historically there were some incentives due to Microfitbit, and 2024 there was incentives for the large solar ISO program, and that's why we used the historical incentives, and we know that it will have an impact on how the increase in DERs will develop over the years, and that's why it was used at this time.

M. BROPHY: Okay. And I think the examples you just gave are actually renewable DERs, and I understand that, and there's alignment with provincial policy to increase renewable DERs. It was just the non-renewables that looked a little odd.

So for the non-renewable DERs, those are all customers, or are any of those related to Hydro Ottawa projects.

M. FLORES: They are all customer projections.

M. BROPHY: All customers? Okay. Thank you.

Okay. The next question relates to Pollution Probe 3D and 11E, so you may not need to pull them up but if we do, I'm happy to wait for the right ones.

So both of those references, Pollution Probe 3D and Pollution Probe 11E, indicate that Hydro Ottawa has been coordinating with IESO on the Ottawa DER potential study.

I am assuming the panel is familiar with that?

S. CARR: Mr. Brophy, this is Shawn Carr. I would just like to clarify by Ottawa DER study that you are referring to the local achievable potential study that we discussed earlier?

M. BROPHY: Yes, my -- I'm -- because you didn't use the term DER in the previous study title, I'm assuming that was a different -- that was an EDSM potential study, not the DER one. Are you talking about the same thing, or are these two different studies?

S. CARR: My assumption in just reviewing this IR was that you were referring to the same study.

M. BROPHY: Okay. This one is for Pollution Probe 3D and 11E, specifically related to the Ottawa DER potential study, which is about DER potential in Ottawa. You are familiar with that study?

S. CARR: No, I am not. I -- my assumption was that you were -- that was referring to the local achievable potential study, which is going to consider, again, incremental opportunities for EDSM, including opportunities for DERs, energy efficiency demand response, and other technologies, so, again, my understanding was that you were referring to the same study.

M. BROPHY: So maybe I can just clarify this way. So first of all, there is questions the DER -- the Ottawa DER potential study and Ottawa's participation. Is that this panel or another panel?

L. HEUFF: Mr. Brophy, could you provide a reference to the DER potential study that you are referring to?

M. BROPHY: I don't have it available here right now, but it is an -- IESO launched last year two potential studies, one for Toronto, one for Ottawa, and they've been coordinating with what we have been told Hydro One and Hydro Ottawa on the Ottawa DER potential study, and it's just seeming a little odd that --

L. HEUFF: Are you certain that it's not the IESO-led local achievable potential study, which, you review the responses on the page now, it is looking at both the EDSM and DER assumptions.

M. BROPHY: Well, it could be possible that it has expanded beyond DERs.

L. HEUFF: So the only study that I'm familiar with that would include Hydro Ottawa, the IESO, and Hydro One looking at EER potential is the local achievable potential study that is underway currently.

M. BROPHY: Okay. And that's planned to be finalized when?

S. CARR: Hello, Mr. Brophy, this is Shawn Carr. Our understanding is that the IESO is expected to release the results of that study in Q4 of this year.

M. BROPHY: Okay. So not far away. And so it sounds like -- okay. Now that we know we are talking about the same study, even though the report hasn't been released yet, have you included any of the information from that study conducted over the last year in your capital plan or demand forecast?

S. CARR: No, we have not. We have not received any results from that study as of yet.

M. BROPHY: Okay, thank you.

Just a few of these questions were covered this morning, so I just want to make sure I don't duplicate.

Okay. I have a question. It relates to 1 Pollution Probe 6. And again, well, this one, it had panel 1, 2, and 3 listed, so I will try this panel, but you can quickly let me know if it should be one of the other panels.

And so Pollution Probe 6-8 clarified that Hydro Ottawa Holdings Inc. has committed to net zero operations by 2030, correct?

S. CARR: That's correct. The net zero target is at the holding company level.

M. BROPHY: Okay. And if we need to -- I don't know if we do -- there was the corporate structure reference you gave, which is 161, figure 1. You know, if we need it, we can pull that up.

So given that Hydro Ottawa Limited and the regulated utility are subsidiaries under Hydro Ottawa Holding Inc., would both Hydro Ottawa Limited and the regulated utility be encompassed under that commitment made by its parent corporation, Hydro Ottawa Holdings Inc.?

S. CARR: Mr. Brophy, I just want to clarify, again, that Hydro Ottawa’s Net Zero commitment is at the holding company level. But you are correct that, as the major subsidiary, we are a major contributor to that commitment.

However, Hydro Ottawa Limited itself does not have a Net Zero target.

M. BROPHY: Okay.

S. CARR: It is as part of the company; it is at the holding company level.

M. BROPHY: Okay. So all the entities, including the regulated utility then, would have to undertake activities in support of their parent holding company’s goal.

Is that reasonable to say?

S. CARR: That is correct.

M. BROPHY: Okay. And if one of the entities under Hydro Ottawa Holding Inc. undertook an activity that increased emissions, then the other entities, which could include the utility, would then have to do something to offset that.

Is that also reasonable to say?

S. CARR: Yes, I think that is a reasonable statement. Again, the target is at the holding company level, so the emissions associated with the subsidiaries would contribute to that. So Hydro Ottawa as a utility is committed to reducing its scope 1 emissions -- an example -- that will contribute to the holding company’s target.

M. BROPHY: Okay. Okay, I think I understand that. I thought it would automatically apply to every entity under, but I understand your response. Thank you.

And then in reference to 1-Pollution Probe-7(e), it's a similar situation. So 1-Pollution Probe-7(e) notes that:

“Hydro Ottawa Holding Inc. has a strategic direction which includes an objective to leverage and promote distributed energy resources.”

Are you familiar with that?

S. CARR: Yes, that's correct. That is one of eight strategic priorities at the holding company level.

M. BROPHY: Okay. And then how would that then apply to the entities underneath Hydro Ottawa Holdings Inc.? So, for example, does that mean that the utility has an objective to leverage and promote distributed energy resources? Or not?

S. CARR: Yes, that is the utility's objective.

M. BROPHY: Okay. So in that case, you share. So your holding company has it, and the utility shares that objective. Is that correct?

S. CARR: That is correct. And the response to part (e) of this interrogatory that you are responding to outlines all of the various activities that Hydro Ottawa as a distributed utility is undertaking to increase DERs and leverage the benefits that they provide in our community.

M. BROPHY: Okay. So in that case, if the utility felt comfortable adopting the Hydro Ottawa Holding Inc.’s objective so it is aligned, why wouldn't the utility also adopt Hydro Ottawa Holding Inc.'s commitment to Net Zero by 2030? What's the reason why not?

S. CARR: Sorry, can I ask that you, sorry, repeat the question. You are asking about why we would not adopt a Net Zero commitment the same way that the holding company has?

M. BROPHY: Yes, for the utility.

S. CARR: Yeah. Our commitment has been to focus on reducing our emissions. And maybe I could just provide some context on, you know, what our journey has been to date in that regard.

We have been working to lower our scope 1 emissions and, as the main subsidiary, we have been committed to continuing to make progress in that regard.

However, I would like to point out that the investments that we have made in this particular investment period have very limited funds associated with achieving Net Zero. We had to make that decision in order to balance affordability for the repair and, therefore, you know, that supports -- you know, one of the reasons why we are only committed to reducing our missions, because there is very -- we have very limited impact with the investments that are being proposed.

That said, we are committed to continuing to reduce our scope 1 and 2 emissions, and contribute to that target.

M. BROPHY: Okay. Thank you, for that.

So those are all the questions I have today on behalf of Pollution Probe, and I think that is it. There was a few referrals to panel 2 and 3, so I will just go back and make note of those adjustments so that they can be addressed with those panels. But thank you, very much, for the responses.

M. MILLAR: Thank you, Mr. Brophy.

Mr. Gluck, I think I have you up next. Are you there?

L. GLUCK: I am.

M. MILLAR: Lawrie, if you don't mind, maybe 10 minutes or so until a break, whatever, if you can find something in there?

L. GLUCK: Sure.

M. MILLAR: Or we can break now, if you like. What is easiest for you?

L. GLUCK: That is fine. I could go for 10 minutes?

M. MILLAR: Yeah, take us 10 minutes, and then we'll find a break. Thanks.

# Examination by L. Gluck

L. GLUCK: Okay, thank you.

Good afternoon. My name is Lawrie Gluck, and I am a consultant for the Consumers Council of Canada. I am hoping we could start with the response to 2-Staff-104 part (a), please? Okay.

And in this response, Hydro Ottawa discusses that it doesn’t include cable injections as part of its planned cable renewal program, but notes that it has in the past applied a cable injection strategy that it views as unsuccessful.

Is that a fair summary of this response?

M. FLORES: That's correct. We did have a pilot. There was applied in 2015 to 2019 period. That was not successful.

L. GLUCK: Was there any formal analysis completed at that time that shows the poor results of the previous cable injection program?

M. FLORES: We were of service on actually cable faults months after the cables were injected. So we would have the number of cable faults as a result of that.

L. GLUCK: Okay. Can you please undertake to provide any analysis and, if all it is is the cable faults, that's fine, but any analysis that Hydro Ottawa completed with respect to its views of the lack of success of the cable injection program that it ran previously?

M. FLORES: Let me confirm for a minute.

L. GLUCK: Sure.

M. FLORES: Okay. We will look to see what data we have, and we will provide what we have to support that.

L. GLUCK: Thank you.

M. MILLAR: That is JT1.20.

UNDERTAKING JT1.20: TO PROVIDE ANY ANALYSIS THAT HYDRO OTTAWA COMPLETED WITH RESPECT TO ITS VIEWS OF THE LACK OF SUCCESS OF THE CABLE INJECTION PROGRAM THAT IT RAN PREVIOUSLY

L. GLUCK: Can you advise whether you have tried to apply cable injections more recently than 2019? Or was that the last time that you applied that strategy:

M. FLORES: That was the last time.

L. GLUCK: Okay, thank you.

And do you have a high-level estimate of the cost differential between cable replacements and cable injection?

M. FLORES: Not at this time.

L. GLUCK: Can you undertake to provide that?

M. FLORES: Sure.

L. GLUCK: Thank you.

M. MILLAR: That is JT1.21.

UNDERTAKING JT1.21: TO PROVIDE A HIGH-LEVEL ESTIMATE OF THE COST DIFFERENTIAL BETWEEN CABLE REPLACEMENTS AND CABLE INJECTION

L. GLUCK: If we could please go to 2-Staff-59 part B, please? And in this response Hydro Ottawa discusses that it has no formal documentation regarding pole rehabilitation and the response notes that there is an investigation on this matter that is ongoing that forms part of a wider continuous improvement initiative; can you please advise when investigation began?

M. FLORES: It is still at the very early preliminary stages.

L. GLUCK: Should I take that as it hasn't really started or what happened --

M. FLORES: Initial discussions have started, but we don't have anything to share at this time.

L. GLUCK: Okay. And prior to this current investigation has Hydro Ottawa looked at pole rehabilitation in the past, or is this the first time?

M. FLORES: Yes, we have looked at that in the past, especially with pole wrapping, we have done it in the past.

L. GLUCK: And so, you have any analysis or reports that you did in the past in relation to pole rehabilitation or pole wrapping?

M. FLORES: No, we do not.

L. GLUCK: Okay. And can you provide a high-level estimate of the cost differential between pole replacement and pole rehabilitation?

M. FLORES: No, I wouldn't have that.

L. GLUCK: Can you undertake to provide that?

M. FLORES: Not at this time. It wouldn't be an analysis that could be completed by the time undertakings are due.

L. GLUCK: And when I say a high-level estimate, you know, is there something like -- is there sort of industry information that you could provide with respect to the differential between pole replacements and pole rehabilitation?

L. HEUFF: Mr. Gluck, I think the challenge that we're having with the response on this one is that it would largely depend on what analysis we are looking to undertake. So actually confirming that the pole wrapping was an effective technique would have to come first before we would be able to confirm what the cost differential would be. Presumably a number of the poles that were in too far of a degraded condition wouldn't be a good comparable for doing a full wrapping because it wouldn't necessarily remediate the issue.

And so, I think this one needs to be done more in a two-stage manner where we need to confirm whether any of the techniques that are on the market and available today would suffice to be leveraged in some manner still to be determined. And then at that point doing a comparative analysis from a cost basis would be more relevant at that point in time.

So, just because we haven't done that analysis and we don't have any basis to start with I think that's where we are kind of struggling to be able to provide that response.

L. GLUCK: Thanks. Are you aware of, you know, other LDCs in Ontario applying a pole rehabilitation type strategy?

L. HEUFF: Personally I'm not, it doesn't mean that others within this team are not however.

L. GLUCK: Okay. Okay, thank you for those responses. Mr. Millar, I think it's 3:30 now so happy to take our break.

M. MILLAR: Okay, great. You're not finished though, right, Mr. Gluck?

L. GLUCK: I am not.

M. MILLAR: Okay, great. Let's break now for 15 minutes and we will return at 3:46.

### --- Recess taken at 3:31 p.m.

### --- Resumed at 3:46 p.m.

M. MILLAR: We will continue with you, Mr. Gluck.

L. GLUCK: Thank you. If we can please go to CCC 18, Part C, please. In this response Hydro Ottawa notes that there is a $14.1 million cost overrun with respect to the Piperville MTS; is that correct?

S. CARR: I believe the reference is 14.7 million but, yes, the cost overrun statement is correct.

L. GLUCK: I think it is 14.1. It's the 38.7 million minus the 24.6 in the sentence before that, just for the record.

S. CARR: Yes, my apologies. I was referencing 14.7 earlier -- later on.

L. GLUCK: Okay. Thank you. And can you please undertake to provide a detailed analysis that compares the original cost estimate and the actual cost for the Piperville MTS, and with respect to any material cost variances, please provide detailed rationale.

S. CARR: So just so I understand the question, you're looking for the previous -- the approved funding for the Piperville MTS project, the presently forecasted total cost inclusive of spending from '21 to '25 period out until energization with '26, and then providing their major reasons -- reasons for major variances within that cost table?

L. GLUCK: Yeah, that would be right. The way I'm looking at it is, there would have been an original estimate with a number of line items that sort of build up to the budget for the Piperville MTS, and then now you have an updated forecast that is higher, and then you show those line items against each other, and then you explain any of the material differences.

S. CARR: Understood. Thank you for clarifying. Yes, I can undertake to provide data analysis.

L. GLUCK: Thank you.

M. MILLAR: That is JT1.22.

UNDERTAKING JT1.22: TO PROVIDE A DETAILED ANALYSIS THAT COMPARES THE ORIGINAL COST ESTIMATE AND THE ACTUAL COST FOR THE PIPERVILLE MTS, AND WITH RESPECT TO ANY MATERIAL COST VARIANCES, PLEASE PROVIDE DETAILED RATIONALE.

L. GLUCK: If we can please go to CCC 20, Part E, please. So in the question, Part E to CCC 20, we had asked about the details and the calculations showing how the 2026 to 2030 residential subdivision capital budget was forecast, and in the response here Hydro Ottawa provided a summary of the approach used to derive that forecast.

Could you please undertake to provide the detailed calculation used to forecast the budget for the residential subdivision capital program in Excel format?

S. CARR: Mr. Gluck, just to clarify your request, so you are looking for a tabular form of our gross cost budgeting approach for residential programs, whereby we took the gross cost averages from '21 to '23 and then inflated those by the stated reference within Part E?

L. GLUCK: That's right. So basically everything that you did to move from a historical cost to a forecast cost for '26 to 2030, we'd like to see, you know, every assumption that you made that moved from that historical period to the forecast period.

Maybe I can just give you my understanding of what you did, and maybe that will help, in terms of getting the correct information. So I understand that you took the -- it says 2021 to '23 average gross expenditures, excluding the discrete projects, you increase for growth, you made adjustments for inflation related to equipment and materials, and I assume that there had to have been a removal of discrete projects from the historical period, and you -- I mean, I don't know this, but did you add back discrete projects for the forecast period?

S. CARR: Subject to check, I believe, that was our approach to budgeting, yes, is removal of discrete projects and then inflating the historical average of the gross cost as you described and then re-adding the projects back in.

L. GLUCK: So that's what I'd like to see, how that -- with numbers, how that all came together.

S. CARR: Understood. Thank you. Yes, we can undertake to provide a tabular format of what's described in Part E.

D. COBAN: Thank you. Mr. Millar, can we give that an undertaking?

M. MILLAR: Yes, I'm sorry, it's JT1.23.

UNDERTAKING JT1.23: TO PROVIDE THE DETAILED CALCULATION USED TO FORECAST THE BUDGET FOR THE RESIDENTIAL SUBDIVISION CAPITAL PROGRAM IN EXCEL FORMAT.

L. GLUCK: And I have a number of very similar requests, so I think the quickest way to do it is I will just read the names of the programs, and I'm requesting the exact same thing that we just talked about for the residential subdivision program, so the other programs I'm interested in are the commercial development program, which is discussed in response to CCC 21, Part E. I am interested in the infill services program, which is in response to CCC 22, Part E. And I am interested in the system expansion program, which is referenced in CCC 23, Part D. So if you could undertake to provide the same sort of information as you agreed to for the residential subdivision program, thank you.

S. CARR: Thank you. And confirming I understand your request to be a tabular format of the description of the gross cost estimation approach for commercial infill and system expansion per the undertakings that you stated?

L. GLUCK: Yes. That's correct.

S. CARR: Yes, I can undertake to provide that.

M. MILLAR: That is JT1.24.

UNDERTAKING JT1.24: TO PROVIDE A TABULAR FORMAT OF THE DESCRIPTION OF THE GROSS COST ESTIMATION APPROACH FOR COMMERCIAL INFILL AND SYSTEM EXPANSION.

L. GLUCK: Thank you. If we can go to 2 CCC 23A, please. And there is a table A below, and can I ask for you to undertake to provide an expanded version of this table that includes 2023 and 2024, please.

S. CARR: Yes, I can undertake to provide an expanded version of that table inclusive of '23 -- excuse me -- yeah, '23 and 24, yes.

M. MILLAR: That is JT1.25.

UNDERTAKING JT1.25: RE: 2 CCC 23A, TABLE A, TO PROVIDE AN EXPANDED VERSION OF THIS TABLE THAT INCLUDES 2023 AND 2024.

L. GLUCK: And if we can please go to Part E of the same response. And here you provide a list of the discrete projects in both the historical and test years for the system expansion program.

And first of all, is that listing for the forecast period of those the projects, is that -- are those all of the discrete system expansion projects for the test year -- or for the test period, sorry?

S. CARR: No, those are not the expansive list of -- pardon me, they are not the list of -- the full list of discrete projects. That's merely in response to the reference in the question on page 53.

L. GLUCK: Okay. Thank you. Can you please undertake to provide all of the discrete projects for the forecast period and show both the gross capital and the capital contribution separately for those discrete projects?

S. CARR: I'd like to confer for one moment, please, thank you. Thank you, for that. I will need to confirm explicitly what is in the budget for discrete projects. However, I would like to note that some discrete projects are listed as placeholders based on conversations and inquiries with customers, as well as historical projections forward as to the volume of discrete projects. So we can provide those caveats in any undertaking, if requested.

L. GLUCK: That works. Thank you.

M. MILLAR: Okay. So that is JT1.26.

UNDERTAKING JT1.26: RE: 2 CCC 23A, TO PROVIDE ALL OF THE DISCRETE PROJECTS FOR THE FORECAST PERIOD AND SHOW BOTH THE GROSS CAPITAL AND THE CAPITAL CONTRIBUTION SEPARATELY FOR THOSE DISCRETE PROJECTS

L. GLUCK: Thanks. And with respect to the historical years here in the same table, 2021 to 2025, I am going to assume those are not all of the discrete projects; is that right?

S. CARR: Subject to check, I believe that is correct. But I would need to double-check the budget.

L. GLUCK: Okay. And can you please undertake to provide for the historical period all of the discrete system expansion projects for the historical period broken out between gross capital and capital contributions, similar to the request for the forecast period, or for the historical period?

S. CARR: Yes, I can undertake to review the financial information and provide that as requested for the 2021 to 2025 period.

L. GLUCK: Thank you.

M. MILLAR: JT1.27.

UNDERTAKING JT1.27: TO PROVIDE FOR THE HISTORICAL PERIOD ALL OF THE DISCRETE SYSTEM EXPANSION PROJECTS BROKEN OUT BETWEEN GROSS CAPITAL AND CAPITAL CONTRIBUTIONS

L. GLUCK: We could move to 2-CCC-24 part (a), please. We could go to -- if there is a table below? And if we scroll down a bit further?

So my understanding is -- actually on the next page please. My understanding is these removals are now being handled, the cost of those removals is being budgeted as part of the EOL voltage conversion program for the test year or the test years. Is that correct?

S. CARR: The cost that will result in the removals is budgeted under the end-of-life voltage conversion. However, the removals themselves are budgeted under the station decommission within OM&A.

L. GLUCK: Okay. Okay, that's helpful. Thank you.

Can we please go to exhibit 2, tab 5, schedule 4, page 304, please? Thank you.

So in this table, in table 38, Hydro Ottawa describes the various scenarios used in the decarbonization study. And I understand that Hydro Ottawa used the reference scenario to inform the IRP forecast.

Is that correct?

M. FLORES: That's correct.

L. GLUCK: And in the context of the release of Ontario's Integrated Energy Plan, can you please provide Hydro Ottawa's views on whether it continues to believe that the reference scenario is the most likely to occur? Or has the dual-fuel scenario, for example, become a more probable outcome since the release of the IEP?

M. FLORES: We haven't completed that analysis at this time.

L. GLUCK: Is that an analysis you are working on?

M. FLORES: Not currently, but it will be done.

L. GLUCK: And what would be the implications for your capital plan if you were to complete this analysis and come to the conclusion that the dual-fuel scenario is the more appropriate planning forecast?

M. FLORES: So our capacity investment plan is not -- it is driven by the Hydro Ottawa planning forecast, which addresses the immediate constraints of the system as well as its capacity for the committed loads.

The reference scenario which informed the IRP forecast is used to determine the actual size of the new stations that we are building. It wouldn't change the projects that we are putting forward for 2026 to 2030.

L. GLUCK: Thank you. Can we go to 3-CCC-34 part (a), please? And I think there's a table here? Thank you. So in table A, you provided the IRP forecast. And I understand that Hydro Ottawa submits an IRP forecast to the IESO in the context of the regional planning process. Is that correct?

M. FLORES: That's correct.

L. GLUCK: And can you please undertake to provide the IRP forecast report or document or whatever format it is in, that you submitted to the IESO?

M. FLORES: The IRP document, it is a public document that is available currently in the IESO website.

L. GLUCK: Okay. And can you advise when Hydro Ottawa first developed an IRP forecast? Was there an IRP forecast that was done prior to 2025?

M. FLORES: Yes. The IRP forecast was done prior to 2025, because the IRP process was started in 2024.

L. GLUCK: So there's no --

M. FLORES: Sorry.

L. GLUCK: I may have misstated my question. I mean, there was no IRP forecast for a year prior to 2020?

M. FLORES: No. The IRP process, it's a five-year process.

L. GLUCK: Okay, thank you.

M. FLORES: So the last one was completed in 2019.

L. GLUCK: Right. So just to confirm I am understanding your response: So there is no -- if I were to ask you to expand the column with respect to the IRP forecast, so go to years prior to 2025, that there would be nothing for you to provide? Is that a correct understanding?

M. FLORES: That's correct.

L. GLUCK: Thank you. And I think you mentioned this to me just a few minutes ago: Am I correct that Hydro Ottawa’s planning forecast that it uses for capital investment purposes is different from the IRP forecast that we are looking at in table A?

M. FLORES: The Hydro Ottawa planning forecast is a short-term forecast. And we also use the IRP forecast as the long-term forecast.

We need to consider both because, when sizing the station, we need to make sure that it's able to support future growth. A substation has a lifespan of around 50 years, so we will need to look at the mid- and long-term requirements to make sure that we are sizing the station accordingly.

L. GLUCK: Okay. And is there a Hydro Ottawa planning forecast that is different with respect to the numbers from what is shown for the IRP forecast? Would you have different numbers for the years between 2025 and 2030?

M. FLORES: Yes. And the Hydro Ottawa forecast is shown in exhibit -- in schedule 254, section 9 -- section 9.1, where we show the different forecast by region. Let me just find your page. One second. So, here is an example where we are showing the Hydro Ottawa forecast as well as the IRB forecast, figure 74, and this is specifically for the 44-KV region, which includes three transmission connected stations.

L. GLUCK: Thank you. And would it be possible for you to provide the total? I assume that's what I'm asking for. Is the total of the planning forecast across your various reasons in the same format as table A so that it is comparable? Table A to CCC-34, so that it is comparable to the IRP forecast; is that something that you can provide?

M. FLORES: Yes, we can provide that.

L. GLUCK: Thank you, and I have a little bit more that I think would fit into the same undertaking. Can you provide the planning forecast that we just talked, about going from 2015 to 2035, if it is available?

M. FLORES: Sorry, can you repeat the question?

L. GLUCK: Can you provide the planning, Hydro Ottawa's planning, forecast that we just discussed going back to 2015 up to 2035?

M. FLORES: Are you asking for the actuals because our forecast was started in 2024?

L. GLUCK: Okay. So, the actuals from 2015 to 2024 and then the forecast from 2025 to 2035?

M. FLORES: We have provided the actuals in one of the undertakings. Let me find it for you and see if that has sufficient information.

L. GLUCK: Sure.

M. FLORES: K. Can you bring up 272, Staff-272, please. Next page, please. So, here we are showing the actuals from 2000 until 2024; is that what you required?

L. GLUCK: Yes, that's fine. That's right, that is what I am looking for. So, for the 2025 to 2035 period, can we get Hydro Ottawa's planning forecast?

M. FLORES: Just to 2030?

L. GLUCK: 2035.

M. FLORES: At this time we are only able to provide until 2030.

L. GLUCK: Okay. So that's find then, thank you.

M. FLORES: Do you need it in a tabular format?

L. GLUCK: Yeah, in a table would be great. I think it depends on the response that you're going to give to SEC about this MVA versus megawatt issue, but if there's a planning forecast that's in megawatts and a planning forecast that is in MVAs we would want both.

M. FLORES: Okay.

M. MILLAR: The undertaking is JT1.28.

UNDERTAKING JT1.28: TO PROVIDE THE HYDRO OTTAWA PLANNING FORECAST 2025 TO 2030, IN TABULAR FORMAT, IN MEGAWATTS AND IN MVAS

L. GLUCK: Thanks.

M. RUBENSTEIN: Sorry, Mr. Gluck, if I can just jump in for a second. Ms. Flores, Mr. Gluck asked you about the IRP forecast that you provided to the IESO and I think you pointed him to the website; did I catch that correctly?

M. FLORES: I believe he was asking for the report and the report would be on the website as well as the underlying data that went into the report.

L. GLUCK: I was asking for the submission that Hydro Ottawa made to the IESO.

M. FLORES: Yes, and that will be an attachment to the report.

M. RUBENSTEIN: So this is why I have jumped in. My understanding is that the distributor, when they are providing their load forecast, they are providing it in more than just sort of a topline number; right? You are providing much more detail and as well as the method, the assumptions and the underlying data, there may be a template Excel file, I think the IESO uses for some?

M. FLORES: The IRB report has the tabular information by station as well as the rationale or the methodology description.

M. RUBENSTEIN: And we are talking about the most recent sub-region IRP or are we talking about the 2020 IRP?

M. FLORES: Yes. We are talking about the most recent one that was published at the end of July of this year.

M. RUBENSTEIN: But am I correct you are providing a much more detailed load forecast to the IESO? Forgetting what's in the report, you are providing something to the IESO with detailed load forecast information?

M. FLORES: We are providing load forecast information at the station level.

M. RUBENSTEIN: And can you provide that? Can you provide what you provide to the IESO, specifically?

M. FLORES: That's exactly what you will find in the attachment to the report.

M. RUBENSTEIN: Well then, is that -- I don't think -- presumably you are providing probably an Excel spreadsheet with specific information; can you provide specifically what's provided to the IESO?

M. FLORES: That's exactly -- we provide annual forecast at the station level, which is included in the attachment of the report.

L. HEUFF: Mr. Rubenstein, just for clarification is the request that you just want the Excel file or is it the data itself? Because the data is identical. Is it because you want the format to be Excel rather than the PDF format that it is in; is that the concern?

M. RUBENSTEIN: Well, I don't have the document right in front of me. So, how about we just hold it for now and circle back? I want to take a look at it.

L. GLUCK: Thank you. If we can go to Exhibit 1, Tab 3, Schedule 1, page 25, please. And here in table 8 you provide the 2025 to 2030 forecast system capacity that is used as part of the growth factor calculation. Can you please explain the differences between this forecast and the planning forecast that we previously discussed?

J. GILLIS: Yes, I can provide the difference. So the difference in the reference here is that this is the incremental capacity added to the system as opposed to a forecast of load growth.

L. GLUCK: Okay, thank you. And can you please undertake to expand table 8 with the historical system capacity from 2015 to 2024, if it is not already on the record.

M. FLORES: Yes, we can provide that background information, I believe.

L. GLUCK: Thank you.

M. MILLAR: That is JT1.29.

UNDERTAKING JT1.29: TO EXPAND TABLE 8 WITH THE HISTORICAL SYSTEM CAPACITY FROM 2015 TO 2024

L. GLUCK: And can we go back to 2-CCC-17, Part K, sub-part I, please. And here you responded that as the revenue load forecast was not employed in the capacity needs assessment, the impact on capacity needs and related capacity expenditures cannot be furnished. I do understand your response that you did not use the revenue load forecast to determine the capacity needs.

However, as a hypothetical, could you provide a summary discussion of the implications with a high-level estimate to the change in the capacity expansion-related expenses if you had used the revenue forecast for that purpose?

D. COBAN: Mr. Gluck, I don't -- can you help me understand how that's going to be of any assistance here, when the witness has and the response indicates that this is not what was used for planning purposes? I'm struggling with the relevance of your hypothetical.

L. GLUCK: It provides a sense of the differential between what is funded in rates now, paid for by ratepayers, and the amount that the utility is building for. So I think it is useful information to have a -- even if it's high-level -- an understanding of the differential between what is building and the cost of building for the future and the cost of what is being used in the upcoming term.

D. COBAN: I guess I'm struggling with it. I mean, maybe the witness can help us clarify whether something like this can be produced to the extent it was -- the planning wasn't done on this basis, you'd be asking us to redo the plan based on a hypothetical, which seems a bit beyond the scope of what we can do on undertakings, but maybe we'll ask the witnesses to comment on the feasibility of what is being asked here.

J. GILLIS: Yes, I would agree with Ms. Coban's assessment, and that we would have to redo the entire basis of the plan, and it doesn't seem practical at this point.

L. GLUCK: Okay. Thank you.

Can we go to CCC-17, Part K, that is sub-part 2, please. In this response Ottawa explains that if the six large load projects in the load summary stage are removed from the planning forecast, the Greenbank MTS and Cedarville MTS projects would be impacted.

And can you confirm for me that both of these projects are expected to be placed in service in 2028?

J. GILLIS: I will just have to take a moment to find the appropriate reference before I confirm for you.

L. GLUCK: I think it's in the table in CCC 7.

J. GILLIS: So the reference I was looking for, we don't -- I don't believe we need to pull it up -- was in Schedule 258. I'm looking at the Cedarville MTS upgrade. Right now we have it projected as going into service in 2028, and then the other reference station was Greenbank MTS, which is in the same section of 258. We have it listed as going into service in, as well, 2028.

L. GLUCK: Okay. But can you confirm that the total cost of these projects is approximately $74 million?

J. GILLIS: Sorry, again, before I confirm, I would like to make sure that I look at the specific evidence.

So in looking at page 50 in Schedule 258, the total cost we have associated with Greenbank MTS is 38.5 million; and the total cost we have associated with Cedarville is 35.3 million. So your assumption of roughly $70 million is correct.

L. GLUCK: Thank you. And in the response that we were looking at a second ago at CCC-17, Part -- yeah, there it is -- there's a bit of a discussion about -- that these projects can be diverted but not eliminated in the context of the response of eliminating the six large load projects. Can you discuss a bit more what you mean by deferred but not eliminated?

J. GILLIS: Yes, and that would be with respect to the timing of the specific needs as identified through the regional planning. While the growth is still expected to require the addition of a new station, as stated for Silver and Greenbank, the timing of that station may not be as exact based on the inclusion of those large loads.

L. GLUCK: In terms of that timing, would it be after the current CIR term, so after 2030?

J. GILLIS: I wouldn't be able to give you that information right now.

L. GLUCK: Thank you. Can we go to CCC 29, Parts A and B, please. So in these responses Hydro Ottawa explains that when large loads drive the need for system expansion, it follows the DSC to determine whether the project is an expansion or an enhancement, and to determine whether a capital contribution is required from the connecting and large-load customer that uses the OEB's prescribed economic valuation methodology.

And just for some context, can you confirm that, with respect to the capacity upgrade program, Hydro Ottawa has planned capital expenditures of nearly $350 million during the forecast period?

J. GILLIS: Sorry, can you repeat what cost you were referring to?

L. GLUCK: The cost for the capacity upgrade program for the '26 to 2030 period.

J. GILLIS: Yes, for the full program?

L. GLUCK: Yes.

J. GILLIS: Yeah, so that can be found in Schedule 258 on page 5. The costs of the capacity upgrade program for the course of 2026 to 2030 is roughly $343 million in capital.

L. GLUCK: Okay. And related to that capital, there's only $4 million of capital contributions; is that right?

J. GILLIS: I would have to find again the reference for it, but --

L. GLUCK: I'm using 1 Staff 1, the updated Chapter 2 appendix.

D. COBAN: Could you point us to where you are in 1 Staff 1, Mr. Gluck, just so we can all be on the same page?

L. GLUCK: Yes. If we go to Appendix II AA, the capital projects list, if you take the capacity upgrades and you add up those numbers from 2026 to 2030, and the system service capital contributions, it is about $4 million, and I understand that the entirety of those capital contributions is related to capacity upgrades. It would be below there, in the table, system service, if you go down a little bit more, up to capital contribution and then go up a little bit: 1.3, 2.6 and 370.

L. HEUFF: Yes, you are correct; it's also in schedule 258 on page 49.

L. GLUCK: Right, thank you. And for each of the station capacity upgrade projects that have or had capital spending during the 2021 to 2030 period, can you please undertake to provide a table that shows the classification of the project between system expansion or system enhancement the relevant large loads that will be using that capacity and the rationale for the classification in terms of the guidance provided in the DSC?

L. HEUFF: There were a number of requests that were just in that question. So just to clarify, there are capacity upgrades that are done under the capacity system service, where the primary driver is system service, which means that it wasn’t -- the primary driver was not the customer, although there may be customer contributions as a result.

And then there are other projects that are done under the system expansion within system access.

So can you just clarify what it is that you would like us to provide --

L. GLUCK: Yes, sure.

L. HEUFF: -- with respect to those projects?

L. GLUCK: Absolutely. So for the capacity upgrade projects that are listed in system service -- so to narrow it to that, I would like a table that shows the classification of the project between system expansion or system enhancement. And if you are saying they are all system enhancement, then that's what you will tell me, and the large loads that will be using that capacity. So a listing of that, including the megawatts -- so the demand from those customers, and the rationale for the classification that you have applied.

L. HEUFF: So they are all system enhancement as you did note. I believe the information has already been provided within section 258, and the rational; this follows the distribution system code of where the primary driver falls. And if the primary driver was through the load forecasting that the station is required, then it would fall under our system service bucket. And so we could provide to you which customers are considered in which stations.

The only problem is that there is some level of confidentiality that also comes in that we will need to have a discussion about. But Greenbank and Cyrville are the only two stations that currently are under service that I believe have customers attached to them under the system service bucket.

And so those $4 million of capital contribution are just associated with the customers on those two projects.

Under the system expansion bucket, there are station expansions that are under the system expansion bucket as well, for instance, with Hydro Road, where the primary driver was the customer, and the only reason the station is being built it as a request from the customer. And so those ones are all under system access within the system expansion program under system access.

So just to specifically -- like, I am just trying to understand exactly what it is that you are looking for us to provide, aside from what has already been explicitly laid out within the evidence already.

L. GLUCK: So I guess the additional information would be attaching the customers to the projects to the capacity upgrades and, you know, a summary of the rationale for each one, as to why it's your view that they are a system enhancement project based on the DSC.

L. HEUFF: I think I understand what it is you are looking for, and we can endeavour to provide that as best as possible. I mean, I believe, like I've already explained it, so it may just end up being another reiteration of what I have just described to you, but…

M. MILLAR: We will mark that is JT1.30.

UNDERTAKING JT1.30: TO CLARIFY SYSTEM EXPANSION REQUIREMENTS BY ADDING CUSTOMER INFORMATION AND A SUMMARY OF THE RATIONALE FOR EACH, WHY THEY ARE A SYSTEM ENHANCEMENT PROJECT BASED ON THE DSC.

L. GLUCK: Thank you. And I think you have mentioned in that, in the response you just provided to me, that -- so there were two stations or two capacity upgrade projects where you did perform the economic analysis. Is that right?

L. HEUFF: The economic evaluation for the customers on two of the projects.

L. GLUCK: Okay. And can you provide the analysis that you did?

L. HEUFF: Subject to check on confidentiality, I believe we could provide it.

L. GLUCK: Okay, thank you.

M. MILLAR: That is JT1.31.

UNDERTAKING JT1.31: TO PROVIDE THE ANALYSIS BEHIND THE ECONOMIC EVALUATION ON THE TWO PROJECTS.

M. MILLAR: Mr. Gluck, just doing a time-check here. You are pretty much at your time.

L. GLUCK: Yes. I just have one last set of questions. It shouldn’t take too long.

M. MILLAR: Okay.

L. GLUCK: Thank you.

If we go we could go to part (d) and (e) of 2-CCC-29, please. And here, Hydro Ottawa provides a description of its methodology for estimating the cost of station and distribution capacity upgrade projects.

For the Greenbank MTS, can you provide the detailed calculations showing the cost estimate?

S. CARR: Hi, Mr. Gluck. So just to clarify, are you looking for the cost breakdown for the Greenbank MTS project?

L. GLUCK: It's a cost breakdown. And, in reading this response, you mention how you do it. It is a summary of how you came to the cost estimate, and you use a -- it is discussed that you used historical comparator projects. And that's how you built up the estimate.

And what we are looking for is the math again, similar to the previous set of questions around the system access programs. But I am just using the Greenbank MTS as an example of your methodology, including the numbers of calculating the budget for the project.

L. HEUFF: Sorry, Mr. Gluck, could you please repeat the reference? I am just having a hard time finding where we are speaking of the -- what you are actually requesting. I don't see that in the reference to IR.

L. GLUCK: It's 2-CCC-29 part (d). In part (d), I asked:

“For each of the station projects, please explain the methodology applied for estimating the cost and provide the historical comparator projects that were considered in developing the cost estimates.”

And then here is the response. And it does summarize it, but I am looking for one example of the map that was done.

S. HAWTHORNE: Yes. We can generally provide the cost breakdown for the Greenbank MTS project as submitted within the rate application and the cost basis for the summary line items associated with that estimate.

However, I would like to caveat that in certain line items, there will be descriptions as to the scaling that were performed, and it may not be an exact table with calculations as you have requested, but we can commit to providing the cost estimate breakdown and the cost basis per line item, with an explanation as to a calculation in the sample as noted there, where available.

L. GLUCK: That works. Thank you, very much.

M. MILLAR: That is JT1.32.

UNDERTAKING JT1.32: TO PROVIDE THE COST ESTIMATE BREAKDOWN AND THE COST BASIS PER LINE ITEM OF THE GREENBANK MTS PROJECT, WITH AN EXPLANATION AS TO A CALCULATION IN THE SAMPLE AS NOTED, WHERE AVAILABLE

L. GLUCK: And I just have one last question. It's very similar, for the Greenbank MTS distribution upgrade, so this is really related to part (e), and I am using Greenbank MTS as an example again.

Can you provide the detailed calculations, showing the development of cost estimate?

S. HAWTHORNE: Again, similar to my response on the station side, we will provide a breakdown as to how the cost developed for the distribution capacity upgrade was informed for Greenbank MTS. And I can undertake to provide that.

That's great. Thank you.

M. MILLAR: That is JT1.33.

UNDERTAKING JT1.33: TO PROVIDE A BREAKDOWN AS TO HOW THE COST DEVELOPED FOR THE DISTRIBUTION CAPACITY UPGRADE WAS INFORMED FOR GREENBANK MTS

L. GLUCK: Okay. That is it. Thank you, very much, panel. I appreciate it.

M. MILLAR: Thank you, Mr. Gluck. Mr. Ladanyi, are you there? I have Pollution Probe next.

T. LADANYI: I am here, you can see me on the screen.

M. MILLAR: I can see and hear you great. Can you take us to -- well, if you finish before, great. But we have until 5:00.

# EXAMINATION BY T. LADANYI

T. LADANYI: Thank you, very much.

So I said hello to the panel already, and nice to see you again. In my first items, I would like to follow up on something that you discussed with Mr. Garner earlier today. And are you aware of the OEB's consultation on vulnerability assessment and system hardening it's actually for the court reporter, the short form is V-A-S-H, all in capitals and that was under docket EB-2024-0199.

M. FLORES: Yes, I am aware.

T. LADANYI: Did you participate in that? I actually checked the list of participants there, 97 participants, and I couldn't spot anybody from Hydro Ottawa, maybe you were there?

M. FLORES: I wasn't personally there but we did have one of our engineers participating.

T. LADANYI: Very good. So, I noticed that the OEB released in April a toolkit a VASH toolkit -- sorry, I'm going to have a drink of water. That would assist a participants or utilities in justifying investments for system hardening. For example, to project a system from severe weather events; are you aware of the toolkit?

M. FLORES: Yes, I am aware.

T. LADANYI: So, I presume the toolkit came out too late, you didn't actually use it for this application; did you?

M. FLORES: Not that specific toolkit, but we did have consultations with the OPB to review our resiliency value, which is very similar and in alignment with the VASH because it looks like at climate projections and it also asset-based variability assessments, and then it employs quantitative analysis to prioritize investments. So, that's a value that we use as part of our project optimization.

T. LADANYI: So, do you actually have, since you've consulted with the OEB and you have those, would it be possible for you to file this as an undertaking, this assessment that you essentially got from the consultations with the OEB?

M. FLORES: So, we do have a section in 254 that shows our resilience assessment.

T. LADANYI: That's of a summary nature, isn't it? But do you have a more detailed information? Specific projects --

M. FLORES: Can I talk for a --

T. LADANYI: Please.

M. FLORES: So the resiliency business case that we did, which is attached in 254, attachment E, it goes through the methodology; is that what you are referring to?

T. LADANYI: More or less.

M. FLORES: Yeah, because this is a methodology that we would review with the OEB for the consultations.

T. LADANYI: Very good. Well, I'm going to review that, so this was only a side question. I was not originally planning to talk about this. Well, thank you, all. I will check that and maybe deal with it later in this case.

So, my first area of focus, and I sent the areas of focus in my letter to you on September 15, my first area of focus is the cost imposed on Hydro Ottawa by customers who own rooftop solar exporting DERs and the revenues that Hydro Ottawa collects from them. I should first disclose that I'm on every OEB committee and working group dealing with DER connections, so I write up on DER stuff. So, I mean probably know more than I ever want to know about DERs. But, anyways, so please turn to interrogatory response 4-EP-5. And can we have that on the screen, please? Thank you. And question A, I asked what percentage of Hydro Ottawa customers currently asked what percentage of Hydro Ottawa currently own DERs and you replied that the percentage is 0.4 percent, which is a very small number, as you know. And then in question B, I asked what percentage of your customers will own DERs by 2030, and the percentage is 0.5 percent so it's less than one-half of 1 percent. And then in your answer you directed me to figure 13 of Schedule 251. So, can we have that on the screen, please? Exhibit 2-5 Schedule 1, and it's on page 74. And there it is. Thank you very much.

We see there the number of requests for DER connections has increased from less than 50 to slightly more than 150 by over the span it was reported, which was by 20 -- sorry, I can't see very well -- 24.

One of the problems when discussing DERs is what is a DER? And in figure 13 you show 6 categories. You show solar; BESS, which is Battery Energy Storage System, which is a combined solar BESS; solar PV; fossil diesel; fossil CHP, which is combined heat and power; and natural gas, biogas, and battery energy storage systems. Why did show those categories like that? Because they're just kind of unusual grouping, and I was surprised when I saw it, and I'm still kind of confused. Because typically OEB doesn't show DERs this way. Can you explain why you decided to show them this way?

M. FLORES: The purpose just was just to reflect all the different requests that we get for connection impact assessments.

T. LADANYI: When I look at this table, or actually figure, am I right that some of these are only low displacement and that they are for the customers' use only, while others are low displacement and exporting which they export excess power to the system; is that right?

M. FLORES: That is correct.

T. LADANYI: Now, you discussed earlier today with Mr. Brophy the customers that might be using, let's say, fossil fuels and you mentioned that they were trying to avoid paying global adjustments. So these would be the customers under the Industrial Conservation Initiative; is that right?

M. FLORES: That's correct.

T. LADANYI: And that's open to certain customers. Initially I think that it was limited to customers whose load was greater than 3 megawatts, and then the government reduced it to 1 megawatt, and then they expanded it to include institutional customers. So that would account for the growth wouldn't it; that Mr. Brophy was mentioning and wondering about?

S. CARR: Hello, Mr. Ladanyi. Shawn Carr here. I'm sorry, I'm not sure that I'm in a position to be able to answer your question as it relates to how this correlates with who is participating in ICI.

T. LADANYI: Well, why don't I explain it to you another way, just so we understand the issue that Mr. Brophy was bringing up. Let's see if we can agree on what this is really about. So, under ICI a customer that can generate their own power during 5 peak hours during the year can avoid paying a portion of the global adjustment. And so, therefore the customer has to be able to generate electricity whether it's in the middle of the night or, you know, when there's no wind, when there's no sun. So, therefore, they have to have a very reliable source of electricity. One possible is batteries, but they are more expensive and most of these customers have actually a gas turbine or a reciprocating engine, that is what they really have. Would you be aware of that?

M. FLORES: Yes.

T. LADANYI: Very good. Would you for a moment turn to a previous page. So this is table 12, yeah, here. So, how does this relate to the -- when you say total system generator account. So these are people that connected to your system who can generate their own power; would that be right?

M. FLORES: That's correct.

T. LADANYI: And these would be what kind of customers? Would they only be people who actually, like, have generators or would this also include also the customers that might have rooftop solar?

M. FLORES: It would include both.

T. LADANYI: Okay, thank you. Now, one other area which might be included in here, I understand that the Building Code requires that tall buildings with more than 6 stories are required to have an emergency power generator so they can power elevators and water pumps in the building if the power goes out. And are these included in this

in this total? So are these the buildings with emergency power generators included in this?

M. FLORES: No, that would not be included in this total, because they wouldn't require connection impact assessment, since they are not connected parallel to our systems.

T. LADANYI: Very good, thank you.

So in question C of the interrogatory referred to, which was 485, I asked you to please confirm that customers that own DERs impose higher costs on Hydro Ottawa than customers that do not own DERs, and you actually agreed with that. You say they may impose higher costs. And then you listed some of the kind of reasons why they would. From billing and settlement perspective, customers who export the grid impose higher costs, as it requires additional activities such as billing function, data capture of view time, and settlement with the IESO.

Can I ask you, what is the estimate of those costs for the test year? So these would be incremental O&M costs that customers that own DERs impose on the Hydro Ottawa system.

M. FLORES: I would have to refer that question to panel 3.

T. LADANYI: Very good. I'll ask panel 3.

Now, this panel can perhaps answer about capital costs that these customers impose. So for example, capital for DERMs, or DER management systems. Can you please turn to your letter to Mr. Murray of July 4th, 2025? It's on the record in this proceeding. Yes, scroll down a bit. Right here the Board Staff has asked you to update some numbers, and you did, and here it shows what you are spending on SCADA and ADMS, and just for the record, and for everybody in the room who may not be up on these things, so what is SCADA -- and by the way, for the court reporter, it is S-C-A-D-A, all in capitals.

G. CHRETIEN: Yes, it’s Guillaume Chretien here. So basically, SCADA is a supervisory system that captures data coming from the field asset.

T. LADANYI: Yes, I think it stands for supervisory control and data acquisition system.

G. CHRETIEN: That is correct.

T. LADANYI: And does Hydro Ottawa need to have SCADA in place where they are exporting DERs?

G. CHRETIEN: So actually, a SCADA system is the baseline system, right, to -- but DERs, like, especially large load, can be directly connected through the SCADA system to be managed. However, for smaller loads -- and this is why the project here -- we need SCADA plus DMS, which is part of the DMS project, to basically then put a DERM system on, so basically, to take a step back from the technology standpoint, the advanced distribution management system is basically foundational for DERMS.

T. LADANYI: Well, thank you. So as I understand it, to have a system with many DERs on it, you really definitely need ADMS, and you would probably already have SCADA on the system, so these are two costs that are caused by having DERs. If you did not have DERs, you would definitely would not need ADMS; is that right?

J. GILLIS: No, I wouldn't quantify it as so simply as that. ADMS enables a number of different functions, including just the ability to better manage the grid regardless if there are DERs. There are additional benefit that can be unlocked through it with DER. However, it's foundational just for operational purposes of the grid and the system.

T. LADANYI: Well, it's nice to have for other reasons, but what I'm saying, if you have DERs and you don't have ADMS, then you can't operate. You need to have ADMS. Now, ADMS can be used for other things, as can SCADA; is that right?

J. GILLIS: It can be used for other things, and I would quantify that you can perhaps operate a system with DERs, depending on the size and scale and complexity of your network, without an ADMS.

T. LADANYI: So for the -- one of the problems that DERs may cause is islanding? Can you tell me what islanding is?

J. GILLIS: Yes, islanding refers to when the grid doesn't provide power and the generator themselves can back feed on to the system.

T. LADANYI: And they can therefore remain charged, and then when the grid comes back on there could be some issues with synchronizing; is that right?

J. GILLIS: That's correct.

T. LADANYI: Okay. So one of the systems, as I found out from other proceedings, is that one should have FLISR, which is F-L-I-S-R, for the court reporter, which is fault location and system restoration -- and service restoration, sorry, and you have FLISR on your system?

J. GILLIS: No, we do not.

T. LADANYI: Are you planning to sell FLISR? Because some utilities in Ontario are. Are you?

J. GILLIS: I believe that it is -- we are looking at it as part of our ADMS program.

T. LADANYI: Okay. So if -- well, because you have so few DERs, so as you have more DERs, which I expect you will, you are going to eventually need FLISR, and there will be a cost associated with FLISR; isn't that right?

J. GILLIS: So I would actually provide a point of clarification that FLISR is actually used for fault location identification and service restoration, which is in use regardless if there is DERs or not, and perhaps you are referring to a DERMS platform, which is the distributed energy resource management system, instead?

T. LADANYI: All right. Okay. Very good. And there is also another one, another system is volt wire optimization. Do you have that?

J. GILLIS: We do not.

T. LADANYI: Some of the utilities in Ontario are installing that because of DERs. You are not installing that because of DERs? Are you even looking into it?

J. GILLIS: It's further down on our road map to contemplate, should there become an issue. Right now we don't have any of those concerns that would require a volt wire optimization.

T. LADANYI: Now, I understand that the OEB is developing a province-wide capacity information map in response to a directive from the Minister of Energy, and all distributors, including Hydro Ottawa, are all participating -- I'm absolutely sure they are -- and one of the objectives of the map is to assist DER owners in finding locations to connect DERs. That's actually stated. So are you aware of that initiative?

J. GILLIS: Yes, I am.

T. LADANYI: So how much is Hydro Ottawa spending on the capacity information map?

M. FLORES: So we are participating in the working group conversations. Earlier this year, I believe it was in July, we published the capacity map as requested by the OEB. We're currently working with the OEB working group to provide information for the wider province-wide capacity map that would be available in the OEB website, and not just capacity for load, but also the hosting capacity map that is being currently discussed.

T. LADANYI: So I'm a member of the working group on the capacity map, and I suggested at an earlier meeting there should be deferral account to collect all the costs, but nothing has happened there. Are your costs substantial, or are they negligible, so you don't care what the costs are?

M. FLORES: For the initial request by the OEB, we were asked not to incur any cost to develop that map and just do it with existing services. For the future one, again, we are just using information that we have available. I don't believe we have a cost right now for that.

T. LADANYI: But this will be an ongoing cost, because you'll need to update the map each quarter; is that right?

M. FLORES: That's correct.

T. LADANYI: So I have some questions about operation and maintenance administration costs that customers who own exporting DERs impose on Hydro Ottawa. Is that for this panel or another panel?

J. GILLIS: Sorry, can you restate the question, please?

T. LADANYI: Yes, there's operation maintenance and administration costs that customers who own DERS impose on Hydro Ottawa, and I wanted to have an estimate of those costs, so that would be for another panel; is that right?

J. GILLIS: Yes, I think it probably would, but you can potentially ask if there's any specific questions that we can answer from our perspective.

T. LADANYI: Yeah. Well, actually, I am most interested in this part because, as I see it, that customers who own exporting DRs are causing a revenue deficiency. Either revenues received from those customers are not sufficient to pay for all of the costs, all of the O&M, and also capital costs.

Would that be right?

L. HEUFF: Any related questions are much better positioned for panel 3, Mr. Ladanyi.

T. LADANYI: Very good, thank you.

So let's go to another interrogatory, 4-EP-4; I am almost finished. And can we go to that? And if we go to table A, which is in the response. And there it is. Very good. And you show transportation electrification assumptions. Under “charger types” you show L1, L2 and DCFC. What do those stand for?

M. FLORES: That would be the level 1, level 2 and level 3 charger.

T. LADANYI: What do the letters, “DCFC”, stand for. Is it DC fast charger? Is that what it is?

M. FLORES: That is correct.

T. LADANYI: Okay. What is the peak load of each of those chargers, in kilowatts?

M. FLORES: I don't have that information available, right now.

T. LADANYI: All right. And what is the peak load of a residential home without an EV recharger?

M. FLORES: I don't have that information available.

T. LADANYI: Can I have an undertaking? And I will explain the undertaking: I would like to compare the peak load of a home, a typical home -- and you can decide what is your typical home in Ottawa -- without an EV charger compared to a typical home with an EV charger.

And, from other proceedings with other distributors, I have found out that a typical home with a level 2 charger is equivalent to about three typical homes without a level 2 charger.

But your numbers could be different. I mean, it depends on insulation and the type of typical homes in Ottawa. But this is what I am kind of expecting to hear from you, but maybe you can provide what it is for Ottawa?

L. HEUFF: Just to clarify the request. Are you looking for the capacity or the consumption?

T. LADANYI: I am looking for the highest load, because I am trying -- I don't care about the capacity. I am looking for what it is, you know, because what kind of demand is a level 2 charger placing on a home, on your system?

So you have can have a street, for example, and one house has a level 2 charger; probably no problem. But suppose that all houses, let’s say all -- a hundred homes suddenly have level 2 chargers. Then you are going to have a system upgrade of some kind. You are going to need probably new distribution transformers, whatever.

And this is the issue that I am getting at, the costs that are imposed on the system by people who have EV chargers, particularly level 2 chargers. And I don't think the level 3 chargers are actually for residential customers; they are commercial.

L. HEUFF: So what I understand you are looking to gather is the peak demand, that is the difference between a home with and without a residential charger, and you are looking to understand the differences in peak demand forecast, for one home?

T. LADANYI: Yes, but only for one -- exactly, only for a level 2 charger. Level 1 I know already is negligible, because it is too slow.

L. HEUFF: Understood. We can look to see whether we have that information available, and provide it to you.

T. LADANYI: Thank you.

M. MILLAR: That is JT1.34.

UNDERTAKING JT1.34: (A) TO ADVICE THE PEAK LOAD OF EACH OF THOSE CHARGERS, IN KILOWATTS; (B) TO ADVISE THE PEAK LOAD OF A RESIDENTIAL HOME WITHOUT AN EV RECHARGER

T. LADANYI: Did you take into account the loads of an EV chargers in your distribution system plan?

L. HEUFF: For this point in time for any of our new residential connections are considering EV chargers, we do have -- have clarified that our standard, the UKS 171 standard, which has been submitted as part of this filing, does consider EV chargers at residential homes. And so all new residential construction does contemplate having EV chargers in the homes.

T. LADANYI: That would mean having proper size distribution transformers; is that right?

L. HEUFF: That's correct.

T. LADANYI: So EV customers -- with EV now -- not everybody in Ottawa is going to have an EV charger. There are older parts of Ottawa that probably nobody has an EV charger. So if you are proceeding with what you are doing, well, won’t the customers in older parts of Ottawa who do not have level 2 chargers end up subsidizing customers who do have EV chargers?

L. HEUFF: Not necessarily. Heat pumps as well, if you consider the usage of heat pumps, they would also require a 200-amp panel. And so our analysis is looking to ensure that all customers can have 200-amp panels on their service, which is a standard service size offering for this point in time, which will enable both EV chargers, but also heat pump adoption as well.

And so that's something that could potentially be used by some customers and not others, as well as the heat pump versus the EV charger, but both would require the service upgrade in order to enable them.

T. LADANYI: My last area, and actually it probably will not be for this panel; it is the cost imposed on Hydro Ottawa by customers converting from home heating with natural gas to home heating with electricity, and the revenues that Hydro Ottawa collects from them or would collect from them.

And I wanted to know how and why -- in the question I asked, how and why is accelerated electrification driving up OM&A costs. Would that be for you? Or would it be for another panel?

L. HEUFF: It would depend on which OM&A cost you are specifically referring to, if they are operational OM&A costs, then this panel would be able to speak to them. If there are other OM&A costs, such as billing or anything else, them potentially not.

T. LADANYI: Well, we can just go to this. In your answer, you took me to pages 9 to 10 of exhibit 4, tab 1, schedule 1. Can we have that on the screen, please? And that is my last area, really.

Okay. And pages 9 and 10? Okay. And there is a listing of -- sorry, let’s go to growth and electrification. That’s right. So go to the next page. And the next page lists the specific areas that electrification is causing cost increases.

Do you see that? So would that be for this panel, or for another panel?

L. HEUFF: It might be a mix of the two.

T. LADANYI: Okay. Can you tell me just in general terms how much is electrification increasing OM&A costs from 2025 to 2026? So this is just like a one-year increase.

L. HEUFF: Sorry, I don’t have any -- I wouldn't be able to provide that number. I don't believe we have ever undertaken such a calculation.

T. LADANYI: But you are saying it is increasing; it’s right there on the screen in front of us, isn't it?

L. HEUFF: Yes. I think that is a more than -- just to say in a traditional sense.

T. LADANYI: Okay. So on electrification, you just told me t is causing you to change how you are designing your system. So it's increasing capital costs. And I am putting to you that it's also increasing OM&A costs. I mean, you pretty well admitted it; I just wanted to know the exact numbers. But it is increasing.

L. HEUFF: It's also increasing the load, as well, so that's where I think question -- panel 3 is probably the better panel to direct your question, since the costs are directly also related to the load that would be increasing as well. So I don't think this is the appropriate panel to be discussing the cost recoveries and the allocations.

T. LADANYI: Quite right, and I will discuss it with them. I intend to show in my argument, and argue, that electrification is causing a deficiency, a large deficiency for Hydro Ottawa, as it is causing deficiency for many utilities across the province. And this came up during the cost of capital proceeding two years ago.

Anyway, these are all my questions, and thank you, very much.

M. MILLAR: Thank you, Mr. Ladanyi.

And that concludes Day 1 of the technical conference. We will be back tomorrow, promptly at 9:30, with BOMA, I think, so that is Mr. Lee.

Ms. Coven, is there anything more we need to discuss before we adjourn for the day?

D. COBAN: No. I think we are good. I did make a request for us to be able to just review the list of undertakings before the transcript is published, Mr. Millar, just to make sure that they have been all adequately captured on the transcript if that is possible.

M. MILLAR: Well, we will see what we can do. But normally the transcript will be issued, like, very shortly. So maybe we can take this offline. I know sometimes there are issues with undertakings and sometimes we have to deal with that by clarifying them after the fact. But we will see what we can do here, and it's probably not useful for us to discuss it in the open session here.

So why don't we adjourn for the day and we will see everyone at 9:30. Thank you.

### --- Whereupon the hearing adjourned at 5:07 p.m.