

ONTARIO ENERGY BOARD

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| FILE NO.: | EB-2021-0110 | Hydro One Networks Inc. |
| VOLUME:  DATE: | Technical Conference  December 15, 2021 |  |

EB-2021-0110

**ONTARIO ENERGY BOARD**

**Hydro One Networks Inc.**

**Application for electricity transmission**

**and distribution rates and other charges**

**for the period from January 1, 2023**

**to December 31, 2027**

Technical Conference held by videoconference

from 2300 Yonge Street,

25th Floor, Toronto, Ontario,

on Wednesday, December 15, 2021

commencing at 9:00 a.m.

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TECHNICAL CONFERENCE

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JAMES SIDLOFSKY OEB Counsel

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NANCY MARCONI OEB Staff

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ASHLEY SANASIE

MICHAEL DESONGO

TRACY GARNER

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JONATHAN McGILLIVRAY Resource Coalition (DRC)

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SCOTT POLLOCK Canadian Manufacturers & Exporters (CME)

TOM LADANYI Energy Probe Research

ROGER HIGGIN Foundation

KENT ELSON Environmental Defence (ED)

RANDY AIKEN London Property Management Association (LPMA)

IAN NOKES Ontario Federation of Agriculture (OFA)

RAEYA JACKIW Ontario Sustainable Energy

TRAVIS LUSNEY Association (OSEA)

MICHAEL BROPHY Pollution Probe (PP)

JOHN DeVENZ

RICHARD STEPHENSON Power Workers' Union (PWU)

MIKE McLEOD Quinte Manufacturers Association (QMA)

MARK RUBENSTEIN School Energy Coalition (SEC)

JAY SHEPHERD

FRED ZHENG

MARK GARNER Vulnerable Energy Consumers

BILL HARPER Coalition (VECC)

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Wednesday, December 15, 2021

### --- On commencing at 9:00 a.m.

MR. SIDLOFSKY: Good morning, everybody. Welcome to day 3 of the technical conference for the Hydro One joint transmission distribution application. We are still on panel 2. And I believe that Mr. Garner has a preliminary matter.

# Preliminary Matters:

MR. GARNER: Yes, thank you. Mark Garner for VECC. It's directed towards Mr. Keizer, and maybe I just can't find this. Mr. Keizer, last night when I was preparing, I couldn't find any of the CVs for any of the panels, and as I was trying to determine certain things. I am just wondering, were those filed and I just haven't found them in the right place?

MR. KEIZER: I don't believe they were filed, but they --

MR. GARNER: I am sorry, I didn't hear that.

MR. KEIZER: Sorry, sorry, I don't believe that they were filed, but we will do so.

MR. GARNER: Thank you very much, Mr. Keizer.

MR. KEIZER: No problem.

MR. SIDLOFSKY: And if that's all for preliminary matters, we are going to begin with Energy Probe this morning. Mr. Ladanyi.

# HYDRO ONE NETWORKS INC. - PANEL 2, DISTRIBUTION PLAN & GENERAL PLANT, resumed

Bob Berardi

Kevin Marcotte

CK Ng

Teri French

Peter Faltaous

David Paish

# Examination by Mr. Ladanyi:

MR. LADANYI: Good morning, panel. My name is Tom Ladanyi. I am a consultant to Energy Probe. It's great to see some of you again. I think the last time I saw you was in EB-2017-0049. You may not remember me. I have a beard now. It's a good way to hide a double chin.

Anyways, so let's start. I have quite a lot of questions. Please turn to B3-Energy Probe-31. And this is going to be for Mr. Paish. That's right. And here Energy Probe asked for an explanation of how the forecast of total investment costs of the meter-sustaining program was prepared.

So can you please then turn to page 2 of the response. And here in the top table you mentioned an error of $9.6 million. Can you explain what the error is and how it came about?

MR. PAISH: Mr. Ladanyi, this is Dave Paish. You can see that we have provided the corrected version directly below.

MR. LADANYI: Yes, I see that. I was wondering why there was an error. It seems to mention something about the costs of removal. Can you tell me, were they forgotten or did the accounting change? That's what I actually want to know.

MR. PAISH: There was an omission. The cost of removal was just omitted and corrected thereafter once we realized it.

MR. LADANYI: So are the costs of removal charged to accumulated depreciation? Would you know that?

MR. PAISH: No, I don't believe it is, but I cannot be certain myself.

MR. LADANYI: Okay, we might leave that for the hearing.

So has the rate base increased as a result of the correction? Do you know that?

MR. PAISH: I do not believe that the rate base has increased as a result of the correction.

MR. LADANYI: Okay, so turn to page 3, please. So page 3, there is also a correction as well because of costs of removal.

And may I ask you this: Are you the person who has actually noticed these errors and corrected them or did somebody in finance notice these errors and correct them?

MR. PAISH: It was discovered by our planning group once they reviewed the numbers.

MR. LADANYI: Okay. So you were not part of that finding of the error.

MR. PAISH: I was not personally involved, no.

MR. LADANYI: Okay. So you just accepted what they said. Fine. So maybe you can turn to, then, page 4. Maybe I will ask you a question you could answer.

If I see that on page 4 the number of units, see the units on the top line and how they seem to be sort of declining over the years? What does that indicate? Does that indicate that you're removing the old AMI equipment and replacing it with some new equipment; is that what it indicates?

MR. PAISH: That is correct.

MR. LADANYI: So when you replace -- I am assuming that -- so these are mainly what I used to call smart meters; are they not?

MR. PAISH: Yes, it is smart meters, but also the other infrastructure --

MR. LADANYI: The other equipment. I understand there's other equipment as well.

And so there were technical problems with those, and as they're kind of tested and found to be faulty they are replaced with new units? Is that what's going on here?

MR. PAISH: With the AMI2 project, which we are contemplating, we will be replacing with new technology. However, the AMI1 meters, currently installed meters, are continuing to fail and will be replaced as they do so, either in a -- hopefully a mass deployment initiative, but as they fail in an area we will be replacing them as one by one.

MR. LADANYI: So are they currently being replaced or is this something that's going to be entirely in the future?

MR. PAISH: Today as the meters are failing we replace them one by one --

MR. LADANYI: With AMI2, or are you replacing them with the same, AMI1?

MR. PAISH: Same, AMI1.

MR. LADANYI: Okay. And the reason why you're still using the old AMI1 is that you have not actually made a final decision to kick off the AMI2 replacement; is that right?

MR. PAISH: That is correct.

MR. LADANYI: Okay, thank you. Now we will go to another interrogatory, and this is going to be for a different witness. Please turn to B3-Energy Probe-33. And there we are talking about the distribution lines, trouble call, and storm damage response program. So if you can turn to page 2, you mention in that middle paragraph that you found another error. Could you explain to me what the error was?

MR. FALTAOUS: Good morning, Mr. Ladanyi, this is Peter Faltaous.

MR. LADANYI: Yes, thank you.

MR. FALTAOUS: So as we were going through this in the description we basically just talk about how we calculated the budget for the storm damage response using historical values, and you can see that we go quite a ways back in terms of years, and upon reviewing this it was determined that the 2005 year specifically was accidentally left out of the calculation, and so that was corrected and the revised numbers were provided here.

MR. LADANYI: So on Table 1, those estimates are really based on the projection of a trend that you saw in previous years; is that right? You are using numbers from the previous years and you're somehow extrapolating them into the future; is that what I am seeing there?

MR. FALTAOUS: That is correct, we are using historical numbers to project the dollars that are needed for this demand program going forward.

MR. LADANYI: So that's why I see sort of a linear projection. That's what it looks like to me, just eyeballing it. Would I be right?

MR. FALTAOUS: That's correct.

MR. LADANYI: Okay, thank you. Can we turn to B3-Energy Probe-34. And here we are talking about the pole sustainment program. Could you tell me, look at the table, could you go up higher, yeah. Right. The table. Now, I look at the table. Can you explain to me what are the units of the numbers in the table? What are they in -- they are just numbers, but should they have some kind of units?

MR. FALTAOUS: So the risk mitigated would be risk units, and the risk spend efficiency would be risk unit per dollar spent, although this -- I can't tell you whether or not there is a specific multiplier in here. I think that would be a more appropriate question for panel 1. But that is essentially what these two different columns represent in terms of units.

MR. LADANYI: Yeah, I actually looked at the reference either in (b) -- you reference B-3-01, section 3.7, page 9, line 4, and I read that -- and by the way, your name is on that evidence. But anyway, then I also went to section B-01-01, and your name was not on that evidence. And I tried to figure it out and I must tell you I could not figure out how the fact of the units, or anything. So I am very puzzled by it.

I will tell you this. What do you expect the commissioners to conclude by looking at these numbers? So forget about me. Think about the commissioners. They are going to see this table, and what conclusion should they make looking at this table?

MR. FALTAOUS: So your question is a little bit -- it's not very specific. I mean, I can tell you what this table represents, which is essentially --

MR. LADANYI: Can I make it specific for you? Let's say when I look at this and I look at this table, in some

-- in some lines, the number in column 1 is smaller than column 2, and in some lines, it's larger than column 2.

Is that significant in any way?

MR. FALTAOUS: I am sorry, which number specifically are you referring to?

MR. LADANYI: Let's look at pole replacement reliability 7. In the first column, I see 1,186,560 and in the next column, I see 1,316,761, okay. So the column 2 number is bigger than the column 1 number.

Then I go up, for example, to policy replacement reliability 5, and the first column is 18,702,010, and next to it is 207,271. And I don't know what -- I certainly can't make any conclusions about it, but --

MR. FALTAOUS: Sure.

MR. LADANYI: But maybe the commissioners could.

MR. FALTAOUS: So let me help you, Mr. Ladanyi. So essentially what you are looking at under risk mitigated is the total risk points that are mitigated by this investment. So specifically, if we are looking at pole replacement reliability 3, there is a total risk unit mitigation of approximately 5.4 million.

Risk spend efficiency is a measure of the risk mitigated per dollar spent, so that's why it's called risk spend efficiency because it's a measure of how efficient is that investment, are you mitigating a lot of risk per dollar spent.

And so that is really what these two columns represent. One is the total risk that is being mitigated, and the other one is the risk per dollar spent.

So if you have an investment that is a higher efficiency investment, then you are essentially mitigating more risk per dollar spent within that investment.

MR. LADANYI: So reliability 5 has a lot of risk, but it has a relatively low risk spend efficiency. So should one do that, or not?

MR. FALTAOUS: So reliability 5 has a high number for total risk, and that's because there are a lot of poles on our system within that category. The risk spend efficiency is still relatively high relative to other investments, and this is ultimately one of the ways -- and again, panel 1 would be able to better speak to this as part of the investment planning process. But risk spend efficiency is one of the main factors when it comes to optimization and what actually makes it into our plan.

So investments that have high risk spend efficiency generally speaking will make it into the plan over investments that have a lower risk spend efficiency, with some caveats in there about because of optimization, there may be some, you know, minor shifts and so on. I believe there was a specific question around that yesterday from SEC that we took by way of undertaking to explain.

MR. LADANYI: That's right, and I will get to that in a second.

So when I look at this, I am trying to still get my mind around priority. So let's say if I have scarce dollars, what would be my first choice here? Would it be wood pole test and treat? Would that be the first choice, or what would be the first choice?

MR. FALTAOUS: It would be your reliability 7, pole replacement reliability 7, because you can see that has the highest risk spend efficiency. So that is where you are mitigating the most risk per dollar spent.

MR. LADANYI: All right. And if you go to part (a), I actually asked whether all of these costs are capital or some are considered OM&A. And you said they are all capital.

So I am trying to understand. So you do have a program that actually has maintenance of poles, don't you, which is elsewhere. It's not actually in here at all; it's somewhere else in the evidence.

MR. FALTAOUS: Sir, which program specifically are you referring to?

MR. LADANYI: Well, I am looking at this and this is pole sustainment program, and what this tells me in your answer (a) is that you actually do not do any maintenance on poles. And I think that's a wrong conclusion. So I am asking you to tell me you actually do maintenance on poles, but not as part of this program.

MR. FALTAOUS: We do inspections of our poles and that is OM&A work that is grouped in with our patrols for veg. So when we are doing our teching for veg, collecting veg defect data, we are also collecting information on the poles including any defects for other equipment that are on our lines as well.

MR. LADANYI: So are you telling me that maintenance is only inspection, there is no work -- if there's any work whatsoever being done on the pole, that's all capital?

MR. FALTAOUS: That is correct. So whether if you're replacing a pole or if you're refurbishing a pole, or the chemical treatment of a pole, all of that is capital.

MR. LADANYI: Okay, thank you. So can we turn to B3-Energy Probe-36. And I think Mr. Rubenstein took you there yesterday and he asked you a couple of undertakings, which I am quite interested in seeing.

Now, as a result of our discussion just now, I was wondering whether -- could you go up higher? I would like to see the list.

So there's a list of projects there. And they appear to be -- if I look at it, they appear to be -- they continue on to the next page as well, but we don't want to have to go to the next page. They appear to be alphabetical, is that right? So it's not a priority --

MR. FALTAOUS: I don't -- I don't believe it's directly alphabetical.

MR. LADANYI: The first one is Angus and the last one is underground cable injection. They kind of look alphabetical to me, except commerce way is kind of mixed up. Maybe it was --

MR. FALTAOUS: I see Waubaushene in there before Crosby. There's a few in there that --

MR. LADANYI: Yeah, anyway, can you actually reorganize this list for me as an undertaking as a priority list, since you are telling me that there is -- you can actually tell the priority of projects using this type of information. Can you do that, please?

MR. FALTAOUS: Mr. Ladanyi, I think I would like to be clear that these are the projects that have made it into our plan based on their relative priority to everything else that was a proposed candidate into our investment plan.

So these projects in and of themselves are not prioritized amongst each other. They are evaluated with respect to all other investments that are part of the investment plan, essentially. And ultimately these projects made it into our plan.

MR. LADANYI: I understand. In your undertaking JT2.23 yesterday is going to give a complete list of all projects. But I am asking you to prioritize these ones. That can't be that hard. I could probably do it myself. But I would like to have it in evidence in case I want to use it later in the case. That couldn't be difficult for you.

MR. FALTAOUS: But again, Mr. Ladanyi, I wouldn't -- ultimately I think the term "prioritize these projects", again we don't prioritize within the context of just these projects amongst each other. They are prioritized within the context of the overall investment plan.

I think one of the things that you can look at here is risk spend efficiency, say which projects are more efficient to proceed with. But I would not characterize this as a specific prioritization because again, that falls within the overall investment planning optimization process and ultimately it's these projects evaluated against every other investment candidate that is input into the plan.

MR. LADANYI: All right, can you then reorganize this in the order of risk spend efficiency with the highest on top and the lowest on bottom. It can't be that difficult.

MR. FALTAOUS: I mean we can do it -- the numbers are right here. But sure, if that would be really helpful, then we can give you a revised table that just ranks them from the highest efficiency to the lowest.

MR. LADANYI: Could you please do that?

MR. FALTAOUS: We can.

MR. LADANYI: Can I have an undertaking?

MR. SIDLOFSKY: Yes, you may, we will make that JT3.1.

UNDERTAKING NO. JT3.1: TO PROVIDE A COPY OF THE TABLE IN B3-ENERGY PROBE-036(B) SHOWING PROJECTS RANKED FROM HIGHEST TO LOWEST EFFICIENCY

MR. LADANYI: Okay. Can we go now to B3-Energy Probe-38? So on page 1, you mention the 30.3 million-dollar error in the cost of removal. I assume that you -- Mr. Paish, you can't answer that, how this was found or why it was missed. Can you explain to me that one?

MR. PAISH: Similar to our previous discussion, the error was noticed. We actually had a new planner, a new set of eyes on it, and on that quality check we did discover the discrepancy and addressed it.

MR. LADANYI: Could you at least tell me, was this discrepancy discovered during the interrogatory process as a result of me asking this interrogatory?

MR. PAISH: Yes, it was.

MR. LADANYI: So there's some value to interrogatories. That's great.

Now, on page 2 you mentioned that a new AMI system is a 20-year investment. Can you tell me how long the existing AMI1 lasted?

MR. PAISH: The current AMI1 system is still in place, 14 years later, 15 next year.

MR. LADANYI: 15. So it's -- essentially, it's 15-year life that's what's been expected out of it now? You are not expecting 20-year life out of that system?

MR. PAISH: No, we are not.

MR. LADANYI: Okay, thank you.

So let's turn to B3-Energy Probe-39. So in B3-Energy Probe-39, you mentioned that you found an error in part (b) and you corrected it. Could you explain the error, please?

MR. FALTAOUS: Yes, I can, Mr. Ladanyi. So upon review it was determined that some of the projects that were included under this category, specifically this ISD, were incorrectly put there, and so they were moved to the appropriate ISD under -- sorry, just one second here. Yeah, so these projects were incorrectly listed under D-SR-04 and are now -- they have been moved to D-SS-01, as they are driven by load growth.

MR. LADANYI: So can you tell me, so by how much did SR-04 increase?

MR. FALTAOUS: Just give me one minute, please.

MR. KEIZER: Sorry, you mean SS-1 or SR-04?

MR. LADANYI: Well, apparently it's been a transfer of money from -- or projects from SS-01 to SR-04, or maybe the other way around, so maybe you can just explain how much has gone where.

MR. FALTAOUS: If I can take you to page 4 of this interrogatory.

MR. LADANYI: Right.

MR. FALTAOUS: You can see that we have provided the revised tables there. So these are the corrected tables, essentially, for both SR-04 and SS-01.

MR. LADANYI: Yeah, these are corrected tables. Right. So how much did each one increase or decrease? Can you tell me the amount?

MR. FALTAOUS: I can. Just give me one minute, please.

MR. LADANYI: If you would prefer an undertaking, we can take an undertaking to keep going.

MR. FALTAOUS: Sure, why don't we do that by undertaking.

MR. KEIZER: I mean, is it a simple thing that we could do math on and advise you potentially on the record after the break, or...

MR. LADANYI: Sure, you can do that as well on the transcript if you prefer.

MR. KEIZER: Instead of adding another undertaking for something so simple.

MR. LADANYI: Okay. Very good.

MR. FALTAOUS: Let's do that.

MR. LADANYI: If you can turn to page 3 of the response. Yeah, on top of the page. Could you just move over? Yeah. This is -- have a look at Midhurst Wilson DS feeder development to Carson Road, and I am looking at the two numbers in the two columns, and they are identical, and I was just totally puzzled. Is this a coincidence or does this mean something?

MR. FALTAOUS: I can't say for certain, Mr. Ladanyi. I mean, if that's something -- we can certainly take it back and double-check, but I can't tell you whether that's, you know, a coincidence or not.

MR. LADANYI: So coming back to this table -- and it's a similar kind of question that I had before -- you know what? I think you have to imagine the commissioners looking at the table like this and being puzzled by what exactly is this table trying to tell them. What exactly is Hydro One trying to communicate to the commissioners by filing this table?

MR. FALTAOUS: So I think, again, it goes back to the discussion we had previously, and ultimately we have a process by which we quantitatively assess the risk of our investments, determine how much risk is being mitigated, and assess the merits of the investment based on their risk spend efficiency, which ultimately is done through our investment planning process to provide a plan that overall is providing the most value per dollar to ratepayers. And again, panel 1 is really the best panel to talk about the process in-depth, but that is essentially what this table represents. It's the risk quantification and assessment that is ultimately used to evaluate investments against each other to provide a plan for ratepayers that is providing the most value in terms of risk mitigated per dollar spent.

MR. LADANYI: So when you say projects against each other, so there is a -- so let's -- comparing Midhurst to Carlisle right below it, how would they compare? Can you at least tell me that?

MR. FALTAOUS: So just based on the numbers here, I would say that Midhurst is a more efficient investment. You are mitigating more risk per dollar spent. However, the fact that Carlisle is on here also indicates that it was an efficient-enough investment to make it into the plan. And so again, this kind of -- this is all within the context of the overall investment planning process, which is best described by members of panel 1.

MR. LADANYI: Okay, thank you. Let's turn to B3-Energy Probe-42. And this one deals with energy storage solutions, and there was a fair amount of discussion about that yesterday.

When I look at the table on the bottom, the risks mitigated seem very large. Why are they so large?

MR. FALTAOUS: They are large because it ultimately has to do with how much reliability risk is being mitigated by these projects. So as mentioned in the relevant ISD, these are communities and customers that experience some of the worst reliability on our system, and so by being able to significantly improve their reliability through the deployment of battery storage we are mitigating a significant amount of reliability risk.

MR. LADANYI: So when comparing the grid-scale storage to residential storage, should the commissioners conclude that the residential storage is better because it has higher risk spend efficiency?

MR. FALTAOUS: I wouldn't characterize it that way. I think what this says is both of them are highly efficient investments, and they both made it into our plan as a result.

MR. LADANYI: Now we are going to have a few questions on the general plan, so can you turn to B4-Energy Probe-45. And if you can scroll down to -- I think there is more attachments to this, more tables, and maybe go to the graph, keep going down. Yeah, this. Very good.

So the general plant expenditures are rising rapidly and resulting in high overhead costs per megawatt hour of load, transmission, and per customer distribution.

What step did Hydro One take to reduce general plant expenditures in 2020? You can see them dropping in 2022 and then they are rising again. And why can't this kind of reduction in general plant expenditures continue beyond 2022?

MR. BERARDI: Mr. Ladanyi, it's Rob Berardi from Hydro One. The plan that we have in front of you is based on needs, and we have paced it appropriately during the planning years from 2023 to 2027, but it is based on needs and condition assessments.

So when you look at things like fleet, when you look at facilities and real estate, it's actually addressing the end of life from previous years that we have under-invested in those programs.

MR. LADANYI: So then what happened in '22?

MR. BERARDI: In '22, we reprioritized general plant because when we look at the total investment plan for the whole company, we are managing at the capital envelope and we reprioritized general plant in 2022 for other investments and system renewal, and system access and others.

MR. LADANYI: Can you just explain the word "reprioritized" in that context?

MR. BERARDI: So part of our investment planning process is we have a reprioritization that happens on a regular basis and as new demands come into 2021, 2022 -- so for instance, if we have significant storms in 2021, it may displace some previous planned investments, and that's what we are seeing in 2022. Some of those planned investments have been displaced.

MR. LADANYI: Okay, thank you. Let's turn to Energy Probe 46. And here you are discussing greenhouse gasses reductions as a metric. So why are GHG reductions the appropriate metric for judging general plant investments? Why should not cost efficiency, for example, be the metric?

MR. BERARDI: Mr. Ladanyi, this is one metric. When we look at general plant, we look at things like end of life, you know, the impacts on our operations. And specifically with fleet, we look at minimizing lifecycle costs and equipment down time. And lowering our greenhouse gas emissions is part of our investment as well.

MR. LADANYI: So that's one of the criteria you are using?

MR. BERARDI: That's correct.

MR. LADANYI: And they are not, let's say, weighted differently, are they? They are weighted equally?

MR. BERARDI: Our focus on our fleet investment has been to minimize lifecycle costs and equipment down time, and the consideration has also been for lowering our greenhouse gas emissions.

MR. LADANYI: So I think from your response to Energy Probe 45 that we were just looking at, the cost efficiency is actually declining over the years, would that be right, of general plant investments?

MR. BERARDI: Mr. Ladanyi, can you please help us? What exactly are you looking at? Can you please clarify?

MR. LADANYI: Yeah, it's -- can you look at response to, I think, (f).

MR. KEIZER: (F) of 45 or (f) of --

MR. LADANYI: (F) of 45, sorry. And there's expenditures per megawatt in tables 4 and 5, that's what I was referring to. But maybe I am drawing the wrong conclusion.

MR. BERARDI: I am not sure that this metric for general plant is appropriate, expenditure per megawatt. General plant investments are enablers for the operations to be efficient and to deliver on our work programs.

MR. LADANYI: So you're saying general plant is ancillary to the main business of Hydro One, is that right? So it's not really the main driver, would I be correct?

MR. BERARDI: I suggest general plant is an enabler to the business. So for instance, if you take fleet or IT or facilities, it would be difficult for us to execute our work program without those enabling investments.

MR. LADANYI: You don't have any metrics where you compared your general plant investments to those of other utilities, do you?

MR. BERARDI: Well, for fleet, we do have the Utilimarc benchmarking study where we have done those comparisons. So if I can draw your attention to that, that talks about some of our operational efficiencies.

MR. LADANYI: That's in the evidence, is it? Sorry, I don't have it in front of me. You don't have to turn to it. Just give me the reference and I will look it up.

MR. BERARDI: Just bear with me for a minute, I will get you the reference. It is B-04-01\_4.3\_01, and it's the Fleet Operations Benchmarking Report. And with that report, it does show that benchmarking against our peers that we are in first quartile and second quartile.

MR. LADANYI: Okay, thank you. I will look that up. Could you turn to B4-Energy Probe-48? This will be for Mr. Marcotte.

There was a mention of the Gartner benchmarking study yesterday, I believe. And the question that I have here is given the major increase is in IT spending, why should the intervenors and Board rely on an outdated Gartner benchmarking report?

MR. MARCOTTE: Hi, Mr. Ladanyi. I wouldn't characterize this as an outdated report. This report was done and the purpose of the Gartner benchmark is to be looking at actual spend. And so when this study was commissioned in 2020, we were looking at actual spend, which was 2019.

So this allow us to compare not only the 2019 against peers, but also how we may have changed some of our spending patterns from the previous benchmark, which was done in 2015.

MR. LADANYI: And is there a possibility you could retain Gartner to update the report using the latest data, or you don't feel that's possible; could you tell me? With possibly a projection to 2023?

MR. MARCOTTE: The benchmarking study --

MR. KEIZER: Sorry, go ahead, Mr. Marcotte.

MR. MARCOTTE: Sorry, I was just going to indicate, the benchmarking study and the methodology used by Gartner is to look at actuals and a bottoms-up, so I am unaware of any conversation with Gartner about how such a comparable activity could be done on a future forecast basis.

MR. LADANYI: Okay, thank you for that. And my last question is going to be Energy Probe -- B4-Energy Probe-50. And I think it might be for another panel, but I will try it with this panel. It has to do with the electrification of the fleet. And my question is this: Can you provide a cost-benefit estimate of the program that would have as a baseline scenario no electrification, and another -- and then your program, which is EV program scenario mix of vehicles, and to include for each scenario the capital and operating costs? Would that be possible? You can leave that to another panel, because I see Mr. Chhelavda is listed as a witness there, so we can ask him the same question.

MR. BERARDI: No, Mr. Ladanyi, it's Rob Berardi. That question is for me. I am just trying to understand, you're asking us to do a compare of historical having only combustion engines versus our current plan; is that correct?

MR. LADANYI: That's right, yes, yes.

MR. BERARDI: We can do that.

MR. LADANYI: Okay, thank you.

MR. SIDLOFSKY: We will make that -- sorry, we'll make that JT3.2.

UNDERTAKING NO. JT3.2: REFERRING TO B4-ENERGY PROBE-50, TO DO A COMPARE OF HISTORICAL HAVING ONLY COMBUSTION ENGINES VERSUS THE CURRENT PLAN.

MR. LADANYI: So I am pleased to say that I am finished now, and I am ahead of time, so I am giving you back almost 20 minutes. And I hope that I will get rewarded by getting Roger, who is coming up, I think, tomorrow with questions, to give him more time. Anyway, thank you, panel. I thank you for your answers.

MR. SIDLOFSKY: Thanks, Mr. Ladanyi. We are moving on to VECC.

# Examination by Mr. Garner:

MR. GARNER: Thank you. And maybe I will use up Mr. Ladanyi's time. Can you see me and can you hear me, is my question. Thank you for that.

I'm going to try and be very quick and to the point. Mr. Berardi, if you pull up E-Staff-248, and while you are pulling up I will just explain what's in it. This is about both we in VECC 80 and Staff in that IR asked you about a benchmarking study with the energy fees and -- et cetera, and in essence you refused to provide that study. And as your counsel would tell you, I am not here to argue about your refusal, I am actually just more interested in whether I am actually interested in the report at all anyways, because I had made an assumption about that report, and maybe you can dissuade me of it, which was that what the report was doing was that it was comparing the energy fee structure to alternative ways of producing the same outcomes, and therefore it would be demonstrative of the fact that your insourcing was the least-cost exercise.

Is that what that benchmarking review does in any sense?

MR. BERARDI: The benchmarking review looked at a few different scopes. One of them was to look at our sourcing approach and the other was to review our supply chain costs.

MR. GARNER: Well, I guess, Mr. Berardi, maybe the other way to ask the question, because I am still not sure I understand. Did it all inform you of making the decision to insource those functions? Was that part of the, you know, the table of information that was used?

MR. BERARDI: Mr. Garner, that was one piece of the input. What we also reviewed was the value of insourcing, and so we conducted a business justification on the true value of insourcing and whether it was -- from a service and value proposition, whether that made sense.

MR. GARNER: Okay. I think I understand it, at least enough to move on, thank you, Mr. Berardi.

My next question is going to be to Mr. Paish. And we had it at VECC 80, but actually, the interrogatory I want you to take a look at is B3-SEC-154, I believe. And I will tell you, just to preface my question, I am a little embarrassed to ask you this question, because I have to say I think you did a very good job of explaining the AMI2.0 stuff, both in the evidence and in two interrogatories, both this one and one to Staff at 105, so bear with me. I still have some questions about how this all works.

And if you go to that interrogatory, I believe you'll see a table that provides a -- the AMI, it says -- you give a 7-year and a 5-year plan. And -- yeah, that's the one. So let me just ask you it this way.

As I understand it, the project that's listed as whatever the SR or SS project is -- this is SR-12, I think, right -- that project is summed up by the first three rows of that table. I guess that's my first question; is that correct?

MR. PAISH: Mr. Garner, I am not sure the first three rows of this table will take us into the first year of the rate filing period. But it is a multi-year deployment.

MR. GARNER: Well, yeah, and I am not trying to be clever. That wouldn't be possible. What I am really trying to do is say when I look at SR-12 in Appendix 2AB, I believe, the one that's by project, I would get a figure of for 2023 of $30.9 million, and then if I add up the first

-- if I go to 2023 in this table and I add up the first three rows in there I get roughly pretty much that same number, so I made the assumption that the first three rows in here equal the same as that row, SR-12 or whatever it is in the appendices. And I am asking you to confirm that that's correct.

MR. PAISH: I believe you are correct.

MR. GARNER: With the subject to check you can check. And as I said, I am not trying to discover anything in that. That's my assumption I was working on.

MR. PAISH: Yeah.

MR. GARNER: And I was going to use this table to ask you these questions. If I look at the first row, AMI mass deployment, that's meters; is that right? That's all meters, actual meters that you need to acquire for the new meters?

MR. PAISH: Meters are only one component of it. We still -- AMI requires network devices as well --

MR. GARNER: But I am just talking right now about the first row, just so you're clear. I just want to talk about that first row, what's in it. Sorry.

MR. PAISH: So AMI2 requires meters and network devices.

MR. GARNER: I am sorry, I missed the last part of what you said.

MR. PAISH: And network devices --

MR. GARNER: And that's all in the mass deployment row?

MR. PAISH: I believe so.

MR. GARNER: And then when I get to the next row, HES and network management systems, can you describe what that is in the AMI rollout? What is that category of items?

MR. PAISH: The head end system is a computer-based software which is used to communicate to both the meters and the network equipment.

MR. GARNER: Okay. So that's the software. And then what's the last row, the IT integration? Can you explain what that one does?

MR. PAISH: The head end system communicates data to a variety of systems, and so some integration work is required.

MR. GARNER: I see, so that's like to integrate things like CIS if it's required and other IT systems within the organization?

MR. PAISH: That is correct.

MR. GARNER: Now, the way this works, you are replacing the meters, and I guess when you were saying there's more than the meters, in the way this system works you have to back-haul your data so you have some towers or other equipment along the way, some of which doesn't need to be replaced because it's like a tower, but electronic equipment does need to be replaced in order to deal with these new meters. Is that a fair way of describing it?

MR. PAISH: The AMI1 environment, all of those devices will still be in use to support any remaining AMI1 meters. But the AMI2 deployment requires new infrastructure.

MR. GARNER: Thank you, that leads me to the next question I had, and I think you are kind of answering it. I was wondering how does the transition work. So the transition works that the old system is in play until in essence the last old meter drops off? Is that how it works?

MR. PAISH: That is correct.

MR. GARNER: Okay. So there's some flexibility in the timing simply because you don't have to, in essence, replace everything. I mean, your timing is flexible to some extent, but not -- they do wear out, I get it, but you have flexibility in your timing of rollout?

MR. PAISH: The deployment is area by area based, so we can encapsulate it.

MR. GARNER: Okay.

MR. PAISH: But we do need to maintain it until the very last area is completed.

MR. GARNER: Okay, thank you. There was a -- you don't need to bring it up, but there was a map in your original evidence of what I call the blanked out areas, do you know what I mean? They were not being --under the current system, they were not being integrated.

Does this new system address some of those or any of those what I'd call blank spots that weren't covered under the old system?

MR. PAISH: Can you point me to the map that you're referring to, please?

MR. GARNER: I wish I could, and I did have it yesterday. Yeah, it's in your -- it's in the main body I believe of your evidence, and what it is, it's a map that shows some whited out areas, some around the lower Sudbury area, some toward the Ottawa area that had sort of -- they were areas where it showed no coverage, basically.

Well, maybe put it this way. Are there areas right now that have no coverage under the current AMI system?

MR. PAISH: There are areas which have no communication or unreliable communication, and those areas in AMI1 continue to exist.

In AMI2, due to the nature of the technology, we hope to extend that reach.

MR. GARNER: So I guess the answer to my question would be if there are areas where you're not able to utilize remote reading smart meters, this technology will help you address, at least in part, some of that?

MR. PAISH: Correct, in part.

MR. GARNER: Right, but not totally. Now, if you go to SEC 154, there was a Board presentation that you provided. And if you go to page 10 of 13 of that document, you will see a rate base addition table, additions per JRAP, or however the acronym is being said, right at the bottom. And that table is different than the capital table.

And partly it's different -- I was a little confused because partly it's different in that there are years where in the advanced metering, like in 2021 -- or sorry, there's no spend on this project in 2020 according to the appendix 2AA. But in 2021, there is some stuff in there.

I guess my question really comes to this. Is this table still what I might call congruent with the appendix 2AA? So am I looking at a table that basically says yes, the capital spend in 2AA is the is correct, and this table is correct as showing the actual in-service amounts of that project?

I am just trying to say -- can I use them both, so to speak?

MR. PAISH: Can we go to the other table, please, that you're referring to?

MR. GARNER: Well, that's appendix 2AA.

MR. PAISH: Yeah, I see it, yeah.

MR. GARNER: And I am at line 34, I believe, and that's the AMI table in there. If you're looking for this one, it's on page 10 of 13, I believe.

MR. KEIZER: I just want to make sure we have the right reference.

MR. GARNER: Yeah, that's the one that's in the Board report. And then there's another one in appendix 2AA. And if you'd like to do it by undertaking, I don't want to put you on the spot. I just want to understand if I can utilize both tables without being inconsistent. One is showing in-service and one is showing in capital.

MR. PAISH: Subject to check, I believe that is correct.

MR. GARNER: Okay, I will leave it subject to check, thank you.

The other thing, as I understand -- is this project still being done in conjunction with Alectra, at least in the pilot stage of it?

MR. PAISH: It is.

MR. GARNER: And just another confirmation. As I understand it, and correct me if I am wrong, the new meters will have a 20-year life, and the current meters have a 15-year life. Does anybody know if that's correct?

MR. PAISH: We have attestation that a 15-year life is expected but not guaranteed by the current vendor --

MR. GARNER: I was under the -- I had thought I read this, that the new meters had a 20-year life under the AMI2.0 program.

MR. PAISH: That is our expectation. Currently we are in negotiation, but that is included in our intended contract, 20-year life.

MR. GARNER: All I was trying to ascertain is that would be, if it comes to fruition, five years longer than the current meters are. The current meters, I believe, are 15, but I am looking to you to tell me if I am right or wrong.

MR. PAISH: You are correct.

MR. GARNER: Okay, thank you. Thank you, Mr. Paish. Mr. Faltaous, if you go to VECC -- sorry, SEC, B3-SEC-148, there is a table in there that you're using for new connections. You'll see the new connection lines, right, in there?

And then if you were to go over to your main body of evidence where you talk about the load forecasting -- and I will give you the reference, it's D, tab 5, schedule 1, page 37.

And while you are drawing it up, just let me tell you where the issue is. That gives you a table of new customers and customer growth. And I was trying to find how to make the new connections line equal the increments in that table, so that I could understand that what you were using here was consistent with what you were using in that part of the evidence, in the revenue load forecast in part of the evidence. And I could not make them work, so to speak. I could not find them.

And this, I think, you'd have to do by undertaking. Could you take the table 1 that's in B3-SEC-148, look at the new connections line, and then explain to us how the table that's E3 -- E.3 at D, tab 5, schedule 1, page 37 -- how those reconcile together for new connections, because I can't make that math work.

It could be that they are not reconcilable for some reason, or it could be simply I am not using the right --there is a lot of columns in there about different categories of connections. It could be I have to remove some. I don't really understand.

So I am looking to understand that what you're using, quite frankly, in your evidence for distribution capital is congruent with what you're using in your evidence for load forecasting. Do you know what I mean?

MR. FALTAOUS: I believe I understand your question, Mr. Garner. If you just give me one minute, please?

MR. GARNER: Sure, absolutely.

MR. FALTAOUS: If I can take you to Energy Probe 29, please.

MR. GARNER: Sure.

MR. FALTAOUS: If you can go to the response to part (e), so in here we have essentially described how we have determined the volume of new connections going forward, and you can see that in the text there on line 17 it says that the new connection volume forecast for Hydro One was calculated by multiplying the average annual number of upgrades over the '17 to '20 period by the compounded forecast annual customer growth rate, which comes from the load forecasting team.

So we are essentially looking at a four-year average, multiplying it by that forecasted annual customer growth rate, to forecast the number of new connections going forward.

MR. GARNER: Okay.

MR. FALTAOUS: Does that provide you the information you're looking for?

MR. GARNER: Well, it tells me that you're saying that they are congruent. It still doesn't tell me how I make them congruent between those two tables. Do you know what I mean? It doesn't tell me how that table that you have at E.3 somehow equals the new connections in the IR that I raised.

So I'd still ask you to take a look at those two to show me why -- or explain to me how they are the same table just showing different things or they're not comparable. Do you know what I mean? For whatever reason.

MR. FALTAOUS: Okay. Yeah, we can undertake that undertaking, thank you.

MR. GARNER: Thank you.

MR. SIDLOFSKY: Make that JT3.3.

UNDERTAKING NO. JT3.3: TO EXPLAIN OR RECONCILE THE NEW CONNECTION DATA SHOWN AT E3-5-1, PAGE 37 WITH THE DATA IN B3-SEC-148

MR. GARNER: And I am almost there, but some things, unfortunately, technical conferences raise questions than take them away. Yesterday -- this is to you, Mr. Faltaous. Yesterday you had a conversation with Mr. Elson that got me and some of my clients a bit confused. And this was -- and it was, if you want to get the transcript, it was at page 137. But let me describe the conversation that you two are having.

Mr. Elson is asking you about amp service changes and the cost to customers, et cetera. And as I read -- listened and then read it yesterday -- and he was talking about EV chargers, and I am not really interested in that per se. But as I read that, I was -- I didn't really understand what you were saying was consistent with my and some of my clients' experience about what happens.

And first of all, you were explaining to him as 100-amp service is a standard service in a new residence; correct?

MR. FALTAOUS: Correct.

MR. GARNER: And he was talking, obviously, for his purposes about moving from 100-amp to 200-amp, and he had also spoken about 20-amp, which I'd never heard, because you know probably the most consistent other change is from 60-amp to 100-amp, right, and there is insurance issues with low-amp services, so people like my client are often people wanting to move that type of service to 100-amp, often for insurance purposes.

And what I didn't understand about what you were saying is, as I understood it you were saying, well, there was no cost unless the pole had to be changed and the transformer had to be changed, which I understand to be a very rare circumstance. And it's not the way I understand how this works, that there is generally a cost, and generally the way it works -- and let me describe it; you can tell me if I am wrong -- you make a request to Hydro One, Hydro One generally will send out someone to do what's called a technical layout, the technical layout will then result in a contract being offered to you, and then you will either accept or not accept that contract; is that the way the process generally works?

MR. FALTAOUS: That is correct.

MR. GARNER: And, in fact, it's very rare not to have a cost for that, because certainly from 60 to 100 or 200-amp the line has to be changed, and also, depending -- and you have many customers. You're not like many LDCs. You have customers in very unique and difficult places. Often there's requirements in there to either clear your right of way or if you clear the right of way there's a cost to that; is that correct?

MR. FALTAOUS: Sorry, Mr. Garner, are you talking about -- you are talking about an existing service?

MR. GARNER: Yeah, I am talking about an existing service that's moving, and so was Mr. Elson yesterday, in the existing service that's looking for an upgrade on an amperage basis?

MR. FALTAOUS: Yes, so the reason that I am asking the question is because if it's an existing service, then clearing the right of way, so long as it's a Hydro One-owned portion of the line, is Hydro One's obligation. That is not something that we would be charging the customer for.

MR. GARNER: Yeah, I was just pointing out that some of your customers have things like farms where you are running a line along there a fair distance and you're required by the ESA to make sure that the right of way back in to their place is cleared out, and if they haven't cleared it out you can't either connect them, because you have to have a clear right of way in. So when you are doing an old amperage, sometimes that's an issue, right? That's all I was driving at. And that's part of the technical layout, as I understand it. Someone comes out and makes all those assessments for you.

MR. FALTAOUS: And if you're talking about a portion that is the customer-owned portion of the line, then that would be appropriate.

MR. GARNER: So let me finish this way, is that you left me with at least the impression that making an amp service is generally not a cost, and my experience, clients' experience, is in fact moving amp services is almost inevitably a cost, because at a minimum you have to have a disconnect/connect charge as your new meter is put into the mount that the electrician puts in.

MR. FALTAOUS: I'd like to clarify, Mr. Garner, that we do offer all of our customers one free disconnect/ reconnect per year, and so that is -- assuming that the customer has only utilized that one disconnect/reconnect, it would not be a charge to the customer.

MR. GARNER: So going back then -- thank you. Going back to the question, is it very common to have -- move, like, amp services without a charge to a customer of some type? Let's use 60-amp to 100-amp service.

MR. FALTAOUS: So I think it depends on the specific circumstances, and I think that is really what it comes down to. So the example that you mentioned where there is a customer-owned portion of the line that may require some clearing, well, yes, there is a cost there, and it's not a Hydro One-owned line, and therefore, you know, it's not Hydro One's cost to bear.

So it really would depend on the specific circumstances of that one connection. I don't think we can make a general statement and say that, you know, there will be a cost or there will not be a cost. I think if the requirement is for transformation upgrade and there is no requirement to replace the pole, and that is, you know, all that is needed to connect the customers, then there would, generally speaking, not be a cost. But if there are other requirements, depending on the specific circumstances, there may be some cost.

MR. GARNER: Well, that seems contrary to my experience, but I hear what you're saying. Maybe we can -- I can resolve it at least in my mind this way. If you look at Exhibit D, Tab 2, Schedule 1 -- and this is actually Mr. Spencer's evidence, not yours, so I am not asking you to tell me something here. There's a table that talks about other external revenues, and I guess what I would ask, then, is if you could tell us, for the period that this covers, 2018 to 2027, how much, or if any, of the external revenues, other revenues of Hydro One are forecast for upgrade of services for customers?

MR. FALTAOUS: We can do that.

MR. GARNER: Thank you. If we can have an undertaking.

MR. SIDLOFSKY: JT3.4.

UNDERTAKING NO. JT3.4: TO THE TABLE IN EXHIBIT D, TAB 2, SCHEDULE 1, TO ADVISE FOR THE PERIOD 2018 TO 2027 HOW MUCH, OR IF ANY, OF THE EXTERNAL REVENUES, OTHER REVENUES OF HYDRO ONE ARE FORECAST FOR UPGRADE OF SERVICES FOR CUSTOMERS.

MR. GARNER: And I think I've met my -- and five minutes early for Mr. Sidlofsky. Thank you very much, panel. Thank you for those responses.

MR. SIDLOFSKY: Thanks very much, Mr. Garner. On to AMPCO. Ms. Grice.

# Examination by Ms. Grice:

MS. GRICE: Good morning, panel. I am Shelley Grice, representing AMPCO. I want to start -- I just have a follow-up question regarding the discussion this morning on Energy Probe No. 34, if we could just turn to that first, please.

And I am just -- I am looking at the response to part (b) in the table there that shows the pole groupings, the risk mitigated, and the risk spend efficiency. So are you able to provide the number of poles under each of the alternatives, 3 to 7, that are shown in the pole grouping table? Is that something you could provide? The number of poles replaced?

MR. FALTAOUS: Just give me one minute, please. If I can take you to ISD SR-07, page 4. So actually -- my apologies, this is number of poles in poor condition. Okay, we can do that, Ms. Grice.

Actually, so figure 6 does show it graphical format. I don't know if that's sufficient for you or not, figure 6 in the same ISD. It's on page 9.

MS. GRICE: So that looks like it's showing poles in poor condition over the planning period. I was looking at for each of the alternatives that you have in the pole grouping table in Energy Probe 34, if you had the number of poles that were forecast to be replaced under each of those alternatives.

MR. FALTAOUS: Okay.

MS. GRICE: That's what I am looking at.

MR. FALTAOUS: Okay, yeah, we can provide that.

MS. GRICE: Okay, thank you.

MR. SIDLOFSKY: JT3.5.

UNDERTAKING NO. JT3.5: WITH REFERENCE TO IR ENERGY PROBE NO. 34, PART (B), TO PROVIDE THE NUMBER OF POLES FORECAST TO BE REPLACED UNDER EACH OF THE ALTERNATIVES.

MS. GRICE: Okay, then, back looking at this table, can you tell us which of those pole replacement alternatives was ultimately selected?

MR. FALTAOUS: Yes, I can clarify that. So each one of these represents a grouping of poles that has a certain risk associated with it, and so all of these are in the plan.

MS. GRICE: Okay. Thank you. Then --

MR. FALTAOUS: It would have been -- so there would have been others, other candidate groupings that would not have made it into the plan and are not included here.

MS. GRICE: Would that be pole replacement reliability 1 and 2?

MR. FALTAOUS: Correct.

MS. GRICE: Could we get the information for those groupings as well?

MR. FALTAOUS: Yes, we can do that.

MS. GRICE: So in the same format as the table here in part (b) showing risk mitigated, risk spend efficiency, and the number of forecast poles in each of those, in 1 and 2?

MR. FALTAOUS: We can do that.

MS. GRICE: Okay. Sorry, just before we give an undertaking, I just want to ask one last question. Are there more than seven? Are there groupings beyond seven?

MR. FALTAOUS: No.

MS. GRICE: Okay, thank you.

MR. FALTAOUS: No problem.

MR. SIDLOFSKY: Sorry, I just lost my connection there, but I think that was all undertaking JT3.6, correct? That was a single undertaking?

MS. GRICE: Correct.

MR. SIDLOFSKY: Thanks.

UNDERTAKING NO. JT3.6: TO PROVIDE INFORMATION FOR RELIABILITY 1 AND 2 GROUPINGS IN THE SAME FORMAT AS IR ENERGY PROBE NO. 34, PART (B), SHOWING RISK MITIGATED, RISK SPEND EFFICIENCY, AND THE NUMBER OF FORECAST POLES

MS. GRICE: So can you just explain what you mean by pole grouping? Just an explanation of that, please.

MR. FALTAOUS: Yeah, so it means poles that would have a similar consequence if they were to fail. So actually if we can go back to the ISD where we just were, and if we can go to specifically -- so this is ISD SR-07 and it is specifically page -- give me one second here -- page 4, so this chart here. It shows you the customer minutes of interruption that would be impacted by a pole in that category essentially. And this lines up with our reliability taxonomy, the reliability consequence taxonomy for distribution.

MS. GRICE: Okay. Then just in terms of the risk spend efficiency column, would you be able to calculate how you arrived at the numbers for each of those five reliability groupings?

MR. FALTAOUS: So just in terms of how we determined the consequence level for each?

MS. GRICE: Well, what's the underlying calculation under the third column? Are you able to provide that for all of the groupings in the table?

MR. FALTAOUS: Yes, we can. So basically you're asking for the pole 7 grouping down to the pole 2 -- sorry, to the pole 3 in the table, to just basically show how we came up with the calculation for each essentially?

MS. GRICE: For each of the pole groupings in the table and then plus the two that were not in the table.

MR. FALTAOUS: Yes, we can do that. And specifically you're looking to understand how it was determined that this was the CMI impact for each one, correct?

MS. GRICE: Well, how you ended up with the values in the risk spend efficiency table.

MR. FALTAOUS: We can explain that.

MR. SIDLOFSKY: JT3.7.

UNDERTAKING NO. JT3.7: WITH REFERENCE TO THE TABLE IN ISD SR-07, PAGE 4, TO PROVIDE OR EXPLAIN THE UNDERLYING CALCULATION OF EACH OF THE FIVE RELIABILITY GROUPINGS

MS. GRICE: And then with respect to the last two, wood pole test and treat and wood pole structure refurbishment, were there alternatives evaluated under each of those groupings as well? Or not -- I shouldn't be using the word alternatives, I am sorry. Is there underlying groupings underneath each of those?

MR. FALTAOUS: No, there is not.

MS. GRICE: Okay. In the undertaking where I asked for the number of poles in each of the first five pole groupings, are you able to provide -- add to that the number of poles in the last two? So wood pole test and treat and wood pole structure replacement?

MR. FALTAOUS: Sorry, just one second, please. So that information, Ms. Grice, is in the ISD. And that is on page 8 of the ISD. It shows you the number of poles by year that are being refurbished and the number that are being test and treated in table 1.

MS. GRICE: Okay. So all of those poles, then, are part of the calculation for the last two groupings?

MR. FALTAOUS: That's correct.

MS. GRICE: Okay. And just so I understand your response earlier that in terms of the wood pole test and treat and the wood pole structure refurbishment, you didn't look at alternative quantities as part of your evaluation in determining the investment level for those two?

MR. FALTAOUS: I'd have to confirm whether there was different levels of investment specifically for those ones, Ms. Grice.

MS. GRICE: Would you be able to do that? And then if there is an analysis of different quantities for test and treat and pole refurb, if you could provide the analysis for that in terms of risk mitigated and the risk spend efficiency?

MR. FALTAOUS: We can do that.

MS. GRICE: Thank you.

MR. SIDLOFSKY: JT3.8.

UNDERTAKING NO. JT3.8: TO CONFIRM LEVELS OF INVESTMENT FOR THE CATEGORIES WOOD POLE TEST AND TREAT AND THE WOOD POL STRUCTURE REFURBISHMENT; TO PROVIDE THE ANALYSIS FOR THAT IN TERMS OF RISK MITIGATED AND THE RISK SPEND EFFICIENCY

MR. FALTAOUS: Sorry, Ms. Grice, did you intend for that all to be part of the same undertaking?

MS. GRICE: I think that's a new undertaking.

MR. FALTAOUS: Okay.

MS. GRICE: Okay, thank you very much. So if we can go into AMPCO interrogatories now, please, starting with number 51. And in this interrogatory, we asked in part if Hydro One had adjusted the expected service life for any of its distribution assets since the last proceeding.

And in the response, you indicate that for wood pole station transformers and meters the expected service life has not been adjusted. So you didn't comment on other assets in that response, and I just wondered is there a reason for that? Do you use ESL in a different way beyond these three assets?

If you can just elaborate on why other assets weren't included in the response.

MR. FALTAOUS: So I believe that there was a discussion on the use of expected service life earlier on as part of this conference and an indication that, you know, it's not actually directly utilized in terms of the actual development of the plan. But with regards to other distribution assets, I am not aware of anywhere the expected service life has changed. And I guess I will also ask Mr. Paish to weigh in in case he is aware of anything from his end.

MR. PAISH: Ms. Grice, it's Dave Paish. As far as I am concerned there's no additional components.

MS. GRICE: So no -- sorry --

MR. PAISH: I am talking about the metering.

MS. GRICE: Okay. I am sorry, I don't know what you mean by that.

MR. FALTAOUS: Sorry, Ms. Grice, it seems that we are having some technical issues over here. A number of the panel members have their computers frozen. Can you just bear with us for a minute, please.

MS. GRICE: Sure.

MR. PAISH: Can you hear me, Ms. Grice?

MS. GRICE: I can, yes.

MR. PAISH: So the metering end of ESL doesn't begin until 2022, so there is no change for this year. Is that your question, or can you restate it, please.

MS. GRICE: Well, I guess my question was -- yes, okay. So the connection to all of this is I believe you have a demographic risk factor that you use for all of your assets as part of your initial evaluation of your asset needs. And that demographic risk factor looks at a comparison of the age of an asset relative to the expected service life of the asset type.

So I just -- my question in my interrogatory was just whether or not the expected service life had changed for any of the assets in this plan. And the response only speaks to poles, transformers, and meters. So I just want a confirmation that if there had been a change with any of the other assets with respect to expected service life, that's all.

MR. FALTAOUS: So, Ms. Grice, I can confirm that there has not been a change with respect to expected service life for other assets. But I would also like to correct the fact that the use of a demographic risk factor in terms of development of the plan, we base our plan based on condition. Demographics is not a direct input into the development of the plan itself.

MS. GRICE: I am sorry, on my end I couldn't hear that response, I am sorry. I don't know if anyone else had that problem.

MR. KEIZER: I heard it, so I don't know. It may be your issue, Shelley. Can you hear me?

MS. GRICE: I can hear you, yes.

MR. KEIZER: So maybe Mr. Faltaous can try again, because I heard him, so I don't want the witness -- just repeat the response and see if we can do it then.

MR. FALTAOUS: Can you hear me now --

MS. GRICE: Okay. Actually, Mr. Keizer, you are cutting out a little bit for me as well, so perhaps it is my connection.

MR. KEIZER: Well, do we want to take an early break and you restart, or -- can you restart now? Or have you frozen? Oh, I think she is restarting. Let's just see if she comes back and give it another go.

[Technical discussion]

MR. KEIZER: Why don't we say we come back at -- it's now 10:30 -- we come back at 10:45?

MR. DAVIES: That sounds good. So we will take a 15-minute break and resume at 10:45.

MR. KEIZER: All right, sounds good.

### --- Recess taken at 10:31 a.m.

### --- On resuming at 10:46 a.m.

[Reporter reads back]

MS. GRICE: I understand that, but just to clarify, it is an input into your asset needs assessment, is that correct? Is my understanding there correct?

MR. FALTAOUS: The needs on the -- sorry, this is Peter Faltaous. The needs on our distribution system, at least for the assets for which I am accountable, are driven by the condition of the assets.

MS. GRICE: Okay. I didn't intend to spend a lot of time on this, but I am just a little bit confused. So could we turn to AMPCO 65, please?

And in this response, we asked in part (b) for asset types or subtypes with condition algorithms, and then we asked for the condition algorithm for any of the assets identified in part (b).

And in the response, you refer us to an interrogatory from the last proceeding in EB-2017-0049, which is I-24-Staff-119(b). Is that something you could bring up?

MR. MARCOTTE: Ms. Grice, do you mind repeating the reference?

MS. GRICE: Sure it's I-24-Staff-119(b).

MR. KEIZER: But it's related to the last 2017-0049 proceeding, not the current proceeding.

MS. GRICE: Well, actually it's related to what algorithms you use for your data and I believe in your response to AMPCO 65, it sounds like you still use those algorithms.

So if you look at part (c), it says:

"Condition algorithms do not exist for metering assets. For all other assets, please see"...

And it's the reference I just gave. And if you go to that reference, it gives you the algorithms for demographics and then for condition, for station transformer, station reclosures, station -- site structures and wood poles. So it gives the condition algorithms for those assets.

But the one I was interested in was the demographics risk factor which said that for all asset types, the way that you calculate the demographic factor under asset needs is a comparison of the age of an asset relative to the expected service life of the asset type.

That's why I just wanted to confirm there hasn't been any change between then and now in terms of how you account for demographics in your asset needs assessment, so if --

MR. FALTAOUS: Ms. Grice.

MS. GRICE: Yes?

MR. FALTAOUS: I would like to clarify. So we have underlying demographics information and there is the demographic index that you are referring to. But in and of itself, it does not drive proposed replacement needs on our system. And that is really the clarification that I'd like to make.

MS. GRICE: Okay, and then -- I understand that. All I was trying to get from AMPCO 51 was just confirmation that the expected service life has not changed for your assets, and I believe you have confirmed that?

MR. FALTAOUS: That is correct.

MS. GRICE: Okay. So let's move on, then, to AMPCO 60, please. So in this interrogatory, we were asking about the total number of asset failures and then the asset failures that resulted in an interruption.

I just want to clarify the answer. So you say that you only have total number of asset failures available for station transformers and mobile unit substations, and you can see that in the table quite clearly.

I just want to understand your -- how you manage your data. So with respect to the assets where it says not applicable or not available, why would you have it for the first two and not the others? I am just trying to understand your data management.

MR. FALTAOUS: This is Peter Faltaous. So with respect to station transformers and mobile unit substations, it's a relatively small number of failures and we have actually been tracking it manually. And so that is why we have numbers for those specifically.

With regards to the other assets, that data it's not available. We don't have a mechanism by which to say, okay, you know, this asset failed and, you know, we had to replace it and have that holistic view across all failures across our system, we do not currently have that data.

MS. GRICE: Okay, thank you. And then with respect to the interruptions in 2018, '19, and '20, so the last three columns, just looking at the table it says that -- or it shows that you don't have interruption data for circuit breakers, station service transformers. Is there a reason why that data's not collected?

MR. FALTAOUS: I would not be able to answer that question for you, Ms. Grice. That's really a -- panel 1 looks after the performance data.

MS. GRICE: Okay. Okay, thank you. Can we go to AMPCO 64 next, please? In this interrogatory, we were just asking for the variance between the annual forecast quantities compared to actuals, and there's just some N/A points in the table and I am just seeking clarification about why the data wasn't able to be populated into the table for transformers, MUS trailer replacements, and stations targeted for spill containment.

I guess the most important one would be transformer replacements.

MR. FALTAOUS: I believe the answer to this question, Ms. Grice, is that these specific ISDs are -- they were -- they did not exist in this manner, I believe, in the previous application, and that's why.

So the work -- I think the ISDs that are being referenced here did not actually exist in this last application and that's why, I believe, it's showing up as N/A. Or the program, the specific program that that ISD represented was essentially discontinued.

MS. GRICE: That's fine, thank you. If we can please go to AMPCO 65 again. So this -- this is just regarding this discussion that we had regarding the condition algorithms and in response to part (c), we were asking for the condition algorithm for the specific asset types, and we were referred to Staff 119, which we have already talked about. And then we were also referred to Staff -- or SEC 114. So if we can please go to SEC 114.

And in that interrogatory SEC asked for Hydro One to explain all changes in its asset condition assessment methodology since EB-2017-0049, and you mention here that you do additional testing for poles which is data around pole ground line.

So just a quick question there. I assume that's a visual type of inspection that you do for pole ground line?

MR. FALTAOUS: No, that is actually a quantitative assessment. So we actually drill into the pole and measure the remaining shell thickness at the ground line.

MS. GRICE: Okay, thank you. And then with respect to transformers, it says here that Hydro One now incorporates oil leak data into your station transformer condition assessment algorithm.

So would you be able to by way of undertaking update that condition algorithm information from I-24-Staff-119(b) to include the oil leak data so that we can see the new distribution of weightings across your condition factors? And that reference that I am giving is from the last proceeding.

MR. KEIZER: Sorry, is that the reference you earlier tried to bring up -- we tried to bring up on the screen?

MS. GRICE: Yes, and my apologies, I am sorry I didn't provide it to you earlier, but essentially it provides the condition algorithm for transformers and it shows the weightings across all of the factors that you consider, and now you have added a new one, so I am just asking for that condition algorithm to be updated on the record.

MR. KEIZER: I am asking Mr. Faltaous, do you need that document in front of you? I think it would probably be helpful to you if you had it.

MR. FALTAOUS: Yes, it would be helpful, Mr. Keizer.

MR. KEIZER: Do we have that? I am just asking the Hydro One folks if we have it. Staff 119, is that what it was?

MS. GRICE: Yes, 119(b). I-24.

MR. KEIZER: That's 19. That's 19, that's not 119.

MS. GRICE: No, it's 119.

MR. KEIZER: Yeah.

MS. GRICE: Yeah, sorry.

MR. KEIZER: Oh, on the screen it wasn't the right one. Are you sure you have got the right --

MS. GRICE: Yeah, that's it, there we go.

MR. KEIZER: Okay, thank you.

MS. GRICE: So the condition risk factor for the station transformer is shown there. And the algorithm is shown in the weightings that are given to each of the supporting factors. And my understanding is that you have now added one, which is oil leak data. So I just wondered if you wouldn't mind updating the condition risk factor algorithm for station transformers to incorporate that new test.

MR. FALTAOUS: Can you go back to the IR response in the current application, please. So I would just like to clarify, Ms. Grice -- and you can see it there -- it say "Hydro One now incorporates oil leak data into station transformer condition assessments". It does not say that it specifically incorporates it into the condition assessment algorithm. And the reason I would like to highlight that difference is the algorithm is -- really, the intent of it is to flag where planners need to take a closer look to determine whether or not there is a need that needs to be addressed by way of some sort of investment.

So I did just want to clarify that the algorithm in and of itself is not the end all and be all when it comes to condition. It does have condition data that underlies it, but there may be other condition data that we layer in on top, including, you know, subject-matter expertise and so on, to ultimately determine the actual condition of our assets.

So we can certainly take it back and see whether or not the algorithm itself has been updated to incorporate the oil leak data or not yet, but I did just want to clarify that, regardless of whether or not the algorithm itself has been updated, that is data that planners are taking into account with regards to assessing the conditions of the assets. I just wanted to make sure that that part was clear.

MS. GRICE: Okay.

MR. FALTAOUS: But we can certainly take that back and check.

MS. GRICE: Thank you, yes, if you could check to see if the algorithm has been updated and then please provide it. And then if not, if you could explain what weighting is given to oil leak data in terms of determining your investment level for condition transformers, if that -- if there is an explanation you can give with respect to the current weighting of this new test.

MR. FALTAOUS: So we can provide an explanation. Ultimately it would be an assessment of the condition of the transformer to ultimately inform what the need is and what needs to be done to address it, but we can provide an explanation on that.

MS. GRICE: Okay, as well as updating the algorithm if it needs to be.

MR. FALTAOUS: If the algorithm has been updated we will identify that as well, that's correct.

MS. GRICE: Okay. I appreciate it, thank you very much.

MR. FALTAOUS: Thank you.

MR. SIDLOFSKY: That will be JT3.9.

UNDERTAKING NO. JT3.9: TO ADVISE IF THE ALGORITHM HAS BEEN UPDATED AND THEN TO PROVIDE IT. AND THEN IF NOT, TO EXPLAIN WHAT WEIGHTING IS GIVEN TO OIL LEAK DATA IN TERMS OF DETERMINING INVESTMENT LEVEL FOR CONDITION TRANSFORMERS; TO PROVIDE AN EXPLANATION WITH RESPECT TO THE CURRENT WEIGHTING OF THIS NEW TEST.

MS. GRICE: Can we please go to AMPCO 66. I think most of my questions are just clarifying data, so hopefully I won't take too much longer. So AMPCO 66, this was a question that we asked for asset replacement numbers, and if we go down the table under line transformers in the attachment 1. There's just a blank in the data for 2026 and 2027 for pole mounted transformers. I just wanted to understand what the blank in data means.

MR. FALTAOUS: I'm sorry, are you specifically asking with regards to pad mounted transformers -- or, sorry, okay, no, you are asking about pole mounted transformers.

MS. GRICE: I think it's pole mounted transformers. For the last two years the columns are blank, and I just didn't know if that should be a 0 or, you know, it is just an omission of data and there actually should be numbers in there.

MR. FALTAOUS: Just give me one second and I will confirm.

MS. GRICE: Thank you.

MR. FALTAOUS: Those should appropriately be zeros.

MS. GRICE: Okay. Great, thank you. And then just one more, under submarine cables. In what you have replaced under 2018 you have got kilometres, and then the next -- the next columns reflect units. And I just wondered if you can explain what that means. Is it 155 kilometres?

MR. FALTAOUS: No, it is individual units. So it's individual cables. So it's 155 cables. And the reason for that change is a change in the way that we were reporting. So we did transition from reporting kilometres of submarine cable to reporting the number of cables, and that's why you see that change there.

MS. GRICE: Can you translate that into kilometres easily?

MR. FALTAOUS: Not with any confidence and degree of accuracy, essentially.

MS. GRICE: Okay, okay, and so there's no standard length of a unit?

MR. FALTAOUS: No. The length depends on the specific application and where it's going from, you know, the water body that it's going through, essentially, so it can vary.

MS. GRICE: Okay, thank you. If we can now please turn to AMPCO 88. Just a quick question under part (b). In part (b), we asked for the numerical values for the chart for spending, and you provide up to 2020. I wondered if you'd be able to provide to Q3 2021.

MR. FALTAOUS: Sorry, just give me one minute, please.

MS. GRICE: Sure.

MR. FALTAOUS: Sorry, Ms. Grice, what values are you specifically looking for?

MS. GRICE: Just under part (b), you have dollars in millions for '16, '17, '18, '19 and '20. I am just wondering if there's a value for Q3 2021 on the same basis.

MR. FALTAOUS: Q3 2021?

MS. GRICE: Yes.

MR. FALTAOUS: If I can take you to SEC 2, the attachment, please -- and sorry, that would be attachment 4. So you can see here SR-05, distribution lines trouble call and storm damage, and it does provide the 2021 Q3, year-to-date value.

MS. GRICE: Okay, okay. Thank you. And maybe we should just hang on to that because maybe my questions coming up are in this table. So my apologies if they are, but let's see.

AMPCO 92; I just had a question on part (a) where you say that you don't have the number of poles that fail by year that are in poor condition, because that information is not captured. Is that correct?

MR. FALTAOUS: That's correct.

MS. GRICE: And so when a pole fails under a trouble or a storm condition, do you track any data related to the pole, such as its age or any other data? Or it's just replaced as part of the demand program?

MR. FALTAOUS: I believe some data would be available, Ms. Grice, although I would have to confirm. So actually

-- sorry, I do believe that the age -- I believe age would have to be available. Although I am not perfectly clear, to be honest. So I would have to go back and confirm that.

MS. GRICE: If you can just confirm, please, what data you track when you replace a pole under trouble or storm conditions, that would be helpful.

MR. FALTAOUS: Sure, so we can confirm if we track the age at the time of failure.

MS. GRICE: And any other data.

MR. FALTAOUS: Sure.

MS. GRICE: Thank you.

MR. SIDLOFSKY: That will be JT3.10.

UNDERTAKING NO. JT3.10: TO CONFIRM TYPES OF DATA TRACKED AT THE TIME OF POLE REPLACEMENT UNDER TROUBLE OR STORM CONDITIONS

MS. GRICE: Okay, AMPCO 93, please. In part (a), you provide your actuals for 2018, 2019, and 2020 with respect to pole replacements. The data that's shown for 2021 and 2022, is it possible to get Q3 actuals for 2021? Or is that Q3 actuals?

MR. FALTAOUS: Can we go to a breakout room, please?

MS. SANASIE: Sure, the room is open.

[Witness panel confers in breakout room]

MR. FALTAOUS: Hi, Ms. Grice. Actually in part (b) the response to this question, you can see we did provide the 2021 Q3 actuals.

MS. GRICE: Okay, so those are -- okay. And then your forecast for 2022 is shown there as well?

MR. FALTAOUS: That's correct.

MS. GRICE: Oh, I am sorry. I see, I see. Okay. Could I get the dollars, then, for 2023 -- 2021, that have been spent to date?

MR. FALTAOUS: You are looking for the Q3 dollars for 2021?

MS. GRICE: Yes, please.

MR. FALTAOUS: I believe that would also be found in SEC 002, the same attachment that we looked at earlier.

MS. GRICE: Okay, okay. Very good, thank you. And then AMPCO 96, just a point of clarification. In the response where we ask for information on the number of interruptions attributed to cross-arm failures, if you go to bottom of the table, I just want to confirm what N/A means. I'm assuming it means that you don't track the data, you don't track the condition of the failed asset; is that correct?

MR. FALTAOUS: Sorry, just give me a minute, please.

MS. GRICE: Sure.

MR. FALTAOUS: I believe the reason that it was not provided for 2021, Ms. Grice, is because 2021 is still ongoing, and so it would be an inappropriate comparison to provide a 2021 value relative to year-end values for the other years.

MS. GRICE: I am sorry, I was looking at the bottom row. I understand 2021, just the bottom row on number of interruptions due to assets in poor condition.

MR. FALTAOUS: Oh, my mistake. So, yes, you're correct, that data would not be available.

MS. GRICE: Okay. And my last couple of questions just regarding dollars, and you referred me to the SEC appendix. My understanding, it shows the dollars based on Q3 for the whole program, but it doesn't show the sub-components, and some of these questions I think we have been talking about are related to the sub-components. So I just want to make sure...

MR. FALTAOUS: So for the pole program, you are looking for the dollars associated with the sub-components for 2021 Q3 with regards to replacement, refurbishment, and test and treat?

MS. GRICE: Yes, I believe so. Are you able to provide that?

MR. FALTAOUS: Can we go to breakout room, please?

MS. SANASIE: Sure, it's open now.

[Witness panel confers in breakout room]

MR. FALTAOUS: Hi, Ms. Grice. Mr. Ng was going to provide a response, and unfortunately he has just been accidentally kicked out of the meeting, so he is rejoining. It will take him a minute.

MS. GRICE: Okay, thank you.

MR. NG: Good morning, Ms. Grice, this is CK Ng from Hydro One speaking. Can you hear me?

MS. GRICE: Yes, I can, thank you.

MR. NG: Regarding the questions -- the request that you just put forward, yesterday SEC had a similar request which was captured in an undertaking. I believe it is JT1.12. That is asking for us to provide an update to Exhibit B-3-1, section 3.9, Table 4 and 5. So we have made a commitment to provide that update to the tables. I think you will find the answer there.

MS. GRICE: Okay. So that would provide the Q3 dollars for the three programs under pole replacement? So it would give the dollars for test and treat, pole refurbishment, and pole replacement broken out?

MR. NG: It will give you the numbers based on the program level. If you go to that exhibit and have a look at the table, it will do the same thing there.

MS. GRICE: Okay. I guess -- I think we need it at the sub-program level, we need the dollars. So if Undertaking JT1.12 does it at the program level, we need a little more detail. So if we could just get the undertaking then? If it is in JT1.12 then it's there, that's great. But I guess what I am looking for is the Q3 dollars for test and treat, pole refurbishment, and pole replacement.

MR. FALTAOUS: Okay. We will take the undertaking.

MS. GRICE: Thank you.

MR. SIDLOFSKY: JT3.11 --

MR. FALTAOUS: Sorry, go ahead, please.

MR. SIDLOFSKY: That was JT3.11. Sorry to interrupt.

UNDERTAKING NO. JT3.11: TO PROVIDE THE Q3 DOLLARS FOR TEST AND TREAT, POLE REFURBISHMENT, AND POLE REPLACEMENT, OR TO PROVIDE THE EVIDENTIARY CITATION TO THIS DATA

MR. FALTAOUS: I was just going to indicate that if the information is provided as Ms. Grice mentioned in another undertaking, then we will just point to it, but otherwise we will work on it. Thank you.

MS. GRICE: Okay, thank you. AMPCO 97. In this interrogatory you provide the actuals replaced from 2018 to 2020, and then you provide 2021 and 2022 data. Can you confirm that 2021, are those Q3 actuals or is that -- was that a previous forecast?

MR. FALTAOUS: I believe this was -- I believe this is a 2021 plan for the year. So I do not believe this is Q3 actuals.

MS. GRICE: Would you be able to provide Q3 actuals?

MR. FALTAOUS: Yes, we can.

MS. GRICE: Thank you.

MR. SIDLOFSKY: JT3.12.

UNDERTAKING NO. JT3.12: WITH REFERENCE TO AMPCO 97, TO PROVIDE Q3 ACTUALS.

MS. GRICE: Okay. AMPCO 98, please. So this shows number of transformers replaced under SR-08, and same question. Is the 231 in 2021, is that a Q3 actual or a plan number?

MR. FALTAOUS: I don't believe it's Q3 actuals.

MS. GRICE: Okay. Could we get Q3 actuals, please?

MR. FALTAOUS: Yes, we can.

MS. GRICE: Thank you.

MR. SIDLOFSKY: JT3.13.

UNDERTAKING NO. JT3.13: WITH REFERENCE TO AMPCO 98, TO PROVIDE Q3 ACTUALS FOR NUMBER OF TRANSFORMERS REPLACED UNDER SR-08.

MS. GRICE: AMPCO 99, please. So this is sentinel lights replaced. Same question. 2021, is that a Q3 actual or plan number, and if it's a Q3 -- or if it's not a Q3 actual could we please get the Q3 actual?

MR. FALTAOUS: We can.

MS. GRICE: Thank you.

MR. SIDLOFSKY: JT3.14.

UNDERTAKING NO. JT3.14: WITH REFERENCE TO AMPCO 99, TO PROVIDE Q3 ACTUALS FOR SENTINEL LIGHTS REPLACED.

MS. GRICE: Okay, AMPCO 100, please. I would just like to understand the data provided for 2021 and 2022. Is 2021 Q3 actuals with respect to costs, or is that a plan number?

MR. FALTAOUS: Just give me one second, please.

MS. GRICE: Sure.

MR. FALTAOUS: I will have to confirm, Ms. Grice. I can't confirm right now, but I believe it's a 2021 plan number and I can confirm that.

MS. GRICE: Okay, and if it's -- and provide Q3 actuals if it is.

MR. SIDLOFSKY: Is the panel agreeing to do that?

MR. FALTAOUS: Yes, we will take a look at that. We will take that undertaking.

MR. SIDLOFSKY: So we will make that JT3.15.

UNDERTAKING NO. JT3.15: WITH REFERENCE TO IR AMPCO 100, TO CONFIRM WHETHER THE 2021 Q3 FIGURES ARE COSTS ACTUALS OR PLAN NUMBERS; TO PROVIDE Q3 ACTUALS, IF AVAILABLE.

MS. GRICE: Okay, I am almost done, sorry. So in AMPCO 102, you provide in part (a) data on submarine cables replaced or refurbished, and you've got 400 kilometres for -- I believe it's kilometres for 2021.

Again, is that a plan number or a Q3 actual?

MR. FALTAOUS: I'd like to confirm, Ms. Grice, that that is not kilometres; it is number of cables as per the note underneath the table.

MS. GRICE: Okay.

MR. FALTAOUS: And I believe it is a plan number.

MS. GRICE: Okay. could we get the Q3 number, please?

MR. FALTAOUS: Yes.

MR. SIDLOFSKY: JT3.16.

UNDERTAKING NO. JT3.16: WITH REFERENCE TO IR AMPCO 102 PART (A), TO CONFIRM WHETHER THE 400 SUBMARINE CABLES REPLACED OR REFURBISHED ARE ACTUALS OR PLAN NUMBERS; TO PROVIDE Q3 ACTUALS, IF AVAILABLE.

MS. GRICE: Okay, the last one, AMPCO 103, please. So what this is it's information on your line work, and I believe it is regarding SR-10. And can you just please confirm whether or not the data provided in the table in part (a) and (b) is 2021 Q3 actuals or plan numbers?

MR. FALTAOUS: I believe it's plan.

MS. GRICE: Okay, again could you please provide the Q3 actuals?

MR. FALTAOUS: We can take this one back and take a look at what we can provide, Ms. Grice. I think it may be a challenge to do this breakout based on a Q3 because we are talking about kilometres of line. But we can certainly take it back and see what we can provide for Q3.

MS. GRICE: Okay, I appreciate it, thank you.

MR. SIDLOFSKY: We will make that JT3.17.

UNDERTAKING NO. JT3.17: WITH REFERENCE TO IR AMPCO 103, PART (A) AND (B), TO CONFIRM WHETHER THE 2021 Q3 FIGURES ARE ACTUALS OR PLAN NUMBERS; TO PROVIDE Q3 ACTUALS, IF AVAILABLE.

MS. GRICE: Thank you very much for your indulgence. Those are my questions. Thank you.

MR. SIDLOFSKY: We are moving on to Anwaatin.

# Examination by Mr. McGillivray:

MR. McGILLIVRAY: Thank you, Mr. Sidlofsky. Jonathan McGillivray, counsel for Anwaatin here. Can you see me. I can't see myself, but I suspect I am there. Awesome, thank you.

I will get us situated by asking you to pull up Anwaatin 1, and specifically part (c). And I covered part of this with Mr. Jesus, but really the indication was that this was better suited for panel 2. So I am going to cover a little bit of the same train, but I think I will get into questions that are relevant for this panel.

In part (c), we asked you to file all reports, presentations, analysis, data and other materials related to the First Nations electricity reliability improvement plan, and I will just call that the plan. And down the page on the next page, your response was that the First Nation reliability report in the evidence includes the materials related to the plan. And there are a couple references to the plan in the prefiled evidence. I don't think we have to go there, but I will just read them out. One is in Exhibit A, tab 7, schedule 2, at page 6, and the other one is in the business plan Exhibit A, tab 3, schedule 1, attachment 1 at page 21 and a list of key programs and initiatives for 2023 to 2027.

So my question really goes to understanding and confirming that there's nothing further on the plan, other than what's in the report, the First Nations reliability report that's in evidence, and your response to this interrogatory. Is there anything else that I am missing on the plan?

MR. FALTAOUS: Hi, Mr. McGillivray, it's Peter Faltaous. So you are correct, the report that was included as attachment 1 to Exhibit A, tab 7, schedule 2, is the report that outlines the Plan for Reliability Improvement for First Nations Communities.

MR. McGILLIVRAY: Okay. Thank you, that's helpful. I think that's, I think that's consistent with what it says in your response to (f) here, Hydro One will -- sorry, I can't see who is speaking.

MR. KEIZER: Sorry, we are we having technical issues again?

MR. NG: Yeah, we are disconnected.

MR. KEIZER: We can hear you.

MR. NG: Mr. Keizer, can you hear me?

MR. KEIZER: Yes, we can.

MR. NG: We are having a bit of technical issue here, Mr. Faltaous is just starting -- reconnecting.

MR. KEIZER: Okay.

MR. McGILLIVRAY: Okay.

MR. FALTAOUS: Mr. Keizer, can you hear me?

MR. KEIZER: Yeah, we can hear you.

MR. FALTAOUS: Okay. And can you see me as well?

MR. KEIZER: I can see you as well.

MR. FALTAOUS: Okay, it seems to have be resolved. Sorry about that, Mr. McGillivray.

MR. McGILLIVRAY: No problem. I think I was just about to look at the response to 1(f) on the page there, which says that Hydro One will engage in the development and implementation of the plan following OEB approval of the proposed plan for energy storage solutions, which is in ISD D-SS-04.

So my question is -- and we can go to that ISD, I think. My question is we have the report, we have the plan, and we have this ISD. And those are the parts of, I think, the application that are on First Nations reliability investments and planning.

And my question is: What proportion of the investments that are planned under that ISD are intended to support the First Nations electricity reliability improvement plan? And it might be helpful to go to -- I think it's the next page of this ISD that has a breakdown of the grid and the residential.

MR. FALTAOUS: It's page 8 of the ISD.

MR. McGILLIVRAY: Thank you.

MR. FALTAOUS: So I can confirm, Mr. McGillivray, that the grid-scale storage portion of this ISD is targeted at the First Nations communities.

MR. McGILLIVRAY: So all of the grid-scale storage proposal here is targeted at the First Nations communities and there's none that's targeted to other communities?

MR. FALTAOUS: So the First Nations communities are the target. Now, I will say that if there are other customers that are within proximity that have also experienced really poor reliability that may be benefiting -- that could benefit from the grid-scale deployment, we will not necessarily leave those customers out. So it is targeted at the First Nations communities, but I wouldn't say that there will be, you know, 0 customers that are not First Nations that may benefit from this.

MR. McGILLIVRAY: Okay, that's really helpful. And I guess the corollary to that question is -- and I think there's only 100 customers in the residential storage portion of this, but are any of the residential storage investments likely to benefit First Nations communities or not?

MR. FALTAOUS: So I'd like to correct what you said in that there's 2,100 customers that are targeted for the residential storage.

MR. McGILLIVRAY: Okay.

MR. FALTAOUS: And the plan is not to target First Nations communities for residential. The grid-scale is really what is targeted for the communities.

MR. McGILLIVRAY: Could you just direct me to that 2,100 number to make sure that I haven't missed something.

MR. FALTAOUS: Give me one minute, please.

MR. McGILLIVRAY: Actually, it's on page 6. Page 6 says:

"Hydro One proposes to install residential battery storage at around 2,100 homes across the province over the plan period."

Just below that. That's --

MR. FALTAOUS: You got it faster than I did.

MR. McGILLIVRAY: I understood that as going to -- my computer is not responding here. That's mentioned in the context of the Aroland S pilot project, but that number speaks to the residential storage investment; is that right?

MR. FALTAOUS: I am sorry, Mr. McGillivray, you are cutting out for me. I don't know if that's just a problem with my computer or if that...

MR. McGILLIVRAY: Can anyone tell if it's my computer or Mr. Faltaous's?

MR. KEIZER: Could you repeat the question maybe and see -- oh, he has gone off now, so...

MR. McGILLIVRAY: Oh, he seems to be frozen.

MR. KEIZER: You are there, Mr. Faltaous?

MR. NG: Mr. Keizer, can you hear me?

MR. KEIZER: Yes, we can.

MR. NG: We are again having some technical difficulty here. A few of our panel member got bumped off the Webex

-- not Webex, the Zoom call, so we are trying to re-establish connections.

MR. KEIZER: Okay. Maybe, Mr. McGillivray, when they are back on you can repeat your question for Mr. Faltaous.

MR. McGILLIVRAY: Sure. And I think I have found another relevant point that may clarify this.

MR. KEIZER: Are you good to go, Mr. Faltaous?

MR. FALTAOUS: I believe we are all here, Mr. Keizer. We can continue.

MR. McGILLIVRAY: I will just repeat the question. We were talking about the 2,100 number, and there was some confusion, because I used the number 100. The place I got that was the response to SEC 156, part (b), and I think the confusion is that that interrogatory response goes to the pilot project for residential storage and not the proposed investment over the 2023 to 2027 period. But I just want to make sure that I have got it right, because on page 6 of the ISD, the 2,100 number is mentioned under the Aroland S pilot project and not under the residential storage section of the ISD.

MR. FALTAOUS: So your understanding is correct. The SEC IR that you reference is with regards to the pilot and the plan, not the installations over the 2023 to 2027 plan, whereas here the 2,100 customers is for residential battery storage over the '23 to '27 plan, and that portion is not targeted at First Nations communities.

MR. McGILLIVRAY: Okay. Thank you so much for that. I understand that there are 24 -- I am going to focus in on the grid storage part of it in light of that. I understand that there are 24 candidate communities for the 2023 to 2027 period, and Anwaatin 001 part (h) provides, I think, an updated much longer list. It's longer than 24 communities, and my understanding is that this is all First Nations communities that are served by Hydro One; is that right?

MR. FALTAOUS: Can you scroll down, please. Yes, that would be correct, Mr. McGillivray.

MR. McGILLIVRAY: Thank you. And I am also correct that there's 24 candidate communities that have been selected for the plan period; right?

MR. FALTAOUS: That's correct, we have identified 24 candidate communities. The plan is to deploy storage for 20 communities of those candidates.

MR. McGILLIVRAY: Thank you. Can you describe the process you used to select the 24? Or direct me to a place in the evidence where it's described? I don't think it is, but maybe there is a place where it is.

MR. FALTAOUS: The selection of the communities was based on the ones that were experiencing the greatest number of hours of interruption.

MR. McGILLIVRAY: The greatest number of hours of interruption?

MR. FALTAOUS: That's correct. Just give me one minute, please. I will see if I can find a reference for you, but that is essentially -- that is essentially what it was.

MR. NG: Mr. Keizer, can you hear me?

MR. KEIZER: Yes, we can.

MR. NG: Mr. Faltaous just got disconnected again, so he needs to re-establish connections. Just give us a moment here.

MR. KEIZER: Okay.

MR. FALTAOUS: Can you hear me?

MR. McGILLIVRAY: Yes.

MR. FALTAOUS: My apologies. My connection keeps cutting in and out here.

So Mr. McGillivray, the answer to your question is they were selected based on their total outage hours of duration, total duration of outage hours over a three-year period. That is essentially how those communities were prioritized.

MR. McGILLIVRAY: Okay. If we can go to the top of this table, I think that will help. Yeah, or even there, just to see the top row.

So if I sorted this table by the second column, "average of annual hours of interruption 2018 to 2020", in descending order, would I get the list of 20 -- the 24 communities?

MR. FALTAOUS: I believe there is one small nuance here, which I believe the original list was developed based on the '17 to '19 data. And then I think the tables were updated for '18 to '20, although I don't believe that the list changed. I think if you were to do that, you find -- I believe the vast majority of the communities were unchanged, I think 23 of the 24. There may have been one that would change just based on their change in terms of that rolling three-year average. But that is essentially what you would do to determine how we got those communities, just with that one nuance of using '17 to '19 data, which at the time that we were looking at this, the 2020 data was not available.

MR. McGILLIVRAY: Okay, thank you. And just a final question on this. The third column, average of annual numbers of interruption, that wasn't used to select the communities for this first subgroup, correct?

MR. FALTAOUS: That's correct, we primarily looked at the duration of interruptions as opposed to the number.

MR. McGILLIVRAY: Okay, thank you. In part (g) of this interrogatory response, which is --

MR. FALTAOUS: I am sorry, Mr. McGillivray. Sorry, my apologies. I do need to correct something.

So we were just looking at average of annual hours of interruption -- okay, no, that is correct. Sorry, I was -- I thought that that may have been the average interruption duration, but, no. That is correct, I am sorry. What I stated is correct.

MR. McGILLIVRAY: Okay, thank you. On the previous page in response to part (g), you speak about how the candidates will be divided -- the candidate communities will be divided into subgroups; a study on the first subgroup of these 24 that we have been discussing by Q4 of 2022, based on a series of factors.

And I realize we are talking about the 2023 to 2027 period, but in order to assess that proposed investment, I just wondered if you could speak to how you're envisioning delineating future subgroups beyond the initial 20 to 24 communities?

MR. FALTAOUS: Sorry, just to clarify your question, you are saying future subgroups beyond the specific candidate communities that we have identified?

MR. McGILLIVRAY: Yeah, and I just -- I am just thinking that way because of the use of the words "first subgroup". Is there going to be a second subgroup? What are the thoughts around the second subgroup?

MR. FALTAOUS: Yes. So to clarify, I think what we mean by "subgroup" here is it is a subgroup of the candidate communities. So it's not the 24 communities are one subgroup and then there's going to be another set of communities that's another subgroup. It is a subset of the 24 communities that will be the first subgroup.

MR. McGILLIVRAY: Okay. That is not exactly how I read it, because if you read the whole sentence, "the study will be completed for all candidates in the first subgroup by Q4 2022." So I thought that meant all of the 24.

MR. FALTAOUS: Can you repeat your question, Mr. McGillivray? I am sorry, Mr. McGillivray, my connection has cut out again. I did not get the last thing that you just said, if you don't mind repeating that, please.

MR. McGILLIVRAY: No problem. It's just when I read the whole sentence, it says:

"A study will be completed for all candidates in the first subgroup by Q4 2022."

So I didn't take from that that the subgroup refers to the subset of the 24 communities that are going to be pursued. I thought subgroup referred to all of the 24 candidates.

MR. NG: Mr. McGillivray, this is CK from Hydro One speaking, can you hear me?

MR. McGILLIVRAY: Yes.

MR. NG: Again, Mr. Faltaous is having connection problems and he needs to re-establish connection, so give us a moment here.

MR. KEIZER: Maybe we should -- can we -- is it something that we should take five minutes and let Mr. Faltaous reboot his computer maybe? Would that be helpful?

MR. FALTAOUS: Mr. Keizer, I can hear you now. I can try logging out of the Zoom session and coming back in, and perhaps that will address the issue.

MR. KEIZER: Maybe we should. For your purposes, Mr. McGillivray, is that okay for us to do that?

MR. McGILLIVRAY: Yes, that's fine with me. I think that would be helpful. After this question, I just have one other area that I want to go to, and then I will be done, just for context.

MR. FALTAOUS: I can hear you now. I don't know if you want to take our chances and try again, or would you like to stop altogether?

MR. KEIZER: Let's try one more time with feeling, let's go for it.

MR. FALTAOUS: Okay.

MR. McGILLIVRAY: Did you hear my question or not?

MR. FALTAOUS: No, I'm sorry, Mr. McGillivray, you were cutting out.

MR. McGILLIVRAY: Okay, it was about the -- basically the definition of the word subgroup. And I think you said that subgroup is meant to refer to the subset of the 24 communities that you're going to pursue.

MR. FALTAOUS: That's correct.

MR. McGILLIVRAY: Okay. But I guess my confusion is that I was reading the sentence as a study proposed for all candidates in the first subgroup. So it sounds to me like the subgroup is all of the candidates.

MR. FALTAOUS: I think if you read the first sentence, it says the candidates identified in Exhibit A, tab 7, schedule 2, attachment 1, will be divided into subgroups. And perhaps the ambiguity there is the candidates piece. So when we are referencing candidates, we are referring specifically to the 24 candidates that were identified, not the full list of all the First Nations communities. Perhaps that's where the lack of clarity is.

MR. McGILLIVRAY: Okay, I think that's enough, thank you. The last area that I'd like to go to is pages 9 and 10 of the ISD D-SS-04, and these are the alternatives. There's four alternatives in your analysis. Do nothing -- alternative 3, traditional poles and wires solutions. Alternative 3 is the one that you're recommending, and alternative 4 is an accelerated pace alternative.

And under alternative 3, you indicate that 4,100 customers will benefit, and I assume that's the grid storage plan plus the residential storage plan. Is that right?

MR. FALTAOUS: That's correct.

MR. McGILLIVRAY: And under alternative 4, the accelerated pace alternative, 8,500 customers would benefit. But you've indicated that there's less support according to customer engagement results.

And I am wondering if you can speak to, or just provide some background on why there was less support for the accelerated pace alternative.

MR. FALTAOUS: This would actually be a better question for panel 1, as they were sort of overseeing the customer engagement piece.

But I can tell you that as part of our customer engagement where we went through a Phase 1 and then subsequently, as part of Phase 2 customer engagement, we went back to our customers and we basically gave them trade-off scenarios and we basically identified specific to energy storage.

Some of the trade-off scenarios -- just give me one minute. I will see if I can find a reference for you.

I am sorry, I was disconnected again. Can you hear me now?

MR. McGILLIVRAY: We can barely hear you.

MR. FALTAOUS: I will try again. Is that any better?

MR. McGILLIVRAY: Yes.

MR. KEIZER: Yeah, we can hear you.

MR. FALTAOUS: Okay. So I don't have a reference [audio dropout] for you [audio dropout] engagement [audio dropout] again, panel 1 would be able to provide that, and if I could take you to Exhibit --

[Reporter appeals]

MR. FALTAOUS: Okay. No problem. I can repeat it. So what I was saying is that I don't have a reference for you for the direct customer engagement material itself, as again that would be panel 1, but I can take you to Exhibit B, tab 3, Schedule 1, section 3.7, and specifically if I take you to page 13 of that, if you scroll down, please, a little bit.

So it's a system service piece, where you can see there under battery storage it says that there was a clear preference for the draft plan with less appetite for an accelerated pace than in previous investments, so with regards to the draft plan.

And so this was essentially the results of our customer -- Phase 2 customer engagement. We would have provided customers with a view of what the draft plan would have looked like in terms of pacing, which represents 4,100 customers. We would have also provided a view of an accelerated pace for energy storage for 8,500 customers, and then we had feedback from our customers, and the majority of customers were supportive of the draft plan as opposed to the accelerated pace. And again, this was part of the customer engagement which, as I mentioned, is better spoken to by panel 1. But that is essentially what we are referring to.

MR. McGILLIVRAY: Okay. I understand the caveat about panel 1. I think my only follow-up question is this part of the customer engagement was not specific to First Nations customers, or was it?

MR. FALTAOUS: I -- I can't say with certainty, Mr. McGillivray. I think that would be a question for panel 1 to confirm. I do know that as part of customer engagement we did have engagement with First Nations, as well as with all of our other customers, for representation of all of our other customers, but in terms of, you know, this specific result, I can't say whether or not -- who specifically is rolled up into these specific results.

MR. McGILLIVRAY: In light of the fact that panel 1 has come and gone and your name appears at the bottom of the ISD on this, I am wondering if you could just undertake to confirm that the reference to battery storage on the page in front of us is based on customer engagement that did not focus specifically on First Nations.

MR. FALTAOUS: So we can take back -- I believe what you're asking is, you know, were these specific engagement results the results from First Nations communities or were they are the results from our broader customer base. I believe the answer, it was from our broader customer base, but, again, I don't want to say, as I am not certain. So I think that is something that we can take back and confirm as an undertaking. Would that work for you, Mr. McGillivray?

MR. McGILLIVRAY: That's perfect, thank you.

MR. SIDLOFSKY: We will make that -- sorry, that's JT3.18.

UNDERTAKING NO. JT3.18: TO CONFIRM THAT THE REFERENCE TO BATTERY STORAGE AT EXHIBIT B, TAB 3, SCHEDULE 1, SECTION 3.7, PAGE 13 IS BASED ON CUSTOMER ENGAGEMENT THAT DID NOT FOCUS SPECIFICALLY ON FIRST NATIONS.

MR. McGILLIVRAY: Okay. Thank you, that's the end of my questions. Thank you very much.

MR. KEIZER: Mr. Sidlofsky, maybe so we can get our IT things moving in the right direction, if we could take a break now so we could get Mr. Faltaous' computer rebooted for the afternoon session that would be helpful.

MR. SIDLOFSKY: That was going to be my suggestion anyway, because I didn't want to break up Pollution Probe if we didn't have to, and we also took what amounted to our morning break a little bit early, so why don't we take the lunch break now.

Could I ask people to stay on after we go off the air, though, just for a brief scheduling discussion.

MR. KEIZER: Sure.

MR. SIDLOFSKY: Thanks very much, and we will take the break now.

### --- Luncheon recess taken at 12:02 p.m.

### --- On resuming at 1:03 p.m.

MR. SIDLOFSKY: Let's go ahead with panel 2, Pollution Probe. Michael Brophy, you're up.

MR. KEIZER: Sorry, Mr. Sidlofsky, if I may, there is just a couple of clarifications coming out of this morning that the panel would like to speak to, and then Mr. Brophy can take it away.

MR. SIDLOFSKY: Sure, thank you. Thanks, Mr. Keizer.

# Preliminary Matters:

MR. PAISH: It's David Paish, and I would just like to do a couple of clarifications.

There was one clarification required from Mr. Garner's question regarding Hydro One working with Alectra for the MI2 pilot. We are currently working collaboratively with Alectra on the procurement of the AMI2 vendor. However, we will be running entirely separate AMI2 projects, including the pilot phase.

And then the second one is also a question from -- I believe it was Mr. Ladanyi, about replacing AMI1 with AMI2 meters which requires clarification.

It's not currently possible to replace AMI1 meters with AMI2 meters because they are not interoperable. This will change in the future only after AMI2 network is deployed.

MR. KEIZER: Can I just clarify, since we just heard "recording is in progress", whether Mr. Paish's earlier comments actually would appear on the record.

[Reporter confirms inclusion in record]

MR. KEIZER: If you can proceed, Mr. Faltaous, please.

MR. FALTAOUS: Thank you, Mr. Keizer. This morning there was a question from Mr. Ladanyi, and it was specifically with regards to Energy Probe 39, and the ask was how much dollars were moved from the SR-04 ISD to

SS-01.

So I do have a number for you here, Mr. Ladanyi, so specifically in total over the '23 to '27 period it was $5.8 million. Did you want a breakdown by year?

MR. LADANYI: No, I don't need a breakdown by year.

MR. FALTAOUS: Okay, thank you.

MR. KEIZER: I assume that's it for the clarifications, panel? There's nothing further.

MR. SIDLOFSKY: Let's go ahead with Pollution Probe.

MS. GRICE: I am sorry, it's Ms. Grice from AMPCO. I am sorry to jump in. I just had a clarification on one of our undertakings that -- if I could just clarify with the panel; would that be okay?

MR. KEIZER: That's fine.

MS. GRICE: Okay, thank you. So I had a discussion with a couple of the parties over the break on the scope of undertaking JT3.6, and this was in relation to our discussion regarding Energy Probe 34 part (b), where there was that table that showed the pole groupings and the reliability groupings for poles replaced 3 to 7.

And what the undertaking asked for was for Hydro One to provide the same information as the table in part (b), but for reliability 1 and 2 groupings, showing the risk mitigated, the risk spend efficiency, and the number of forecast poles.

And the thing I want to clarify, just for the benefit of the parties I was speaking to in Hydro One, this undertaking, as it is worded, I believe responds to testimony that there were no reliability groupings beyond seven, meaning there wasn't a number 8, 9 and so forth. Can you just please confirm that's correct?

MR. FALTAOUS: This is Peter Faltaous. That is correct, Ms. Grice.

MS. GRICE: Okay, thank you. That's all I needed to clarify. Thank you so much.

MR. FALTAOUS: Thank you.

# Procedural Matters:

MR. SIDLOFSKY: And sorry, Mr. Keizer, I think I've got the scheduling matters straightened out at this point. So I can tell you that when we do start with panel 3, we will be starting with -- sorry, we will be starting with Energy Probe, followed by OSEA. They have offered to move up a bit in the schedule. And then Board Staff will follow along after that.

We will have one block for Board Staff, there will be Staff and Mark Lowry will be asking some questions tomorrow. But our parts of the questioning will follow consecutively. So to address Mr. Shepherd's question before, we will have one block of questions, but they will be split, I expect, over the evening. Thanks.

MR. SHEPHERD: Jamie, do we have a time for Board Staff for panel 3 duration?

MR. SIDLOFSKY: Yes. Sorry, Martin, can you help me with that?

MR. DAVIES: Yes, I believe we are looking at about an hour and a half on the load forecasting area, and an hour for PEG, roughly speaking. So we are probably around two and a half hours, which includes the 55 minutes moved from panel 2.

MR. SHEPHERD: So basically about the same total?

MR. DAVIES: That's right.

MR. SIDLOFSKY: It is about the same time. We are just moving one set of questions from panel 2 to panel 3.

MR. DAVIES: Yeah, that's the difference.

MR. SHEPHERD: Thank you so much.

MR. GARNER: Sorry, it's Mark Garner from VECC. I don't want to drag this conversation too long, but since we are talking scheduling and I promised to get back for Hydro One's benefit.

I talked to Mr. Harper, and he is hoping to have his questions for panel 3 in late tonight; there is a time difference, obviously. He doesn't anticipate having any time for panel 3. I have time, but I think it's only about 15 minutes, less than you have down there. And we will have time on panel 4. I don't believe it will be the 55, it will probably closer to less than 30.

I just ask, when we are rescheduling for tomorrow, the new thing, it just helps us if we are on after 11:30 a.m. for our stuff, just due to time difference between Alberta and here for us to listen in and deal with it.

Sorry, Jamie. Thank you.

MR. SIDLOFSKY: Thanks, Mark. We will keep that in mind when we are setting up the schedule.

And now I think we are ready to go with Pollution Probe.

MR. BROPHY: Thank you. Good afternoon. My name is Michael Brophy on behalf of Pollution Probe. For the court reporter's benefit, I didn't make an appearance this morning. Mr. DeVenz has our consolidated questions and will be proceeding with those. However, I provided discussion and input into those.

So to the extent that there's clarifications or other issues that come up, I will be available for this portion. I just wanted to make the court reporter and parties aware. Thank you. And I will pass it over to Mr. DeVenz.

# Examination by Mr. DeVenz:

MR. DeVENZ: Good afternoon, panel. My name is John DeVenz representing Pollution Probe, as Michael Brophy just indicated.

We are going to start off -- I would like to start off with an item that was deferred from panel number 1 on Monday, and it is related to B1-Pollution Probe-006.

If we go down to the response, and go down further to (d). So at the very top there, so it talks about Hydro One's supply chain has a process for reviewing the overall impact of its material and equipment purchases. And I'm just looking to confirm if that process includes information on vendor GHG emissions and embodied carbon related to their products.

MR. BERARDI: Hello, Mr. DeVenz, this is Rob Berardi from Hydro One. The answer is yes, and we also have some information in our supply chain policy that highlights our principles with respect to the environment and Indigenous.

And we also -- as a mandatory requirement, we request our suppliers to sign our supplier code of conduct, which talks about environmental stewardship.

But specifically, I will give you a real example. On our recent RFPs, requests for proposal, on fleet, part of our evaluation was on fuel efficiency. That was part of the evaluation criteria.

MR. DeVENZ: I see. Okay, thank you for that. Are you able to -- for the process you use, are you able to tell me approximately what weighting goes into your process, your procurement process, with respect to these environmental issues that you consider; is it material weighting?

MR. BERARDI: It really depends on the category. So when you use, for instance, the fleet category, it's at 5 to 10 percent. And if you look at other categories, there's also some other weightings with respect to Indigenous businesses and Indigenous procurement as well in that 5 to 10 percent range.

MR. DeVENZ: I see. Are you able to provide us with some of the documentation and questions that you ask in your RFPs, your request for proposals?

MR. BERARDI: Provided it's not an open RFP, we can provide that.

MR. DeVENZ: Okay. Could we get an undertaking for that, please.

MR. SIDLOFSKY: It will be JT3.19.

UNDERTAKING NO. JT3.19: TO PROVIDE SOME OF THE DOCUMENTATION AND QUESTIONS THAT ARE ASKED IN THE REQUEST FOR PROPOSALS.

MR. DeVENZ: Thank you. So now we move on to B4-Pollution Probe-20. And if we can go down to the responses on -- and the last one, I believe, number (f), yes. And so we just wanted to confirm that you use the Association for the Advancement of Cost Engineering, AACE, classification system when preparing project cost estimates.

MR. BERARDI: That's correct.

MR. DeVENZ: Okay, great, thank you. And your response indicates that you use order of magnitude class 5 estimates that range from, I guess, a low of minus 50 percent to plus 100 percent. I just wanted to

confirm -- I guess it's in there, but I just wanted to verify that.

MR. BERARDI: Just to clarify, that's during the needs and the feasibility phase. As we move through to the next stage, if you will, of our business case development, that estimate does get refined.

MR. DeVENZ: Right. So at this stage what you'd submitted, for all of the eight projects, the eight new facilities and major renovations, are they all at the stage of a class 5, an order of magnitude estimate at this point?

MR. BERARDI: Yes, they are.

MR. DeVENZ: Okay, great, thank you. As we noted in the IR, this category represents a 65 percent increase in the 2023 to 2027 over the 2018 to 2022 period. Can you help us understand the large increase?

MR. BERARDI: The large increases are primarily due to end-of-life replacement of our assets and also optimizing our real estate in order to better serve our operations group.

So when you look at those type of investments you have to take into context that we have 50 percent of our assets in poor condition and reaching end of life. So that's another dimension for consideration when we are looking at these investments.

MR. DeVENZ: Great, thank you. So I am just trying to understand what would be the contingency plan if, say, you know, on average say your projects were 30 percent over budget? Would you have to cancel some projects to stay within your budget envelope?

MR. BERARDI: We do manage to the budget envelope, and we would reprioritize based on that portfolio view.

MR. DeVENZ: Thank you. So we asked for business cases, but were advised that they will be done later. So just, will you be considering as part of your business cases, you know, other alternatives to what was proposed, or is what you submitted pretty much what you planned to do?

MR. BERARDI: We will be as part of the business case assessing other alternatives. However, maybe if I can walk you through an example, because just to emphasize the need and truly the benefit. So if I can walk you through an example in GP-03, and I am going to pick specifically Orillia OC, and I will maybe wait until that gets up on screen. And it's page 10. Can you go to the bottom of page 10, please. And maybe I will start on page 11. If we go to the map.

So Mr. DeVenz, what this proposal for this investment is consolidation of multiple facilities, leased facilities and owned facilities. So the pure benefit of this investment would be consolidation and also to drive efficiencies, both cost efficiencies and operational efficiencies, so consolidating multiple facilities, four facilities in this example, to one.

MR. DeVENZ: Great, thank you, that's helpful. If we could move to IR B4-Pollution Probe-19, please. And we go to the response. At the top (a) there it says:

"No, the intent of the fleet electrification is to reduce GHG emissions."

So it's basically indicating that the primary -- or at least the way I was interpreting it is that the primary driver for fleet purposes was GHG emissions.

Now, on Monday, Mr. Jesus had indicated something different or interpreted differently, and if you'd like we can pull up the comment from Mr. Jesus in the transcript. I have the page number and lines, if that's helpful.

MR. BERARDI: Yes, that would be helpful.

MR. DeVENZ: Okay. So, yes, Monday's transcript, page 106. So if we look from line 7 -- and I will just let you read that if you'd like -- down to roughly line 15.

MR. BERARDI: Yes, Mr. DeVenz, I have read it.

MR. DeVENZ: Yeah, so just trying to reconcile in the IR response there, the way I interpreted it was that, you know, you were doing fleet vehicles for GHG emissions purposes, that was the primary driver. But Mr. Jesus was indicating that it was business reasons, economic, I assume -- well, business reasons. And that really that, you know, scope -- environmental emissions were a secondary benefit, or that's how I interpreted it.

I am just trying to reconcile that difference of understanding, if you could clarify that.

MR. BERARDI: Maybe what I will try to do is I will provide clarifications on our fleet investments. I really don't want to provide an opinion on Mr. Jesus's comments. But what I will provide is a discussion on why our fleet investments.

There's two primary objectives of our fleet investments. It's to minimize life cycle costs and equipment down time, and also to lower our GHG emissions.

MR. DeVENZ: All right, thank you.

MR. BROPHY: Can I just ask a quick question just to clarify?

MR. DeVENZ: Sure.

MR. BROPHY: Just to clarify then, my understanding is there are elements including in your fleet purchases where you look at your policy considerations, some of your policy commitments, and you take into account environmental factors and, you know, in line with what Mr. Jesus said on Monday, you do economic analysis.

But it sounded from our interpretation of his response Monday that you are basically ignoring any of those other policy factors, such as emissions reductions. But I think I have heard correctly today that you actually do consider those, is that correct?

MR. BERARDI: We do consider those. As we are looking at our lifecycle costs for our fleet, we have in our mix, in our investment plan for fleet replacement both combustion engines and electric vehicles.

MR. BROPHY: Okay, thank you for the clarification.

MR. DeVENZ: Okay, if we could please move to B4-Pollution Probe-18. In one of the questions that we'd asked for an economic -- the financial analysis, and if we go down to the response -- further down, I believe.

Well, I can't quite find it, but really my question was wanting to know what types of vehicles, electric vehicles and hybrid vehicles, are you purchasing. Because I believe in one of the responses that you indicated that commercial vehicles such as pickup trucks are not commercially available today.

So really I'm just trying to understand what types of vehicles are you able to purchase that are electrified.

MR. BERARDI: Mr. DeVenz, going forward from our '23 to '27 plan, we will have work trucks available for investing or -- purchasing, I should say, of those fleet vehicles.

The challenge has been on the larger pieces of equipment, them being available. For instance, a large bucket truck, we do have technology now with where the boom is electrified. And so we are able to make those purchases and we believe that those type of classes of vehicles will be more mature in that '23 to '27 time frame.

MR. DeVENZ: Thank you. Are you able to provide for the vehicles that you're purchasing -- you know, you talked earlier about the two issues, the minimizing costs and the lower GHG emissions. Are you able to provide financial analysis and any numbers with respect to the GHG emissions that you've realized specifically -- I will repeat that.

Can we get a financial analysis that you've done on this? I know we talked about it this morning. Mr. Ladanyi, I believe, asked a question. But I think his question was around historical numbers and we are really looking for something forward-looking.

So, you know, if you had a net present value analysis showing operating and maintenance costs differences, incremental costs, any rebates, you know, what do the economics look like.

MR. BERARDI: Mr. DeVenz, I am just trying to understand how it's different than Mr. Ladanyi's. It is -- is it the same as Mr. Ladanyi's, or is it something incrementally different?

MR. DeVENZ: I thought it was different and when he first started saying it, I was thinking, oh, we can just use his. And then I thought I heard him use the word historical, and I -- so that puzzled me, and that's why I am asking it. If it is the same, then I don't need an undertaking.

MR. BERARDI: I believe it is the same, the way I understood that undertaking, but subject to check and a review of transcript, it is my understanding it was for 2023.

MR. DeVENZ: Okay, okay. Yes, okay, thank you. With respect to having larger fleets of electrified vehicles, have you looked into any mitigation strategies, you know, if the grid were to go down such as backup generators, either natural gas or diesel?

MR. BERARDI: So, Mr. DeVenz, I am actually glad that you're on this part of the interrogatory. So as you can see, we are taking a balanced approach and a very gradual approach. So 16 percent for 2023, 16 percent of our fleet will be electric vehicles and plug-in hybrid electric vehicles. The remainder would be our traditional combustion engines.

So that would help mitigate. Having that type of balance and gradual approach would mitigate that type of risk that you're referring to.

MR. DeVENZ: I am just wondering about if -- let's just say, you know, that you were to increase your percentage higher than what you've planned here, would you see that the potential risk of the grid going off line being something that's going to be a hurdle that you wouldn't want to actually increase it because of That, because of the risk of the grid going down?

MR. BERARDI: I don't see that situation being able to not -- not being able to provide operational support. Because, like I did say, is that we will have that mix within our fleet that we will not have 100 percent electric vehicles in a zone, for instance. We will have a balance and a combination of electric and combustion engine.

MR. DeVENZ: Okay. So just so I am clear, so the grid -- the potential for the grid to go down is not a deterrent for you to potentially increase your fleet of electric vehicles? Or -- I know you're talking about having a balanced approach.

MR. BERARDI: Sorry, Mr. DeVenz, can you clarify the question?

MR. DeVENZ: Yeah, I was just wanting to make sure I confirmed that risk of a grid failure, you know, because one of the things I read through somewhere through the proceeding is that if the grid were to go down, that would be a potential deterrent to increasing the percentage of the fleet to be electrified.

And I was just trying to understand and you say, okay, that's a potential risk, what are the things we can do to mitigate it. I would think one option would be backup generators, either natural gas or diesel, so that if the grid were to go down. So that's not going to prevent you from wanting to increase -- it's not a roadblock to increase the percentage of electric vehicles, if you can mitigate that risk, that one particular risk.

MR. BERARDI: That's correct.

MR. DeVENZ: Yeah, okay. All right. So that is -- that's all my questions. Mr. Brophy, do you have anything you'd like to add?

MR. BROPHY: Yes, it's Michael Brophy. I just have one clarification, and I apologize if this was covered this morning. It should be very quick. Mr. Berardi mentioned some of the discussion at the beginning of the questions here would be addressed by elements in the Hydro One supply chain policy. Is that on the evidence already? Is there a reference to that?

MR. BERARDI: Yes, Mr. Brophy, it is E-05-02, and there's also an attachment 1. So it's both documents.

MR. BROPHY: Okay. Perfect, thank you very much. That's all for me.

MR. BERARDI: You're welcome.

MR. DeVENZ: That's all for me also. Thank you, panel.

MR. SIDLOFSKY: Thanks very much. That takes us to DRC. Mr. McGillivray.

# Examination by Mr. McGillivray:

MR. McGILLIVRAY: Thank you, Mr. Sidlofsky. Jonathan McGillivray, counsel for the Distributed Resource Coalition.

I have one follow-up on an area of questions that Pollution Probe was just addressing, and it's actually in relation to a DRC interrogatory, specifically 002 part (d). If we could bring that up. Thank you, that's great.

We had asked you to estimate the quantum of efficiency savings, including fuel cost savings that Hydro One anticipates it will achieve by utilizing hybrid vehicles and EVs rather than traditional internal combustion engine vehicles. And then in your response you said from 2022 to 2027 Hydro One is focusing -- sorry, forecasting 2.3 million litres offset and a fuel cost savings of $2.7 million based on a fuel price of $1.15 a litre. I think that's just on the next page of the response.

And I just wanted to ask in relation to the questions from Pollution Probe whether there are other efficiency savings that you would anticipate from this transition, the transition to a hybrid and EVs that underlies this calculation under maintenance and operation savings, and are carbon benefits. I want to see if there are any additional efficiency savings, because that is what the question was, beyond the fuel cost savings.

MR. BERARDI: Mr. McGillivray, it's Rob Berardi here. We, at this point, are only forecasting the fuel savings. There is the possibility of having some additional savings in maintenance costs. However, it's too early to tell at this point in time.

MR. McGILLIVRAY: Okay. And so this answer is effectively a best-efforts assessment of -- a forecast, I guess it is, of the expected savings based on a series of assumptions, and that's kind of how you're thinking about it at this stage in time?

MR. BERARDI: That's a fair assessment.

MR. McGILLIVRAY: Thank you. I'd like to go to Environmental Defence Interrogatory 24, part (a). And the question was:

"What investments is Hydro One making over 2023 to 2027 to accommodate an expansion of electric vehicles? Please describe these and provide the dollar total."

And in the response, there's an indication that Hydro One's projected investment in EVs for 2023 to 2027 is $85.1 million, and then additional investments will be made to install EV charging infrastructure.

So I wanted to get a better sense of what underlies that dollar figure of 85.1 million, and also to understand whether it's the same or different from the second sentence in that response, which goes to EV charging infrastructure.

MR. BERARDI: Maybe we can unpack that, Mr. McGillivray, and I will answer these one at a time.

So the first question with respect to the $85.1 million, I believe your question is how did we determine that number. And to provide a little bit more clarity, if you take the percentages that we had in PP-018 -- and I will use an example. We had 16 percent for 2023, and then it went up to 42 percent for 2027.

If you take those percentages against our annual fleet investment, that's how we determined the 85.1. But happy to provide you the details and breakdown per annum if that's helpful.

MR. McGILLIVRAY: I think that would be great if you could.

MR. BERARDI: Yes, I could.

MR. SIDLOFSKY: We will make that Undertaking JT3.20.

UNDERTAKING NO. JT3.20: TO PROVIDE THE DETAILS AND BREAKDOWN PER ANNUM FOR HYDRO ONE'S PROJECTED INVESTMENT IN EVS FOR 2023 TO 2027 OF $85.1 MILLION.

MR. McGILLIVRAY: And then one follow-up question on that is, I understand that this interrogatory came about in relation to the proposed externally driven distribution projects variance account. And it's therefore not contemplated as part of the investment plan. So maybe you can just help me understand the difference between this 85.1 million and a proposal for an investment of 85.1 million. What's the distinction? Because I don't think it tracks to an exhibit in the DSP; does it?

MR. BERARDI: I can't talk to the variance account that you're referring to, but I can talk to the investments that we have planned for fleet. And those investments can be found in GP -- let me make sure I get the right exhibit -- GP-01. So within GP-01 there is a fleet subset of that investment. So the $85.1 million is within GP-01.

MR. McGILLIVRAY: Does that number actually appear in there or is it within a category and therefore the number itself doesn't appear?

MR. BERARDI: If you can go to the top, please. Yeah. It does not appear, Mr. McGillivray. And that's the undertaking that I will provide you that additional information.

MR. McGILLIVRAY: Okay. Understood, that's great, thank you. I'd like to move to DRC interrogatory response 001, part (b). We asked you to indicate whether Hydro One considers electric vehicles to be DERs and discuss the related implications for your distribution system and system capacity. And you replied, indicating that EV assessment from a loading perspective is actively being evaluated and the EV penetration rate is not yet significant and is estimated to be between 1 percent and 2 percent in Hydro One's service territory; do you see that?

MR. FALTAOUS: Hi, Mr. McGillivray, it's Peter Faltaous, and yes, I do see that.

MR. McGILLIVRAY: That's a reference to what I assume is the current estimated EV penetration rate. Is that right?

MR. FALTAOUS: I believe that is correct, Mr. McGillivray. I will say that this is actually a better question for panel 3, but I believe that that is correct.

MR. McGILLIVRAY: Okay. It's possible that my next few questions will also be for panel 3 as well, but I just wanted to test this with you given -- given that it seems like some of this goes to you, and some of it goes to panel 3.

My question is really around given this response, and the statement specifically that EV assessment from a loading perspective is actively being evaluated, I just want to clarify. Because my understanding is that typically the impact of EV growth on load is embedded in the load forecast, but this seemed to suggest that perhaps there's another element of EV impacts that's not reflected in load forecast and therefore has to be actively evaluated. I just wanted to explore that a little bit.

MR. FALTAOUS: Sure. I can explain. So the forecast load that we have on our system, the load forecast -- and again this is certainly better with panel 3, if you'd like to go in depth -- it does account for increases in EV Load. And really what we are talking about in terms of assessing the impact on the system is we are looking more at a localized level, so trying to understand at a local level, you know, at a specific transformer, what is the impact going to be in terms of, you know, specific service wire size, for example. So that is what we are talking about, trying to understand right from the customer service and going upstream to get a better picture as to what the impact will be when you -- if you do have, let's say, a cluster of growth from an EV perspective.

But overall, the growth associated with EVs is part of the load forecast that panel 3 can speak to in detail.

MR. McGILLIVRAY: Okay, thank you for that. I will follow up with panel 3. I have a few other questions on that and I will follow up with panel 3.

I have a final area that might also go to panel 3, but I am going to bring it up now as well. It's DRC 006 part (b). I am not sure if that can be brought up.

MR. FALTAOUS: I think we are having some technical issues over here. Just give us a minute, please.

MR. McGILLIVRAY: Thanks.

MR. FALTAOUS: Mr. McGillivray, just perhaps while those technical issues are being resolved, so I am looking at the specific chart that you are referring to and I will say that that one would be better asked of panel 3.

MR. McGILLIVRAY: Okay, you are basically saying part (b) of that interrogatory response goes to panel 3.

My question is what part of this interrogatory response -- not just part (b), but all of parts (a) through (c), what part of it goes to this panel? Is there any part of it that does, or is it mainly for panel 3 given the focus on load forecast?

MR. FALTAOUS: I believe the majority of the IR does go to panel 3, Mr. McGillivray. I think we were just asked about specifically contributing whether or not there is any potential funding sources out there, but the rest of the IR is specific to panel 3.

MR. McGILLIVRAY: Just the references to the Grid Innovation Fund and NRCan financial support?

MR. FALTAOUS: That's correct. That would have been the one piece to which we contributed.

MR. McGILLIVRAY: Okay, that's helpful. I will reserve the rest of my questions for panel 3, and I think those are all of my questions, thank you.

MR. SIDLOFSKY: Thanks, Mr. McGillivray, we will move on to OFA.

MR. NOKES: Thank you, good afternoon. Can you hear me?

MR. MARCOTTE: Yes, we can.

MR. NOKES: Thank you. My name is Ian Nokes. I am representing the Ontario Federation of Agriculture, known as OFA in the proceedings. I hope to be pretty brief this afternoon. I am only referring to Exhibit I, tab 16, schedule B1-OFA-001.

OFA's interest in these proceeding are related to the quality and safety of electricity deliveries through the distribution system, and any relationship to the age, condition, or obsolescence of certain transformer --distribution transformer station assets.

Of particular interest to the rural and agricultural businesses in Ontario is mitigating uncontrolled ground current or voltage, also known as farm stray voltage.

For the benefit of those participating, appendix H of the Distribution System Code specifically outlines the distributor investigation procedure of farm stray voltage testing.

Appendix H is the protest -- I am sorry, the process to test for farm stray voltage, and it also refers to the thresholds that would trigger mitigation of the system related to farm stray voltage at that location.

In our submission to Hydro One for this hearing, OFA asked whether Hydro One considers the impact of uncontrolled electricity or ground current when considering repair versus replace -- or I should say update of distribution assets.

Hydro One responded that each stray voltage investigation is unique, and can require a different solution. Stray voltage mitigations are outlined in

ISD D-SS-06 and are non-discretionary. Also, they responded that Hydro One maintains records of test locations, test results, and the mitigation taken.

So the actual testing costs are non-discretionary, and if the test results in triggering mitigation action on behalf of the local distributor, those costs are also non-discretionary and are covered by rate revenues.

The mitigation typically consists of hammering in additional grounding rods and additional poles along the line, or installing something called a dairyland filter at the pole that supplies the customer power. That mitigation could result in moving the stray voltage down the line, or worsening a problem for other customers.

But my question in the IR was about the possibility for grid system -- that is, the local transformer

station -- discretionary investments.

You indicate in your response that you do not know the condition of distribution line transformer assets. So what I am looking for is: Is there any facility or ability for Hydro One to look at obsolete, damaged, or failing assets at the local transformer station to a farm that has stray voltage, to find out whether those assets could be causing uncontrolled ground current problems in that rural region?

If that type of investigation is not possible financially and it's not covered, I would understand that. I guess what I am asking for is what would -- what is the procedure to request that Hydro One, or that the IESO or the Energy Board direct Hydro One to conduct research where Hydro One farm stray voltage data has found chronic distribution-system-scale farm stray voltage to see if the local transformer components may be causing or exacerbating the problem. So that's my question to you folks.

MR. FALTAOUS: Hi, Mr. Nokes, this is Peter Faltaous. So I apologize, is your question what is the process to direct Hydro One to undertake appropriate studies? Is that your question?

MR. NOKES: Well, my first question was have you ever looked at the condition of those local transformer assets to see if they are causing systemic farm stray voltage? Your response is it was -- just described the existing steps of your farm rapid response team.

So I take from that that you have never looked at that -- the condition of those transformer assets. So if that's the case I want to know how I would get Hydro One to conduct some research and see if there is a relationship, since you don't know the condition of those assets at the transformer.

MR. FALTAOUS: So, Mr. Nokes, if you're specifically talking about the station transformer assets, so the assets at the distribution stations, so we do assessments of our station transformer assets, and that is described both in section 3.2. And if you'd like I can give you a specific reference. Just give me one second, please.

So section 3.2.2.1 in Exhibit B-3-1, which is page 6 of section 3.2. So we basically start there to talk about the components of our distribution stations, and we talk about -- you can see that there a breakdown there for station transformers, and we talk about their demographics, their condition. There's a lot of information in the section. And then in ISD SR-04 is where we talk about the investments that we undertake to renew distribution station transformers.

Is that what you're looking for, Mr. Nokes?

MR. NOKES: That's good, that's great. So I guess then I am moving on to the last part of that question, which is because you have information about the results of your testing and mitigation of stray voltage for the last, let's say four years that your farm rapid response team has been in existence, I guess I am then asking what's the process to see if you guys could actually overlay that data with transformer station data and do some research to see if there's a relationship between the quality or obsolescence of those assets and stray voltage?

MR. FALTAOUS: Can we go to a breakout room, please.

MS. SANASIE: Sure, the room is open now.

[Witness panel confers in breakout room]

MR. FALTAOUS: Hi, Mr. Nokes. Can you hear me? Okay, perfect.

So with regards to stray voltage, I mean, I think the one thing that I'd like to say is stray voltage is a complex topic, and so it's not necessarily the condition of the transformers at our stations that may be contributing to stray voltage. And I do think the challenge with stray voltage is each situation is unique, and so it does require sort of an individual investigation.

So I don't know that I have a straightforward answer for you, because I think it is a complex topic, it's not, you know, one thing that we can change and everything is resolved. I think stray voltage in and of itself obviously is a natural by-product of delivering electricity in a four-wire system, obviously recognizing that, you know, there are levels that are harmful and they do need to be mitigated. But I don't know that there is a straightforward answer to say, well, if we go and do this then everything will be resolved. I think it is very, very much specific. It's situation-based, and every situation can be unique.

MR. NOKES: Thanks. So let me put it this way. Yes, so appendix H lays out testing and triggers for mitigation. There are issues behind the -- on both sides of the meter for stray voltage. None of that is in question. I am not questioning the procedures in appendix H. Those are non-discretionary, you are required to do them when you meet the triggers.

I am asking how, in addition to the complexity -- and yes, it's a part of the nature of the way we deliver electricity in North America. But there may be a relationship with the data you have collected on those individual locations where you were required to test and may or may not have been required to mitigate, and the condition of certain assets of these transformers.

So I am asking what would be the process to trigger some discretionary spending to research whether the relationship between those stray voltage areas and the condition or obsolescence of some of those assets could be triggering the stray voltage.

MR. FALTAOUS: So I think if your question is with regards to how can Hydro One have some funding to do some, you know, specific work with regards to the stray voltage portfolio. I am not really sure that's a question that I can answer.

MR. NOKES: Okay, then that's the question I guess I will have to put something to the Energy Board itself at a later date, and that is the end of my questions.

MR. SIDLOFSKY: Thanks very much. We will move on to OSEA, please.

# Examination by Mr. Lusney:

MR. LUSNEY: Hello, everyone. It's Travis Lunsey, Power Advisory, representing OSEA. I hope you can hear me fine. Great. Nice to see everyone, and thanks for taking the time.

I am going to start with reference to OSEA 006, if we could go there. I still see the stray voltage mitigation up.

MR. KEIZER: I don't know if there's technical difficulties or not.

MR. FALTAOUS: Yes, sorry, Mr. Keizer, there are some technical difficulties. Just give us a minute here, please.

MR. LUSNEY: No problem.

MR. FALTAOUS: Sorry, we are going to see if somebody else can share their screen. So apologies, just bear with us for another couple of minutes.

MR. LUSNEY: That's quite all right. Okay, great. So if you can scroll down to the answer to (b), so OSEA asked what are your assumptions for non-wire solutions when coming to kind of address distribution system needs, you look at wires and you are going to look at non-wires now are growing.

And you referred to Pollution Probe 3 in terms of how non-wires are there -- sorry, because we just went here, but can we go to Pollution Probe 003, please.

Now, I recognize the question from Pollution Probe is with respect to the IRRP and RIP, but I am a little confused on the answer in (c). So if we scroll down to (c), it says at the end:

"Hydro One does not have responsibility to assess or bring forward non-wires or DER solutions for OEB consideration."

My understanding is that's not true. That as -- and especially within the distribution system planning responsibilities, that while the IESO has some crossover with respect to integrated regional resource plans, a large majority of the planning is the responsibility of the distributor and in your service territory, that's Hydro One Networks.

So is it correct that Hydro One would, as a distributor, be able to and be expected to bring forward cost effective non-wires and DER solutions?

MR. FALTAOUS: Hi, Mr. Lunsey, this is Peter Faltaous. So I can take you to ISD SS-04 and it was the second part of that response to OSEA-006 where it did talk about the battery storage systems that we have proposed as a non-wires alternative for improved reliability to a number of customers on our system that have experienced significantly poor reliability.

So if you go to ISD SS-04, it specifically talks about energy storage solutions, and how we are proposing to use these as non-wires alternatives for the sake of improving reliability on our system.

MR. LUSNEY: Okay, so that's great. So I think first of all then, yes, you have the responsibility to bring it forward in the DSP; right. That's great because if it's cost effective, Hydro One should be able to bring it forward.

The question that OSEA was asking is given these comparisons, what is the kind of underpinning of the analysis when you compared it. So to be clear, what was the capital cost you assumed, what was the fixed O&M, I think most importantly for energy storage, what was your variable O&M, because charging is going to have a wholesale market energy charge and/or a distributed rates charge if it's small enough, because there is some residential energy storage.

I am just trying to understand the conclusions to deploy energy storage as it relates to the traditional wires solutions in these communities. And I am happy to have this as an undertaking take away to address it. That's where our question was trying to get to because from OSEA's point of view, we think this could be applied more broadly.

MR. FALTAOUS: Within this ISD, we did talk about different alternatives and that is specifically on page 9 of this ISD, and one of the alternatives will be traditional pole and wire solutions.

But what I can tell you specifically is -- I think we may have lost sharing again. I will keep talking, if that's okay, Mr. Lunsey.

MR. LUSNEY: That's okay, that's okay.

MR. FALTAOUS: With regards to traditional poles and wires solutions, a lot of these communities are fed at the end of very long radial lines, so whether it be long radial lines that are fed from long radial transmission lines or even if the transmission is not radial, the distribution lines are long and radial.

So if we are talking about looking at a wired solution for some of these communities, you are talking about investment that is significant and by significant, I

mean -- I would say for a single community I am talking about, you, know it could be -- I will throw out a number and I know it's going to sound ridiculous, but it could be 30, 40, 50 million dollars, so --

MR. LUSNEY: If it's a long feeder, it's going to be costly to build.

MR. FALTAOUS: Correct. So if you have a 100-kilometre feeder essentially you would have to rebuild in order to give them a redundant source of supply. You would need to build another 100 kilometres' worth of an alternate supply feeder to that community just to give them redundancy, and at the same time that will not in and of itself guarantee a significant reliability improvement, because now you have the exact same problem on the second feeder that you build, which is, it has increased exposure, and it's going to be susceptible to outages and so on.

So from a cost perspective with regards to the traditional poles and wires solutions for these communities versus energy storage, it -- you know, the traditional poles and wires is really not even economically viable. It's not something that, you know, we could reasonably consider --

MR. LUSNEY: I think what I'm more -- and sorry to interrupt. What I am more interested in is on page 5 of 10 of D-SS-04, the Arlo BESS pilot project, in the second paragraph at the bottom, so lines 23 to 27 it says:

"The total cost of the Arlo BESS pilot project is approximately $10 million."

And I would like a breakdown of that cost, both on the capital and the O&M going forward, in terms of how you build that up, because my assumption -- and you can correct me if I am wrong -- is a BESS deployment, its cost is not going to vary as much. You are putting -- and I think that's the value of it, is you can put it kind of anywhere. You are putting it at the customer's site. Whereas a wire solution is going to be dependent on the geography that it has to transverse.

MR. FALTAOUS: That's correct.

MR. LUSNEY: So I think -- so I'd like to have an undertaking to kind of follow up on the question OSEA asked, which is, can you give me a breakdown of that rough $10 million, both in terms of capital cost upfront and your O&M over the life of the project.

MR. FALTAOUS: We can do that.

MR. LUSNEY: Okay.

MR. SIDLOFSKY: That will be JT3.21.

UNDERTAKING NO. JT3.21: WITH REFERENCE TO IR OSEA-006, TO PROVIDE A BREAKDOWN OF THE ROUGHLY $10 MILLION, BOTH IN TERMS OF CAPITAL COST UPFRONT AND O&M OVER THE LIFE OF THE PROJECT.

MR. LUSNEY: Okay. Staying within this exhibit, and if you go to D-SS-04, there's 78 projects listed to -- for system service to -- in response to load growth, and

OSEA -- I am just trying to find which one it was. Apologies for a second.

Still with OSEA 006, in response to (c), Hydro One aims to improve reliability. The details of investments are found in SS-04. No CDM activities, and I am using the broader definition of CDM, which would include both resource energy efficiency, and demand response, were used in any of the 78 projects brought in under DS -- D-SS-01.

Did Hydro One consider CDM activities in each of those and conclude they were not viable, or not cost-effective if viable?

MR. FALTAOUS: Give me one minute, please.

MR. LUSNEY: Sure.

MR. FALTAOUS: So I will start off by saying that CDM is accounted for within the load forecast, so for any load growth projects, CDM, that will impact that forecast, is accounted for. But I will also ask to take you to ED-14, specifically part (a), which is schedule B2-ED-14.

And you can see here on line 4 that updated CDM guidelines, including the provision for distribution rate-funded CDM, are currently being reviewed under EB-2021-0106. And so any consideration of distribution rate-funded CDM will essentially be after that process is completed. And as of right now there is no obligation to make requests for rate-funded CDM, and so we have not done that in this proceeding.

MR. LUSNEY: And would it be fair to say you haven't done it -- okay. I guess my question is, you haven't done it or you haven't done the analysis because you don't have an obligation to do the analysis of targeted CDM?

MR. FALTAOUS: So CDM is considered as part of the regional planning process. And any CDM that has been identified has been accounted for as part of our load forecasts, but beyond that we have not taken further activities looking at CDM specifically as an alternative.

MR. LUSNEY: For distribution system plans which are outside of the scope of the IRRP and regional planning process?

MR. FALTAOUS: I just want to clarify that not all of them are. Some are tied to an outcome of the regional infrastructure plan, but, yes, including for ones that were not as a direct result of the regional -- the IRRP or the RIP.

MR. LUSNEY: Okay. Coming back to D-SS-04, that we were looking at before, and I can't remember -- give me a second. I can give you the exhibit.

For the energy storage on the regional -- on the residential side deployed, in questioning panel 1 yesterday I asked if through the distribution system planning the distributor and LDCs would ask for potential transmission system benefits for the deployment they are going to go after, and the panel said, yes, they do, if asked, they provide any benefits.

With respect to these projects, was there any transmission system benefits identified and valued?

MR. FALTAOUS: Sorry, can you clarify what you mean by transmission system benefits, please.

MR. LUSNEY: So when you compare wire solution to this energy storage solution, you would have, you know, a cost comparison, but you'd also -- the cost wouldn't be just the distribution, you might be able to avoid potential transmission system costs that would be applied to the distribution system customers, say you had to -- if you didn't do this you would have to build a new wire and potentially have to upgrade the transmission system.

Was any upgrades to the transmission system identified under the traditional wires solution?

MR. FALTAOUS: No, there were not.

MR. LUSNEY: Okay.

MR. FALTAOUS: I'd just like to clarify, Mr. Lusney. So if your question is would -- would a reliability improvement for these communities, a wired solution of reliability improvement, specifically require transmission investments, the answer is, possibly. It would obviously depend on the specific community and the specific customers that we are talking about here.

But if what you're asking is, you know, whether actual planned transmission investments for the sake of these reliability improvements that are now no longer required, the answer to that is, none that I'm aware of.

MR. LUSNEY: Okay. No, that's fair and helpful. If we could go to OSEA 004. So -- I will just wait until it loads. And this is with respect to behind-the-meter installations.

MR. FALTAOUS: Sorry, Mr. Lusney, I think we are having technical issues again.

MR. LUSNEY: That's okay. Thank you. So this question kind of goes -- there's embedded generation, which I will refer to as directly connected or front of the meter. But then there's also customers that install behind-the-meter generation or resources that will have an impact on the forecasted demand and potentially system either passively or actively; passively, they are just going to do their production; it will have impact on coincidental peak demand, which drives a lot of your system expansion; and/or active where they may respond to price signals in the market, or potentially could in the future

-- and assuming your answer to be that you have no reliability service contracts -- could respond to a Hydro One system control reliability event through some sort of contractual basis with your customers.

My understanding of the responses to these questions is that Hydro One does not forecast future behind-the-meter resource uptake in any way. It says in response to OSEA 005, which was just a list of what you have installed to date.

So is it correct that as part of your load forecast as part of your system design, you are not assuming any new behind-the-meter resources connected at customer sites?

MR. FALTAOUS: That's actually a better question for panel 3, Mr. Lusney, for the witness that is named on this IR. I believe he would be the best person to respond to that question.

MR. LUSNEY: Okay. Then in OSEA 005, the response you -- you have a table showing behind-the-meter resources connected to Hydro One's feeders. Could you provide a breakdown of that by transmission system -- by transmission station under normal connection?

I mean normal, because recognizing under certain situations you might move a customer to a different feeder or a different station. What transmission station are all those behind-the-meter installations at?

MR. FALTAOUS: Okay, so basically just a further breakdown of this to identify what transmission station?

MR. LUSNEY: Yes.

MR. FALTAOUS: Yes, I think we can do that.

MR. SIDLOFSKY: We will make that JT3.22.

UNDERTAKING NO. JT3.22: WITH REFERENCE TO OSEA-005, TO BREAK DOWN BEHIND-THE-METER RESOURCES TO IDENTIFY TRANSMISSION STATIONS

MR. LUSNEY: Great.

MR. FALTAOUS: Numbers, I see some are quite substantial, for solar, 1,275. I think maybe I will just qualify it to determine how much effort is that going to require. Assuming it's reasonable, we should be able to provide it and if there are any challenges with doing so, then we can certainly let you know.

MR. LUSNEY: My assumption is that everything that connects to your system, even if it's behind the meter, is going to have to have some sort of connection assessment, whether a full CIA or more likely just an offer to connect to micro sizes saying you are making a change and we have to maintain safety. But understood, and I will appreciate the follow-up.

That's the end of my questions for this panel. Thank you very much for the time.

MR. SIDLOFSKY: Thank you very much, Mr. Lusney. We will move on to OEB Staff. Now it's 2:30 right now. I am just wondering how the panel's doing, if you wanted to break now.

We are at about 45 minutes, or we will be about 45 minutes for Staff questions.

MR. KEIZER: Jamie, it would be a good idea to break not just for the witnesses' sake, but I think we just need to do a bit of a tech solution to fix the screen sharing.

So I don't know if you want to take a like a ten minute break or something like that. Does that make sense or -- it's up to you?

MR. SIDLOFSKY: Sure, why don't we break until 2:45 and then we can start in with Board Staff. Is that all right with you?

MR. KEIZER: Yeah, that's fine. We can do the tech solution and come back for your last 45 minutes.

MR. SIDLOFSKY: Okay good, thank you.

### --- Recess taken at 2:28 p.m.

### --- On resuming at 2:48 p.m.

MR. SIDLOFSKY: Good afternoon. We are continuing with panel 2 and OEB Staff, and I will introduce two of my colleagues. Sorry, just a small technical problem on my part here. Margaret DeFazio, project advisor, and Andrew Frank, advisor, and Margaret will be beginning the questioning.

# Examination by Ms. DeFazio:

MS. DeFAZIO: Okay. Hello, panel, thank you.

Could we please turn to B3-Staff-129.

MR. SIDLOFSKY: Sorry, if I can just interrupt you, Ms. DeFazio. There's also David Martinello, another one of our advisors on Board Staff. All three of my colleagues will be asking questions this afternoon.

Go ahead.

MS. DeFAZIO: Hi, panel. Oh, there we are. If we could go to the answer for part (a), please. Does this pertain to the BESS battery solutions? And as we can see, the information provided is that tree contacts are responsible for significant amount of outages that supply these customers.

What's the -- can you confirm that the outage reduction analysis for the project, did it happen prior to or after the implementation of OCP?

MR. FALTAOUS: Hi, Ms. DeFazio, this is Peter Faltaous.

MS. DeFAZIO: Hi.

MR. FALTAOUS: So the OCP implementation has happened over a number of years for cycle 1, so 2018 to 2021, essentially. And so certainly this analysis would have been somewhere in the middle of the first cycle of OCP.

MS. DeFAZIO: Okay. Was there consideration given in the business case to increased vegetation management, perhaps clearing or work to reduce the number of outages to these communities? In the ISD there was traditional line solutions, which were capital. I was just wondering if there was an evaluation done for vegetation as well.

MR. FALTAOUS: There was not a specific evaluation for vegetation, stand-alone evaluation. But the entire system is going to be receiving the benefits of the OCP approach, which has been our change in vegetation management strategy.

But what I would like to highlight, Ms. DeFazio, is even if you were to improve reliability for vegetation-caused outages specifically, given the length and exposure, the nature of supply to these communities, there will still always be essentially -- because of the added exposure there will always still be the potential for outages, and so I think even if you were to get an improvement from veg here, I don't think that the improvement will be sufficient for -- given that the current extent of outages that these communities are experiencing.

MS. DeFAZIO: Okay. If we could go to the answer for part (f), please. Oh, thank you for that.

Could we have requested if Hydro One was able to provide reliability data specific to R1 and R2 customer classes; is that something your system would allow you to undertake?

MR. FALTAOUS: I am not certain, Ms. DeFazio, as my team does not look after the performance management data, but that is certainly something that we can inquire about.

MS. DeFAZIO: Okay. Can we make note of that, please.

MR. FALTAOUS: Sorry, Ms. DeFazio, maybe I can clarify one thing. So are you specifically asking if we can track our reliability for rural customers separately from urban customers?

MS. DeFAZIO: Yes. So we have -- I believe you did provide some data on what was rural. We were looking at the R1 versus R2 split.

MR. FALTAOUS: Okay. So you are asking specifically whether or not we can separate out reliability for R1 versus R2 customers?

MS. DeFAZIO: Correct.

MR. FALTAOUS: I will assume that the answer to that is no, just because the -- I will assume that it has to do with the distribution of the customers along the feeder, if some are considered R1, some considered R2. I don't know that you can actually separate out. So I believe the answer is no, but again, I can take that back and confirm.

MS. DeFAZIO: Okay, please, thank you.

MR. SIDLOFSKY: Sorry, we will make that JT3.23.

UNDERTAKING NO. JT3.23: TO ADVISE WHETHER IT IS POSSIBLE TO SEPARATE OUT RELIABILITY FOR R1 VERSUS R2 CUSTOMERS.

MS. DeFAZIO: When you did the sizing for the batteries -- and this would be for both the behind-the-meter storage and the grid-scale solutions -- there's a certain number of amp-hours that are -- that batteries will be sized for. Is the concept behind the design that the customers won't know that they are on battery supply? Or will the customers be notified or signalled somehow that they are on battery supply so that they could perhaps make decisions about their usage to extend the backup duration?

MR. FALTAOUS: I can say that that is not a detail that has been firmed up yet. So whether or not the customers will be officially notified I can't say with certainty. I think some of it will depend on the vendors that we go with and their capabilities. Certainly if we can inform the customers so that they can potentially conserve and get even more backup, that would certainly be helpful, but I can't confirm if for all of these projects specifically the customers will be notified at this point.

MS. DeFAZIO: Okay, thank you. In the ISD it states that the battery expected life span is 15 to 20 years. Would that be for both the behind-the-meter and the bulk energy?

MR. FALTAOUS: That's correct, that is our expectation.

MS. DeFAZIO: Okay. And you've provided an answer -- sorry, in section (j), again -- that was B3 129 (a), okay? The capital costs are approximately estimated at 29,500 per home. Are there any OM&A costs anticipated over the life span of the batteries? Sorry, for behind-the-meter, yes.

MR. FALTAOUS: For the behind-the-meter there are no specific OM&A costs. There is a, I believe it's a licensing fee for the monitoring, but aside from that there is no OM&A costs.

MS. DeFAZIO: That would be like a yearly licensing fee per unit or something along those lines?

MR. FALTAOUS: I believe it is, Ms. DeFazio.

MS. DeFAZIO: Okay. And you don't expect to have to do any functional tests or inspections --

MR. FALTAOUS: That's correct.

MS. DeFAZIO: -- as a routine thing? The last question is regarding (n). Did Hydro One do an estimate of the value of the storage for customers? So perhaps avoided customer costs or avoided Hydro One costs as part of the analysis? Again, this is behind-the-meter.

MR. FALTAOUS: I don't believe we have done that analysis. Now, I'd also like to clarify that for the Hydro One side, I mean, if there is an outage on the system, while the customers will receive the benefit of getting the backup through the battery energy storage system, the cause of the outage will still need to be rectified, so it will still need to be addressed.

MS. DeFAZIO: Hydro One's costs would still remain relatively constant?

MR. FALTAOUS: Correct.

MS. DeFAZIO: Okay. If we could change to poles for a little while, please. This would be OEB Staff B3-114.

I did note your conversations with Ms. Grice and the undertaking around poles there, and that was regarding the poles that failed during -- that are replaced partially under emergency response and, I guess, not in the plan program.

So my question is more around when you're doing the inspections, so your crew is out doing pole inspections and they find poles that they put on the planned list or forward to be part of the planned list, and they identify poles that require immediate attention, and those poles being replaced under emergency response and storm reparation, how long would it typically take to replace one of those poles? Would it be days, weeks, months, like would you say it's replaced immediately?

MR. FALTAOUS: So you're specifically asking in a case where we come across a pole that needs to be addressed as an emergency essentially. Is that correct?

MS. DeFAZIO: Correct, yes.

MR. FALTAOUS: It would be addressed within a very short time frame, typically -- I will ask Mr. Ng to weigh in, but the time frame would be very short.

MR. NG: Good afternoon, Ms. DeFazio. This is CK from Hydro One. Can you hear me?

MS. DeFAZIO: Yes, thank you.

MR. NG: In the case of an emergency, it will be within hours, right. If you have a pole broken because of a vehicular accident or incident, within hours we would be replacing the pole. It also depends on the complexity of the pole. Some poles are easier to do, some poles are harder to do, but the response will be quick.

If we are not able to replace it, we will make it safe and then within days, it will be replaced.

MS. DeFAZIO: Okay, perfect. Now, is there a data tie in either through your GIS or some staff reporting back to the asset condition inspection condition assessments for poles that have been identified in poor condition, as part of a plan that they could then be removed from -- it would be indicated that that pole had been addressed?

MR. FALTAOUS: I apologize, DeFazio. The sound cut out a little bit for me, so I didn't get all of your question. I got a piece of it and perhaps you can let me know if I understood.

Was your question whether, when we are replacing a pole in an emergency, are we collecting the data on the pole to say what condition it was in?

MS. DeFAZIO: That was going to be a letter question, but the question was do you tie the data back in, kind of close the loop on the data, so that if that location of pole had been scheduled to be replaced in two years, your planning staff would now know that it had been addressed and didn't need to create a work order for it? And would your asset condition assessment be kept up to date?

MR. FALTAOUS: That's correct. So the data would be updated to indicate that that pole is now no longer -- so if the pole was previously assessed as a poor condition pole and then it gets replaced, the data would be updated.

But what I'd like to clarify is if as a result of having to replace that pole under emergency, at the last assessment that pole was not identified as poor condition and it has since degraded and now it needs to be replaced under emergency, they are not updating it at that point in time to say this is a poor condition pole and then replacing it, they are just replacing it.

MS. DeFAZIO: Excellent. Okay, so your asset condition would then be reasonably up to date, it would not have a seven-year inspection lag, that would be correct? Due to items that had been replaced.

MR. FALTAOUS: So that is correct. I mean, I am not sure about the reference to the seven years specifically. Is that tied to the six-year --

MS. DeFAZIO: Sorry, your six year -- sorry, correct, your six-year inspection cycle. Thank you, that addresses that.

Now, when you replace poles on emergency, I am wondering if you do an analysis to see had this pole been identified as poor or not, to see if you're replacing poles --

[Reporter appeals due to audio issue]

MS. DeFAZIO: Are you able to do an analysis on poles that are replaced under emergency conditions to see if you're able to address poor condition poles, or if it's mostly due to extreme forces, if that makes sense.

So a car accident is not due to a poor condition pole; it's external damage versus poles that perhaps were in poor condition and failed prior to you attending to them.

MR. FALTAOUS: Just to make sure that I understand the question, you're asking can we identify poles that failed that were not due to external factors such as a car hitting a pole, for example?

MS. DeFAZIO: Yes.

MR. FALTAOUS: Just give me one minute, please. If I can ask you to go the Exhibit B, tab 3, schedule 1, section 3.2, and specifically page 49.

MS. DeFAZIO: B3-1?

MR. FALTAOUS: Section 3.2, page 49. And if you look at figure 33, pole caused interruption excluding FM. So this, Ms. DeFazio, is essentially what you're asking for. This is where we have had outages that were not -- so outages where a pole failed and was not due to external factors. So it would be excluding things like motor vehicle accidents, external interference, as well as if tree fell on the line and caused the pole to break.

This is essentially what you are asking for, I believe; it's the outages where a pole failed causing an outage and it was not due to an external factor.

MS. DeFAZIO: Okay, thank you. Could we please go to B Staff 102, the answer for (a).

MR. SIDLOFSKY: Sorry, could I just interrupt. Was there an undertaking there, or...

MS. DeFAZIO: No.

MR. SIDLOFSKY: Okay, thank you.

MS. DeFAZIO: Okay. The answer to this indicates that poles in poor condition are more susceptible to failing when they have an external force on them --

MR. MARCOTTE: Ms. DeFazio --

MS. DeFAZIO: Yes?

MR. MARCOTTE: -- just one second. Mr. Faltaous has lost audio, so if you just give him a minute he will come back on.

[Technical interruption]

MS. DeFAZIO: So example (a) -- sorry, response (a) is shown, poles of course fail -- are more likely to fail if external stresses are placed on them. Hydro One is proposing to increase pole replacement to 10,300 per year.

How has Hydro One taken into account the improvements from the OCP program in coming up with that number?

MR. FALTAOUS: So just to clarify, you're -- sorry, I am just getting some feedback here.

[Technical interruption]

MR. FALTAOUS: Okay, all right. Sorry about that.

MS. DeFAZIO: No problem. I will start over so that you know we are at the same spot.

Of course poor condition --

MR. FALTAOUS: Okay.

MS. DeFAZIO: You're good?

MR. FALTAOUS: I believe so.

MS. DeFAZIO: Okay. So poor condition poles tend to fail -- sorry, are more likely to fail if a force is placed on them, such as tree contact or branch contact. Hydro One is proposing increasing pole replacement to 10,300 per year as well as increased vegetation management activities.

How has Hydro One incorporated the results of the OCP in the projected or the requested pole replacement numbers?

MR. FALTAOUS: The proposal for the pole replacement is based on the population of poor condition poles, so it's really to address that we have a large number of possibly 79,000 poles on our system that are in poor condition and so it is not directly tied to OCP.

MS. DeFAZIO: If we could please go to E-Staff-221. Sorry, I did not write down if it was (a) or (b). But in this, it's stated that the OCP resulted in an OM&A trouble call reduction of $4.9 million, unless I have the wrong reference here -- oh, there we go.

How has Hydro One captured this reduction in trouble calls into a reduction in emergency response capital?

Sorry, before that, have you seen a decrease in emergency response capital associated with the decrease in emergency calls?

MR. FALTAOUS: Can we go to the breakout room, please?

[Witness panel confers in breakout room]

MR. FALTAOUS: Ms. DeFazio, I'd like to clarify that this reduction in $4.9 million here, this is not for the capital trouble program. This is for the OM&A trouble program, so this would not be associated with capital replacement meaning when poles fail as an example and we have to replace them. This is not what the production is associated with trouble OM&A reduction.

MS. DeFAZIO: Correct. I understand that, but if I -- if you sent a crew out to do emergency response and it ended up being OM&A work, and you're seeing a reduction in those volumes, I would expect also to see a reduction in the follow-up capital. So you send a crew out, maybe they do some switching, it's OM&A. You send a crew out, maybe they do some switching, they replace a transformer, that becomes capital. So I guess the question is have you seen a reduction in distribution emergency response and storm restoration due to the success of the OCP? Distribution emergency response and storm restoration is the largest capital project, and the OCP seems to be achieving some of its results.

MR. FALTAOUS: If I can take you to SEC-150, please. So that is specifically Exhibit I, tab 22, Schedule B3-SEC-150. So if you can go to the response for part (a). So this essentially shows you for our trouble capital under emergency pole and equipment replacement, what that forecast as well would be historic actuals for 2018, '19, and '20 look like. You can see from these numbers, I would not say that we have seen significant reduction in terms of actuals within our emergency pole and equipment replacement trouble capital.

MS. DeFAZIO: Okay. So then I'm -- would it be correct to assume you haven't incorporated a saving going forward because you haven't seen it to date?

MR. FALTAOUS: That would be a fair assessment.

MS. DeFAZIO: Okay. Okay, thank you very much, that's all my questions. Have a good day.

MR. FALTAOUS: Thank you, you too.

MR. SIDLOFSKY: Thanks, Ms. DeFazio. I believe it's Mr. Frank next.

# Examination by Mr. Frank:

MR. FRANK: Yes, thank you. So I will turn you to the response to Staff 183. So in this question we asked about the trend in external revenues from secondary land use. In particular, there's a large project, Waterdown to Finch, a pipeline project, responsible for significant revenues. OEB Staff calculated and Hydro One confirmed that after normalizing for this project, external revenue is forecasted to fall from a historic average of 26.1 million to 23.5 million in 2021. When asked about the difference, Hydro One stated that it is due to granting easements and land sales in the historic period which are difficult to forecast.

Do I have that much correct?

MR. BERARDI: Yes, that's correct, Mr. Frank.

MR. FRANK: So --

MR. KEIZER: I think someone has their mic open. I think there is some interference on the line.

MR. FRANK: Okay.

MS. SANASIE: They just muted themselves.

MR. FRANK: Okay. So excluding the Waterdown to Finch project, how much revenue has been reported for secondary land use in 2021 year-to-date using -- well, whichever most recently available data?

MR. KEIZER: Sorry, sorry, Mr. Frank, I am not clear as to whether or not this question is for this panel or -- since it is identified as Andrew Spencer at the bottom of the IR. So -- and whether this is panel 1 -- but there was also some external revenue information that that was deferred to the finance panel, which was panel 4. Just let me get some clarification for you.

MR. FRANK: Okay.

MR. KEIZER: It should go -- my understanding, it should go to the finance panel, which is the last panel.

MR. FRANK: Okay. Well, this is my question, so I think I will end here for now.

MR. KEIZER: Okay. You can put your question on the record, and we can deal with it when we get to panel 4, if you'd like.

MR. FRANK: Are you asking me to read out the question?

MR. KEIZER: No, no, it's up to you, I am sorry, it's up to you what you want to do with your question. It's...

MR. FRANK: All right. I am happy to save it for panel 4.

MR. SIDLOFSKY: Thanks. Then Mr. Martinello.

# Examination by Mr. Martinello:

MR. MARTINELLO: Thank you, Mr. Sidlofsky. Is everyone able to hear me okay? Wonderful. If I kindly ask if you could please turn to OEB Staff interrogatory B3-Staff-127, and specifically to the response in question (b).

Now, in that response, lines 20 to 22, there is the statement of:

"As the third-party contracts were established in early 2018, each contractor truck required two utility arborists as agreed upon with the union to align with Hydro One's internal practice."

Can you just give me some clarity on, you know, the operational reasons for using a two-arborist crew for vegetation management implementation?

MS. FRENCH: Hi, good afternoon. Teri French here from Hydro One. I am more than happy to answer that question for you.

So one point of clarification just before I make my comment here in regards to the two arborists. In the Clear Path report that was -- the -- sorry, 2017 projection was not including a two-arborist work program, it was one, so that was some of the cost differential that you will see in the response that you referred to just a few moments ago.

The two-person in the truck from a safety -- is there for a safety perspective. There are some elements that are involved in the vegetation management program for Hydro One, and due to some of the complexity in the environment and the geography, some of the practices that our arborists need to do in order to have safe work practices need a two-person crew.

MR. MARTINELLO: Okay, thank you. Now, would there be any circumstances, whether it be now or moving forward, where Hydro One would utilize -- consider utilizing crews of potentially, you know, like a mixed crew structure, essentially one arborist or, you know, another type of employee type for this type of work? And, you know, would that be allowed potentially in collective agreements, I guess?

MS. FRENCH: Well, we would always have to keep the spirit of the collective agreement in any of our work practices. Hydro One from our perspective already do look at our work programs and different elements of the work program, and where we do or need one skilled arborist versus someone who is not as skilled, for example, a labourer, for example, we do look for opportunities to partner that. So we already are looking at that from a cost-effectiveness perspective.

MR. MARTINELLO: Thank you. And just my next question that I would like to follow up on, if you could please turn to E-SEC-194, and just while that's being pulled up I will maybe give some context to orient ourselves. In OEB Staff E-Staff-229, Staff inquired about some increases regarding the research, development and demonstration OM&A.

So in that question, you directed Staff to this response that was in a question provided by SEC. And I am just curious. You note that several of these programs are ongoing, the collaborative industry, the research, the operational enhancements, whereas the emerging technologies have varying timelines.

Just out of curiosity, do any of these programs or initiatives that Hydro One is undertaking have any legislative requirements for timelines of when they must be met? And for context, I give this as an example of Hydro One needs to meet PCB remediation requirements by December 31st, 2025.

So would any of the initiatives outlined in response to SEC 194 have any sort of legislative requirements or timelines that need to be met by a certain date?

MR. FALTAOUS: Mr. Martinello, this is Peter Faltaous. Not to my knowledge. I don't believe there is anything in here that would meet the criteria that you are asking about.

MR. MARTINELLO: Would you just be able to undertake to confirm that, Mr. Faltaous?

MR. FALTAOUS: Yes, I can certainly do that.

MR. MARTINELLO: Perfect. Would we be able to mark that.

MR. SIDLOFSKY: We would, JT3.24.

UNDERTAKING NO. JT3.24: TO CONFIRM WHETHER ANY OF THE INITIATIVES OUTLINED IN IR E-SEC-194 HAVE ANY LEGISLATIVE REQUIREMENTS OR TIMELINES THAT NEED TO BE MET.

MR. MARTINELLO: Thank you very much. Those are all my questions. I appreciate your time.

MR. FALTAOUS: Thank you.

MR. SIDLOFSKY: And that concludes Staff's questions for panel 2. That brings us to panel 3, beginning with Energy Probe followed by OSEA and then Board Staff.

Mr. Keizer, do you need a few minutes to swap panels there?

MR. KEIZER: Yes, I will assume we need a few minutes for people to log on.

MR. SIDLOFSKY: How about if we -- it's just coming up on 3:40. How about 3:45 then we can come back on?

MR. KEIZER: Should be okay for the crossover, but if could ask panel 2 to retire with their thanks, and then I am going to turn it over to panel 3 and I don't yet see counsel on the screen yet. So. But it's not many.

I will then take my leave and say thank you very much for everybody, and I will I am sure we will see each other again.

MR. SIDLOFSKY: Thanks, Mr. Keizer. Let's come back at 3:45 then, that's just five minutes.

### --- Recess taken at 3:41 p.m.

### --- On resuming at 3:46 p.m.

MR. SIDLOFSKY: And Mr. Myers, if you'd like to introduce your panel that would be great.

MR. STERNBERG: Hi, Mr. Sidlofsky, it's actually Arlen Sternberg. I have joined, if you can hear me, and hopefully we have our panel members who have all managed to join.

MR. SIDLOFSKY: Sorry, Mr. Sternberg, I just keep seeing Mr. Myers prominently on my screen there.

MR. STERNBERG: Okay. What -- we're -- everyone's connected and the sound is working fine. I think we can resume, and I will just make a quick note of one thing and then I'd be happy to introduce panel 3. So if we are set to resume -- the one thing I wanted to just note in terms of appearances as counsel to Hydro One, as you have seen, both Mr. Myers and myself are involved in areas relating to this panel and also panel 4, so depending on the area of questioning it may be either of us that speaks to points as they arise.

If there are no other preliminaries I will proceed to introduce panel 3, which is the rates and custom IR panel, starting first with Steven Vetsis, director of pricing and regulatory policy. Next, Bijan Alagheband, manager of economics and load forecasting. Next, Clement Li, manager of transmission and distribution pricing. And next, Steve Fenrick, principal consultant, Clear Spring Energy Advisors. So those are the members of panel 3.

# HYDRO ONE NETWORKS INC. - PANEL 3: RATES & CUSTOM IR (RATES)

Steven Vetsis

Bijan Alagheband

Clement Li

Steve Fenrick

MR. SIDLOFSKY: And we will begin with Energy Probe.

# Examination by Mr. Ladanyi:

MR. LADANYI: Good afternoon, panel. My name is Tom Ladanyi. I am consultant to Energy Probe. I am going to ask, I think, about three questions and then my colleague, Dr. Higgin, will take over for the rest.

So if I can have you turn to D-Energy Probe-56. So we are looking for D like Donald, Energy Probe 56.

UNIDENTIFIED FEMALE SPEAKER: One moment, please.

MR. LADANYI: Okay. There we are. So in this interrogatory I asked you to reconcile the distribution load forecast and distribution capital projects justified by load growth, such as ISD D-SA-02, new load connections, and ISD D-SS-01, system upgrades, driven by load growth to the load forecast. And I understand you are not able to do this. Can you explain to me why, again? Sound, please. I can't hear you. Sound.

MR. STERNBERG: Bijan, can you please unmute.

MR. ALAGHEBAND: Okay. My name is Bijan Alagheband from Hydro One. This interrogatory was very specific related to certain projects, and it was -- and it was assigned to me, and what -- I provided the general answer in regarding to -- in regards to load forecast and capital projects are in line with each other. Both of them are based on forward-looking economic forecast that we have, so actually, when there is a forecast, that affects the capital decisions and also the load forecast itself. So there are quite -- in general there should be -- they would be in line with each other.

In some cases it could be that there are, you know, developments in the field that are not captured by fundamentals in the economics because they are basically related to, say, government initiatives or policy decisions, and in that case we simply add that development into our forecast, the loading that type of that development into the forecast. And one example of that in this filing is regarding to Leamington and surrounding areas.

MR. LADANYI: So how can the commissioners be assured that you are not using the same load growth to justify multiple projects, that there is no double-counting?

MR. ALAGHEBAND: In what sense? Please clarify.

MR. LADANYI: Well, you know, you have a certain amount of load growth, which is sufficient to pay for certain capital project, now that load growth is used up, and so that chunk of load growth can't be used to justify another project again.

MR. ALAGHEBAND: The way that load growth actually goes into capital projects is through local studies, so actually we have -- you know, once in a while there is a --we will conduct local study or regional study, and in that one there are many, you know, stakeholders involved, including IESO. And we go through the, what is the load there, and other -- other distributors also provide the load and the load growth forecast, and then we look at the situation and then, you know, decide according to the load growth related to that area is not something that could very general. At Ontario level load growth, no, it's not like that.

MR. LADANYI: Let me try just a slightly different way. So when you look at ISD D-SA-02, new load connections, how much new load do all these new load connections bring? There must be a number.

MR. ALAGHEBAND: I am not familiar with that project itself alone. Actually, I don't know the name of that ISD D-SS-01. I have not been involved in that. But it could be that there was a, perhaps a request by a planner, that maybe, you know, it could be that, that we provided it and then -- it could be that. But I have to know the name of the planner. I am not familiar with the project names.

MR. LADANYI: So can I have an undertaking just for that one, new load connections, how much load does the new load connections produce? Is that too hard to do? I am sure you have to talk to a planner, but I am sure it's a number that can be calculated.

MR. ALAGHEBAND: Actually, I am not sure if I can find who was actually responsible for what year is that, what project is that, and it could be that, you know, there is a portion of the study is used there. I am not -- okay. I try to get it. I do my best to get it, yes, but I am not sure if I can.

MR. SIDLOFSKY: JT3.25.

UNDERTAKING NO. JT3.25: TO MAKE BEST EFFORTS TO ADVISE HOW MUCH LOAD NEW LOAD CONNECTIONS PRODUCE; IF NOT, TO ADVISE WHY THAT IS THE CASE

MR. LADANYI: Thank you.

MR. MYERS: So just to clarify, that undertaking is to take that back to see if Mr. Alagheband can provide that requested information, and if he can then he will. If it cannot be calculated, then we will advise as to why that's the case.

MR. LADANYI: That's fine.

MR. MYERS: Thank you.

MR. LADANYI: So can we turn to Energy Probe No. 57, which is just the next interrogatory. So here we are discussing amount of embedded generation in the load forecast.

For a start, how much embedded generation is there in the load forecast?

MR. ALAGHEBAND: Embedded generation for this applies to transmission, and if we go to the Exhibit D-3-1 -- sorry, 4-1, which is the pre-filed evidence for transmission load forecast, there are figures in that -- in that exhibit showing that, how much embedded generation are there. So if you go to that exhibit --

MR. LADANYI: Could you give it to me again, the reference, please?

MR. MYERS: Let's just pause until it's on the screen, perhaps.

MR. ALAGHEBAND: D-4-1, oh, yes. Okay. Actually, this is the one that you were referring to, yes.

MR. LADANYI: Yes. And there's a table there, you say?

MR. ALAGHEBAND: Yes, there is a table at Table -- I believe it's Table 3. If we go to Table 3, I can identify that table. Yes, it's Table 3 on page 17.

MR. LADANYI: I don't think we need to look it up, I will look it up myself. This is only a technical conference. If this was a hearing, we'd go there.

MR. ALAGHEBAND: Oh, okay.

MR. LADANYI: I am going to ask you another question about the load forecast. Now in (b) if you look, scroll down to (b), it says "the load impact of large scale energy storage is included in the load forecast."

So is that included in that table, or is that hidden some place?

MR. ALAGHEBAND: Well, the load forecast takes into account the storage units in implicit way. So what we have here is when storage units are used, it can reduce load and one aspect of that, which was mentioned in the interrogatory response, is due to some customers that use a storage unit to reduce the peak at -- the time of highest power peak time to reduce their worldwide adjustment payment. This is in relation to industrial conservation initiative, or ICI. And so that's one.

There is an estimate of that that we get from IESO, that how much was involved in that. And then we also have other storage unit usages that reduce the load, but we don't have to account for that. Those things are already reflected in the actual load.

So the way we actually consider these things is actually implicit in the load. And because it is implicit in the load, then, you know, the forecast would be --according to that it would be actually reflecting that reduction also into the future.

You may say that, okay, so if storage units are going to be used more in accelerated way, well, in that case actually what happens here is what they pick up is the trend in the storage unit usage inside the forecast, implicit in the forecast, so it accelerates faster than that future load would be lower than what we forecast and that, you know, that actually would be in the benefit of customers is not -- Hydro One would not gain out of that.

MR. LADANYI: So that's interesting. If I understand what you're saying, you are saying -- let's say there's a total load forecast of 100 units and then you have large scale energy storage and then you subtract that from the 100 units and you get, let's say, 98 units with storage; is that what you're saying?

MR. ALAGHEBAND: Actually what I am saying is that the actual load reflects how much load was -- was deducted based on storage units. So for example, at the time of peak, if there is a, you know, say a class A customer reduces his load based on industrial conservation initiatives to reduce the global adjustment, in that case we observe lower load. We are using that observed lower load. You are not deducting offset anything. It is already reflected in the actual.

MR. LADANYI: It's the actual, but we are talking about load forecasts. So it's not the actual we are discussing; we are discussing a forecast.

MR. ALAGHEBAND: Yes, and the forecast is based on actual, you know, so we are looking at the trend in the actual, and that trend is applied because the storage units has been used in the past and we know that for sure some class A customers have been using that. That trend is going forward.

MR. LADANYI: So again, I am just trying to understand how you are taking storage into account. So if there are 100 units of load and then you add 100 units of storage, you would end up with 0 load, would that be right?

This is an extreme example, but I am trying to understand the mathematics of this.

MR. ALAGHEBAND: That's right, yes. The actual load would reflect how much implicitly the storage units deducted from the load. We don't have access to all the storage unit information. What we have access to the actual and we are using the actual load and on that basis, we go forward.

MR. LADANYI: And do you know what the actual storage, large scale energy storage that's now attached to the transmission grid? Do you have a number for that? Does anybody?

MR. ALAGHEBAND: We don't have a number for that, no.

MR. LADANYI: So you are just guessing through econometrics. You actually don't have hard numbers you can tell me?

MR. ALAGHEBAND: We are not guessing. We are using the actual numbers which are solid numbers, and we are simply looking at the trend of its usage into the future and, as I said, you know, if there is a program which looks to be like that to actually accelerate usage of storage units that would be, you know, the actual in the future would come lower than what we forecast. We are not over forecasting.

MR. LADANYI: I will have to think about that for the hearing. Maybe I have a related question to this that might be for Mr. Vetsis. Does Hydro One have a standby charge?

MR. VETSIS: Mr. Ladanyi, can you hear me?

MR. LADANYI: Yes.

MR. VETSIS: Hydro One does not have a standby charge. On the distribution side, our subtransmission customers are billed on a gross load billing basis and on the transmission side, I believe our line connection and transformation connection would be billed on a gross load basis.

MR. LADANYI: So you're not contemplating of having a standby charge like some distributors are?

MR. VETSIS: The OEB currently has a commercial/ industrial rate design consultation ongoing, and so we are awaiting the outcome of that consultation to determine what changes to rate design might be required.

MR. LADANYI: Actually, many people are awaiting the results of that for many years.

I have one more question and perhaps it might not be for this panel, and it has to do with D-Energy Probe-54. And it has to do with granting access by Hydro One Networks to Hydro One Telecom and for use of their fibre optic cable. Is that -- is this you people, or should it be the next panel?

MR. VETSIS: Could you scroll down a little bit, Carla?

MR. LADANYI: Yeah, it's Mr. Jodoin--

MR. VETSIS: I haven't seen this IR and I doubt anyone on our panel would be able to speak to this.

MR. MYERS: Yes, this is for the finance panel.

MR. LADANYI: Thank you very much. These my questions, and now Dr. Higgin will take over.

# Examination by Dr. Higgin:

DR. HIGGIN: Okay, can everyone hear me?

MR. VETSIS: Yes.

DR. HIGGIN: Good. So I am Roger Higgin, the other consultant, and I am the other half of the Energy Probe tag team.

So good afternoon, panel, and to Mr. Fenrick. How is the weather in Madison today, Mr. Fenrick?

MR. FENRICK: Hello, Mr. Higgin, how are you doing?

DR. HIGGIN: Good to see you.

MR. FENRICK: Good seeing you. It's cold. I am in Kentucky right now, but it's cold down here too.

DR. HIGGIN: Okay. So unfortunately, Mr. Fenrick, most of my questions today are for you, okay. So could we start with Energy Probe IR No. 4, and look at the response to that which is part (e).

So you may want to look at the question, because I was asking you about the results of the Brattle and PEG productivity studies in Quebec; that was in the question. And I was just going to ask you first of all have you had a chance to now examine those results that were listed in the interrogatory.

MR. FENRICK: This is Steve Fenrick from Clear Spring responding, Mr. Higgin. I have looked through the reports. However, you know, not having access to the working papers, I am somewhat limited in knowing the exact methodology of both of those research reports.

DR. HIGGIN: Okay, thank you. Now, does Clear Spring know what is the current factor for Hydro Quebec transmission?

MR. FENRICK: Not off the top of my head, no.

DR. HIGGIN: So I will tell you. It's positive 0.57 percent, positive. Okay.

Now do you know which econometric method was used, was actually Concentric Energy Advisors to arrive at this result, and then was accepted by the regime.

MR. FENRICK: I have not reviewed the prior decision, so, no, I do not know.

DR. HIGGIN: Okay, thank you. So just to [audio dropout] analysis that did it, correct? Did you know that?

MR. FENRICK: Could you please repeat that question? You were kind of cutting out a little bit.

DR. HIGGIN: Yes, I am sorry. So it was done by the Kahn analysis method. You know that method, I assume.

MR. FENRICK: Yes, I am familiar with that.

DR. HIGGIN: So have you done similar Kahn productivity analysis for Hydro One Distribution or Transmission during your retention by Hydro One?

MR. STERNBERG: Mr. Higgin, it's counsel for Hydro One. Perhaps you can assist us with what you say the relevance of the question is and how it relates to this IR response in seeking clarification of it, because it seems to me as I am hearing it you are beyond the scope of either of those things, and the witness has also indicated he is not familiar with the details of some of what you're asking him about now. So perhaps you could assist.

DR. HIGGIN: Okay. Well, I will leave it there just to note for the witness and for Hydro One this is another methodology that has been used in the U.S. and elsewhere to set the productivity factor. And that's why was inquiring. Mr. Fenrick is well aware of it.

MR. STERNBERG: Thanks for the clarification. I take it from what you said that you will move on to your next question, but we have heard your -- the clarification you have put on the record.

DR. HIGGIN: Right. Now, in the part (b) of this particular one, so if we can look at part (b). At the beginning you discuss the stretch factor, and you say that the X factor contains a considerable stretch factor. I believe that's what you say here. Is that right?

MR. FENRICK: Yes, that's right. We found the transmission TFP trend in the U.S. industry to be negative 1.66 percent. And so when -- we recommended a productivity factor of 0 percent. So that contains -- that recommendation of 0 percent contains a very sizable stretch factor within it.

DR. HIGGIN: Now, can you confirm that the benchmarking analysis for the stretch factor is a very different concept and a very different model?

MR. FENRICK: If I could just clarify, relative to the TFP trend analysis?

DR. HIGGIN: Yes.

MR. FENRICK: Yes, yes, that's -- that can be confirmed. The total cost benchmarking examines the performance levels, performance cost levels of the utility, whereas the trend, the TFP trend analysis, looking at the industry trend over time and how that's changing. So, yes, it's two different, entirely different models.

DR. HIGGIN: So this is totally different to the productivity of 0.0 percent that you recommend from the TFP analysis. So why do you link the two in this way?

MR. FENRICK: Economic theory and incentive regulation principles would dictate that the productivity factor should be based on an external TFP trend growth found within the industry. You know, since the productivity factor is not being set equal to that TFP trend finding of the industry of negative 1.66 percent, but rather we are recommending the 0 percent, that difference is a very sizable stretch factor that the company -- Hydro One essentially needs to hit 0 percent rather than what its industry peers have been hitting, which has been a negative 1.66 percent number. And so the company's a very sizable

-- stretched or challenged beyond what the industry experience has been.

DR. HIGGIN: Yeah, the problem I am having is the technical aspect, and that is that you're talking here about two different things. You are talking about the term X plus S, and then you are then putting it together with the productivity factor, the X factor. And so this answer, then, just to clarify, am I correct that you're talking about X plus S here?

MR. FENRICK: We are talking about the productivity factor plus the stretch factor equalling the X factor, which is essentially what the company needs to -- basically the productivity target that the company needs to attain, in this case that productivity target that we recommended of 0 percent, which is the productivity factor of 0 percent plus the stretch factor of 0 percent, based on the total cost benchmarking results of the company. That productivity targets is quite, quite meaningfully higher than what the industry TFP target would be, which is again that large negative number. And so that's why we call that -- it's an implicit stretch factor that the company's productivity target recommending is, you know, a great deal higher than what the industry and what economic principles for incentive regulation would dictate.

DR. HIGGIN: Yeah, but the problem I am having is simply technical, and that is that X plus S is the term we are dealing with, okay, here, and so basically you have to deal with the two parts separately and then bring them together in a recommendation, which you do.

So that's the problem I am having. It's the way in which you presented it. So would you like to try and clarify that for me, by saying, for example, the X factor we think should be minus 2.66 percent. We think that based on our benchmarking work -- that's the other study -- we think the S factor should be S. Put the two together, we have X plus S, and you say that's 0 again. That's the technical problem I am having.

MR. FENRICK: Let me -- Mr. Higgin, let me try to explain kind of the rationale and how we got to that. You know, absent, absent Board precedents, we would have likely recommended a negative productivity factor equal to negative 1.66 percent, because that is what incentive regulation principles would dictate; that's what, you know, the economic theory would say. There have been a number of precedence of negative X factors throughout in other jurisdictions. And so, you know, given our research and empirical results and empirical findings, a negative 1.66 percent productivity factor would be justified in what would be -- that would be our recommendation.

Now, given, you know, the fourth-generation IR and other Board precedents of setting that productivity factor at 0 percent, we've aligned ourselves with that recommendation and those precedents. However, we feel there should be some recognition that that productivity factor of 0 percent, it has an implicit or a far more challenging target to the company than what 0 percent is. And so that's that implicit stretch factor.

DR. HIGGIN: So what is the S factor that you are using then for the X plus S to come up with 0? That's all I am asking.

MR. FENRICK: The stretch factor we are recommending is 0 percent based on the company's total cost performance, which is a minus 34.5 percent. During the CIR period, the company ranked second in our entire sample. And so based on fourth-generation IR precedents of very strong or superior cost performers receiving a 0 percent stretch factor, we recommended a 0 percent stretch factor on top of that 0 percent productivity factor.

DR. HIGGIN: Thank you. The problem I am having, to be clear, is this idea that you are using the word "implicit", because it's not implicit. It is something that you have looked at in detail, come up with the result for the benchmark, okay, and then based on the benchmark, you make this recommendation that it should be 0 percent S.

That's the problem I am having, is that "implicit."

So I don't know whether you want to correct this, but in the hearing I need to get this properly on the record that says you did the TFP analysis and it came up with that, but because of various precedents, we think that the TFP should be 0 and we did the benchmark. And based on the 35.4 percent below, we would recommend an S factor of 0. It's not, not rocket science, Mr. Fenrick.

MR. STERNBERG: Mr. Higgin, if I can interject again. I have listened I think you have asked for some clarification a couple of times and Mr. Fenrick has provided it.

I am not sure if you are asking for further clarification in response in respect of this IR or not. If you are, perhaps you could ask it.

DR. HIGGIN: Mr. Sternberg, this is not an issue that I am going to just drop. Okay. I am going the raise it in the hearing, and I am going to give Mr. Fenrick a chance to clarify things here in the technical conference, that's all.

MR. STERNBERG: I appreciate that and all I am saying to assist in moving things along is that if you have asked him the clarify a couple times, and he has. If you are asking a further clarification question, perhaps you could pose that and he could respond.

But I am not clear myself on whether you are asking for some further clarification at this point on this IR response, or some other related IR response.

DR. HIGGIN: I am asking for clarification to his "implicit" S factor. That's what I am asking for. I am asking it to be put on the record that it required two separate studies, one for TFP and one for benchmarking and an S factor.

I am giving him the opportunity here to clarify it, rather than in the hearing. I don't want the spend so much time on it.

MR. VETSIS: Mr. Higgin, just for the record, it is on the record. So if I could take you, for example, to Exhibit A-4-1 of the application where we define -- on the very first page, we define the S factor as the sum of Hydro One's custom total industry total factor productivity measure, as well as Hydro One's custom productivity stretch factor measure.

So I guess in your nomenclature, you have separate terms; you have X and an S. In our nomenclature, X is actually the sum of the two things that you're already talking about.

And then further from there, we are very clear when we go on to A-4-2 as well as A-4-3, where the specific recommendations come from for each of these factors --

DR. HIGGIN: Mr. Vetsis, I am sorry to interrupt you. It's very clear in economic analysis that the term contains an X factor and an S factor. There is no issues about that. I can go to 20 texts and Mr. Fenrick knows this.

MR. STERNBERG: Just to clarify -- perhaps, Mr. Vetsis, can be allowed to finish the answer he was partway through, and then we can go on to another question, if there is one.

MR. VETSIS: Mr. Higgin, as I noted in our evidence, we are clear that for the purposes of RCI, the X factor represent a sum of total factor productivity analysis, which measures the overall productivity of the sector itself, and then a stretch factor which is the result of a total cost benchmarking analysis. This is both in our evidence, both in A-4-1 -- like in the A-4 series, and there are specific references actually in Mr. Fenrick's report as well, where he mentions that the stretch factor is the result of a total cost benchmarking analysis.

If fact, if I could even take you to his report, attachment 1 of this exhibit, just on page 6 itself. Actually, you know what? Carla, it's page 6 of the report, so you will see at the top a heading "1.4."

Again you will see here there are two items identified specifically for transmission. These are the two separate analyses that Mr. Fenrick has mentioned. Nd so, yeah, based on my understanding, he is very clear that he has done two separate analyses and recommended those factors separately.

So I think it's very clearly on the record.

DR. HIGGIN: Okay. If Mr. Fenrick has nothing to add on this, I will move to my next question.

Okay, let's go to Energy Probe 5, number 5, part (a), and the Clearspring response. I am just rolling it up on my screen. There we go.

So this is the same issue. It's lack of clarity in terms. I will have to continue to pursue this because I think it's important to have some clarity on it. So I will leave this. You had an opportunity, that's my job here to try and clarify things and give you an opportunity to clarify. So I will still go to the hearing on that.

So now let's go to Energy Probe Number 7, part (a) and the Clearspring response. You may just want to have a quick look at the question and how we got to this point for a minute, Mr. Fenrick. So I don't want to sandbag you, so I want you to look at it, the question, and then I will start my question.

Okay. So I will start with Hydro One Distribution, since most of the IR response relates to distribution. So first of all, what was the sample used for the US benchmark score for distribution? Is it the same sample as transmission? Is there a difference? Is there anything special about the sample? And were the years for the sample up to 2019, or some other recent year?

MR. FENRICK: If I could direct you to my Clearspring report, A-4-1, attachment 1. Page 38 contains the distribution sample.

DR. HIGGIN: Okay.

MR. FENRICK: I will just wait until that comes up.

DR. HIGGIN: Is there something you would like me to specifically look at on this page?

MR. FENRICK: It's page 38 of 84. So, yeah, scroll up. One more page, please -- there we go.

DR. HIGGIN: Yes, okay, I understand --

MR. FENRICK: This contains the distribution sample that we used for the benchmarking analysis. To get to your other questions, the sample period began in 2000 through 2019 for the sample, the sampled utilities, and there are some differences between the distribution and transmission samples. In the States, not all of the distribution utilities also provide transmission and things like that.

But the sample universe that we began was the same, but there are some differences in the sample.

DR. HIGGIN: Okay. Now the first question is why did you compare -- well, first of all I will ask, which years did you compare for the benchmark of the historic data to Hydro One Distribution costs?

MR. FENRICK: In doing the econometric approach we take in all of the data. So we use all of the observations beginning in 2000 through 2019, so that's 20 years for each utility. So all of those observations, you know, so the number of utilities times 20 -- there's a few years where the utility did not have good data, but on the most part we are using 20 observations for each utility to create the econometric model which correlates the service territory variables and how they impact and how they cause total costs in designing those parameter values. So we are using the entire sample to fashion the benchmark or for [audio dropout].

DR. HIGGIN: Okay. Now, for Hydro One Distribution what years did you compare to that sample, the full sample? What years would you -- did you compare?

MR. FENRICK: Using that sample, we looked at Hydro One Distribution 2005 through 2027, obviously with the years that -- you know, 2021 and beyond were projections provided to us by the company. But we provide on page 40 of our report, page 40 of 84, we provide the benchmarks and the results for --

DR. HIGGIN: Yes. Now, the sample year, the last sample year, was what, 2019? Is that correct?

MR. FENRICK: That's correct for the sample, yes.

DR. HIGGIN: Yeah. So why would you not compare Hydro One Distribution For those same years rather than projecting out another ten years?

MR. FENRICK: In the -- basically, to provide useful information to the Board and intervenors as far as the company's plan and proposed spending plan how that would compare to the benchmarks during the custom IR period, so it's to provide information to people.

DR. HIGGIN: But the benchmark is supposed to compare the sample over the same years to the subject utility. That's the normal practice; is that correct?

MR. FENRICK: No, I would not say that's the normal practice. It's an out-of-sample approach, which we have done through a number of proceedings in Ontario, and it's a way of just providing those projections and providing the benchmark, which is based on the historical sample data, but fashioning that benchmark into the future to provide that information to interested parties.

DR. HIGGIN: Yeah, the problem I have is that Hydro One's costs are going to increase going forward. Would you disagree or not with that statement?

MR. FENRICK: The costs provided to us as far as the projections, yes, increased over time.

DR. HIGGIN: In the projections. So that's my issue. If you have anything you'd like to clarify or you think that the auto is not -- auto is not a good system that you have used in the past and you wanted to add in the additional ten years' data, which, as I suggest, is higher costs for Hydro One.

MR. FENRICK: Could you repeat that question? I am sorry, I missed the question.

DR. HIGGIN: So I am concerned, shall I say, that not using the auto, that means the same sample period for both utilities, and projecting Hydro One's costs, which will increase to 2021, may not produce a fair result. That's my concern.

MR. FENRICK: I would disagree with that concern. The benchmarks that we are providing both historically for the company and the projections are the best available benchmark analysis that could be provided at this time.

DR. HIGGIN: We have to go back to the question of how many did you do that use the same sample period for both the subject utility and the sample. And is this the first one that you have actually done with adding ten years of projected increased costs?

MR. FENRICK: No, this is not the first one that we have done. This has been regular practice through, you know, Toronto Hydro, Hydro Ottawa, the prior Hydro One applications where we provided benchmarks both on the historical and the projections.

DR. HIGGIN: Well, I am not going to go there, because I was in those cases and I know exactly what was provided. First of all, you did the benchmark, and then you were asked by the utility to do the projections separately. Am I wrong?

MR. FENRICK: Mr. Higgin, there has been so many -- I believe normal practice has been in the reports itself when I am doing the research we put in those projections. I do recall maybe Hydro One Distribution where we -- maybe we were asked afterwards, because -- as custom IR was relatively new at that point. But for a number of the most recent proceedings this has been the normal practice that we have done. We haven't done anything special in this proceeding.

DR. HIGGIN: Okay. I will leave that there. Thank you for your answers on that issue.

So I think my next question, thankfully for you, is probably for Hydro witnesses, although it affects the IRM formula, and this is going to Energy Probe No. 9.

MR. SIDLOFSKY: Dr. Higgin, just before you ask your question, could I just get a sense of timing from you?

DR. HIGGIN: This is my last question.

MR. SIDLOFSKY: Okay, thank you.

DR. HIGGIN: So go to number 9. Perhaps read a bit the preamble and then the response to part (b). So this table -- maybe you would like to describe what it shows, and then -- rather than me talking too much, why don't one of the witnesses tell us what this table shows.

MR. VETSIS: Sure, Mr. Higgin, I can do that. I think, reading the question, it sounded like our understanding of your request was to provide a table that shows a relative, you know -- I think I can provide sort of a relative view as to the amount of the capital, related revenue requirement that's recovered through the I minus X adjustment, versus the amount that is recovered through the capital factor.

As I note here in the response, the way we calculate these values is as a percentage change relative to the prior year's revenue requirement, and if you take a look at the specific lines identified here which are taken from Table 1 of Exhibit A-4-2, but there's a similar copy for distribution in A-4-3, you can get a relative view of the amount of the capital that comes from the I minus X formula versus the amount that comes through the capital factor. Just here it's expressed as a percentage change relative to the prior year's revenue requirement rather than as a dollar value. But the ability to get a relative view, you can get that from here.

DR. HIGGIN: Thank you.

Now, my problem, Mr. Vetsis, is this, that first of all, can you confirm that this response relates to distribution or, if not, if it is transmission?

MR. VETSIS: Can we scroll up in the question -- actually, the reference here is A-4-2 for transmission.

DR. HIGGIN: Right, okay.

MR. VETSIS: So I would expect that these values would come from that table. However, if you wanted a similar analysis for distribution, in A-4-3 we have a similar table, also labelled as Table 1, and we have identified that -- the particular lines here in the interrogatory response, which should line up as well in A-4-3, if you wanted to get the percentages --

DR. HIGGIN: That's helpful. So what we would like to understand is the split between the capital recovered in the I minus X plus S factor, and that recovered under the capital factor. So can you provide a table showing for distribution and transmission the 2023 to '27 capital by the five major categories the OEB uses, and which capital is indexed and which is increased under the capital factor?

MR. VETSIS: We can't do that, Mr. Higgin. That's not the way this is calculated. What we have is a total capital related revenue requirement in line 10. And through line -- line 12, I apologize -- and from there flow these calculations to determine, you know, the various percentages.

But we don't go through and allocate specific projects to I minus X versus C. That would be an arbitrary distinction.

DR. HIGGIN: I wouldn't even want to deal with the projects level. I am talking about the total capital, I am trying to understand how much is going to be increased during the IRM plan by the X -- the I minus X plus S factor and how much is going to be in the capital factor.

I am just trying to understand that going forward. These numbers are percentages and they don't help me with that number. Can you help me?

MR. VETSIS: So, I mean, I guess if you wanted to estimate a value, you could take, for example, the relative proportion for the I minus X adjustment. So in the table here, if we are looking at the year 2024, Mr. Higgin, if you took -- oh it's gone now.

So if you were to take, for example, 1.2 percent in line 17 and divide that by the 4.13 percent in line 16, that would give you the relative percentage, the relative amount that is recovered through the I minus X adjustment.

Similarly, if you took line 18 and divided it by line 16, you would get the relative amount that is recovered through capital --

DR. HIGGIN: I have looked at this table and the math. Just to confirm on line 6, this is the revenue requirement proposed in the system plan, is that correct? It's not the results from the system plan, is that what I am looking at in line 6?

MR. VETSIS: Yes.

DR. HIGGIN: Okay. So I am still having a little struggle how to get from there, because if I said let's do a hypothetical, Mr. Vetsis, and say, okay, the I minus X plus S will actually be, because of Mr. Fenrick's recommendation, will be just inflation. Is that a reasonable assumption?

MR. VETSIS: In transmission that's not correct because there is also the incremental stretch on capital of .15 percent.

DR. HIGGIN: That is what I was going to ask you about, yes, exactly. So that comes in as a separate factor. Can you help me how to see where that is here, the stretch factor bit?

MR. VETSIS: That happens -- unfortunately, we are on the distribution table here.

DR. HIGGIN: Yes, but --

MR. VETSIS: It would be in line 9. So in this particular instance, you see we have the distribution stretch of .3, plus .15 which is the incremental stretch on capital.

DR. HIGGIN: Okay.

MR. VETSIS: I would note just for the purposes of being helpful, if you take a look at our response to Staff 7, we did provide an Excel sheet that has the actual formulas for all these calculations --

DR. HIGGIN: Ah, that was my last question, Mr. Vetsis. You always anticipate me, don't you? I will look that up; I had missed that. So thank you, panel, for the responses --

MR. VETSIS: For your own benefit, it's attachment 1, Mr. Higgin, to that IR.

DR. HIGGIN: Again, thank you, Mr. Fenrick -- Dr. Fenrick, I apologize. It's nice to see you again and maybe we will see you in the hearing. Thank you.

MR. SIDLOFSKY: Thank you, Dr. Higgin. I just got a message from Mr. Lusney saying that he unfortunately can't stay longer this afternoon, so I am going to leave it open to the panel and to Hydro One's counsel. We can call it a night at this point, it's just about twenty to 5, and we can start with OSEA followed by Staff in the morning, or we can get a few questions in from Mr. Frank for Board Staff. Mr. Sternberg?

MR. STERNBERG: Sure, we can -- perhaps you can give us a moment.

MR. SIDLOFSKY: Sure. Do you want a breakout room?

MR. VETSIS: Sure, I would appreciate that, thank you.

MR. SIDLOFSKY: Coming up.

MS. SANASIE: Will it be the witnesses only, or should I put Mr. Myers and Mr. Sternberg as well?

MR. SIDLOFSKY: The witnesses and Mr. Myers and Mr. Sternberg.

MS. SANASIE: Okay.

[Witness panel and counsel confer in breakout room]

MR. SIDLOFSKY: Thanks.

MR. STERNBERG: I am not sure if the witnesses are back yet, but they are content to carry on until 5 clock.

MR. SIDLOFSKY: I am not sure if you heard my conversation with Mr. Garner, but it sounds like he is in a position to go ahead and use this time, and he could finish off his questions this afternoon.

MR. STERNBERG: Sure, whoever is set to go is fine with us and, as I said, we are content to carry on. Can we just confirm -- have we got all the witnesses back now?

MS. SANASIE: Everyone is back.

MR. STERNBERG: Okay, great.

MR. GARNER: Can someone tell me when we can start?

MR. SIDLOFSKY: Feel free, Mr. Garner.

# Examination by Mr. Garner:

MR. GARNER: Okay, it's Mark Garner, hello -- good evening or whatever time it is. My name is Mark Garner and I am a consultant with VECC.

My questions are going to be to Mr. Fenrick and to Mr. Vetsis. And because I wasn't expecting to be here, I am going to go by the fly and if we need to pick up the document, we can.

Mr. Fenrick, good to see you. I only really have one question. I don't think we need to bring up the interrogatory, but it was A-Staff-09.

You might recall in your evidence -- and tell me if any of this that I have got incorrect.

In this round when you did your studies, you took out the US rural electric cooperatives, is that right, because you had a data problem with them?

MR. FENRICK: Hello, Mr. Garner. Yes, that's correct. In the prior Hydro One distribution study, we included the rural electrical cooperatives. However, the data has not been updated, to our knowledge, since 2011, and so that's just too stale to include in the benchmarking study.

MR. GARNER: Okay. And can you just give me a sense of, in the sense of data points in your studies, what does it mean to take out the cooperatives? Can you give me a sense of how that affects your study and the number of -- you know, the amount of data you have running through the model?

MR. FENRICK: Yes, so, I mean, the cooperatives are a sizable number of utilities. Now, they also tend to be the smaller utilities in the States. They serve those rural areas in between the investor-owned utility service territories, kind of those higher-cost areas. You know, the reason why we included them in the last study was that they are more similar to Hydro One in that they serve those kind of those remote rural areas versus the investor-owns. But, yeah, so it does -- it does reduce the number of utilities in our sample.

MR. GARNER: How does that affect -- I mean, it's been a long time since I have done any econometrics. How does that affect the validity of the model, so to speak, because you're reducing the amount of data that you have in the model? Can you explain to me what that means to model that way?

MR. FENRICK: Yeah, so in the last -- in the last proceeding, not Hydro One Distribution, the last proceeding there, you know, we included the rural electric cooperatives. Board Staff's consultant PEG did not include them and only included investor-owned utilities, very similar to the sample we are using here. And so the results were actually very similar between us and PEG at the time, so it did not seem to appear to have too large of an impact.

There are some advantages of not including the cooperatives, as far as cost definitions, excluding pensions and benefits, for example, or customer service and information. There are some advantages. But I would also characterize it as a disadvantage to not include those cooperatives, because Hydro One is so rural and remote relative to the rest of the sample that it does have that disadvantage that we are perhaps not properly capturing.

MR. GARNER: Okay, thank you. And in that interrogatory, too, there was discussion about you not having the Ontario small utilities, and one thing -- in your sample. And one thing I noticed, only anecdotally if I looked at it, but what struck me by looking at some of the rural electric cooperatives in the U.S. is they were actually much more strikingly like small Ontario utilities than I would have thought, and part of the reason being simply the way densities work in rural United States versus the way densities work in rural Canada, and so that often I was looking at utilities which actually looked fairly similar to a small Ontario utility.

So when you were including these cooperatives had you done anything other than, as you're saying, is, well, they serve rural areas, but have you done any study that actually compares the cooperatives to a typical Ontario, you know, like, small LDC? Has there been anything there that actually demonstrates that assumption you've just articulated?

MR. FENRICK: Just based on my general knowledge of the cooperatives and the other LDCs in Ontario, the other LDCs in Ontario tend to serve municipalities, you know, specific towns or cities and things like that, versus the cooperatives. Basically, those municipalities get essentially carved out of their service territory, and they are only serving those rural areas. You know, there's exceptions, of course, but on the whole they are filling in the rest of the country, if you will, not including those pockets of --

MR. GARNER: Well, that was where -- sorry, that was where I was going, though, because when I looked at a few they looked more to the exception you are saying, which is they look a lot like a municipality. They were a small town, very similar to let's say an Ontario small town, and surrounded by municipal areas, similar to the municipalities that are basically the genesis of many of the small Ontario utilities. So it didn't actually look very dissimilar to me at all, although I suspect there are some that are much more rural, and so I was wondering when you were including them, you were including all of them, and you hadn't done any adjustment to make a distinction between the cooperatives; had you?

MR. FENRICK: Just if I could add on to the other point, the rural cooperatives do have much lower customer density than, you know, the typical LDC in Ontario. I think there's a pretty -- pretty distinct difference there. But the last time we did it, no, I don't believe there was any sort of, you know, variable or any other distinction other than, you know, including them into the sample with the thought that it would better capture the rural challenges that Hydro One faces.

MR. GARNER: Okay. And just one final question on that is, one of the other reasons you left them out of your study, you wrote in that response, was the issue about making pension adjustments. Can you elucidate on that? What's the problem with making a pension adjustment for the data from the Ontario utilities?

MR. FENRICK: Mr. Garner, do you mean for the rural cooperatives or the --

MR. GARNER: Yeah. Well, what I read was basically there was an issue about making pension adjustments if you did include the small -- I thought it was the small Ontario utilities.

MR. FENRICK: The problem is actually with both, so my answer can actually --

MR. GARNER: Okay. Well, maybe explain what the problem is for both to me then.

MR. FENRICK: Yeah, so for the cooperatives, you know, that data is just not available to disentangle the pensions and benefits with the total costs, and so there's not a separate line item for pensions and benefits, so we can't subtract those out.

For the Ontario distributors, you know, in doing a number of these studies we found that data to be unreliable in the uniform system of accounts, you know, the pensions and benefits get recorded differently depending on the utility, and so, you know, there's -- we are not able to know which -- what those actual values are and then subtract them out, so that was one of the improvements that we could make with not including Ontario utilities or -- and not including the cooperatives is, we could have a consistent definition and exclude those pensions and benefits from the cost definition.

MR. GARNER: Okay. Thank you, Mr. Fenrick.

Mr. Vetsis, I have a question for you. It's on VECC 8. And I probably put this question poorly, because I put it in terms of, did you get proper notice, but I was perplexed by this idea that you're considering a proposal for a mid-term update to the cost of capital components in this plan you have, and I thought, well, this is an application. Are you considering it or are you doing it? And we are going to be going into settlement eventually, and I am wondering, what exactly is the proposal here? Is there a proposal to update cost of capital parameters, and how would it work? Or is that not a proposal to do that?

MR. VETSIS: I have to admit, Mr. Garner, I am looking at the interrogatory here and I don't see a link to a cost of capital update.

MR. GARNER: Maybe I have got the reference wrong.

MR. VETSIS: Yeah. It's not something that would have been in my evidence. So I am not aware of any such formal request at this time. However, you could confirm that with the finance panel when they come on.

MR. GARNER: Okay. Maybe I will do that, and then maybe I will also get my reference correct. As I said, I wanted to see if I could get to you in this evening, so thank you, I will take that under advisement and take a look at it.

Also, I think my last question -- and I wasn't sure where to take it -- and again, you may throw me over to panel 4. I was thrown off of panel 1 even though the authors were Mr. Jesus and Mr. Jackson. I think this is for panel 4. And this is about the CISVA true-up accounts. Would that be a question for you or would that be a question for the finance people? And it's basically about how the true-up works and why it's different for transmission and distribution.

MR. VETSIS: I can only speak to that at a high level, Mr. Garner. I think the specifics and the details between the difference in account are probably more appropriate for the finance panel.

MR. GARNER: Well, let me throw the question -- I threw it out to that panel. I will throw it out to you. I was really just perplexed. There was -- there is a difference between the way it's, I called it trued up, and apparently that was the wrong word. I wanted to know why it was the wrong word. But the other one was, what it was that was driving the difference in what I am calling the true-up mechanism between the distribution function and a transmission function in those account. So is that again best for them or...

MR. VETSIS: I can give you a sentence, Mark, and if you ask anything after that I am going to have to punt you to the other panel. But --

MR. GARNER: Okay. I heard punt, not punch, so...

MR. VETSIS: No, you definitely heard correctly. I hope that's correct in the transcript as well.

But I believe there is a sentence about this in -- and I think it's G -- let me find it for you first. G-1-2, page 21.

MR. GARNER: G-1-2, page 21. There is a sentence, and do you have it in front of you? Do you want to read it?

MR. VETSIS: Yeah, sure, I can read it. So I will read the whole thing.

"This modification would remove the incentive to complete projects in December of any given year, when it would be more appropriate and cost effective to instead complete such projects in January of the following year, which is an issue that is particularly significant for the transmission business where projects are large in scale and multi-year in nature."

MR. GARNER: I think I remember reading that, okay, thank you for that. I am not sure what I will do with raising it.

I actually think that is all that I had for this panel. As you know and may have been told, my friends in cost allocation and load, Mr. Harper has promised very detailed questions in writing for you sometime this evening. We are hoping that you can spend the next Christmas holidays working on them.

So those are all my questions, Mr. Sidlofsky, and hopefully that brings us to 5 o'clock.

MR. SIDLOFSKY: Thanks, Mr. Garner. It is about four minutes to five, and I am calling it close enough to five to call it an evening. Sorry, how long do you expect Mr. Harper to be tomorrow? We are scheduling him for after 11:30 or later, I think.

MR. GARNER: I think he will not have any questions of this panel. He will have all of his questions I believe in writing, unless I suppose if he is online and he hears something with the other cross-examination that he hasn't put into his questions. I think he is hoping not to have any, and therefore we would be finished panel 3.

The only thing I would ask is your indulgence if he does. Because he is there and he is doing these questions, we might want a few minutes to just clarify something. But his question will come in writing.

MR. SIDLOFSKY: Okay, so we won't schedule VECC for anything further for --

MR. GARNER: Not unless I ask, and with your indulgence and with Hydro One's indulgence.

MR. SIDLOFSKY: Okay, good. Thank you.

MR. GARNER: Thank you.

MR. SIDLOFSKY: With that, I am going to close the session for the evening. Thanks again to our reporter, and we will be back with the continuation of panel 3 tomorrow. And we will -- my thought is to start with OSEA and then we will move on to Board Staff.

If Mr. Lusney has some issue with that, then we will

-- then Staff will go first. Thanks very much, everybody. And we will see you at 9 o'clock again tomorrow.

### --- Whereupon the conference adjourned at 4:59 p.m.