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on Thursday, March 5, 2026, commencing at 9:29 a.m.

VOLUME 1

A P P E A R A N C E S

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A P P E A R A N C E S

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--- On commencing at 9:29 a.m.

R. DHILLON: Good morning, everyone. Good morning. Well, again, good morning, everyone. Welcome to the multi-day technical conference for Alectra Utilities Corporation, application number EB-2025-0252.

My name is Raman Dhillon. I am OEB counsel, and I will be your host for the next couple of days.

I would like to ask Ms. Connell if she can start with the land acknowledgement.

LAND ACKNOWLEDGEMENT

S.A. CONNELL: The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the territory of the Anishinaabeg, the Haudenosaunee, and Huron Wendat Nations, and that this land is covered by historic treaties. Traditionally, the territory now called Toronto was a meeting place for many nations and is still home to many Indigenous peoples from across Turtle Island. We are grateful for the opportunity to live, work, and learn on this land and acknowledge our shared responsibilities to our relations. Thank you.

R. DHILLON: Okay. And I just wanted to introduce Ms. Narisa Jotiban, who is the case manager on this matter.

N. JOTIBAN: Good morning, everyone.

R. DHILLON: Okay. I am going to start with the

appearances, for which I will do a roll call. I do understand that there are two preliminary matters that we will deal with after roll call.

So if I may start with Alectra, Ms. Coban.

D. COBAN: Good morning. Daliana Coban, counsel for Alectra.

J. MYERS: Jonathan Myers, counsel for Alectra.

D. COBAN: And my apologies. I should just introduce that we have here next to us Ms. Long from Alectra. Thank you.

R. DHILLON: And I will just go down the list. Association of Major Power Consumers in Ontario.

S. GRICE: Good morning. Shelley Grice representing the Association of Major Power Consumers in Ontario.

R. DHILLON: Thank you, Ms. Grice.

Building Owners and Managers Association Greater Toronto.

C. LI: Good morning. Clement Li representing Building Owners and Managers Association of Toronto. Thank you.

R. DHILLON: Thank you, Mr. Li.

Coalition of Concerned Manufacturers and Businesses of Canada.

T. LADANYI: Good morning. My name is Tom Ladanyi. I am representing CCMBC.

R. DHILLON: Thank you, Mr. Ladanyi.

Consumers Council of Canada.

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

R. DHILLON: Thank you, Mr. Gluck.

Distributed Resources Coalition.

D. VOLLMER: Good morning. Daniel Vollmer, counsel for Distributed Resources Coalition.

R. DHILLON: Thank you, Mr. Vollmer.

Energy Probe Research Foundation.

T. LADANYI: Good morning again. Tom Ladanyi. I am representing Energy Probe Research Foundation.

R. DHILLON: Thank you, Mr. Ladanyi.

Environmental Defence.

Okay. Maybe we will have them join in a later panel.

Ontario Association of Physical Plant Administrators.

S. WALKER: Good morning. Scott Walker representing OAPPA, who are fundamentally Ontario's universities and colleges.

R. DHILLON: Thank you, Mr. Walker.

Power Workers' Union.

D. ROSENBLUTH: Good morning. Dan Rosenbluth here for the Power Workers' Union, and I am joined by my colleague Bayu Kidane.

R. DHILLON: Thank you, Mr. Rosenbluth.

School Energy Coalition.

M. RUBENSTEIN: Thank you. Mark Rubenstein, counsel for School Energy Coalition, and I am joined

remotely by SEC consultant Jane Scott.

R. DHILLON: Thank you, Mr. Rubenstein.

Vulnerable Energy Consumers Coalition.

M. GARNER: Good morning. Mark Garner for VECC, and I am joined virtually online by Mr. Bill Harper.

R. DHILLON: Thank you, Mr. Garner.

Unless I have missed anyone, I believe that is it for roll call.

We are just going to start with a preliminary matter from Mr. Walker.

PRELIMINARY MATTERS

S. WALKER: Thank you.

If there were CVs that were provided, I apologize. I didn't actually note those. I was just wondering -- sorry. Not contesting the validity of any of the panel members, to be clear; however, if in your introductions you could identify if any of you are actually power system engineers and your experience related to design of underground overhead and substations and if you have actually had experience with protection and control and if any of you have actually functioned as linesmen or in the electrical mechanical world or as forestry, please.

J. MYERS: Okay. We will now turn it over to our panel to introduce themselves, and if they can, to include the additional information that Mr. Walker requested.

T. WASIK: Good morning. My name is Tom Wasik.

I am the senior vice president of asset management. I am an electrical engineer by trade. I have been in the industry for 25 years now in a variety of engineering roles, including asset management.

To my right.

H. IBRAHIM: Hany Ibrahim -- Hany Ibrahim, director of capital investment planning. I am an engineer by trade. I have been in the industry about 16 years and with the variety of roles, including asset management.

R. BASSINDALE: Richard Bassindale, director of standards and asset sustainment. I am an electrical engineer with 18 years' experience with the utility. I have experience on a lot of the items you have raised. Some of it might be a little rusty. Haven't been doing it all, but I will try to assist.

J. BUTLER: Hello. Jim Butler, vice president of centralized operations. I have been in the industry 34 years, and I am a licensed professional engineer in Ontario. Through my 34 years, I have been involved with most areas of the utility, but for this application, I currently am responsible for system control, reliability stations, and PNC.

D. FAIRCHILD: Good morning. My name is Doug Fairchild. I am the vice president of distribution design. I oversee the design activities of, you know, our customer connections, you know, our asset management-driven work, not the station design work

specifically. I am an electrical engineer. I have been in the industry since 2000, and I do have some PNC experience, but those aren't really been active for several years, so, yeah. Thank you.

M. WITTEMUND: Hi. Good morning. My name is Mike Wittemund. I am the vice president of lines operations with Alectra. I have been in the industry for over 20 years. I am a licensed professional engineer by trade, and I have experience and oversight with design as well as operations of the electrical distribution. Thank you.

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

Sorry. Maybe just as an administrative matter before we get going, we have three sets of written technical conference questions that we would like to enter in as undertakings. OEB Staff has indicated that they will be providing written questions as well as their oral questions, so we would like those to be marked as JT-1.1.

UNDERTAKING JT-1.1: PROVIDE OEB STAFF'S WRITTEN QUESTIONS AS WELL AS ORAL QUESTIONS

J. MYERS: And then ED has a set of questions. We would like those to be marked as JT-1.2.

UNDERTAKING JT-1.2: PROVIDE ED'S WRITTEN QUESTIONS AS WELL AS ORAL QUESTIONS

J. MYERS: And DRC, their questions would be marked as JT-1.3.

UNDERTAKING JT-1.3: PROVIDE DRC'S WRITTEN QUESTIONS AS WELL AS ORAL QUESTIONS

R. DHILLON: Sorry, Mr. Myers. Can you repeat the last one?

J. MYERS: DRC, JT-1.3.

And so all the questions for each of those three would be included under that number.

R. DHILLON: Thank you. So we are marking as Undertaking JT-1.1 the undertaking responses; JT-1.2, the ED -- or the set of ED; and then JT-1.3, the DRC; is that correct?

J. MYERS: Correct. Thank you.

R. DHILLON: Thank you.

The time is now 9:40. We will aim to take a break around 10:45 this morning. And with that said, I will turn it over to School Energy Coalition, Mr. Rubenstein.

CROSS-EXAMINATION BY M. RUBENSTEIN

M. RUBENSTEIN: Thank you very much.

I will have some questions, and my colleague Ms. Scott will have some questions at the end. And just to give you a bit of a roadmap, I am going to sort of jump around different interrogatories just so we can deal with sort of different topic areas in sequence.

And the first one I want to discuss with you is at 2-Staff-140. Maybe we can have that pulled up.

And I want to ask about your response to part B. And in it, you were asked about the relationship

between the reliability targets in the application and those with respect to the OEB's performance benchmarking reliability targets. And in your response, you discuss that they are not essentially like-for-like because the OEB targets exclude loss of supply and major event days, and the Alectra targets include loss of supply; do I have that right?

J. BUTLER: Yes, you have that correct.

M. RUBENSTEIN: And as I understand as well, you only have a SAIDI target, not a SAIFI target, as compared to the OEB's benchmarking, which does both?

J. BUTLER: Yes, that is correct.

M. RUBENSTEIN: All right.

And can you help me understand why you wouldn't be able to develop a SAIDI target that excludes both loss of supply and major event days so that there is an apples-to-apples comparison?

J. BUTLER: We -- we chose our target, our SAIDI target. We exclude MED days. We feel that they can bias the results. You know, they are extreme events and don't provide great analysis or insight, but we do include a loss of supply.

We feel that is relevant for our internal metrics and our internal targets and our programs to support. Loss of supply minutes are experienced by the customers, and we try to minimize them, so that is included in our target, and we feel that is best for Alectra.

The targets generated by the OEB excluded those, and I can't speak to why they were excluded there, but we feel it is appropriate to include them in our internal targets.

M. RUBENSTEIN: Yes. Sorry. Maybe I am -- I understand why you are proposing the target. Maybe I am just trying to understand, are you able to take your target and derive a version of it that would then exclude loss of supply?

J. BUTLER: Mr. Rubenstein, our targets are -- they are referring to the 20 percent reduction in SAIDI. Those were derived by assessing the impact of our investment programs that were proposed here. The investment programs don't specifically address lost supply. That is outside of our control. We could attempt to estimate the impact of lost supply, but it is not under our direct control, so it would be a rough estimation. But it is possible, I believe. I don't know if it is relevant, but it is possible.

M. RUBENSTEIN: Well, I mean, I do think it is relevant. I mean, the Board has targets. You have targets. I am trying to -- I think Staff in their interrogatory also is trying to understand what the true difference is, and I think your response was, well, they are not exactly the same.

So I would ask you to undertake to do that. And maybe before that, maybe it would be helpful to understand, are you undertaking investments that

would deal directly with loss of -- reducing loss of --

J. BUTLER: Sorry. Could you repeat that question.

M. RUBENSTEIN: Are you undertaking investments in the investment plan that is the basis of the application that address reducing loss of supply?

R. BASSINDALE: Not as a primary driver, no.

M. RUBENSTEIN: Let me just back up. I understand -- putting aside it is a primary driver, is there any that will have the benefit of reducing loss of supply -- let me say, materially, right?

R. BASSINDALE: Over the course of the DSP, materially, no.

M. RUBENSTEIN: Okay. Well, then I will go back to the undertaking because it seems that if you have no investments that are directly actually addressing reducing loss of supply, then you can essentially do the calculation of what that would look like; right?

J. BUTLER: We could. If I could reference table 6 from AMPCO-54.

So you can see there that this table breaks down the customer hours of interruption by cause code for the last number of years, and when you do the math, loss of supply is approximately 5 percent -- for previous year or the average years, it is always around 5 percent. So it would not have a material impact. Removing loss of supply would not have a

material impact on the impact on our targets. So we could take an undertaking to do that calculation, but they would not have a material change.

M. RUBENSTEIN: Well, let's do that just so later on we are not arguing about what the correct number here is of the math, if you are willing to give that undertaking.

J. BUTLER: So can you please -- can we -- just to make sure I understand the undertaking, can you please repeat it.

M. RUBENSTEIN: Sure. I am trying to understand what would be the equivalent of your SAIFI target -- sorry -- SAIDI target -- I apologize -- SAIDI target if you excluded both loss of supply and --

J. MYERS: And as part of that undertaking, Mr. Butler, are there any qualifications that you feel you would need to include in the response?

J. BUTLER: There may be. We will include them in the response.

M. RUBENSTEIN: Thank you very much. Can we now go to --

R. DHILLON: Sorry. I am just going to mark that as Undertaking JT-1.5.

D. COBAN: I think it is 1.4, Ms. Dhillon.

R. DHILLON: Oh, I apologize. JT-1.4.

UNDERTAKING JT-1.4: PROVIDE EQUIVALENT OF SAIDI TARGET WHEN LOSS OF SUPPLY IS EXCLUDED

M. RUBENSTEIN: Can we now go to 2A-SEC-28. I

have some questions about the optimization process. So in part A, we -- I won't read it, but we asked you to provide in an Excel spreadsheet the key outputs of the final Copperleaf optimization model, and there's specific information, and you provided an attachment.

I just want to make sure I understand what is included in the attachment and make sure I understand how it all works. So just so I understand, the attachment includes all of the projects or programs that are included in the plan; correct?

H. IBRAHIM: That is correct.

M. RUBENSTEIN: But ultimately, there is a larger set of potential projects and programs that ultimately the optimization selected based on the various factors in its optimization process. Do I have that right?

H. IBRAHIM: No. The optimization -- the list you are looking at in tab 1 that is -- of the attachment, that is the portfolio of the final plan. The optimization would have deferred the other investments.

M. RUBENSTEIN: Yeah. So I think we are saying the same thing here. Originally, there are more potential -- there is a selection of potential projects and programs, and then the optimization process selects and determines, based on the constraints, the projects that we are seeing in the final -- in the attachment and ultimately what is in

the plan. Right?

H. IBRAHIM: Right. There are other projects that are deferred.

M. RUBENSTEIN: Yeah. So the question we had asked you, and maybe it just wasn't clear how it was phrased, we were seeking that entire list. Because, as you know, at the end, we asked you, the last question is for you to tell -- the last part of that is if the project or program is to be included in the plan. So we are trying to understand the -- essentially one step back, all the list of projects and their scores.

H. IBRAHIM: Okay.

M. RUBENSTEIN: Are you able to provide that revised attachment?

J. MYERS: Mr. Rubenstein, what is the relevance of the projects that are not part of the plan?

M. RUBENSTEIN: Well, you are selecting certain projects using a process. We want to understand which projects those were selected over. That determines the prudence of the expenditures you are seeking, the individual projects.

J. MYERS: I think we can speak to the process, but I am not sure what -- the relevance of the projects that were deferred.

M. RUBENSTEIN: Well, I think it is directly relevant. You have a set of candidate projects in the process. You have spent a lot of the evidence

discussing the calculation -- you know, how you -- the process of the optimization which comes out with the programs. But, ultimately, those are selected over other projects.

We would like to understand -- to properly understand what the programs ultimately were chosen, we need to understand the larger -- the larger set of programs that were considered as part of the process, and that is what the spreadsheet was asking for. It is entirely relevant.

J. MYERS: Perhaps examples would help clarify how that process works?

M. RUBENSTEIN: No. The -- no. I am seeking the list of projects in -- as requested in the original interrogatory.

J. MYERS: Just one moment.

I think what we can do is we can consider whether we think that is relevant, and if we agree that it is appropriate to provide that, then we will. And if we continue to believe that it is not relevant, then we will explain why.

R. DHILLON: Mr. Myers, would you like to mark that as undertaking number JT-1.5?

J. MYERS: Yes, please.

R. DHILLON: Thank you.

UNDERTAKING JT-1.5: PROVIDE A SPREADSHEET THAT LISTS ALL THE POTENTIAL PROJECTS AND PROGRAMS, INCLUDING THOSE THAT WERE NOT SELECTED

M. RUBENSTEIN: Now, just so I understand the optimization process, and we have that large list, as I understand, there are constraints, and projects have to be taken, and they are -- well, I will ask you about that.

But let's just assume the projects that are not part of that, right, so the ones where you have the ability to defer, as I understand, you're selecting based on a total values score. Do I have that right?

H. IBRAHIM: The optimizations does select based on value, but it is an optimization, not a prioritization.

M. RUBENSTEIN: Okay. I think is it not doing, in some sense, both? It is optimizing between years and, you know, some of the constraints, but it is also then --

H. IBRAHIM: It also has the ability to select different options within a project.

M. RUBENSTEIN: Yes.

H. IBRAHIM: A prioritization would not have that capability, but optimization would. Again, it is trying to maximize the total value.

M. RUBENSTEIN: Okay. But ultimately if we have two -- let's just -- simplest example here. You have two projects that have the same cost, right, and you can only do one of them, the process will pick the one with the higher total value score.

H. IBRAHIM: In a universe of two projects,

maybe. But let me give you an example of three where the selection would be different.

M. RUBENSTEIN: Please.

H. IBRAHIM: And if I may.

So imagine there is a universe of three projects. One for, let's say, an investment of $10, and it would yield 10 points, let's say; and the second one is $6, and it yields 6 points; and then the third one would yield -- of $4 would yield 5 points.

If you were prioritizing and you have with a constraint of $10, it would pick the first project only. But if you were optimizing, you would select the second and the third because they would provide a higher value. 11 points, to be exact.

Optimization can yield a different -- in a universe of two projects, yes, but that is not a fair comparison with a portfolio of hundreds. Optimization would yield a different outcome than prioritization in our portfolio.

M. RUBENSTEIN: But let me ask you this question: Is it looking at total value -- I mean, I hear -- I recognize -- but is it primarily looking at optimizing for the total value or -- how might I put it?

As I understand, total value is the sum of the net benefits and the net -- the net benefit score and the net risk score minus by the net present value of

the investment cost. Do I have that part right?

H. IBRAHIM: That is correct. In light of the -- you have to consider the constraints as well.

M. RUBENSTEIN: Sure. But just of the score component.

H. IBRAHIM: Yes.

M. RUBENSTEIN: And is it looking, then, at optimizing for the total score, or -- so it is optimizing for total score. Is there a reason why you are using that approach versus one that looks at, for example, the total benefits and the total -- the total benefit score, the total risk score, but divided by the investment risk score. So it is what is the total value you are getting for every dollar of investment.

I have seen that approach. Some utilities I have seen use that approach. I am just trying to understand why you are using one, others are using others.

H. IBRAHIM: Our approach is to remove the cost, the net present value of the cost, not divide the cost. Dividing by the cost would actually skew the portfolio or would skew the decision.

M. RUBENSTEIN: No, no, no, I understand that -- what you are doing.

My question is why are you taking that approach versus one that looks at a, you know, benefit -- let me put it this way, sort of changing the value of the

benefits and risks per dollar. I have seen that approach used by other utilities. I have seen your approach also. I am just trying to understand why you have taken one versus the other. It is another way of doing it, obviously.

H. IBRAHIM: It is another way. And I can't comment on the other approach per se. I can comment on our approach where it is essentially a net present value approach. So if there is a return in benefit or mitigated risk in dollars or monetized dollars of risk in value, and there is an investment that is cash flow, you would discount it and do a net present value. I am not -- I can't comment on approach of division.

M. RUBENSTEIN: Okay. Now, the -- in the evidence, it discusses what you call planning groups, which as I -- in the evidence, it talks about the planning groups "exclude," "must do," "in flight not plausible," and "must do something" planning groups. You are familiar with that?

H. IBRAHIM: Yes.

M. RUBENSTEIN: In the spreadsheet, though, that you provided, there is a different -- there is one that is not included in the evidence. I am just wondering if you talk to it. It is called "new to scenario." What is that?

D. COBAN: Mr. Rubenstein, maybe just for the benefit of the room, can you give us an evidence

reference so we are looking at the --

M. RUBENSTEIN: Sure. If you are in 2A-SEC-28 attachment 1 in the big spreadsheet. There is sort of a category of planning groups. And one, I just note it is not referenced in the prefiled evidence when you talk about planning groups. I am just understanding what that one was.

H. IBRAHIM: Mr. Rubenstein, those projects "new to scenario" are basically everything that is the default that is not in a planning group. And I will take that subject to check.

M. RUBENSTEIN: So as I understand, the planning groups in the evidence there is "exclude," which means, I guess, don't include it in the process, as I understand the evidence. One is "in flight not plausible." So it has already been started, can't stop. There is "must do," which means you have to do that project regardless of the value score. And then there is "must do something," which is it is -- you have to do it at some point, I guess, but it is deferrable.

So I am just not clear when you say the default, how does that work? How does that work compared to the other planning groups?

H. IBRAHIM: So the planning groups are select projects where there is limitations to the optimizer and what it does with them.

The "new to scenario," subject to check, is

basically anything that the optimizer can move around, select different options. It is not constrained.

And I would like to basically clarify something in the planning group. So some planning groups, when you say "must do something," that means we are not necessarily selecting an option. It is we are telling the optimizer it has to select an option for the optimization to run.

So there is different -- what I am trying to explain is different planning groups have different constraints. For example, you said the "must do" -- "must do," those are forced in the optimizer because there is obligations towards those projects.

"In flight not plausible," that is basically they started they can't stop at this point. Right.

"Must do something" is different constraints than the other two. That is what I want to point out.

A "new to scenario" is basically everything else available to the optimizer to optimize and move around and basically adjust the start dates, adjust the options, pick whatever would provide the maximum total portfolio value.

M. RUBENSTEIN: And can you just, then, clarify the difference between that and "must do something."

H. IBRAHIM: "Must do something" is a project where we are telling the optimizer you would have to

select an option from that project, a choice of that project.

M. RUBENSTEIN: And so that would be as -- when you say you have, you know, the reduced, accelerated, those -- that is what you are talking about?

H. IBRAHIM: Yes.

M. RUBENSTEIN: You have to select one of those.

H. IBRAHIM: Yes.

M. RUBENSTEIN: Okay. Thank you.

Now, I just have one question about one project that just sort of stood out to me from this list that didn't -- I just didn't know what it meant. You have a project called "AMI metering renewal MRZ," and it was not -- but you also have, then, "AMI metering renewal" for each of the five rate zones. So what is "MRZ"?

H. IBRAHIM: Mr. Rubenstein, that question is better answered by Panel 2.

M. RUBENSTEIN: Okay. Thank you.

Can we go to 2-AMPCO-21. And in part C, you were asked to provide the Copperleaf constraints, and you provided per year in the draft capital plan. And if we go down to page 3, you provide that table.

And you will see for the Capex constraints, they go to -- from 406.9 up to 857.8. Do you see that?

H. IBRAHIM: Yes. I see table 1.

M. RUBENSTEIN: How were those Capex constraints determined? Those are very specific numbers, so help

me understand how those were determined.

H. IBRAHIM: The capital constraint is set by -- or the initial one for the optimization was set by the capital investment planning team and to start the iterations, and as we submitted in the question we went through, six iterations to refine all the constraints within the optimization. And that is where the constraint ended to -- basically for the draft plan.

M. RUBENSTEIN: So are you saying the initial optimization had different constraints? The number was not 406.9; it was some other number?

H. IBRAHIM: The first iteration would have started with a different set of constraints, and it gets refined through the six iterations throughout our company.

M. RUBENSTEIN: All right. Can you provide the total Capex constraints for each of the different optimization scenarios? Or not sure what language you use.

J. MYERS: Mr. Rubenstein, what's the relevance of that? It is not part of the plan that we are proposing.

M. RUBENSTEIN: Well, you started with some number. The first process started with a number. I am trying to -- first of all, I am trying to understand what that number is and really how you got to it. What was the basis of that number that then

you iterated from? What was the starting point? So maybe we can -- you know, you can at least give me the first one.

J. MYERS: And, again, this is --

M. RUBENSTEIN: Sorry. One sec. And if Alectra can explain how those numbers were determined.

J. MYERS: I think we can provide the explanation as to the process of how these were determined, but I don't think the numbers from the earlier iterations are relevant.

M. RUBENSTEIN: Well, I do think they are relevant. You started with a number, some number -- Alectra -- sorry -- not Mr. Myers. The company started with a number that was used to iterate. That was the starting point for a process that led to the draft capital plan. I am trying to understand what those numbers were, and very specifically, how were they determined, right? Someone had to say somewhere, this is a -- we think, a reasonable starting point to develop a capital plan. I am just trying to understand that.

J. MYERS: Well, in terms of the numbers, we can undertake to consider whether we think that is relevant and can be provided, and if not, then we will explain why we think that's not relevant.

M. RUBENSTEIN: Okay. Let's just -- let me just make sure I ask the question so -- it got a little garbled there as I was saying it.

I am looking to understand, and just to simplify it, the first set of capital constraints on the first run. That was the basis, as I understand or I believe, the six iterations that led to the draft capital plan, what those -- what those Capex constraints were per year, and very importantly, how they were determined, what was the basis of those numbers.

J. MYERS: Subject to my -- my earlier qualification, I think we can take that.

R. DHILLON: Thank you. We will mark that as Undertaking JT-1.6.

UNDERTAKING JT-1.6: PROVIDE THE INITIAL SET OF ANNUAL CAPEX RESTRAINTS USED IN THE FIRST MODEL RUN THAT INFORMED THE SIX ITERATIONS LEADING TO THE DRAFT CAPITAL PLAN, INCLUDING THE BASIS AND RATIONALE USED TO DETERMINE THOSE YEARLY CONSTRAINTS AMOUNTS

M. RUBENSTEIN: So just -- now, if I can just understand, there was some number, with the first, and then you ran some various optimization iterations. And maybe you could help me understand what was happening between one and the draft plan, why you were running six, what were the changes that were being made through the process?

H. IBRAHIM: The six iterations. First, let's take into context we are a larger organization, and also we are refining the constraints. And so let's

say we start at, let's say, Iteration 1, the optimization would result in a portfolio that would go into informing how our execution plan will go. It will also inform our workforce planning, and then it would inform also our finance department and OM&A, and that would result in an OM&A non-labour constraint coming back.

And then that is why it is an iterative process; it is not just you plug in the numbers and hit click and it gives you the results. It is an iterative process throughout the company, and that takes iterations to do.

Again, the plan is not just here are a set of projects. It is -- also ensures their executability and, you know, the proper business planning around it.

M. RUBENSTEIN: And were the constraints you are showing on the screen for the draft capital plan -- were those actually the constraints or just the outcome? And I ask it because you can imagine a scenario where I can't find -- you put in a constraint for some very specific number, and, you know, the math doesn't add up. It is going to be maybe slightly different; right?

H. IBRAHIM: To answer your question, you can get no solution from an optimization, that is correct. That is a possible outcome. When you optimize against your constraint, you can get no

solution. So that is a possible outcome, yes.

M. RUBENSTEIN: But to my question, are those the actual constraints or just the outcome of the process of what the capital would look like?

H. IBRAHIM: Subject to check, these are the actual constraints.

M. RUBENSTEIN: Okay. Thank you.

Can we go to 2A-SEC-31. And in part C, we asked you to provide for each draft and final plan the -- essentially the constraints that were used, and in your response, you take us to your answer to part B -- one sec here. Sorry. My computer is freezing here -- where, in part B, you provide actually just the total dollars and so -- for the different plans.

And so do I take it -- I just want to confirm it as I understand, then -- that the -- when you get to the final plan, you didn't rerun the optimization; you just made some adjustments to the draft plan; do I have that right?

H. IBRAHIM: That is correct. And the final plan was an adjusted version of the draft plan --

M. RUBENSTEIN: All right.

H. IBRAHIM: -- incorporating customer feedback.

M. RUBENSTEIN: Can we go to 2A-SEC-29. And in this question, we were asking you about reliability improvement and the modelling you use, and we referenced information you provided in a previous Alectra proceeding where you did provide some

reliability projections.

And the response to part B, as I understand it, is you are explaining -- it references part A. But as I understand, the reliability benefits that you were using or are using is derived from the value framework process; right? Do I have that right?

R. BASSINDALE: That is correct.

M. RUBENSTEIN: And am I correct that how that process works at a high level is you start with a baseline reliability and then what you think the process in terms of what the -- when you do the project, how that would change? Am I understanding that correctly?

R. BASSINDALE: As the reliability value is a benefit, it is the avoidance of outages. So the -- specifically with the scorecard metric, it is based on subject matter experts looking at the reliability from the previous five years and setting that as kind of the baseline and then projecting forward what they think is going to occur if the investment doesn't get completed. And then based on the assumptions, the investment gets completed. There is a potential reduction in reliability.

M. RUBENSTEIN: Okay. And so I think we are saying the same thing. There is sort of a baseline that you determine of what the reliability of that would be without the investment, and then there is a forecast of what the change would be with the

investment; do I have that right? That is step one?

R. BASSINDALE: So, no. We use the historical reliability to forecast. That would occur if the investment doesn't happen. I guess it is a slight little nuance there.

M. RUBENSTEIN: Okay.

As then as I understand, you then take that, and then you translate it to a dollar value based on a value of lost load calculation; do I have that right?

R. BASSINDALE: Yes, that is correct.

M. RUBENSTEIN: Now, you provided, in the DSP appendix C, the value framework definitions. That is confidential, so I am not going to ask you to take it. So I am going to ask you to do this by way of undertaking.

But I have reviewed it, and I can't actually figure out how -- it doesn't -- how you actually go from the change in reliability to the lost load, what the numbers are, and then how -- how the math that you are using is. And then is -- so that is question number 1.

I was wondering if you can provide an illustrative example of a project or a program where you are then taking the change in reliability and translating it to a dollar figure; is that something you can do, sort of explain it and provide an illustrative example? By way of undertaking, just to be clear. I don't mean...

R. BASSINDALE: So to clarify, you would like us to walk you through an illustrative example of how we use the historical reliability to then project out and turn it -- translate it into a net present value for reliability benefit?

M. RUBENSTEIN: Yes.

R. BASSINDALE: Okay.

R. DHILLON: We will mark that as Undertaking JT-1.7.

UNDERTAKING JT-1.7: PROVIDE AN ILLUSTRATIVE EXAMPLE OF A PROJECT OR A PROGRAM THAT TAKES THE CHANGE IN RELIABILITY AND TRANSLATES IT TO A DOLLAR FIGURE

M. RUBENSTEIN: Now, with respect to the lost load numbers, not clear to me -- they're in the -- I don't want to talk about those specifically because I believe they are confidential. But it is not clear to me what the -- where you derive those lost load calculations, what the source of that information is. Can you talk about that, what -- your information you are using, what is the date of it?

R. BASSINDALE: The value of lost load values that Alectra Utilities utilizes is based on a 2015 CEADE study.

M. RUBENSTEIN: Can you provide a copy of that study?

R. BASSINDALE: So we cannot provide the study itself, but we could provide you the values that we

use from that study.

M. RUBENSTEIN: Why can't you provide the study?

R. BASSINDALE: It is confidential through CEADE.

J. MYERS: Mr. Bassindale, is it a matter of needing consent from CEADE to provide their report?

R. BASSINDALE: I would have to validate if that is permissible.

J. MYERS: Okay. So maybe we can take that as an undertaking subject to confirming that we are able to provide the report. If we can't, we will explain why. And if it needs to be filed confidentially, then we would do so.

M. RUBENSTEIN: Sure.

J. MYERS: Does that work?

M. RUBENSTEIN: Yeah.

R. DHILLON: We will mark that as Undertaking JT-1.8.

UNDERTAKING JT-1.8: PROVIDE THE 2015 CEADE STUDY THAT ALECTRA UTILITIES BASES THEIR LOST LOAD VALUES ON

M. RUBENSTEIN: Just so I can understand the study at a high level, is it -- was this a study done for Alectra, or is that a generic study?

R. BASSINDALE: It was a study completed for a number of utilities both in the U.S. and Canada.

M. RUBENSTEIN: Okay.

Can we go to 2-CCC-22. And this is just a good

table to work off because it has a list of all the projects in the lines capacity group. So it is just helpful in that regard.

And as I understand the table, it includes a list of all the lines capacity projects; do I have that right? Just so I am making sure I...

T. WASIK: That is correct.

M. RUBENSTEIN: I was wondering if you could provide for each of the line capacity projects that are listed on this table -- if you could provide the total incremental capacity that they are providing, how many offers to connect you've signed or are in the process of working through with the customer or their discussions or they are underway for each of those lines and the total megawatts of capacity that would account for. Is that something you could do?

T. WASIK: I'm sorry. I didn't understand the first part, Mr. Rubenstein. You wanted the total capacity, and then at the end --

M. RUBENSTEIN: The total incremental capacity of the project, the total number of offers to connect that you've signed related, obviously, to that capacity -- that you've signed or that you are close to signing. You've provided information just as a backup in 2A-SEC-38 with the data centres giving sort of a sense of where those projects are. And then how many megawatts those offers to connect or those in the -- that are close to it would represent for that

project. Is that something you can do?

T. WASIK: Mr. Rubenstein, I think it is possible for us to be able to provide you the megawatts, but it is extremely difficult to be able to then map a specific customer to what could be, you know, 40, 50 different feeder projects that are configured to an open-loop distribution network to determine whether or not they would or not be served by customers or which customers.

These are feeders that we are proposing to develop and construct and implement for larger areas that also benefit existing customers as well. So it's -- we can provide you the megawatts capacity benefit of implementing these feeders, but it would be not feasible for us to be able to map them to specific customers or future customers.

M. RUBENSTEIN: Well, I am not asking you to -- that is why I was kind of getting specific to ones that you have offers to connect or you are close to have offers connect; right? We are not talking about something long in the future. I am trying to understand that are under -- that are, like, in the shorter term, closely underpinning the need for the project.

T. WASIK: I think in that particular case, if you are referring to SEC-38, we have 11 projects that are quite discreet, and we can speak to those with respect to where we are with implementing offers to

connect, sort of receiving design deposits.

But relative to a large number of projects stemming from 2017 to 2031 and mapping them to customers, you know, we could -- we have thousands of customers, Mr. Rubenstein. I don't think it would be feasible for us to be able to map them to these specific projects as you have asked.

M. RUBENSTEIN: Well, then maybe just make sure I understand before I -- just make sure my question is even getting at what I want, then, if -- and what you're saying, just to make sure.

The evidence discusses with lines project -- and I am going to have the same question with respect to the station's capacity project about the need for all the projects; right? You have a lot of evidence explaining developments and large -- you know, some data centres or, you know, whatever it is, some, you know, municipal infrastructure projects.

I am trying to understand -- I am trying to get a sense of it, of how much of that -- that demand that is driving the need for those projects, at this stage at least, is close -- either is underpinned by an offer to connect or close to being underpinned by an offer to connect. That is what I am trying to understand.

T. WASIK: Okay.

M. RUBENSTEIN: And so when you are talking about thousands of customers, I mean, maybe that is

the answer. There is thousands of offers to connect that are being -- for one of these lines capacity projects, but I am not sure that -- that doesn't -- maybe that's -- is that -- is that the answer?

T. WASIK: No, I don't think it is that simple, Mr. Rubenstein. I think -- you ask a question specifically. I know you are referencing a CCC response, but I think you have asked a very similar question in your IRRs relating to what is the date of the need.

If you sort of take your attention to that one. I don't have it lined up. It was your question, I recall, Mr. Rubenstein, where we attempted to provide you what the date of the need is. Maybe that would be able to provide you the context that you are looking for in terms of measuring the timing of when we are planning to construct and implement these solutions and when the load is anticipated to be required in order to meet those needs. And we have mapped that for you in your response. So perhaps if you recall your question.

M. RUBENSTEIN: I did ask a question. I am just trying to -- I don't have it off the top of my head, the number.

T. WASIK: But I do recall, Mr. Rubenstein, you asked for -- tell us the date of the need.

M. RUBENSTEIN: Yes.

T. WASIK: And I think that is more appropriate

for your own findings to match up our timing of constructing with when the anticipated demand for that particular project is required.

M. RUBENSTEIN: Okay. Well, let's do this: Let's pause this question. I will take a look at the break, and we can circle back. I don't want to waste time while I am CTRL F'ing the interrogatories.

Can we go now to, then, 2A-SEC-36. I want to make sure I understand the response here.

So in part B, we asked for 2010 to 2025 for Alectra or the predecessor's utilities non-actual coincidental system peak and non-coincidental system peak on a weather-normalized basis. And then we asked the same thing for the coincidental peak in part C.

And in your response, you provide the 1-in-2 and 1-in-10 starting in 2019. And I just want to make sure I understand what you are doing here.

So is it what you are doing with respect to the -- these weather-normalized approaches? You are taking the actual load that was in that year, so the actual what -- the usage of various customers, and you are determining what it would have been on a 1-in-2 and on a 1-in-10 basis? So if that same customer is using it on a, you know, 1-in-10 hottest day of the year, that is what it would be? Just to make sure I understand.

T. WASIK: That is correct, Mr. Rubenstein.

They are weather corrected to the 1-in-2 and the 1-in-10 scenarios as you describe.

M. RUBENSTEIN: Okay. Thank you.

Now, can we go to 2A-SEC-57. You may have to take this by way of undertaking. And in this, we asked you for some information, which you provided a helpful spreadsheet that breaks down all the different stations and various loading information. And so maybe we will just pull up the spreadsheet, if that is possible. This is the attachment 1.

And if we go to the -- we move to the left-hand, you have the planning zone, and then you have the region, do you see that, for each of the stations?

T. WASIK: Yes, I am with you.

M. RUBENSTEIN: And when I look at this, and I look at the numbers, and I compare it to the information that you have in appendix J, figure 19, which shows the 1-in-10 forecast by planning zone, I get the same total. So all the numbers do add up. But the -- but on a planning zone basis, there are some differences.

And that is also when I -- as I understand, in the other charts, you have -- you don't -- you have -- you break down east into the York and the Simcoe regions. But when I get it, I get different numbers.

And I was wondering if you could reconcile -- and that is also when I take this and I convert it -- I convert those other tables from megawatts to MVA, I

get different numbers. I was wondering if you can reconcile that information for me.

T. WASIK: So just to be very clear, Mr. Rubenstein, what you are asking of me is to reconcile the table in response to 2A-SEC-57 broken down by planning zones, and you would like to see those table's planning zones reconciled to the --

M. RUBENSTEIN: Here, let me give you a -- if we can go to appendix J, figure 19. Sorry. You provided the -- sorry. I am looking at this. Just give me a second here. But I had -- you provided another response to the actual -- in a tabular form. I apologize for this. Yeah, if you can go to -- in 2A-SEC-61 attachment, you provided --

T. WASIK: I am sorry, Mr. Rubenstein, can you repeat the reference.

M. RUBENSTEIN: Yeah, no, I apologize. 2A-SEC-61 attachment 1. It's an Excel spreadsheet where we asked you to provide some of the tables in appendix J in a tabular format.

T. WASIK: Yes.

M. RUBENSTEIN: In figure 19, as I understand, the non-coincident summer peak load forecast with CBM and EV is the planning forecast? The totals are the same? The 1-in-10 is the planning forecast?

T. WASIK: Subject to check about the exclusion of the CDM and EV values to confirm we are comparing apples to apples --

M. RUBENSTEIN: I think they are saying the totals all match up, so --

T. WASIK: Okay. Subject to check, yeah.

M. RUBENSTEIN: And so when I look through 2A-SEC-57 attachment 1, and I try to compare the -- it is the forecast loading number further down on that screen. When I convert those from MVA to megawatts, and then I compare them, the totals, per the regions the way that you have done it in figure 19, they do not add up. The totals all add up, so when you do the total, but the zones -- and I am just trying to understand is it that some stations actually -- they may be listed here but serve a different region or -- I am just trying to -- I couldn't reconcile. Is that something you --

T. WASIK: We can help. We can bring clarity to that, Mr. Rubenstein.

M. RUBENSTEIN: Thanks.

T. WASIK: You are right, there are some stations where the feeders might be, you know, servicing perhaps a different planning zone per se. But we can help you bring that up. So you are asking us to reconcile the '27 to 2031 planning outlook in terms of the megawatts and comparing them with the planning zones to reconcile the numbers.

M. RUBENSTEIN: Yeah.

T. WASIK: We can take that on for you.

R. DHILLON: We will mark that as Undertaking

JT-1.9.

UNDERTAKING JT-1.9: RECONCILE THE NUMBERS FROM THE 2027 TO 2031 PLANNING OUTLOOK IN TERMS OF THE MEGAWATTS AND THE PLANNING ZONES

M. RUBENSTEIN: And then can I ask you about a specific station that you listed here, and this is the Markham TS number 5. And maybe if we sort by plan station or something.

T. WASIK: I am sorry?

M. RUBENSTEIN: Sorry. Just if we can look at the Markham TS number 5.

T. WASIK: Which table am I looking up now?

M. RUBENSTEIN: The one that is on the screen. This is 57.

T. WASIK: Okay. So this is back to your SEC-57 question?

M. RUBENSTEIN: Yeah. So if we just scroll across the screen here, you have projected loading beginning -- you can't see this here, but the 68 is in 2026.

T. WASIK: That might be 2028.

M. RUBENSTEIN: Well, you are -- you see you are getting to my question. I thought the project was not going into service in 2028, but you are showing loading in 2026?

T. WASIK: No, it says 2028.

M. RUBENSTEIN: Is that my error, then?

T. WASIK: Yes.

M. RUBENSTEIN: All right. Well, there you go. I apologize.

T. WASIK: We require the station, yes, 2028, Mr. Rubenstein.

M. RUBENSTEIN: Okay. Ignore that, then.

Can I ask you to go to 2-CCC-26. And if we can go to -- we can just scroll down. In this response, you were asked to provide -- scroll down to the -- just to the table here. You provided information on the various station projects and if there are enhancements or expansions. Do you see that? And you provide --

T. WASIK: Sorry. CCC-26 now?

M. RUBENSTEIN: Yes.

T. WASIK: Yes, I am with you.

M. RUBENSTEIN: And I was just confused by one of them, maybe you can help me with, and that is -- just so I have the right thing up. It is with respect to the GTAA project.

So as I understand -- and you can see this on page 3 of the response, I will just scroll down to that -- the land purchase for the GTAA, that is the second one, is an enhancement. But then the actual transformer -- sorry, the transformer station, which you can see further down, is an expansion that comes a couple of years later.

Can you help me understand? So the land is an enhancement, but then when you build the station -- I

mean, you are getting the land for the station. If the station is an expansion, why is the land an enhancement?

T. WASIK: I see, Mr. Rubenstein. I am going to have to take that one away and look at it. But your -- the relationship between the land and the station, as you point out, is appropriate. So I will have to take that back and look at the classification categorization and provide a response as to --

M. RUBENSTEIN: Thank you very much.

T. WASIK: -- what the appropriate positioning of that is.

R. DHILLON: Mr. Rubenstein, is that an undertaking?

M. RUBENSTEIN: I believe they are giving an undertaking, yes.

R. DHILLON: We will mark that as Undertaking JT-1.10.

UNDERTAKING JT-1.10: ADVISE OF THE REASON WHY THE LAND FOR THE GTAA PROJECT IS CONSIDERED AN ENHANCEMENT BUT THE TRANSFORMER STATION IS CONSIDERED AN EXPANSION

T. WASIK: And you referring specifically just to the land for the station?

M. RUBENSTEIN: Well, it is just to reconcile why all the land is an enhancement but the project is an expansion.

T. WASIK: Understood.

M. RUBENSTEIN: The underlying transformer station that will be built.

Can I ask you to go to -- just give me a second here.

Can I ask you to go to 3-CCC-31. So if we go down, you were asked to provide various information, and you provide a helpful table. In the last line is system capacity in megawatts. Do you see that?

T. WASIK: I am with you, Mr. Rubenstein.

M. RUBENSTEIN: And I am having trouble -- another question by way of undertaking. I am having trouble reconciling that information with the information that you provided in 2A-SEC-57 attachment 1 that we looked at before that has the per stations.

T. WASIK: Can you help me understand which particular -- I understand the system capacity figure that you referenced in table 1 to response to CCC-31. Can you help me understand where you are trying to reconcile it in SEC-57?

M. RUBENSTEIN: Yeah. So if I go to SEC-57, and I do an analysis where I take all the new stations -- if I -- I will just help you understand the analysis that I did and why I have got a different -- where our number -- so SEC-57 provides all the stations and the LTRs for the stations.

And if I take all the LTRs for that station in any given year that that station is in service, I get a very different number -- I get a different number

than what you are showing here, even when I convert those stations' LTRs from MVA to megawatts.

T. WASIK: Okay.

M. RUBENSTEIN: Is that something you can reconcile?

T. WASIK: Yeah. We can provide you an explanation as to how to compare those numbers and how you can reconcile these two particular system capacity numbers with the table.

M. RUBENSTEIN: Thank you very much.

R. DHILLON: We will mark that as Undertaking JT-1.11.

UNDERTAKING JT-1.11: PROVIDE AN EXPLANATION AS TO HOW TO COMPARE AND RECONCILE THE NUMBERS IN TABLE 1 AT 3-CCC-31 WITH THE NUMBERS IN SEC-57

M. RUBENSTEIN: And just to be clear, because it is not the totals on the bottom of the screen that is loading. It is if you went up and you picked, for example -- you know, if it's at a 170 and it's in service, the capacity would be -- at least how I am doing the analysis of what is the LTRs for all the years at the station? You know, you take those numbers and --

T. WASIK: We will provide you the explanation as to the appropriate way of comparing those numbers and rationale as to how that should be done.

M. RUBENSTEIN: Thank you very much.

Can we go to 2A-SEC-41. And here you were asked

about the -- we asked you about the NWS program. And as I understand, the program is about deferring five stations where there are capacity?

T. WASIK: I'm sorry. Can you repeat that? I'm not hearing --

M. RUBENSTEIN: Yeah, I apologize.

As I understand, the program is about -- has the effect of deferring five stations where there are capacity needs?

T. WASIK: That is correct.

M. RUBENSTEIN: Is the program actually deferring projects? By that, I mean you could build it earlier, but the program allows you to push it out, or is it just to solve a capacity crunch that you have until a station can be built?

T. WASIK: So we have identified the need first. We have identified that an NWS solution could assist by deferring that build, that traditional wire build, by several years. So we identify the need first, then we identify that we could deploy a non-wires alternative, a non-wires solution, to -- to defer the build of those particular stations, and we have identified five sites such as that.

M. RUBENSTEIN: So the -- putting it -- saying it back to you a different way, it is -- the project is actually -- will defer -- or potentially defer, I mean. You never know if the load ends up happening.

But based on your forecast of the load in the

area, it will defer?

T. WASIK: That is correct. That is -- that is our proposal.

M. RUBENSTEIN: Okay.

Can we go to 2A-SEC-47. And so here we asked you some questions about the budgeting process, and in table 1, you provide a list of estimation methods by program. And then what you will see is, if you scroll down, you provided further information with respect to those that have a unit cost, and you provide, so -- you know, a -- you provide a range for the unit cost; do I have that right?

H. IBRAHIM: That is correct.

M. RUBENSTEIN: Can you help me understand why there is such a wide range for the wood poles?

R. BASSINDALE: The range is due to the different heights and classes that the poles would have.

M. RUBENSTEIN: And can I ask a question. What is the basis of the unit cost numbers here? Is it a historical average? Is it a forecast of what the unit cost may be based on, you know, whatever your, you know, supply costs are and your estimated labour costs, or can you help me understand how you get -- how you derive the unit costs?

R. BASSINDALE: For wood poles, it is based on historical actuals.

M. RUBENSTEIN: For everything, just sort of as

a general -- or do they differ?

R. DHILLON: Mr. Rubenstein, we are approaching a time for a morning break if you can find a break in your questioning.

R. BASSINDALE: In table 1, we provide the estimation method, which varies by investment category. In conference with the panel, we used historical actuals in coming up with those values, but it provides some additional context. You know, the transformers, you have single phase versus three phase. You have, you know, 50 kVa versus, you know, 3 MVA for the transformation, similar feed vehicles. You have got bucket trucks versus SUVs, again, switches between, you know, manual and automated. So there is a variety of factors in terms of what builds up the -- that range in the values provided.

M. RUBENSTEIN: Sure. But just -- let's just take one asset that you are replacing. It's a, when you say "historical average," multi-year average? Is it just taking the last year of what the actual costs were?

R. BASSINDALE: Subject to check, it is either the most recent year. For filing, it would be 2022 or 2023, or it would be based on an average of historical actuals. And then --

M. RUBENSTEIN: So you obviously did this plan earlier than 2026, and then so is -- if we are using historical numbers at the time you did the plan, then

the costing would have been 2024? And then do you -- less interested about the exact specific year. And then do you -- did you sort of inflate the numbers to get to where we are in the plan?

H. IBRAHIM: Mr. Rubenstein, the -- when the business cases are estimated and material costs are placed, they are from previous to 2024 because the plan was put together in 2024. No added inflation were placed by -- through the estimates. We submitted a question to SEC, and we explained that inflation is adjusted by Copperleaf, and we submitted the response. I just can't find it on me right now. But we submitted that it is about 2 percent per year for the inflation and that Copperleaf adjusts that.

M. RUBENSTEIN: Okay. I had assumed that was within the -- you know, if you are doing the project in -- when you are optimizing and you are moving around years, obviously the cost changes in the context of that, but you are saying it goes back to the -- to all the way back to sort of when the business case was developed?

H. IBRAHIM: So when the business case is developed, the costs are -- like, the known costs are used, and then to give the -- the optimizer is what adjusts for inflation because it can move the project, so it needs to adjust for inflation accordingly.

M. RUBENSTEIN: Okay. Thank you.

Maybe we will take our break now.

R. DHILLON: Okay. Thank you. The time now is 10:48. Let's take about 15 minutes, so return around 11:05. Thank you.

--- Recess taken at 10:49 a.m.

--- Upon resuming at 11:05 a.m.

R. DHILLON: Okay. The time is 11:05 a.m., and we will resume. So back to you, Mr. Rubenstein.

M. RUBENSTEIN: Thank you very much. I have been instructed by everybody to talk a little louder, so I am not raising my voice in anger.

Before the break -- actually, a bit before the break, we were talking about the lines capacity and about various information with respect to, you know, offers to connect that underpin it, and we had a discussion about that.

I propose, actually, to park that. I want -- I -- you referenced another interrogatory. I haven't had as much time to look at that, but I do want to look at that, so maybe we will park that, and I will have a discussion with my friends, and we can circle back later on with this panel up just to address that issue, if that is all right.

I want to ask you now, if we can go to -- sorry -- 2A-SEC-59. And here we had asked you with respect to the station capacity project to provide internal business cases for projects over 10 million, and in the response, you provide -- you cite to appendix Q

for some of them and then others you've provided here. And what you do provide is what you call material investment reports. That is what you refer us to.

I just want to make sure if we are talking the same language here. Is the material investment report the business case that the company would have for these large capital projects, or is it really just a summary of that?

T. WASIK: This is the business case that is used in Copperleaf for optimization, so this is the business case for the station that summarizes the net benefits and risks associated with the investment.

M. RUBENSTEIN: But just backing up for a second, I know that is what you input into Copperleaf and the narrative that you provide, but when you are -- when you are doing work on a very large project like a station, is there, that sits behind this, an internal business case?

T. WASIK: This is the internal business case that we would refer to.

M. RUBENSTEIN: So there is no -- there is nothing behind this? There is no project, you know, analysis of the -- something that is developed, to be clear here, some report that sits that says, these are the costs, here are the risks, here is the benefits, here is the -- you know, the forecast load that we need and all -- or that this station would be

dealing with. That doesn't exist? All you have is this?

T. WASIK: It does, Mr. Rubenstein. It is all included in these particular reports in terms of summarizing sort of the risks. But just to be clear, are you looking for sort of the details that underpin sort of the benefits and the risks for each particular case?

M. RUBENSTEIN: Well, I am just trying to understand what exists first before I -- just to make sure I understand. Because you keep talking about "it summarizes" or -- but is there a document that sits behind this that you are summarizing?

T. WASIK: So in this particular investment report is the summary of the, let's say, main points of the business case that are relevant for discussions, but there are details with respect to each particular -- these -- this business case -- excuse me -- business case for the stations that include the sort of -- the costs, the need for the capacity, the particulars of what the costs are made up of, and how things are put together.

M. RUBENSTEIN: So I am calling that an internal business case, but that is just my language. I don't know what you guys call it. Is there some report that sits behind this that you summarized when you put into Copperleaf?

T. WASIK: Not specifically as the way you put

it, Mr. Rubenstein. What we do is we did include in appendix J, right, and in the DSP further details around each of these particular station requirements. So there is an adequacy assessment report that will provide you, I think, the context that you are looking for in terms of matching sort of the -- what the needs of the demand is and how the station is expected to meet those particular demands and what are the particular benefits and challenges associated with the investment.

M. RUBENSTEIN: You are pointing me to documents in the evidence, and that is fine. But I just want to be clear, from your point of view, from the company, you are developing a project; right?

T. WASIK: Um-hmm.

M. RUBENSTEIN: A significant capital project.

Is there a document that exists -- what I -- again, what I am calling an internal business case that is specific to looking at the need of that project, the -- all the costs, all the risks, any other issues, you know, the options that were determined that is specific to that, that you may summarize in other places that exists for that project?

T. WASIK: I think I follow you, Mr. Rubenstein, but the development of a case for, let's say, a station starts with sort of the load forecast, does the system adequacy assessment, then elements of that

information is carried over into the Copperleaf business case in developing the Copperleaf investment case.

And so what you are looking for is one particular document for a station that doesn't exist. It is carried over from all of the necessary system assessment studies, and we think that is the appropriate way of addressing specifically stations.

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

Can we go to 2-SEC-60. And in part C, we asked you for the internal business case for the distribution automation project. And you provide -- in response to that, you cite us to, again, an investment summary document -- or I think I have got the name wrong. I am confusing utilities with their nomenclature -- but what you call a material investment report.

Now, we just talked about it in the context of stations. Is the same for the case for a project like this? Is there something that sits behind this?

J. BUTLER: Mr. Rubenstein, it's -- in this situation, it is the same as the situation we just discussed with stations.

M. RUBENSTEIN: Okay. So what sits -- so when you're -- the only document we have for, say, the distribution automation project is -- that sort of brings together all the different things that you are

looking at is the three-page material investment report to justify that project internally.

J. BUTLER: Yes.

M. RUBENSTEIN: I understand how the company thinks. Forget about -- sorry. Just to be clear, I am trying to think about how the company is thinking about it when it does it.

J. BUTLER: Yes, that is correct.

M. RUBENSTEIN: Okay.

Can we go to 2A-SEC-63.

T. WASIK: Mr. Rubenstein, before you move on to the next question, I think it might be also helpful to reference you to the DSP narratives, specifically appendix B14, which provides all -- I think the context that you are looking for in terms of how the investment was put together and all of the engineering and thinking around specifically the DA, the distribution automation investments, we think -- we think that might be able to sort of help you understand sort of the process that the Alectra goes through in terms of engineering, developing, and then summarizing all of that into that investment report that we provided to you.

So there is more than three pages. I just wanted to be helpful and help you identify that there is quite a significant amount of explanations with great level of details with respect to the distribution automation and how it fits into the

overall automation and system control process that is available in appendix 14 and starts at page 573.

And it does include quite a lot of analysis, including alternatives, examination of execution of the work, and it ends at page 596. So it is more than three pages. I just wanted to --

M. RUBENSTEIN: Yeah, but that gets to my question --

T. WASIK: -- that it explains how things are put together.

M. RUBENSTEIN: I understand that. But that is a narrative you are providing to us, which that is fine. But I am just trying to understand from the company's perspective; right? I assume you are not walking around with the DSP. Presumably before it is included in the DSP and you are discussing it, all that work is done internally.

And I am trying to -- does it sit in what I call an internal business case, but it may -- you know, you may have it -- I just want to make sure there is not some other nomenclature that you -- that you have.

T. WASIK: We think it is appropriately captured in the narratives of the DSP, which summarize that particular investment driver, the -- all of the qualifications that Alectra took into considerations in terms of developing and putting together. And we used the same document for what we do internally with

what we present in the DSP, Mr. Rubenstein.

M. RUBENSTEIN: Yes. Sorry, to be clear, I am not suggesting that you are doing something different. But I am just -- it is sort of the process from my perspective.

Okay. Can we go to 2A-SEC-63.

And so in this question, we asked you for all the material capital projects since the last rebasing of each of the predecessor utilities, we asked for a certain set of information. Do you see that?

And in the response -- well, first, as I understand, you say we can really only give you information from 2019 onwards. Do I have that right? It is the first issue.

T. WASIK: That is correct.

M. RUBENSTEIN: And then if we go to page 3 before you do the chart, you see this at line 7, you discuss that you are providing the information on a $5 million threshold because if not, there would be about 500 capital investments.

T. WASIK: Yes, that is correct.

M. RUBENSTEIN: And as I look through the table, I am not -- I am seeing more than projects, I am seeing programs. Do I have that right?

T. WASIK: The investments include both programs and projects that we thought were material for you to -- to respond to your interrogatory.

M. RUBENSTEIN: Now, I would like you to provide

a response to the question posed. Let's put aside the time issue, the 2017-2018 for a minute. So the 2019 to 2024, I would like you to answer the question as requested.

T. WASIK: Mr. Rubenstein, there is subparts to the particular question. Can you maybe provide me a little bit more clarity as to what you are seeking?

M. RUBENSTEIN: Well, as I understand it, you have used a 5 million dollar -- the key thing is you used a $5 million threshold instead of a $1 million threshold. And I am asking you to provide, the materiality threshold being 1 million, the response to the question as posed.

D. COBAN: Mr. Rubenstein, the volume of information that that would solicit, as you can see here in the response, we think is just too broad, and so that is why we have put the 5 million threshold. We understand you have accepted this threshold in other proceedings. So at this time, that is going to be a refusal.

M. RUBENSTEIN: All right. Well, maybe let me try to get at the issue more directly a different way.

As I understand in your response to some questions, and including 4-AMPCO-64, you -- the company itself tracks projects delivered that were greater than 10 percent of plan costs and over $100,000. That is a metric the company uses. And

you provide that information on page C -- sorry, on part C. Do I have that right?

D. FAIRCHILD: Mr. Rubenstein, would you mind clarifying your question, if you don't mind, please.

M. RUBENSTEIN: As I understand, a metric that the company tracks is the number of projects delivered that were 10 percent above plan costs and that are over 100,000. Am I wrong about that?

D. FAIRCHILD: That is correct. That is in table 1. That is correct, yeah.

M. RUBENSTEIN: Okay. So maybe a -- and let's use that category of costs as sort of a baseline here, right, costs that are above 10 percent. Because when I see this table, I am looking at about 29 percent of the costs in that period, projects that meet that threshold.

And so maybe a different way to address the issues that I am trying to get to in SEC-63 is if you are able to provide a table, or further information if the information is already included, that we look at that category of projects, the 10 percent above and the 100,000 over, but with a materiality threshold a million dollars -- so that is, again, a subset of those projects that you already are tracking that are above 10 percent -- and that you provide the project name, the original budgeted cost, the final project cost, the original start date, the actual start date, the original target in-service

date, the actual in-service date, and, as available, the CPI and SPI scores. Is that something you can do?

D. COBAN: Again, I think the volume of the information you are requesting and the kind of time and effort that it would take to pull that together is really beyond what we can do here.

But in an effort to be helpful, maybe what we can do is just consider your request. And if we are able to provide something that gets at what you are looking for and is helpful within the times, we can do that. And if not, we will explain to you our refusal.

M. RUBENSTEIN: Okay.

R. DHILLON: We can mark that as Undertaking JT-1.12.

M. RUBENSTEIN: Now, as I understand -- yeah. Sorry.

R. BASSINDALE: Can we clarify what the request was? Because you went through --

M. RUBENSTEIN: Yes.

R. BASSINDALE: -- a number of kind of steps there. I want to make sure I have it down right. It was using the --

M. RUBENSTEIN: Let me repeat it and then -- very clearly, and then you can tell me --

R. BASSINDALE: Okay.

M. RUBENSTEIN: -- where it doesn't make any

sense or you don't understand it.

Can you provide for all material capital projects where the final cost is at least $1 million and there is a cost overrun of at least 10 percent and 100,000 -- so it is a subset of the projects that you are tracking in that metric that we discussed -- and then for each of those projects, as far back as you can -- so I think that table was 2020, but if we have 2019, you would use that, and you would be providing for that the project name, the program that it may sit under, the original budget cost, the final project cost, the original start date, the actual start date, the original target in-service date, the actual in-service date, and as I understand, you do track for the CPI and SPI scores, final CPI and SPI.

D. COBAN: Again, we will consider whether we think that is an appropriate request in terms of the breadth of what you are asking for and the time involved to prepare that information. And we will take that away and advise if we are able to provide you something. If not, we will explain the refusal.

UNDERTAKING JT-1.12: FOR ALL MATERIAL CAPITAL PROJECTS WHERE THE FINAL COST IS AT LEAST $1 MILLION AND THERE IS A COST OVERRUN OF AT LEAST 10 PERCENT AND 100,000, PROVIDE FOR AS FAR BACK AS POSSIBLE THE PROJECT NAME, THE PROGRAM THAT IT MAY SIT UNDER, THE ORIGINAL BUDGET COST, THE FINAL PROJECT COST, THE ORIGINAL START DATE, THE

ACTUAL START DATE, THE ORIGINAL TARGET IN-SERVICE DATE, THE ACTUAL IN-SERVICE DATE, AND FINAL CPI AND SPI SCORES

M. RUBENSTEIN: Okay. Just to be clear, I am trying to narrow down the original question that we asked, that is the intent here, with some other information. And just to be clear, I have had some discussion with my friends trying to get all of our issues into one question here.

Can I ask you, with respect to the pre-2019 information -- and maybe you can help me understand how intervenors or the Board should look at your inability to be able to provide this information. How is -- how, from your perspective, is the Board, most importantly the Board, assess the prudence of these expenditures when you can't tell us if the projects are over budget, under budget, the performance of that?

T. WASIK: So, Mr. Rubenstein, I think we tried to in our response to your question give you a couple examples about how capital investments were managed, reported, and tracked with legacy utilities, and how the harmonization of that work with the implementation of a common ERP system at Alectra in 2019 required us to rethink.

The challenge I think we had in answering your question is you were looking to go historically back and trend moving forward, and what we were explaining

is that it is two different methods.

And so us trying to respond to your question in fullness and provide you what we think are the relevant information that your IR was seeking for would be very confusing trying to explain why projects were bundled quite differently in the legacy EnerSource. And I think we used that as an example to then compare that to projects that were bundled in legacy Horizon.

And so what would happen is there would be a significant amount of confusion with, not only just putting the information together, but trying to explain the variances that you asked for. So that is the first part.

The second part around it is that we have submitted a DSP back in 2019 that also spoke to sort of that transition, that being our first integrated DSP. And so we have already submitted on the record, sort of going back to the previous five years and that DSP, some of the challenges with respect to trying to map and explain things.

But I think the part that we were trying to be helpful with is to bring forward the most relevant sort of investments for you to demonstrate some of the variances that you were seeking and explaining why things went towards the plan or away from the plan as you asked.

M. RUBENSTEIN: In the 2019 to 2024 period.

T. WASIK: So the cutoff we had is 2019 is when we harmonized our practices. And from that moment, we can explain consistently across our entire service area all of the projects.

M. RUBENSTEIN: Yeah, no, I hear -- I read about the technical issues of why you can't do it. But putting that aside for a second, how do you suggest and ultimately -- I mean, the Board has to go back and make a determination that the opening rate base in this case is appropriate, and that is an evolution of projects from Alectra, but also actually from the historic rate terms where there was no approval, right. They were in price cap. So it has to go back.

But we don't have any information about, you know, how the projects went and all that. Do we just kind of accept -- we just have to accept it? It is what it is?

T. WASIK: We provided a schedule of sort of capital investments, right. But what I think you are seeking for here is a breakdown by project and specific program levels. And we are just trying to explain the complexities of the fact that they were structured so differently in the legacy practices that, you know, if you wanted to break it down by project by project, it is not as simple as you asked.

M. RUBENSTEIN: All right.

D. COBAN: I think the challenge we have is with

the specificity of your question getting down to the project level. Perhaps if I can ask the panel is there a higher level that is not project, maybe just looking at categories of investment or what have you, that shed a bit more light on the 2017 and '18 expenditures to address Mr. Rubenstein's question?

T. WASIK: We can take that back and see what we can provide.

M. RUBENSTEIN: That is fine. But just to be clear, it goes back further potentially. It goes back, really, to the rebasing of whatever the predecessor entity was, right. So Hydro One Brampton was 2015, just off -- right. And I am just trying to understand those all -- because that all plays into the rate -- the opening rate base you are seeking in this application.

One of the things I am struggling with, with this proceeding is good reasons, bad reasons, I am not -- I don't mean -- I am not making a judgment on it, we just don't have information that goes -- you don't have information that goes back that far.

And that is the problem that, you know, what do we -- is it just -- so I take the undertaking that I think Ms. Coban is willing, but it is not just to the beginning of the Alectra. It is to the last rebasing proceedings of those predecessor entities.

D. COBAN: Just give me a moment.

Okay. Mr. Rubenstein, I think we can address

that part of your question in the same undertaking. We will comment on the pre-merger capital and in terms of your question around the assessment of that capital and our position as to how that should be done in this proceeding where we have the limitations we do with respect to the data.

M. RUBENSTEIN: Thank you.

R. DHILLON: We will mark that as Undertaking JT-1.13.

UNDERTAKING JT-1.13: PROVIDE INFORMATION ON PRE MERGER CAPITAL EXPENDITURES INCLUDING WHAT HIGHER LEVEL INFORMATION MAY BE AVAILABLE FOR PERIODS PRIOR TO 2019, AND COMMENT ON THE COMPANY'S POSITION ON HOW THE BOARD SHOULD ASSESS THOSE EXPENDITURES IN THIS PROCEEDING GIVEN THE LIMITATIONS IN THE AVAILABLE DATA

M. RUBENSTEIN: Can we go to 2A-SEC-32. And in this question, we were asking you about project execution and monitoring. And the evidence, as we understood, and we cited it in part A, is with respect to how you are -- how the company itself manages or monitors the project and the type of reporting that exists.

And we had asked you for a copy of the monthly reporting, whatever that looks like, it wasn't entirely clear, for three months, right. Just use July as halfway through the year. Nothing special about that, but just to understand over a couple of

years.

And in your response, you talk about the type of reporting that you do provide, but then you decline to provide the specific documents for those years. And I am not -- so I am going to ask again for you to provide it. I am not -- you know, if you want to write some narrative around the documents that helps provide that context, but I -- we do think it is important to understanding how the company is -- internally is monitoring its capital program, so we'd ask you to provide that.

D. COBAN: Mr. Rubenstein, maybe just in the interest of time, I think to be efficient here, you have the witnesses who are available to speak to you about what this process looks like. But as you can note in our response, the basis for this refusal is that any documents that may be extracted lack the context of understanding the specific discussions that happen in the context of these meetings.

So our view is that without the benefit of being at these meetings where relevant information is discussed, the documents, you know, are only a presentation aid to what is happening at the meeting. So I think, you know, we would maintain our refusal, but certainly you are welcome to ask the witnesses questions about the nature of these meetings and the kind of information discussed.

M. RUBENSTEIN: Well, first, let me ask,

presumably the -- I don't know if the presentation or report or whatever document that is provided includes metrics, how the company is doing on projects either at an aggregate level or individual level?

D. FAIRCHILD: That would be a correct assertion, yes.

M. RUBENSTEIN: All right.

And what is it about the -- providing that -- this is to Ms. Coban, not to the witness panel. What is providing those documents that would include that sort of metric so we can understand what the -- what the management is seeing lacks the necessary context? I mean, we could have had that discussion right here if the documents had been provided. And you are happy to provide whatever narrative around it, but we would ask for the information as requested.

D. COBAN: We think the level of detail, which you are asking for that on a monthly basis, is overbroad. It would be quite an undertaking to take every single monthly result and have the ability to provide you the appropriate context around each result.

M. RUBENSTEIN: Well, sorry. To be clear, I didn't ask -- we didn't ask for every month. It asked for three months specifically. We just picked July, but it asked for July 23, 24, 25. We didn't ask for every document -- every report, monthly report. It's just a sample to us so we can

understand.

D. COBAN: At this time, we are going to maintain our refusal.

M. RUBENSTEIN: Thank you.

I just have -- my colleague may have -- will have some questions. I just have one final question.

By way of undertaking, I was wondering if you can provide revised versions of SEC -- 2A-SEC-45, attachment 1, and 2A-SEC-45, attachment 1. These are versions of appendix 2A broken down by segments on a Capex basis and an in-service additions basis. I was wondering if you can provide revised versions that have them on a net basis at the program or segment level. Because currently the 2As have the gross amounts, and then for each category, you see the contributions. I was wondering if we can have it on a program and segment basis on a net basis?

J. MYERS: Could we get those references again? I think you said the same one twice.

M. RUBENSTEIN: There is SEC-44, attachment 1, and then SEC-45, attachment 1. One is a Capex; one is an in-service additions basis of that.

R. DHILLON: We can mark that as Undertaking JT-1.14.

T. WASIK: Sorry, Mr. Rubenstein. I am now looking at the schedule that we provided in Excel format. Can you help me understand --

M. RUBENSTEIN: Sure.

T. WASIK: -- what difference -- what differences --

M. RUBENSTEIN: Yeah.

T. WASIK: -- you are looking for at this point?

M. RUBENSTEIN: So as -- let's just look at the system access category of spending. You are showing -- you have it by each of the programs or segments on a gross basis, and then you will see at the last line -- the second-to-last line, you have sort of the total access contributions, and then you have total system access on that basis; right? Do you see that?

T. WASIK: I do. I am with you.

M. RUBENSTEIN: And what I am looking for is, at the segment level, it all on a net basis.

T. WASIK: Say that again one more time.

M. RUBENSTEIN: At the segment level, it is on a net basis, so it is already taking out the contribution.

T. WASIK: Okay. So you would like to see the contributions per each line?

M. RUBENSTEIN: Yeah, could you just put it in, like, just showing it on a net basis. So we are seeing -- so in a sense of what customers are actually paying for each of these programs.

T. WASIK: Understood. Yeah, we can do that for you.

M. RUBENSTEIN: In segments. Thank you.

And I think my colleague Ms. Scott may have some

questions.

D. COBAN: Let's just mark that undertaking.

R. DHILLON: Sorry. So we will mark that undertaking as JT-1.14.

UNDERTAKING JT-1.14: PROVIDE REVISED VERSIONS OF 2A-SEC-44 ATTACHMENT 1 AND SEC-45 ATTACHMENT 1 SHOWING THE NET BASIS AT THE PROGRAM OR SEGMENT LEVEL

CROSS-EXAMINATION BY J. SCOTT

J. SCOTT: Okay. Good morning, Panel. I just had a few questions on their OM&A questions.

For 2A-SEC-27 -- I don't think you need to pull it up -- asked about the Copperleaf training, and one of the slides there talked about both Capex and OM&A projects to be entered into Copperleaf. And also in Exhibit 4, there was some discussion about using Copperleaf to prioritize OM&A projects.

So is there a -- have you been putting the OM&A projects into Copperleaf, I guess, is the first question?

H. IBRAHIM: Only the OM&A costs that pertain to the capital projects are placed in Copperleaf.

J. SCOTT: Okay. Is the plan to eventually put OM&A projects into Copperleaf and prioritize them that way?

H. IBRAHIM: We haven't -- we don't have that in our plans at this point.

J. SCOTT: Okay.

4-SEC-86 is talking about cable locates, and maybe we can pull that one up. And part C provided a cost per locate, the average locate rate for 2025 of 40.04. Can you just explain what is covered in that? Is it just the contractor cost, or is inspection and supervision included?

M. WITTEMUND: Sorry, Ms. Scott. You referring to part C; is that right?

J. SCOTT: Yes. Yeah.

M. WITTEMUND: Yes. That rate in part C there is directly proportionate to contractor costs.

J. SCOTT: So the -- in 4-CC-53 -- again, I don't know that you need to pull it up -- but the -- at that -- in that chart, if you divide the total dollars by the number of locates, you get a figure of 45.30. That would have -- be all in, then, with the supervision and inspection? That would explain the difference between those two numbers?

If you want to pull that one up, yeah, 4-CC-53, table 1, is the best.

If you take, subject to check, the total number of locates and the total program costs, divide one into the other, I get 45.3. Yeah, because you can see the 40.4. Okay. I think I've answered my own question.

On that chart, it shows, for 2026 going forward, the same number of locates in every year. Is there a reason for that?

M. WITTEMUND: We've -- we forecasted the locate volume from 2026 to 2031 based on an average of the past three years.

J. SCOTT: There is no expectation that the number of locates changes with the amount of capital being done or the amount of construction being done or anything? So...

M. WITTEMUND: The number of locates, the volume of locates, there is a number of factors that depend on that. You are correct, it is based on constructions. It is based on, you know, the dedicated locater program. So there is a number of different variables and factors. We found that, you know, basing it on the past three years, the volumes have been quite consistent over the past three years to help us inform the forecast moving forward.

J. SCOTT: And if we can just go back to 4-SEC-86, and I apologize to the person doing the -- bringing up the...

And at the table 1, can you explain to me how the 40.04 in part C relates to these fees? And maybe it is explaining what the billing unit is about the different -- the explanation in the next paragraph, if you just go down, just scroll down just slightly, yeah, talks about the segment lengths and how that works and what impact that has on the quote or the cost.

M. WITTEMUND: The costs that are represented in

table 1 there, those are a standard single-utility locate cost. So with our locate service providers, there is -- there is various fees that we would pay, depending on the sharing of locates amongst utilities. And one of the factors in those locate costs too, you can see that there is a difference in the billing segment length. We have since harmonized that rate, that billing length, across all of our locate service providers to 300 metres.

J. SCOTT: And is that billing segment length the minimum length that the contractor will bill for; is that what it means?

M. WITTEMUND: It is the length of how the locate is covered. So the locate -- the locate will cover that billing length of 300 metres.

J. SCOTT: Okay.

And I guess going -- you don't have to pull this up. But 4-SEC-89 showed that there is two new FTEs in 2027 related to locates. One is for capital, and one is for OM&A. So assuming that the number of locates is staying relatively constant, what -- are those two positions -- why are they required?

M. WITTEMUND: So captured under the cable locates, portfolio and program is included, our field inspectors that perform field inspections on our capital and operational projects. So the cable locates, that is the -- the resources that are captured under there are included in the locates

portfolio, so there is no direct proportion to the locate costs and the resources required. We don't have internal resources that perform any locates.

J. SCOTT: The internal resources are doing -- oh, so when you say "inspection and supervision," you are not referring to inspection and supervision of the cable locates? You are referring to...

M. WITTEMUND: Correct. It is for inspections of our capital projects.

J. SCOTT: Okay. Thank you.

4-VECC-47, there is a table there that -- and maybe we can pull that up. And it shows the total in 2025 for asset management of 9.64 million. In the updated 2JC, which was attached to 1-SEC-24, showed an actual of 7.48 million, and I am wondering if you can explain the variance there?

T. WASIK: Ms. Scott, I am with you on 4-VECC-48. Can you tell me -- which other table you are trying to reconcile to?

J. SCOTT: The updated 2JC, which was attached to 1-SEC-24. So the -- 7,476,829 in 2025 actuals, comparing that to the 9.64.

T. WASIK: So I am clear you are asking if we prepared the 7 million in 2025 under the asset management program costs --

J. SCOTT: Yes.

T. WASIK: -- to 7.4 million --

J. SCOTT: Yes.

T. WASIK: -- in asset management?

So subject to check, I believe that the -- this particular response of VECC-48 refers only to the asset management segment costs. There is a grid modernization component cost that will be also included in the 7.4 million in table appendix 2JC, subject to check.

J. SCOTT: And where would that be found? Is that in the digital or the --

T. WASIK: Yeah, I think it is in response to 4-SEC-80, table 1. It is rounded in this particular table, but it does reconcile. There you go, 7 million for asset management, 0.5 for grid modernization, for a total of 7.5.

J. SCOTT: Right. That is the actual spend in 2025, so my question was comparing that to the forecast spend.

T. WASIK: Okay.

J. SCOTT: Which I was taking from the VECC-47 just because it comes from the evidence, but it's --

T. WASIK: Yeah.

J. SCOTT: So I am taking that as the forecast there.

T. WASIK: Ms. Scott, I am just trying to follow you. You started with VECC-48.

J. SCOTT: No, no. He has got VECC-47 up. VECC-47 is fine. He is -- yeah.

R. DHILLON: Sorry. Ms. Scott, just a reminder

that we have ten minutes allotted to the scheduled time for SEC.

J. SCOTT: Yes. This is the last question so --

T. WASIK: Yeah, Ms. Scott, it might be helpful if I just take that one away and provide you a response as to the difference.

J. SCOTT: Okay. You could do that.

R. DHILLON: So we will mark that as Undertaking JT-1.15.

UNDERTAKING JT-1.15: PROVIDE AN EXPLANATION FOR THE DIFFERENCE BETWEEN THE 2025 ACTUAL ASSET MANAGEMENT COSTS SHOWN IN APPENDIX 2JC AND THE 2025 FORECAST ASSET MANAGEMENT COSTS SHOWN IN EXHIBIT 4, VECC-47

J. SCOTT: Thank you. That is my questions.

R. DHILLON: So we will hand it over to Consumers Council of Canada, Mr. Gluck.

CROSS-EXAMINATION BY L. GLUCK

L. GLUCK: Good morning. My name is Lawrie Gluck, and I have a few questions on behalf of the Consumers Council of Canada.

I would like to start with some questions about the customer connections program, please. So if we can go to 2-CCC-16, part B, please. And if we could go to the response to that question.

In this response, Alectra explains that in 2025, the actual number of customer connections in the subdivisions program were lower than forecast, but

the connections were at a higher gross unit cost than forecast. Is that a reasonable summary of the response?

D. FAIRCHILD: Yes.

L. GLUCK: Thank you.

And so if we could go to part C of the response, there is a table there. For 2025, the actual residential lot connections were 3,500, and the forecast in the pre-filed evidence was 5,100. Would you take that subject to check?

D. FAIRCHILD: Yes.

L. GLUCK: Okay. Thanks.

And so can you help me with what happened? Why was there a 30 percent drop in residential lot connections relative to forecast in 2025?

D. FAIRCHILD: 2024 was an extremely strong year, but we did notice a decrease in 2025, primarily due for economic reasons in the housing sector.

L. GLUCK: Thanks.

And just so I make sure I understand, the residential lot connections that we are talking about, these are detached, semi-detached, and townhouses largely. Is that right?

D. FAIRCHILD: In referring to table 1, there is residential lots with a quantity, and then there is high-rise with a quantity, so -- and the residential lots, you are correct, it is homes, detached, semi-detached, stackable town homes, partial tied lands.

Yeah, any type of structure like that.

L. GLUCK: Okay. Thank you.

And does Alectra have any concerns with this segment of the residential market in terms of the likelihood that its forecast for the 2026 to 2031 period will be realized?

D. FAIRCHILD: In terms of the housing forecast outlook, I am confident that it will rebound from 2025 actuals. I think there are many positive indicators that would suggest through both federal, provincial, potential of HST rebates, many municipalities are now looking at the removal of development charges to facilitate further housing starts. And -- thank you.

L. GLUCK: Thanks.

And you must be in contact with the subdivision developers regularly. Is that right?

D. FAIRCHILD: Alectra is in contact with subdivision developers. That is correct.

L. GLUCK: And you are not hearing anything from those developers with respect to their plans for housing starts in the next few years?

D. FAIRCHILD: I would knowledge that 2025 was a difficult year, and '26, perhaps, is off to a little bit of a slow start. I am not sure that is, you know -- necessarily play into the future outlook from '27 to '31. Again, I think there is still positive optimism that there will be a rebound in the housing

sector.

L. GLUCK: Thanks.

And with respect to the increase in gross costs in 2025 relative to forecast, so my understanding is the actual cost rate, 8,600 per lot, and the forecast was 7,600 per lot. Can you just tell me what drove that increase in 2025?

D. FAIRCHILD: There are many factors that can influence the cost of a subdivision. For example, looking back at 2023, we did also have a high per unit cost. It is site specific to each and every development in terms of density, in terms of what electrical infrastructure needs to be installed to support any given development.

So we have seen some increase for sure in material cost that -- where I would be comfortable to say that would attribute to the, you know, higher unit cost as well. But I stand by that there's just -- there are many factors that influence the cost, the per unit cost, from -- in the subdivision portfolio.

L. GLUCK: Thank you.

And now looking at the high-rise condo connections, am I right that the original forecast was 22 connections, and on an actual basis in 2025, there were only five connections?

D. FAIRCHILD: Correct.

L. GLUCK: And similar to my question about the

residential subdivision aspect, what happened? For the condo market, that is a 75 percent drop in actual connections relative to forecast.

D. FAIRCHILD: Our forecast was off, I will grant you that. In terms of the -- all the reasons for that is somewhat beyond Alectra's control. But clearly, the economy signaled that there was a slow down in condo starts in that particular year.

L. GLUCK: And similar to my question about residential lots, the company has no concerns with its high-rise connection forecast for the forecast period?

D. FAIRCHILD: With respect to the condo -- potential condo projects in the pipeline, I would point you to table 4 of the same -- the same IR.

So within the projects that are known to us, there is still a considerable amount of condos in the pipeline in the order of 216. You know, our forecast has taken a portion of that into account. Not all of it, but certainly a portion into it. I think what remains is still an underlying demand for housing, residential, single detached, condos that remains.

In this particular point in time, we do appear to be at a little bit of a lull in compared to past. I don't necessarily think that is going to be reflective of future with, again, government initiatives that focus on housing and affordability, the efforts that municipalities, you know, regions,

or the province are taking to activate more housing starts, so...

L. GLUCK: Thank you for that.

And based on your response just now, I understand for the high-rise condo connection forecast, it is based on these proposed developments in table 4, and then reduced with the expectation that not every single project is going to occur. Is that how you did your forecast for the condo segment?

D. FAIRCHILD: Yeah, that is correct. We looked at all of the growth projects in the area. And these are -- I mean, these are known. These are known projects. They are also evidence-supported in appendix B13 -- B12 -- sorry, B13.

So there is definitely lots of activity in growth centres throughout Alectra's service territory. And of the known projects to us -- meaning, you know, developers have spoken to us, we have spoken to developers -- this is the information that we have available to us. Certainly not forecasting that every project, you know, is going to get done, but it certainly is a very strong signal that there is a pipeline of projects to come.

L. GLUCK: Thank you.

And the manner in which you forecasted the high-rise condo segment is different from how you forecast their residential lot segment. My understanding for the residential -- the connection of residential

lots, it is not based on proposed development. Instead, it is a forecast based on historical actuals for '22 to '24, and then you applied a growth factor to that. Is that right?

D. FAIRCHILD: That is correct.

L. GLUCK: Okay. Thank you.

And if we could go to -- there is an attachment to CCC-16. It is in Excel. I just have what I hope is a pretty simple question about this.

If we look at 2027 for the new residential subdivision row, it is a $50.4 million gross cost. And I just want to make sure that that 50.4 million is really just the combination of the residential lot connections and the high-rise connection cost. Those are the two categories of costs that are in that line?

D. FAIRCHILD: That is correct.

L. GLUCK: Okay. Thank you.

If we could go to 2-CCC-18, attachment 1, which is also an Excel spreadsheet, and I would like to discuss the unspecified customer-initiated expansion and relocation projects. And if we go to -- I think it is the first tab. Thank you.

So there is the -- row 4 is this category of projects that I would like to discuss. And I understand that at a summary level, Alectra used the 2022 to 2024 gross costs as the basis for the forecast in the '27 to 2031 period. Is that right?

D. FAIRCHILD: Just to make sure I am hearing you correctly, you want to know the period of the average that we used?

L. GLUCK: Yes.

D. FAIRCHILD: Yeah. '22 to '24, is that what you said?

L. GLUCK: Yes.

D. FAIRCHILD: Yes, that is correct.

L. GLUCK: Okay. And when I took an average of those years in this table, so '22 to '24, I get an annual spend -- gross spend of 13.2 million. So between 2022 and 2024. Would you take that subject to check?

D. FAIRCHILD: You said 13.4 million?

L. GLUCK: I said 13.2.

D. FAIRCHILD: Okay. Okay. Subject to check, yes.

L. GLUCK: Thanks.

And for the '27 to '31 period, I get an average annual growth spend of 22.8 million. So I am just wondering what the difference between those numbers are given that I had understood that you used an average of the historical target.

D. FAIRCHILD: So just to be clear, you are suggesting that from -- 13.2 million was the average from '22 to '24, and then it jumps to 22.8 million from '27 to 2031?

L. GLUCK: Yeah. The annual spend.

D. FAIRCHILD: For the unspecified, the buckets of projects, yes?

L. GLUCK: That is right.

D. FAIRCHILD: So with respect to this category, it really was a combination of both known projects and unknown projects. So there are certainly some known projects identified within the -- within the unspecified customer initiated expansions and relocation projects. And these buckets, they are used to predict -- to help forecast the future.

What we have seen particularly in the last couple of years based on the trend is that we are seeing a lot more system expansions occurring than historical. So we did factor that in as well. So in addition to the very large projects, known projects, there is a subset of anticipated increase for system expansion projects in the historic -- you know, compared to the historic buckets.

L. GLUCK: So just to make sure I understand that response, essentially it is you started with a baseline. You could look at it like '22 to '24 is a baseline. You used that average, and then you added what to it? What did you add as this "known unknown" category?

If you would like to undertake to provide the breakdown of the unspecified category between knowns that are in there versus just using the historical average, that would work for me as well.

D. FAIRCHILD: I can certainly -- I can certainly do that. I mean, looking at the customer initiated gross and net over that period of time, we are actually seeing a reduction in the net -- in the net spend for all categories combined from the known projects and the unspecified projects.

But I will accept to undertake to provide more details for the unspecified customers initiated expansion and relocation projects.

L. GLUCK: I appreciate that. Thank you.

R. DHILLON: Let's mark that as Undertaking JT-1.16.

UNDERTAKING JT-1.16: PROVIDE THE BREAKDOWN OF THE UNSPECIFIED CATEGORY ON 2-CCC-18, ATTACHMENT 1 BETWEEN KNOWNS THAT ARE INCLUDED VERSUS USING THE HISTORICAL AVERAGE

L. GLUCK: And I do have a question also about the percentage of contributed capital with respect to this same category of projects.

When I calculated the historical average contribution, it was 63.6 percent, and in the forecast period, it is fallen to 46.8 percent. And can you help me understand how the capital contribution forecasting the -- for the test period was determined?

D. FAIRCHILD: Sorry, you calculated 63 percent?

L. GLUCK: In the historical period?

D. FAIRCHILD: Yeah.

L. GLUCK: Yeah. And 46.8 in the forecast period.

D. FAIRCHILD: In the forecast.

The contributed -- the contributed capital is decreasing, and that has largely contributed to the -- some of the larger system expansion projects that we are doing, many of which are lowering the customers' contribution due to the revenue offset through the economic model for many of these large VLP projects over the forecast period.

L. GLUCK: This question, though, was related to the unspecified category.

D. FAIRCHILD: Oh, just unspecified?

L. GLUCK: Yeah, just unspecified. So I wouldn't have thought that there would be, like, these large known projects in that bucket of costs.

D. FAIRCHILD: Can we amend that undertaking to include that as well?

L. GLUCK: Yes. Absolutely, thank you.

Moving to 2-CCC-17, part B, please. And this is -- these questions are about the very large projects that are in the customer-initiated distribution expansion and relocation segment of the customer connection program.

And if we go to the response to part B, at the end of the response, it states that:

> "For subdivision-driven system expansions, it is assumed that there will be no customer

capital contribution."[as read]

And then in part C of the same response, it says that the projects that are predominantly residential will be entirely covered by a capital contribution. And I am just struggling a bit with what appears to be a contradiction in those two parts.

D. FAIRCHILD: You are correct. That is a contradiction. That is my fault, and I would like to correct it here today.

For those -- I will start with some -- a little bit of background.

Generally speaking, when a residential subdivision is constructed, there is a cost split between the utility and the developer. Again, generally, that would mean any external expansion outside of that subdivision, that portion of it would be a hundred percent contributed to the customer. Is that -- do you follow?

L. GLUCK: Maybe you could repeat that.

D. FAIRCHILD: Okay. So in our evidence, we state that for a typical residential subdivision, our contribution -- 58 percent contributed, you know, 42 percent Alectra. So, therefore, any additional expansion outside of the subdivision, if we need to bring a feeder or circuit to supply that subdivision, that cost would be a hundred percent borne by the developer.

That is -- that is generally -- that is

generally how the cost apportionment works through the economic model. The error in this response was to the reference to those four projects that you had cited that there was zero contribution. In fact, that is not correct.

We have ran the -- we have ran the economic model for those. Those particular projects are very, very large block projects. The load is quite large. And for them, when we run a preliminary economic model, we do, in fact, see that the revenues pay for the entire external expansion.

And so I can take an undertaking to give you that correction wording for both B and C, but that is essentially the error that was made. And it also -- on 18, CCC-18, very similar. The error was followed through on line 29, which, again, I would offer that we would take the undertaking to provide that correction.

L. GLUCK: Well, that is up to you. I am fine with your correction right now, so --

D. FAIRCHILD: Thank you.

L. GLUCK: -- that is okay.

But I am interested in the response a bit. So you started talking about the very large projects where you ran the economic modelling, and it shows that the revenues are sufficient to cover the cost.

And if we could just go to the table perhaps. So I just wanted to sort of use an example. If we

looked at -- I think it is at the bottom of the table. Maybe it is up -- the bottom of the next page. Yeah, okay.

So looking at the Angus Glen developments as an example, so there is no capital contribution associated with that project; is that right?

D. FAIRCHILD: That is correct.

L. GLUCK: And this is one of the examples you are giving of you ran the economic model, and the revenues are sufficient to cover the cost; is that right?

D. FAIRCHILD: Correct. For table 1, we ran a preliminary economic model for each of these projects to determine the cost share split.

L. GLUCK: Okay. Thank you.

And can you undertake to provide those, the initial economic analysis with respect to the projects that do not attract a capital contribution?

D. FAIRCHILD: So just so that we are clear for that project 152602 and then the last four. So we would undertake to provide a summary. I won't provide the full -- just because of confidentiality of the workings of the economic model -- provide a summary of the output of the economic model, if that is fine.

L. GLUCK: We agree on which projects --

D. FAIRCHILD: Yeah.

L. GLUCK: -- that we are looking for the

information, but we do want the whole model. We want to see what assumptions you made that led to the result that there would be no capital contribution.

D. COBAN: I think we can provide you a summary of the assumptions, but right now we are not prepared to file the model.

L. GLUCK: So you are refusing that part, but you will provide a summary?

D. COBAN: Yeah, and the summary will not just be a number. You will have some --

L. GLUCK: The assumptions?

D. COBAN: Correct.

L. GLUCK: Okay. Thank you.

R. DHILLON: Let's mark that as Undertaking JT-1.17.

UNDERTAKING JT-1.17: PROVIDE THE INITIAL ECONOMIC ANALYSIS WITH RESPECT TO THE PROJECTS THAT DO NOT ATTRACT A CAPITAL CONTRIBUTION

R. DHILLON: And, Mr. Gluck, we are hoping to take a break in the next ten minutes.

L. GLUCK: Sure.

R. DHILLON: Thank you.

L. GLUCK: I will ask one more question. Thanks.

M. RUBENSTEIN: Can I just ask, what is the basis of -- I am just not understanding -- the refusal to provide the model? Is it the model, or just -- just what is the...

D. COBAN: One, we think that having a summary view will just be of assistance to the panel and the parties in order to be able to analyze and understand the key takeaways from the model. We think that is just a more helpful view of the same information.

And, two, as you can appreciate, there is a lot of sensitivity in these models with respect to the customer data. And so, you know, we would be having to file everything confidentially, which would, you know, create additional administrative burden associated with seeking confidential treatment of that. So if the rolled-up view of the information can satisfy the request, we think that is an appropriate sort of level of disclosure that balances those things.

L. GLUCK: If we could go to 2-CCC-22, page 2, please.

Sorry. It is really page 3. I am looking at the table below.

So I have a few questions on the categorization of line capacity projects between enhancement and expansion, and this table shows for each line capacity project whether it has been categorized as an enhancement or an expansion. And can you please confirm that with the exception of two projects, all of the line capacity projects are categorized as enhancement projects?

T. WASIK: Yes, I can confirm that.

L. GLUCK: Thank you.

And I just want to use an example to understand how the company goes about categorizing the line capacity projects between those two types.

And if we could go to page 5, please. And if we look at Project 150716, which is a feeder extension for Williams Parkway to Heart Lake, do you see that?

T. WASIK: I do.

L. GLUCK: And this is an $8.9 million project that has been classified as an enhancement; and, therefore, there is no contributed capital; is that right?

T. WASIK: That is correct.

L. GLUCK: Thank you.

Now, if we go to page 10 of the response and we look at item 26, which is the rationale supporting that categorization, it says that, in part at least, the feeder expansion will provide capacity relief and will supply capacity to new developments in Heart Lake Road and Highway 410; is that right?

T. WASIK: That is what was provided in our response, yes.

L. GLUCK: Thank you.

So at least in part, it appears that this feeder extension is going to be providing a supply to a new development. And so what -- so my question is, so why would that project be categorized as an enhancement?

T. WASIK: So, Mr. Gluck, in categorizing line capacity projects as enhancements, we adhered to the distribution system code, which in section 3.3 does identify that a distributor shall continue to plan and build a distribution system for reasonable forecasted low growth. A distributor may perform enhancements for its distribution system for the purpose of improving system operation characteristics and for relieving system capacity constraints.

We believe under that definition, the explanation rationale for that particular project, which is addressing feeder 136M8, which has already reached its planning capacity in the previous five years, as a fact, is approaching closely to its thermal limits at this particular moment, requires to be addressed.

And in doing so, we are also looking at ensuring that there is sufficient amount of capacity for the general area growth in those particular areas. And so that is how that rationale lines up with our definition of an enhancement.

L. GLUCK: Is there a known development at Heart Lake Road and Highway 410?

T. WASIK: There isn't a specific development that this particular project is being proposed for. It is the general area that is being provided to relieve capacity in the general area, and that is why it is defined as an enhancement.

L. GLUCK: Do you have any applications for connections in that area?

T. WASIK: As I explained earlier to Mr. Rubenstein, we operate on an open-circuit configuration, and so there is constantly a reconfiguration of feeders to be able to accommodate that. I am not aware of that particular project being driven by a specific customer. It is identified as a general growth area.

L. GLUCK: And could you undertake to check if you have any applications in that area?

T. WASIK: For this particular feeder project?

L. GLUCK: Yeah, I am trying -- I am sort of narrowing the request that Mr. Rubenstein made earlier to a single project on the line capacity side to see if you could tie any -- if there are any applications or offers to connect or offers to connect being discussed in that region of Heart Lake Road and Highway 410 that is going to be served by this feeder extension.

D. COBAN: Mr. Gluck, maybe just to understand the relevance of your request, I think Mr. Wasik provided an explanation as to how the determination is made around this project being an enhancement and the rationale around that. So I am not sure that, in light of that explanation, it is really relevant for us to go and chase the additional information you are looking for.

L. GLUCK: I don't really want to debate the DSC or what the DSC says here. I think it would just be helpful information for us to know whether the company does categorize projects as enhancement that do or do not have applications or offers to connect related to them. It is a point of information that would support the company's position that this is an enhancement project.

D. COBAN: We will undertake to take that away and consider your request, and if we think it is appropriate, we will provide the information; if not, we will explain why.

L. GLUCK: Okay. Thank you.

R. DHILLON: Let's mark that as Undertaking JT-1.18.

UNDERTAKING JT-1.18: ADVISE WHETHER THE COMPANY CATEGORIZES PROJECTS AS ENHANCEMENT THAT DO OR DO NOT HAVE RELATED APPLICATIONS OR OFFERS TO CONNECT

L. GLUCK: We can take a break, if that works for you.

R. DHILLON: Okay. Thank you, Mr. Gluck.

The time now is 12:28. We will resume at 1:30.

--- Recess taken at 12:28 p.m.

--- Upon resuming at 1:31 p.m.

R. DHILLON: Good afternoon, everyone. We are ready to continue the technical conference. I will turn it over to Mr. Gluck.

L. GLUCK: Thank you.

If we could start with 2-CCC-26, please. And if we could go to page 2 of that document, sort of picking up where we left off but now with respect to the station capacity projects. And similar to my questions regarding the line capacity projects, I would like to use an example to understand Alectra's categorization of station capacity projects between expansions and enhancements.

So if we could go to the bottom of page 3, please. There is a project listed there as the Webb MS new substation, and this is a $3 million enhancement project that attracts no capital contributions; is that right?

T. WASIK: Sorry. Mr. Gluck, where are you referencing to the contributions?

L. GLUCK: It is not in this table, but my understanding is that there is no capital contributions associated with that?

T. WASIK: That is correct. Yes, I would agree with that.

L. GLUCK: Okay. Thank you.

If we could go to Exhibit 2A, tab 1, schedule 1, appendix Q at page 88, please. Page 88. Sorry. There it is. Thank you very much.

And here, with respect to the Webb MS substation project, at the bottom of this first summary section, it discusses that there are -- there is 45 MVA of new

projects in various stages of construction and energization, and a new station is required to connect these developments. Do you see that?

T. WASIK: I am with you, yes.

L. GLUCK: So can you explain to me why this project would be categorized as an enhancement as opposed to an expansion?

T. WASIK: So in a very similar manner as we talked about with the lines capacity project, when Alectra builds capacity for the general area and it provides a benefit with respect to service and operability and reliability for the general area, we would classify that as an enhancement.

And in this particular case, Webb MS is not only being proposed to be built to provide operational and reliable service to the downtown core area, but when doing so, we are also ensuring that it has sufficient capacity for the general growth in the downtown core as a result of intensification.

L. GLUCK: Thank you.

And do you have any -- would you be able to undertake to provide -- look and provide, if there are any, applications for service, offers to connect, or anything of that nature associated with the Webb MS project?

T. WASIK: So for certainty, we can take that away, confirm. But we can look at Webb MS and confirm whether or not there is any specific projects

associated to it.

L. GLUCK: Thank you.

R. DHILLON: Let's mark that as exhibit[sic] JT-1.19.

UNDERTAKING JT-1.19: PROVIDE ANY APPLICATIONS FOR SERVICE, OFFERS TO CONNECT, OR ANYTHING OF THAT NATURE ASSOCIATED WITH THE WEBB MS PROJECT

L. GLUCK: If we could go back to 2-CCC-26 at page 3, please. So a few of the projects listed on this page are land purchases, and there is in-service dates associated with those land purchases that are in advance of the station that will use that land.

And my question is, are these in-service dates provided here what is used for rate making purposes? Like, you will be entering into rate base land that there is no station on yet?

T. WASIK: Yes. But I would like to clarify, Mr. Gluck, that purchasing of the land and preparing the land for the station is part of the process in terms of building the station. So we -- from an accounting standpoint, upon the purchase of land, and then the work that needs to be done to prepare the land in order to build the station, including all the necessary studies and environmental assessments. There is value in terms of putting that asset into service.

L. GLUCK: Okay. So these land purchases do enter rate base when they are purchased?

T. WASIK: They are put into service upon the purchase and are used in value in preparing for construction of the station.

L. GLUCK: I am being very specific about the rate base part. So is that -- are you saying yes to that part, that they enter rate base --

T. WASIK: Yes.

L. GLUCK: Yes, okay.

T. WASIK: I am.

L. GLUCK: Thank you. Thank you very much.

If we can go to 2-CCC-24, please.

M. GARNER: Excuse me, Mr. Gluck. It is Mr. Garner. Can I just ask you a follow-up about that question?

When you said "rate base," are you saying it goes into rate base, or are you saying it goes into CWIP, as part of a CWIP calculation?

T. WASIK: I think that might be better question to ask to a subsequent panel. Maybe Panel 3, 4.

M. GARNER: Okay. That is fine. Thank you.

Sorry, Mr. Gluck.

L. GLUCK: No. Thank you.

So in CCC-24, we asked a few questions about the treatment of data centres that are connecting to Alectra's system during the upcoming IR term. And the first thing I would like to address is if we could go -- if we go down a bit, there is a table.

And under that table, there is a statement that the station's capacity project related to the data centres connections began in 2025, and the contribution was applied against '25 and '26 expenditures.

Can you first confirm that this means that there was a capital contribution paid related to the stations work?

D. FAIRCHILD: Subject to check, I will confirm we received a contribution.

L. GLUCK: Thank you.

And can you please undertake to expand the table to include the entire cost of the related station capacity project and the total contribution that was made?

D. FAIRCHILD: Total station cost, so total gross, total contribution, total net?

L. GLUCK: That is right. Just going back a few years.

D. FAIRCHILD: Yeah, we can do that.

L. GLUCK: Thank you.

R. DHILLON: We will mark that as Undertaking JT-1.20.

UNDERTAKING JT-1.20: EXPAND THE TABLE IN CCC-24 TO INCLUDE THE ENTIRE COST OF THE RELATED STATION CAPACITY PROJECT AND THE TOTAL CONTRIBUTION THAT WAS MADE

L. GLUCK: Thank you.

And can we go to the next page, please. And in this part of the response, it discusses that Alectra generally applies a 25-year revenue horizon for data centre projects, but it was reduced in one case due to the project-specific circumstances. Is that a fair summary?

D. FAIRCHILD: That is correct.

L. GLUCK: Thank you.

And I would like to avoid discussing any confidential information, if we can. If possible, could you discuss generally what the reason would be to reduce the revenue horizon and what would differentiate one data centre project from another at a general level?

D. FAIRCHILD: The standard revenue horizon apply of 25 years was not used in this case. We find ourselves with the transmitter for those portions as well. That has applied a 15-year revenue horizon, so we match that on the rest of the station portion.

L. GLUCK: Okay. Thanks.

So it is essentially Alectra aligning with Hydro One? Is that what you're...

D. FAIRCHILD: That is correct.

L. GLUCK: Okay. And with respect to the connection horizon for these data centre related projects, how long is that horizon that you apply?

D. FAIRCHILD: Table 2 indicates it is 25 years.

L. GLUCK: No, I am speaking to the connection

horizon now. So the revenue horizon, I see it is 25 years. There is a --

D. FAIRCHILD: My apologies. It is standard 5-year connection horizon.

L. GLUCK: Okay. Thank you.

And you are requiring an expansion deposit from the connecting data centres?

D. FAIRCHILD: Yes.

L. GLUCK: And if the data centres come online at a demand that was forecast at any point during the connection horizon, you refund that deposit? Is that right?

D. FAIRCHILD: Can you just repeat the question?

L. GLUCK: Sure. If the data centre comes online at the demand that was forecast, that you forecast when you were collecting the deposit, you give -- you refund that deposit to the customer. Is that right?

D. FAIRCHILD: I will try and say it in the way I understand it is an economic model would be ran from this. The customer would pay a capital contribution. The remaining balance would be held as a security deposit. If their full load materializes in the course of the connection horizon, then yes, we would return the security deposit on hand to the data centre.

L. GLUCK: Okay. Thank you.

And if the data centre ceases operation after it

has its deposit returned, but prior to the duration of the revenue horizon ending, essentially everyone else on the system will be responsible for covering the revenue shortfall. Is that right?

D. FAIRCHILD: That is a risk, and that is what would happen.

L. GLUCK: Thank you.

And does the company view data centres' load to be more or less risky than other non-residential connections?

D. FAIRCHILD: We treat the load from a data centre similar to other loads. So there is no specific provision for data centres in that regard.

L. GLUCK: And so I assume the answer to my next question is with the exception of the one project where you have matched Hydro One in a 15-year -- using a 15-year revenue horizon, the company has not considered shortening the revenue horizon as a standardized approach for all data centre connections?

D. FAIRCHILD: At this time, we have not.

L. GLUCK: Okay. Thank you.

R. DHILLON: Mr. Gluck, just a reminder that we have about 5 or 6 minutes left allotted to CCC.

L. GLUCK: I will take time from future panels to make up for it.

If we could go to 2-AMPCO-53 attachment 1, please. It is an Excel spreadsheet. And I apologize

that this might be a bit difficult to follow, but I did do some math, and I am going to ask you to take that math subject to check.

So there is a line item here titled "Cable Injection." And the cost -- the total cost of the cable injection and the number of kilometres are the units are set out in this table. And I calculated that the average annual increase in the unit cost for cable injection between '27 and '29 is about 12 percent. And that comes with a decrease of 4 percent between '27 and '28, and then a very large increase of 28 percent between 2028 and 2029. Would you take that subject to check?

R. BASSINDALE: Can you please repeat those numbers so we can just mark them down?

L. GLUCK: Absolutely. So between 2027 and 2028, I calculate a decrease of 4 percent on the unit cost. So what I did was I divided the total cost by the number of units to come up with the unit cost. And between those two years, I see a 4 percent reduction in unit cost.

And then going between '28 and '29, on the same basis, a unit cost calculation, there is a 28 percent increase. And on average, it is a 12 percent annual increase.

And my question is actually what is driving what seems to be a very significant annual change in cable injection unit cost?

R. BASSINDALE: Mr. Gluck, there is a variety of factors between the years in regards to the cable being injected. So, you know, one example could be the size of the cable being injected. Larger cables cost more on a per unit basis. It could also be the number of splices that they encountered when they were going to do the injection work. More splices equal more dollars. That gives a higher per unit average.

I can't, you know, provide more details than specifying that it depends on the exact segments being injected and how much work is involved to make that injection proceed.

L. GLUCK: Okay. So it is more to do -- repeating your answer back, but it is more to do with the type of project you are doing, like, the actual cable that needs to be injected in a given year, as opposed to the actual cost of the activity?

R. BASSINDALE: Yes. I would agree with that statement.

L. GLUCK: Okay. And in terms of -- Mr. Rubenstein talked to you about this a bit this morning, but in terms of -- just using cable injection as an example, for inflationary -- the inflationary adjustment that is applied, what inflation would have been applied to this program in total and for each of labour and materials?

H. IBRAHIM: Mr. Gluck, the project -- the

projects within the program would -- when the optimizer moves them, it would apply the same 2 percent which we have submitted in the S-E-C, or SEC, interrogatory.

L. GLUCK: And so the 2 percent is just a global number and it would apply -- it would capture labour inflation and materials inflation?

H. IBRAHIM: With the movement, yes. So if it shifts a project by, let's say, one year, it would shift it by -- it would add inflationary element of 2 percent to the components that can increase with inflation.

L. GLUCK: Okay. And there is no other adjustments in there for labour, for example? It doesn't use, you know, the company's expectations around compensation increases and the allocation of that compensation allocated to capital?

H. IBRAHIM: No other adjustments are included, no.

L. GLUCK: Okay. Thank you.

We could go to 2A-SEC-63, page 21, please. Thank you. And I think it is just down on this page a little bit. All right.

So there is a project here, the Hamilton South Mountain Feeders capacity relief project, and it looks like it had a cost overage of about $6 million. Do you see that?

H. IBRAHIM: Yes, I see it.

L. GLUCK: And do you have any change orders, project close-out reports, or other internal documentation related to this project?

M. WITTEMUND: Mr. Gluck, we will make best efforts to determine if that information is available. If it is, we can certainly produce it as a -- yes.

L. GLUCK: Thank you.

R. DHILLON: Let's mark that as Undertaking JT-1.21.

UNDERTAKING JT-1.21: PROVIDE ANY CHANGE ORDERS, PROJECT CLOSE-OUT REPORTS, OR OTHER INTERNAL DOCUMENTATION RELATED TO THE HAMILTON SOUTH MOUNTAIN FEEDERS CAPACITY RELIEF PROJECT AND THE EXTEND BUNTING M81 FEEDER PROJECT

L. GLUCK: On the next page, there is a project, the Extend Bunting M81 Feeder project. And same question on that one: Would it be possible to provide any change orders, project close-out reports, or other internal documentation related to this project?

M. WITTEMUND: Yes, we could -- we will add it to the undertaking before this and provide this information if it is available.

L. GLUCK: That is great. Thank you.

If we could go to 4-CCC-50, page 4, please. And I would like to discuss the system control operational budget briefly.

With respect to the system operator program, I understand that the company is seeking to increase the number of operators significantly over the IR term. Is that right?

J. BUTLER: Sorry, Mr. Gluck, I didn't hear the complete question. Can you please repeat?

L. GLUCK: Sure. With respect to the system operator program, I understand that the company is seeking to increase the number of operators significantly over the IR term. Is that correct?

J. BUTLER: That is correct. We are increasing -- we are proposing to increase the number of operators.

L. GLUCK: Thank you.

And if we go to the response in part F, here, it states that:

> "The system control resources needed are proportional to the volume of crews supported."[as read]

And when I read part E and F together, my understanding is that the 2027 to 2031 forecast is based on an extrapolation of the ratio of crews supported by each operator based on 2025 data. Is that right?

J. BUTLER: Yes, that is correct.

L. GLUCK: Thank you.

So if we can please go to Exhibit 4, tab 2, schedule 9, page 9, please. Thank you.

And this table allows you to calculate the ratio of operators to crews supported. And when I look at 2025, the ratio is 1.8 crews supported for each operator. Would you take that subject to check?

J. BUTLER: Yes, I will take that subject to check.

L. GLUCK: And then in 2027, I see that the ratio falls to 1.6. Would you take that subject to check?

J. BUTLER: Yes.

L. GLUCK: So can you help me understand how you -- the methodology used to determine the resources required in the IR term?

J. BUTLER: So if I heard the numbers correctly, the ratio was 1.8 the one year and drops to 1.6?

L. GLUCK: That is right, yeah.

J. BUTLER: Yeah, the -- the -- yeah, the system control is a little bit of a unique area. It is a 7 -- run 7 by 24, 365 days a year, so we need a complete staffing for 24-hour coverage, and the crews generally work 8- or sometimes 10-hour days, Monday through Friday. So the extrapolation was really for the daytime periods and how many operators we would need per day, and it was actually done -- we have essentially five different rate zones we support through the operating room.

So we use that as the basis of the daytime volumes for the extrapolation, but to support those

daytime numbers, you have to be able to fill out a complete schedule, per se, and how many people it takes to run a 24-hour schedule with coverage and all that type of thing. So it is -- it is not 100 percent linear. It is very proportional. But there can be some minor nuance differences just because of the uniqueness of filling out a 7-by-24 shift.

L. GLUCK: Thank you.

So do you have a -- I don't know -- a spreadsheet or a calculation that shows the more granular approach that I think you have just described to me? That -- like, I did it, obviously, in a simple way with the evidence that was here, but it sounds to me that there is sort of a day shift calculation, a night shift calculation, and that led to a requirement to decrease that ratio, essentially that an operator is supporting less crews in the IR term relative to the historic period?

J. BUTLER: Mr. Gluck, at best efforts, I will put together or try and summarize in an intelligible way what a shift schedule would look like across the various rate zones for -- across the various years. It's a lot of data, complicated to convey, but I will make best efforts to have a -- provide you the information you are requesting.

L. GLUCK: I appreciate that. Thank you.

R. DHILLON: I will mark that as Undertaking JT-1.22.

UNDERTAKING JT-1.22: PROVIDE A SPREADSHEET OR CALCULATION THAT SHOWS THE GRANULAR APPROACH TAKEN IN REGARDS TO SHIFT SCHEDULES ACROSS VARIOUS RATE ZONES FOR VARIOUS YEARS

L. GLUCK: Thank you.

I have only one more question.

If we could go to 4-CCC-53, please, and this is at page 10 of that undertaking or interrogatory response. And we asked about the historical use of the dedicated locater program and whether the forecast reflects the cost savings from that program, and I just want to make sure that I understand the response.

The response below the table I take to mean that there is no forecast of the cost savings from the dedicated locater program included in the custom IR term forecast; is that fair?

M. WITTEMUND: That is correct.

L. GLUCK: Thank you.

And do you have available a high-level estimate of the savings that would have resulted from the historical experience with the dedicated locater program?

M. WITTEMUND: That is something we would not have, no.

L. GLUCK: And can you explain why?

M. WITTEMUND: We don't -- actually don't track that information to that level where we would have

details as to the savings where locates would have been involved from a dedicated locater perspective.

L. GLUCK: Thank you.

And just to make sure that I understand the program at a more general level, in table 7, each one of those, it doesn't represent a single locate; it represents a project that they've decided to sign up for this program, and they have their own locater. So there is many locates, individual locates, that underpin, you know, a single number in table 7, a single -- single dedicated locater project; is that fair?

M. WITTEMUND: Yes. So in table 7, we -- we list out the number of projects that are related to the dedicated locater program. Whether or not how many locates are contributed to each of those dedicated locaters or whether or not they would even have locates for those projects if they didn't materialize, those are the dedicated locaters that have signed up in those various years.

L. GLUCK: Okay. Thank you. Those are my questions.

M. WITTEMUND: Thank you.

R. DHILLON: Thank you, Mr. Gluck.

The time is now 2:06. I will turn it over to Mr. Garner for Vulnerable Energy Consumers Coalition.

M. GARNER: Or it is easier just to say "VECC." Thank you.

I think Mr. Harper, who is online, is going to start, if he is actually online.

B. HARPER: Yes, I am, Mark.

M. GARNER: Thank you.

CROSS-EXAMINATION BY B. HARPER

B. HARPER: Thank you. Good afternoon, Panel.

Can we turn to Exhibit 2A, tab 1, schedule 1, ESP appendix J, page 46. It is PDF page 81.

R. BASSINDALE: Was that page 46 or 86?

B. HARPER: It was page 46. I am sorry. There should be a figure 24 on the page. And I believe that is it.

Now, as I understand, as part of your capacity planning process, you develop zone peak forecast as set out in figure 24 here; is that correct?

T. WASIK: I am sorry, Mr. Harper. Can you repeat that? I am having a hard time following -- there's -- your audio.

B. HARPER: I am sorry. As I understand, as part of your capacity planning process, you develop zone peak forecasts, and those are what are set out here in figure 24?

T. WASIK: If I -- I think, if I heard you correctly, figure 24 presents the non-coincidental winter system peak demand inclusive of CDM electric vehicles, decarbonization, and retrofit under a medium scenario for 1 and 2 weather, and the -- it provides both the aggregated peak load per region and

then the total on the right axis.

B. HARPER: Right.

And would I be correct that it's population, housing, and employment that are the key economic drivers that you use in developing these forecasts?

T. WASIK: That is correct. Those are the -- population, housing, and employment are considered in development of the system peak demand forecast.

B. HARPER: Okay.

Can we turn to Exhibit 2A, tab 1, schedule 1, page 91. So I'd be -- would I be correct in saying that if I look at this table, that those economic drivers account for about a third of your non-coincident peak load increase between '24 and -- between 2024 and 2031?

T. WASIK: That would be correct, Mr. Harper.

B. HARPER: And I notice on the same table that transportation and electrification account for roughly another -- a little over one-third of the increase as well?

T. WASIK: That would be -- if you are referring to from 2025 to 2031, that is correct.

B. HARPER: Right. And that's the 524.

And are you able to break that 524 down between transportation and electrification and show -- and give me the two numbers separately?

T. WASIK: So, Mr. Harper, during this particular period of 2025 to 2031, it is all electric

vehicle transportation that are being considered under the peak demand and none of the electrification of heating.

B. HARPER: So there is no heating electrification included in this forecast at all?

T. WASIK: That is correct. It might be simple if I just tell you that the -- there is no capital investments identified in this distribution system plan stemming from electric heating as a driver.

B. HARPER: Okay. Fine.

Now, with respect to the 524, have you made any assessment yet of what the impact of the Government of Canada's new EV strategy is, which anticipates only a 75 percent penetration of EV vehicles by 2035 as opposed to the hundred percent that was in its earlier EV -- EV -- EV availability standard targets? I am sorry.

T. WASIK: So, Mr. Harper, I would take your attention to our response to 2-Staff-137.

B. HARPER: Okay.

T. WASIK: In that response, we identified that we acknowledge the most recent announcements by the Government of Canada to repeal the ZEV mandate sales and replace it with a more stringent emission standard. This particular point, we have also taken into account that the government has also launched an EVAP incentive program. It also introduced a $1.5 billion worth of funding for EV charging networks as

well as increased customer choice for lower-priced EVs through partnerships with imports from China and Republic of Korea.

And on balance, we recognize that it is, at this particular point, too soon for us to evaluate what the full impacts of these particular changes will be, and as such, we believe that the current EV projection forecast that is included in our distribution system plan is still prudent and appropriate.

B. HARPER: Okay. We will leave it at that. Thank you.

Can we turn to Exhibit 2A, appendix 2AA.

Now, would I be correct that those zone peak demand forecasts we were just looking at are a primary driver for the forecast spending for capacity lines and capacity stations component of system service?

T. WASIK: In general terms, yes, but there are also other drivers, including operational efficiency, grid flexibility, and other backup and capacity-related functions. But capacity is a primary driver, yes.

B. HARPER: Are there any other spending categories here where the peak demand forecasts are a primary driver, or was it really just those two?

T. WASIK: Mr. Harper, can you perhaps help me understand which specific investment line you're

referring to?

B. HARPER: Well, I was looking at all of the investment lines you have here in terms of the -- under system access and system renewal and trying to understand if apart from the two we've just discussed, whether there are any other ones where the peak demand forecast is a primary driver in determining the amount of spending you have to make in the future.

T. WASIK: Well, Mr. Harper, the peak demand forecast does inform investments across the entire distribution system. So it is not that straightforward as to just identify a one-to-one relationship. The organization reviews the system peak demand increases and, obviously, makes the necessary adjustments to what else is required with respect to building out the system to meet that. So it is not just a one-to-one relationship between the load forecast and one line item.

B. HARPER: But I would assume something like maybe network metering wouldn't be driven that much by your peak demand forecast?

T. WASIK: So in that particular example, if there is a projected growth increase anticipated across the planning period, metering group would be informed about those particular growths and take into consideration inclusion of budgeting for additional metering for the customers anticipated.

B. HARPER: Okay. So --

T. WASIK: That's just one example. There could be many like that where the necessary budgeting is informed by the overall growth in the organization.

B. HARPER: Okay.

Can we turn now to Exhibit 2A, tab 1, schedule 1, appendix B10, and that will be at page 402. And scroll down to table -- that is right, B10-6.

And I believe you were talking to Mr. Gluck this morning about the fact that for some of these categories, you use a growth factor to forecast the number of connections in the future, and I was wondering if you could tell me for which categories you would be using a growth factor?

D. FAIRCHILD: Specifically, subdivisions included a very modest 1 percent growth factor. On the residential units, we had provided a separate forecast for the condo connections, so that had one growth factor. The others were very much both ICI and the layouts category, which is -- they are listed -- had a component of electric vehicle, electrification. And, yeah, I think that covers it.

B. HARPER: And what was the basis for your 1 percent? Like, I was wondering whether it was linked at all to the population or the household forecast that you had used -- that we had -- that we used in the peak demand forecast?

D. FAIRCHILD: Yeah, the -- so the residential

subdivision forecast looked at the historical units, and I believe, subject to check, that number came out to 2,889. Let me just check that before we guess here. Pardon me. One second. Just almost there.

B. HARPER: Sure.

D. FAIRCHILD: Yeah. So the residential -- for residential, we looked at historicals, and we used a 2022 to 2024 period for the average number of residential units. And from there, we added simply a 1 percent escalator year over year. You know, felt that was a very conservative number.

Where we saw growth in that category was really on the condo side, which we have already articulated.

So it was really just to account for somewhat of an unknown, you know, all signaling to support the -- you know, the province's and municipality's mandate to address housing in the province.

B. HARPER: Right. Okay. Fine. So it wasn't -- the 1 percent wasn't linked at all to the population or the household forecast that you were using as the basis for your peak demand forecast, then?

D. FAIRCHILD: It was not linked.

B. HARPER: Okay. Fine. Thank you.

Looking at that table, you don't have to turn it up, but VECC-11C, in response to that, you indicated that all the connections reported under new subdivisions and condominiums were really new

customers. But when it came to the ICIs and the layouts -- maybe we could just stay back. Okay. If you want to go there, you can look at the response, but I was hoping we could cut this shorter.

But for the residential and commercial layouts of the ICIs, they included both new customers plus upgrades. But in general, when I was looking at the numbers here, would it be fair to say that the number of new customer connections that you are forecasting in each year is something in excess of 6,000? It would be a portion of the layouts and ICIs plus all of the condos and the subdivisions numbers. So it would be fair to say it is more than 6,000 per year?

D. FAIRCHILD: So the number of new -- in this table, table 10-6, the number of new subdivision lots is just that, the -- would be individual, you know, lots --

B. HARPER: Right --

D. FAIRCHILD: -- which would count as one customer.

B. HARPER: Right.

D. FAIRCHILD: And then in addition to that, yes, condo development buildings while it, for example, in 2031 indicates 34, we haven't attempted to say how many units are in any particular condo. It could be 500. It could be 1,000.

Likewise, in the -- in ICI, that could be a separate connection that possibly could have

residential-type living in there. But I think it is important to make a distinction, in a condo, it is classified as a GS greater than 50 customer and --

B. HARPER: I wasn't trying to get at specifically residential. I mean in terms of total number of connections that you are forecasting each year, residential, general service, industrial, the number of new connections, like new connections that are being made, looking at this, would probably be in excess of 6,000 each year. It is going to be all the first line, all the second line --

D. FAIRCHILD: Yes.

B. HARPER: -- plus a portion of the third and fourth lines.

D. FAIRCHILD: Right.

B. HARPER: That would seem to me to be -- probably be in excess of 6,000. I am just asking if that was a reasonable assumption to make, looking at these numbers.

D. FAIRCHILD: I agree with you, yes.

B. HARPER: Okay. Fine. That is really all I was asking about.

When you are talking about connections here, like in subdivisions, is that just individual residential lots, or does that include things like the streetlights as well?

D. FAIRCHILD: No. That is just the individual lots.

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

Can we turn to VECC-12B. Here, we asked you to provide additional information on the very large projects identified in appendix B10, table B10-3. And in terms of existing customer projects, which I believe are identified in this table, you -- can you confirm that there are six existing very large customer projects that are adding additional large load to the system during the 2027 to '31 period?

And I believe those are 151584, 152482, 152602, 152676, 153088, and 153090.

Would that be a reasonable interpretation from this table?

D. FAIRCHILD: That is reasonable. I would like to maybe just point out -- let's see the project, sorry. Project 153088, it is marked as an existing customer, but those are two new facilities being constructed, just to be clear.

B. HARPER: Okay. Okay. So it sounds like it is maybe five instead of six --

D. FAIRCHILD: I agree.

B. HARPER: -- projects there that are new customers -- that are existing customers. So that -- that are existing customers, then.

And in each of -- each of these would be a separate customer. It is not like two projects are related to the same customer; each project would be a separate specific customer?

D. FAIRCHILD: If we can use that one as an example, they are an existing customer that already have four data centres on separate parcels, and they are creating two more data centres on two other separate parcels. So from a customer perspective, they are one customer, but, you know, they are six, I guess, metered points, if that provides clarification you need.

B. HARPER: Well, I guess maybe it is a matter of when you say "customer," is it an account, or do you mean a customer from the perspective in terms of they are each billed -- they are two new customers each billed separately?

D. FAIRCHILD: Yeah, those will be new separate metered accounts. But I would have to look at each one of these individually. For example, you know, GTAA, they are an existing customer, but we could be, you know, bringing in new metered points into, you know, their locations. So it is really, I think, site dependent.

B. HARPER: Right. So you really can't draw a sort of straight line between each of these projects and say this is a new customer being added to the system?

D. FAIRCHILD: I guess if you are looking for a definition, is there going to be a new meter account put on to each one of these, I would say -- I would want to actually just take that back and confirm for

you.

B. HARPER: Is that something you would be willing to do both for the existing and the new customers on this? I am just trying to understand how many new metered accounts this gives rise to. I was assuming the existing ones wouldn't be a new metered account, but the new ones which are listed towards the bottom of the table would be.

So are you willing to take that back and -- maybe I should have asked for this if I didn't understand -- how many new metered accounts this gives rise to.

D. FAIRCHILD: Yeah, the -- part of the -- you know, can we discuss, for example -- let me pick a project here. The very last project, 153236.

B. HARPER: Right.

D. FAIRCHILD: So it is indicating as a new customer.

B. HARPER: Yeah.

D. FAIRCHILD: But the amount of metered points off of there could be thousands. It is going to be a large-scale subdivision over the course of build out to 2036 or even beyond. So, I mean, we can attempt to do that, but I am just wondering the relevance.

B. HARPER: So when you are saying "large load," these -- I guess maybe it is a matter of understanding what the table is showing. It isn't necessarily a large load associated with one

customer. It is a project that is going to give rise to a large load, which could be a subdivision, it could be an individual customer, it could be a mix of either of those two. Is that a better way of interpreting this table?

D. FAIRCHILD: That is correct.

B. HARPER: Okay.

D. FAIRCHILD: It -- I mean, it is -- yeah.

B. HARPER: I think that may be -- okay.

And maybe on my last question, then, if we could turn to Exhibit 2A, tab 1, schedule 1. This is the DSP appendix J again. And go back to page 43. Right. Here it is.

Here, you were talking about the decarbonization assumptions you made for the various scenarios. And in this table -- and I believe the forecast we were talking about earlier was the medium scenario. That is the one that was sort of your expected case, if I believe? The one you were focusing on for the planning forecast?

T. WASIK: That is correct.

B. HARPER: Because I was having trouble because earlier, you talked about how the transportation electrification didn't include any rolling electrification. But if I look at the medium scenario here, it talks specifically about assumptions about electrification of both new ICI buildings and retrofit of the existing ICI building.

So I was wondering if you could reconcile the assumptions in this scenario here with the comment you just made earlier about how the forecast didn't include any electrification.

T. WASIK: So, Mr. Harper, electrical heating for decarbonization is a winter peaking activity. And so as a result, Alectra's distribution system has sufficient amount of winter peak capability, and so any increase in electric heating decarbonization peak demand is within our system's capacity and doesn't require any enhancement.

B. HARPER: Right. I believe -- we don't have to go back to it, but I believe the earlier tables we were looking at at appendix J, there were also tables in there for the wintertime as well as the summertime, if my memory serves me correct. Right?

T. WASIK: That is correct. And --

B. HARPER: So the winter ones is where you would see this -- the sort of the new building electrification due to decarbonization showing up. Would that be correct?

T. WASIK: That is correct. The impacts of electrical heating for decarbonization would only be applicable to the winter peak.

B. HARPER: Right. Okay. Fine. Thank you anyway. Those are all my questions. I will turn it back to Mr. Garner now.

CROSS-EXAMINATION BY M. GARNER

M. GARNER: Thank you, Mr. Harper.

Good afternoon, Panel. Can I take you to 1-VECC-3. And that is the custom performance scorecard. And in this question, I asked -- I asked a question, and I shouldn't have because you pointed something out by pointing me somewhere else, but it had actually answered it in the graph, I just noticed. And that was I asked you why there wasn't a performance metric for failed equipment, and there is.

But what you did when you answered that question, you pointed out there was, but you pointed me to the performance -- DSP performance measures which are at Exhibit 2A, tab 1, schedule 1.

And so my first question -- that got me confused. My first question was what are these two metric tables -- are they the same? Because I started examining them, and they are partially or somewhat the same. In some places, they seem to be the same, but just describing things differently. Are these tables the same, or are they different things?

R. BASSINDALE: They are the same metrics.

M. GARNER: They are identical, you're saying. So I can read one, and I can replace it for the other. They are just slightly -- described slightly differently? Is that what is happening?

Because, for instance, it is like one has

something about assets. I think the first one talks about infrastructure asset renewal. And then I take it if I go to the other one, there is a bunch of infrastructure renewal, and that is where I replace that same -- I get more detail in that one. Is that what is happening?

R. BASSINDALE: Yes, Mr. Garner, I believe there is more detail in the DSP reference.

M. GARNER: Okay. Now, the other difference is the -- there seems to be targets in the one that is in the DSP. They have so many meters installed. Are they the same in that way? They are both -- they both either have targets or don't have targets?

R. BASSINDALE: Sorry, can you clarify what you mean by "don't have targets"?

M. GARNER: Well, so the -- when I looked at Exhibit 2, it wasn't clear to me -- sorry, in the Exhibit 2A, it wasn't clear this one had targets, but there are specific targets in the other one. So they both have the same targets. They are identical in that way too. They are not in any way different in what you are targeting for each one.

There isn't a target line in the other one, so I am just assuming that I can take this target line and it is fine.

So why I am saying that is, for instance, if -- I don't know if they all have the same number of things -- I haven't gone through them in detail.

There is one -- they all have -- this one does have poles, the other one has poles. I haven't done a cross check to make sure they are all the same. But you are telling me if there are targets in them, they are all the same?

R. BASSINDALE: Subject to check, they should be identical.

M. GARNER: Okay. Fair enough.

Now, earlier, Mr. Rubenstein, when he started his examination, he brought you to 2-Staff-140, and then there was a talk about the fact that loss of supply is not in -- is in the SAIDI target, the SAIDI number here but not MEDs, not major event days. Is that the same for both of these too?

If I go to the other one, is that also what I am looking at? Because this one. I am not sure I -- this one just says SAIDI excluding MEDs, it doesn't say excluding loss of supply. This one -- if I read it -- I might have it the wrong way, right.

This one says including MEDs in the DSP, and yet you have excluding MEDs in the one in the performance card. But it wasn't clear to me that the SAIDI in here is also -- was loss of supply in the DSP one.

R. BASSINDALE: It is the same in both. It is SAIDI without MEDs but with loss of supply.

M. GARNER: They are both without loss of supply.

R. BASSINDALE: Sorry, they are both with, with

loss of supply and without MEDs --

M. GARNER: Sorry, they are both excluding MEDs with loss of supply?

R. BASSINDALE: Yes.

M. GARNER: Sorry. Pardon me.

R. BASSINDALE: We provide more clarification on that in 5.2.3.

M. GARNER: Right. And I did look at that and I'm still a little -- I know you said you explained this, but maybe you can help me more. I still don't really understand that.

As Mr. Rubenstein went through this, and as I look at the other stuff, you include major event days, but you can do capital projects that harden your system, I think is the nomenclature, right? But you exclude MEDs -- I keep getting it reversed, pardon me -- and you include the loss of supply which, as I heard this morning, your capital program can't do anything about. I just don't understand that.

Why is the one that you actually conceivably -- and, you know, major event days is an issue. But conceivably, you can do something about major events days in the sense of investment.

R. BASSINDALE: I believe, Mr. Garner, you are mischaracterizing the reference. We had stipulated it wasn't the primary driver for any of the investments, but there are a number of investments we

have that by building out the system to increase feeder ties, if a station were to go down because of Hydro One, we could try to transfer that load off to another station. That wouldn't be possible without those investments.

M. GARNER: Okay. Maybe I heard you wrong this morning. So you are saying there are investments you can make that will reduce your loss of supply outages?

R. BASSINDALE: So the statement I made is within this plan that we have. There are investment -- there are no investments where the primary driver is a reduction in loss of supply, but there are some investments that will have an ancillary benefit of assisting us should a loss of supply event occur.

M. GARNER: Yeah, that would be an outage for a customer. It still would be due to -- then they wouldn't be out due to loss of supply, right, because they would still be on? It wouldn't be a loss of supply outage anymore?

J. BUTLER: The -- yeah, just to maybe help clarity, we do not have any investments in the DSP that are targeted at reducing or eliminating a loss of supply event. A lot of our investments aren't targeted at -- when an event occurs, we have a quicker restoration, therefore, limiting the overall impact.

And those investments, distribution automation

being a great example of one, they are used to help restoration upon occurrence of any event, whether it's a failed piece of equipment, it is a tree contact, it is a loss of supply.

So in that manner, we can reduce the impact of lost supply, but we can't eliminate the occurrence.

M. GARNER: I see what you mean.

And where I am going with this is for a MED or a major event day, you must have investments for that because you put in a whole bunch of evidence from Hatch study on climate change, et cetera, which really goes to how you can make investments to -- again, I will use the term -- harden the system up.

So why aren't you measuring that? I mean, you've provided a lot of evidence on the issue about, you know, the changing weather climate and reliability, and that is what MEDs really gets to is that major event days are generally big climate-type event days, not always. But, like, the derecho, if that is how you pronounce it, that created a major event day?

J. BUTLER: So, yes, we are -- we are working to harden the system, improve reliability, and improve resiliency. And we -- we -- we aim to not have MED days and lower the impact of it, and our customer consultation, those were two important factors is to reduce the impact of adverse weather and reduce the duration of outages when those occur.

So that is -- you know, that is a primary -- or is a very important thing for Alectra, so we are working hard on that, and we have lots of evidence, as --

M. GARNER: Well, I am sure you are, and I don't want to interrupt, but I am just still scratching my head by the metric includes -- excludes one thing you can impact and includes one thing you can't impact.

J. BUTLER: Yeah, yeah. No, no. Sorry. I'll --

M. GARNER: Again, that seems -- you know, that is what I am trying to resolve.

J. BUTLER: Yeah, no. I will get to that right now. Thank you.

What you find is the impact of MEDs are so great, and we take the derecho, for example. When you put it in there and you include that in your analysis for your reliability outcomes and looking for patterns and looking for root causes and what is driving all your things and looking for the areas to target to get the overall improvement, when you take the results that include the MED days that really biases the analysis, and it does not prove useful analysis when you prove the MED days there because it just -- it overwhelms everything else, and you don't get the level of granularity to really know what is driving your system for things that you have better control over.

M. GARNER: Did you --

J. BUTLER: For example, again, I think it is table 6, AMPCO-54, and we don't have to look at it. When you look, year over year, 42, 44 percent of our customer hours of interruption are due to failed equipment, and the vast majority of that is due to underground cables and cable accessories. And when you look at that analysis removing the MEDs, that pattern comes out loud and clear that the biggest driver that we have to improve reliability is investment in the underground.

If you left all the MED data in there, those patterns wouldn't come out, and it wouldn't be as obvious that that is the one lever that we have -- that is the best lever we have to really improve -- or one of the major ones we have -- to improve overall customer reliability and customer experience. You know, it would be flooded with adverse weather, so we would be looking at, you know, tree-trimming or cutbacks.

And -- so really, it gives us a better analysis to do a more prudent and effective investment program if we remove the MED data out of the analysis.

M. GARNER: Okay. So -- and pardon my ignorance if there is something for this. Is -- you did put in in this application this Hatch study and other stuff. Is -- is there a place I go to in the evidence that says or shows me the capital programs that are

addressing that issue about severe weather, MED or not, but that type of thing?

Is -- do you have a whole -- do you have a list of programs that say, these are the programs that are going to address that, and this is how we are going to measure whether that program is a success by whatever metric? Do you have -- do you have something like that in your -- in your application?

I just don't want to miss it. I just am looking for, like, here is a set of projects, and we are going to measure this, and this is what is going to happen after it.

H. IBRAHIM: Mr. Garner, if I can point you to 2-AMPCO-15 --

M. GARNER: Okay.

H. IBRAHIM: -- where we have responded to the expenditure driven by the Hatch study.

M. GARNER: And do you have a metric for those, like, for success with those expenditures, a way to measure whether you are achieving whatever it is you want to achieve?

R. BASSINDALE: So the overall impact would be on reliability, and so that would be on the -- both the SAIDI and the failed equipment CHI.

M. GARNER: Would that be able to be traced back to the projects, then, as a trace to whether that project achieved it or not achieved success? I mean, you can have a general result. I mean, you could

have all the investments in one part of your franchise and all the event in the other one, and the two don't actually come together; right?

R. BASSINDALE: It is too much of a hypothetical to consider whether or not an outage would have occurred in the absence of having made the investment.

M. GARNER: Okay. Fair enough. So the answer would be, no, you don't have what I'm looking for. I am not saying you should have it or shouldn't. I just wanted to know if you had it, and that's fine.

I want to be quick because I don't have much time. And I wanted to just, again -- there are a couple of things, but one of the things I wanted to go to was 2-VECC-15. It goes to 9-Staff-72, which is a DVA thing, but it is really about the -- I think it is called the YRRT overruns or variances in the -- in that project. And there is a table in there. Yeah, I think the table may be -- you know, I don't have -- the table may be in the Staff -- 9-Staff-272, or it may be in here. It is a table that shows the contributions, the approved actuals for that project.

And we asked, like -- we couldn't figure out what -- where the variance came from, and what you said was, well, it came from -- it is explained in 9-Staff-272, and so that is where I went to. Now, that is the table.

And if you read the -- read the narrative below

-- which, by the way, thank you -- it talks about this, and let me just sum it up this way: It sort of says there is two reasons for the overrun; one is beyond our control. The City and other people made changes, and we had to make changes, and one is a little bit about -- is we made some changes because we decided, you know, on the ground we couldn't do certain things or we made scope changes.

And what I am wondering, when you look at these variances, and they are fairly considerable in this project, is there any way to ascertain the difference between those two reasons, the reasons where the changes and the overruns were due to you making a change in scope, you know, for whatever reason, or where the municipality was calling on you to make a change in scope -- caused you to make a change in scope? Is there any way to pull that apart in those -- that table?

D. FAIRCHILD: You are really testing my memory on this one. It is many years ago.

M. GARNER: It looked like I caused a lot of problems there. I'm sorry. I wasn't meaning to.

D. FAIRCHILD: The -- my recollection of the largest change on this project was a joint decision driven by doing -- making a large stretch along Yonge Street underground, and it was caused by a couple factors.

So there was -- there was infrastructure issues

in the way. There was sections where we definitely needed to go underground. And case in point, there was a section that a future building site was going to be built too close to the proposed overhead solution that forced an underground, and there was enough of those along that stretch where the feeder would have been overhead, gone down underground --

M. GARNER: So you just --

D. FAIRCHILD: -- back up overhead, so the decision was made ultimately to go underground. And that was a large --

M. GARNER: That's probably the large --

D. FAIRCHILD: That was a big one.

There was another large one on highway -- crossing the 400 by Highway 7 that's just -- you know, it was MTO lands, and we were just -- where we wanted to locate, we couldn't, and it was just -- it drove up costs because of larger span lengths required.

M. GARNER: And that was a change from the original -- you didn't know that MTO wouldn't --

D. FAIRCHILD: Wouldn't have known, yeah.

M. GARNER: -- let you -- yeah, okay. That is fine. Thank you. That is very helpful actually. Thank you.

Two next ones are very quick.

This morning, Mr. Rubenstein was talking about the table I was interested -- two tables, actually,

we are talking about today I was interested in, and they were 2A-SEC-47, and this is unit cost, and then 2-AMPCO-53, attachment 1 or whatever. It is a table.

And what I would -- first of all, my first question was -- was, could one -- is one deriving these unit costs -- I mean, these are ranges in 2-SEC-47 and in 2-AMPCO-53. It is a table with really individual year-by-year stuff.

Is the data that you are getting your ranges from derived from 2-AMPCO-53? That is the question. And if it is, then I probably don't need to go any farther than that. I am just trying to figure out how these ranges were being made.

So fleet investments, like, I could understand a $13,000 trailer, but I couldn't even figure for a bucket truck it was $1.1 million unless it was, in my term, gold-plated. So I -- you know, but then I saw AMPCO-53, and I saw, oh, there is another line in there. Maybe if I look at that, that is how that average was built up.

So my question is can I use 2-AMPCO-53 attachment 2 in a way to derive those unit cost ranges that are shown in 2-SEC-47? I am not asking you to derive them. I am just wondering if that is a way to do it. Because there is unit cost per year, and then I -- you know, I could make averages and create a system to do that.

R. BASSINDALE: So in 2-AMPCO-53, Mr. Garner,

for example, if we take poles which has been placed together, that would be the entire pole renewal program and then the number of units completed under that. So specifically when you look at individual projects under that, there will be details around pole class and height. That information is then used to derive the unit costing, which is why you see that wide variety of range that was mentioned earlier.

M. GARNER: I am not sure that answers what I was asking, though.

What I was asking -- let's say -- let's stick with poles because it might be a good one, let's say concrete poles. You will see BO-01, concrete poles. You are at -- you have a range of 18,000 to 40,000. And then you have in AMPCO-53, line 7, concrete poles, although it doesn't look like there is a number there. It looks like the wood poles and the concrete poles are commingled, so it may not be a good example. So I would have to commingle these two numbers; is that how I would do it? Would I then get the same average or roughly the same average?

R. BASSINDALE: So, again, maybe we are just missing each other.

So if we look at 2019, for example --

M. GARNER: Right.

R. BASSINDALE: -- there is 11.5 million. That is made up of a bunch of discreet, like, work orders or projects, you know, whatever terminology you would

like to use. When you look into those specifics and you see what height and class of pole is being selected, that helped inform the unit costing that is provided in the other response.

M. GARNER: Okay.

Can I ask you this question maybe because I am being -- I am confused: If I took AMPCO-53 and 2019 and divided 588 by 11.5 million, I wouldn't be getting the combined concrete wood pole average; I would be getting something else like a project average for doing something?

R. BASSINDALE: Correct. You would be getting the project average.

M. GARNER: Whereas I look at the other table, I am actually getting -- what? Am I getting the same or I am getting a pole -- a wood pole average in asset renewal, but I am also getting -- sorry. What I am getting there? What am I shown in that table then, as an average?

So if I go to 2-SEC-47, I look at wood poles, it is 12,000 to 34,000, and then I took how many poles you have --

R. BASSINDALE: So, again, I have established that that is a range based on the pole height and the pole class. So smaller pole, lower class, lower cost; larger pole, higher class, higher cost.

M. GARNER: Okay.

R. BASSINDALE: Also some configuration in

framing. Single circuit two circuit. That plays a part in terms of the cost for installing the asset.

M. GARNER: Okay. Then how did you do table 2A 47, then? Let's just forget about AMPCO, the other one. Let's take vehicles because it is fairly easy.

So vehicles were 13,000 to 1.1 million. The way I read that is the cheapest vehicle is 13,000 and the most expensive is 1.1 million.

R. BASSINDALE: So, unfortunately, I would have to default that to Panel 2.

M. GARNER: Okay. That is fair enough. Maybe that is, at this point, where we should go. Thank you.

I just have one very short question after this, and I think I am done.

D. COBAN: Mr. Garner, sorry, I just want to make sure that you are clear that what we have deferred to Panel 2 is just the fleet-related question. I just don't want you to miss your opportunity to ask questions --

M. GARNER: Oh. Thank you for that. Maybe that -- well, maybe then that is -- maybe that, then, brings me to the question I was just going to ask before about the AMPCO, AMPCO-53.

In order to get these numbers, 12,000 to 34,000, you have a set of data and that -- is there a median or an average for this group? Because that is a range, right, so it doesn't really tell me kind of --

like, if you had 100 units of something, of whatever this, it doesn't tell me anything, really. It just sort of says I have got a range.

How did you get the range? You added up what and what? And was there a median to that range? You know, or an average where, you know, this is the average in the range? Because the range itself is --

R. BASSINDALE: When we did the analysis, we did not do any averaging of a range. We were specifically looking at pole heights and pole classes that were completed in some -- in a variety of project actuals, and then averaging those projects to get the average cost of that pole height and class.

M. GARNER: Can you do a median and average for this unit cost? And/or average? It is not clear to me that you can or can't. That is my question first. Can you do a median or an average?

R. BASSINDALE: So, Mr. Garner, the reason we provided a range is because it is going to be dependent on the situation. Is it a highway crossing? It is a concrete pole? Are we doing more concrete poles in one year? More poles that are four circuit versus two circuit versus one circuit? At this point in time, we do not have a universal global average cost.

M. GARNER: Yeah. Okay. Fair enough. Thank you. I won't take up any more of your time on that.

Last and very quick question, it is for Panel 1,

it says, but I am not quite sure it is.

4-VECC-56. This is just a quick question. It had a number of coordinators for program delivery. And I had two questions.

One is the number of people, this coordinator role, seems to be based on the dollar size of the projects, i.e., the increase seems to be based -- and I'm saying to you, you can correct me -- seems to be based on the fact that the budgets are getting larger and not on the concept that I have a number of projects

So what I was trying to understand was, you know, you could have five projects, and they could be very expensive, and still need the same number of coordinators, so to speak. Or you could have a hundred projects and they are very -- you know, a lot to track and do things.

So, first of all, I have that -- do I have that right? Is the way you estimated your need for coordinators was based on the quantum of your capital budget? Is that way you do it?

M. WITTEMUND: Yes. We use the historical cost to help us inform the number of coordinators we need moving forward. That is right.

M. GARNER: Thank you.

And can you just tell me, you had eight -- it was four in -- I take it six in '24, eight in '25, now it is ten. Is there ten now, like, today?

M. WITTEMUND: There is not ten right now. We are working towards having ten throughout the year.

M. GARNER: Right. How many do you have now?

M. WITTEMUND: At this moment, we have six right now.

M. GARNER: Okay. Those are my questions. Thank you for your indulgence. Thank you, Panel.

R. DHILLON: Thank you, Mr. Harper. We will take a --

M. DEFAZIO: Excuse me. Sorry, can I just jump in for a second?

R. DHILLON: Yes.

M. DEFAZIO: Hi. Sorry. Margaret DeFazio from the Ontario Energy Board. Can I just jump in with a follow-up to Mr. Harper's question quickly?

R. DHILLON: Yes. Go ahead.

M. DEFAZIO: Hi. Looking at the unit costs, understanding that, for example, you know, the make up of the types of poles you would install each year would be different, which would give you a different weighted average, but through what you put into fixed assets and the number of poles that you would check out of stores and install each year, could you not come up with a weighted average for the last couple of years and we could see there would be a range -- like you said, understanding sometimes you have -- it is a lot different to cross the 400 than it is to go down a rural section of Highway 7. As well as some

of the other assets, the switches, et cetera, you could come up with an average.

R. BASSINDALE: So subject to check, the financial is done on a pole basis, not an on individual asset basis. So we would not be able to get that information.

M. DEFAZIO: Do you not know how many poles you install each year? Maybe not from the financials, but you would know that from your inventory or warehousing or GIS.

R. BASSINDALE: So we know the volume at the start of the month and the end of the month. The purposes and reasons why those poles are replaced, we don't have that information.

M. DEFAZIO: So if you know how many poles you installed, and you know how much money you put into fixed assets for poles, that -- I am just confused.

But okay. Thank you.

T. WASIK: Maybe I can help to clarify the last comment. We understand the number of poles at the end of the month and at the beginning of month. But what my colleague was trying to say is sometimes we just install new poles, and sometimes we replace poles, and the pole counts change. So trying to sort of provide sort of a per unit cost for either a new installation or replacement has -- is not separated in our tracking.

M. DEFAZIO: Could you do it combined?

J. BUTLER: So, yes, we know the volume of inventory going in and out of the stores, so we know how many poles go out in a month. But if we are looking at a -- if you are trying to find a comparison, a range, or an average for installation of poles, it is not -- just the volume going out and the total dollar values don't give you a usable range.

Like, when we are replacing poles reactively because they break as part of programs, there is stringing attached, which also goes into the cost base. Sometimes we are replacing a pole because we need to upgrade it because we are replacing a switch, so the -- like, there is so many more assets than just the pure pole and the cost of taking the pole from stores, digging a hole, putting it in the ground. Like, there is a lot more activity surrounding that.

So to try and get you a usable average just based on, you know, inventory volumes, I don't think we would be able to provide a usable range or usable value based on that.

M. DEFAZIO: Thank you.

R. DHILLON: Thank you, Ms. DeFazio.

We will take a short break. The time is now 3:05. We will return back at 3:20.

--- Recess taken at 3:05 p.m.

--- Upon resuming at 3:19 p.m.

R. DHILLON: So next we have AMPCO, and I will turn it to Ms. Grice. I would just remind everyone to stick to the allotted times. We have 60 minutes scheduled for AMPCO. Thank you.

CROSS-EXAMINATION BY S. GRICE

S. GRICE: Thank you.

Good afternoon, Panel. I have reduced the number of questions based on what has already been asked, so I don't think I will be 60 minutes.

Okay. My first question is with respect to 1-AMPCO-2. So in this question, we were referencing the evidence where Alectra talks about a net reduction in the capital program over the 2027 to 2031 period of 106 million due to its customer engagement Phase 2. And I just want to quickly go to the reference for our question, which is Exhibit 1, tab 3, schedule 1, page 22. Okay, thank you.

And if you just look at the description of what happened as a result of the second phase of customer engagement, and I am looking at lines -- beginning at line 1. And it says that the adjustments that were included was an accelerated investment in overhead asset renewal, reduced investment in system expansion, reduced investment in cable replacement, and reduced investment in deployment of AMI 2.0 meters.

So if we can just go back to AMPCO interrogatory 1-AMPCO-2, we asked for a breakdown of all of the

capital reductions that resulted in the net reduction of 106 million. And if we just go to the table 1 in the response, if you just stay -- yeah.

So just with respect to customer connections, which is the second one there, the total change is 71.1 million. And so my understanding, this would be after the Copperleaf iteration where it produced the draft plan. And I just wondered what happened as a result of customer engagement Phase 2 that resulted in a $71.1 million increase in customer connections or, you know, just generally, how did that come to be?

H. IBRAHIM: Ms. Grice, as we reduced system service with the feedback from customer engagement, we also updated the plan as customers have come forward that notified us with their intent to connect. So that is why you see an increase in customer connections. So there is a reduction in system service and an increase in customer connections, and, overall, it is a $106 million reduction.

S. GRICE: So it wasn't specifically related to when you went out and talked to customers; it is just something additional that came to be?

H. IBRAHIM: Yes. So the plan was updated to reflect the latest known information at the time, adjusting the plan with customer engagement.

S. GRICE: Okay. And then if you just go to

page 2, which is the rest of the inputs that make up the 106 million, you have increased facilities management by 4 million. Can you just talk about how that came to be?

H. IBRAHIM: I would defer that particular question to Panel 2.

S. GRICE: Okay. And then I guess you are going to say the same thing about information technology with an increase of 5 million?

H. IBRAHIM: That is correct.

S. GRICE: Panel 2? Okay. Okay. Thank you.

My next question is with respect to 2-AMPCO-19. Just looking at part A, we asked for the results of cost control, so planned actual -- or, sorry, planned capital, which the description says is actual versus budget performance for the years 2020 to 2024. And if we can just go to the response of part A, it says that it can be found in Exhibit 2, tab 1, schedule 1, appendix P, page 3. If we could please just go to that exhibit. Okay. And you see these percentages there of 88.5 percent in 2020 all the way across to 80.5 percent in 2024. You see those percentages there?

R. BASSINDALE: Yes, we do.

S. GRICE: Okay.

I just want to take you one more place because I am just trying to reconcile a couple pieces of evidence. Can you go to 1-AMPCO-3, please.

So you see in table 1, we asked that the plan amounts be shown as well as the actual amounts, and you have shown them there, that the total 2020 to 2024 DSP plan is 1.456 billion, and then the actuals for 2020 to 2024 are 1.456 billion as well. So, in my mind, the ratio of cost control, which was the actual compared to budget, it looks like it is a hundred percent. So that is why I am just confused by the cost control percentages that I took you to in appendix P, why they are, you know, below a hundred percent every year.

R. BASSINDALE: If we can actually please flip back to appendix P. So appendix P, when we are doing this validation, based on the metric that we had submitted in the last DSP, it is specific to projects that were in the last DSP.

S. GRICE: Okay. So it is a subset --

R. BASSINDALE: Yes.

S. GRICE: -- of -- of the --

R. BASSINDALE: Of the actual -- you see in the other number are net new projects.

S. GRICE: Is it -- could we get -- could we get the dollar amounts that make up these percentages? So would you -- could you share the actual versus the budget for that subset of projects?

R. BASSINDALE: Just so I am clear, the undertaking you are asking for is to provide the budget and actual that make up the values from 2020

to 2024?

S. GRICE: Yes. In appendix P. Yes, please.

R. BASSINDALE: For table P-2?

S. GRICE: Yes. Thank you.

R. DHILLON: I will mark that down as Undertaking Number JT-1.23.

UNDERTAKING JT-1.23: PROVIDE THE BUDGET AND ACTUAL THAT MAKE UP THE VALUES FROM 2020 TO 2024 FOR TABLE P-2 IN APPENDIX P

S. GRICE: Okay. My next question is 2-AMPCO-21, part C. Okay. Thank you.

And in part C, we asked Alectra to provide the constraints that were used to develop the draft capital plan, and if you look at the response to part C, and Mr. Rubenstein had a discussion with you this morning about the Capex numbers. And I just had a question about the labour hours. How -- how was that number derived? Like, what is it based on?

H. IBRAHIM: I just would like to clarify which of the constraints, again, you are looking for.

S. GRICE: The labour hours, 195,600.

H. IBRAHIM: And you are looking for where it came from; is that correct?

S. GRICE: Well, how is it derived? Like, why did you use 195,600 as the constraint?

H. IBRAHIM: Okay. I will have to take that one back. So I can provide --

S. GRICE: Okay. Thank you.

And just to expand on it, you have got the same number of labour hours every year, but the capital -- the Capex number is going up, and I just wondered, as part of that undertaking, could you explain why it is the same labour hours every year?

H. IBRAHIM: I can.

S. GRICE: Okay.

And just last question on this --

J. MYERS: Sorry. Can we get an undertaking for that one?

S. GRICE: Sorry. Sorry. Yeah.

J. MYERS: Number?

R. DHILLON: Sorry. So I will mark that down as Undertaking Number JT-1.24.

UNDERTAKING JT-1.24: ADVISE WHY THE LABOUR HOURS ARE THE SAME EVERY YEAR IN REGARDS TO 2-AMPCO-21 PART C, AND COMMENT ON WHAT CHANGES THERE WERE BETWEEN ITERATION 1 AND 6

S. GRICE: And then just a final question. So there were six iterations of Copperleaf, so am I correct in assuming there were six different labour hour quantities used in all of those iterations, or was it the same number for all six?

H. IBRAHIM: I don't have that information on me right now. And as I mentioned before to Mr. Rubenstein, like, this is an iterative process for us to go through as an organization, so I can't comment at this point, like, whether it changed or not.

S. GRICE: Could you make that part of the undertaking, just -- just to comment on what changes there were between iteration 1 and 6?

H. IBRAHIM: For the labour hours, we will take that back and see if it changed between the different iterations.

S. GRICE: Okay. Thank you.

So that will be part of the same undertaking?

R. DHILLON: That is correct. Thank you.

S. GRICE: Thank you.

Okay. I just have a quick question on 2-AMPCO-26 that involves just bringing up the spreadsheet that was completed. And it is just a general question. I just -- I am just wanting to understand your resource strategy year over year.

So if we can just look at -- if you can go down to overhead rebuilds, just as an example. So I am just looking at -- sorry. The first year on the table is 2020 actuals, and you have got a split of 89 percent internal and 11 percent external. And then over in the year 2025, the split is now 38 percent internal and 62 percent external. Can you just explain internally what is happening to drive those differences in internal versus external resources?

H. IBRAHIM: Ms. Grice, if you don't mind, can you point us, again, to the numbers?

S. GRICE: Sure. So I am looking at overhead rebuilds, which is line 70 on the table that is on

the screen.

So in 2020, it is an 89 percent internal versus 11 percent external in terms of the resource makeup. And then if you go to 2025, it is 38 percent internal and 62 percent external. And then you also have two years with zero percent for both.

So I am just trying to understand in terms of your resource strategy what is driving those year-over-year variances.

H. IBRAHIM: We will have to take this one back in order to provide you the explanation.

S. GRICE: Okay. Okay. Thank you. And can you include the zero percent issue as well?

H. IBRAHIM: Yeah, we will.

S. GRICE: Okay. Thank you.

R. DHILLON: I will mark that down as Undertaking JT-1.25.

UNDERTAKING JT-1.25: PROVIDE AN EXPLANATION IN RELATION TO 2-AMPCO-26 FOR WHAT IS DRIVING YEAR-OVER-YEAR VARIANCES INCLUDING THE ZERO PERCENT ISSUE

S. GRICE: Okay.

My next question is 2-AMPCO-28.

Okay. In part B, we asked for Alectra's defined thresholds and approval pathways for the project change request process. And then if you look in the response, in table 1, you identify where a project change request is required and how it is approved,

and you have got two different tiers of projects where the change threshold requires a project change request.

So you have got greater than 0.3 million and less than 1 million and then greater than 1 million. And I guess my question is could Alectra provide the project change requests, the forms for the projects that fall into those two threshold categories?

T. WASIK: Ms. Grice, I believe that this is a question for Panel Number 3.

S. GRICE: I am so sorry. It is. I swear I thought it was on the list. Okay. Okay.

T. WASIK: Panel Number 3 would be --

S. GRICE: Thank you.

T. WASIK: -- the appropriate group to --

S. GRICE: Okay.

T. WASIK: -- address it.

S. GRICE: I will leave that, then.

T. WASIK: Thank you.

S. GRICE: Okay.

2-AMPCO-34, please. So this was a question where we were asking some questions on your asset condition assessment at appendix E, and we asked for the list of asset groups in part C where age has a significant weight in the calculation, and in the response, you indicate that overhead conductors and underground cables have a significant weight.

And in going back and looking at appendix E, age

is an input with varying input weights for most, if not all, of Alectra's assets in the asset condition assessment; would you agree with that?

R. BASSINDALE: Subject to check, I believe age is a criteria on all the assets.

S. GRICE: Okay.

So I want to ask if you could run the asset condition assessment using the same data set as 2023 but removing age as an input; is that something you could do?

R. BASSINDALE: Just quickly, I want to make a correction to an earlier statement. I had mentioned that subject to check, all the assets had age. I believe station assets do not have age in their health index.

S. GRICE: But other than that, all the others do?

R. BASSINDALE: Yes.

In regards to your request, we can offer that we can take it back and take a look at what that would mean in terms of the amount of work to rebuild the ACA to be able to execute that type of analysis. It is a possibility that if it is too intensive, we might try to offer something else. But at this point in time, like, without us taking a look, I wouldn't be able to say whether we can perform the analysis you are requesting.

S. GRICE: Okay. That is fine. Thank you.

R. DHILLON: I will mark that as Undertaking JT-1.26.

UNDERTAKING JT-1.26: RUN THE ASSET CONDITION ASSESSMENT USING THE SAME DATA SET AS 2023 BUT REMOVING AGE AS AN INPUT

S. GRICE: Okay.

2-AMPCO-35, please. And for this one, we need to look at the Excel spreadsheet, if we can, please. Okay. Thank you.

In the question, we asked that if you could qualify, to the extent possible, the data gaps for each category so that "low" would mean there is not much more condition data needed to be incorporated and "high" meaning important condition parameters have yet to be incorporated.

So in this spreadsheet, it looks like for most -- for all of the assets except for wood poles, there is not much more condition data that is required. But with respect to poles, it says "medium." Can you just explain what data gaps are missing with respect to poles for it to have a medium?

R. BASSINDALE: So, first off, just to make sure we are talking about -- you want to know specifically back in 2018 why it was medium, not in 2023? Is that -- does that change --

S. GRICE: Yeah, yeah. No, no. You are right.

R. BASSINDALE: Okay.

S. GRICE: Yeah. Thank you. I looked at it

quickly and -- okay. Thank you very much. That clarifies that.

Okay. 2-AMPCO-39, please.

Oh, can I -- can I just go back and ask. So it moved from medium to low, so can you -- can you fill in, then, what new data is being tracked for poles?

R. BASSINDALE: Increased wood pole testing results.

S. GRICE: So for strength?

R. BASSINDALE: Yes.

S. GRICE: Okay. Okay. Thank you.

Okay. Back to AMPCO-39. We asked a question about -- you showed the voltage conversion projects that are underway 2020 to 2025, being 14, compared to the next time period '26 to '31 being 11. And we asked about the timeline and budget for the remaining voltage conversion projects. And in your response, you explain that until you optimize every project in the DSP, it is difficult to provide this information explicitly.

But I am just trying to get a sense of the magnitude of voltage conversion projects coming that are still sort of on your books that you need to do and when the sunset will be. Is this, like, a 10-year horizon for future voltage conversion projects? Can you shed any light on that?

R. BASSINDALE: So, unfortunately, Ms. Grice, we have the total number of municipal stations, but that

wouldn't necessarily be the ones that would qualify for voltage conversion. Specifically, you are talking the for an EKV in your question. We will have to take that back, but essentially it would be that number minus 8.

S. GRICE: Okay. Thank you.

R. DHILLON: Sorry. Ms. Grice, is that an undertaking?

S. GRICE: Yes, it was.

R. DHILLON: And can you repeat what the undertaking is?

S. GRICE: Yes. It is to provide a timeline for the remaining voltage --

R. BASSINDALE: So --

S. GRICE: Oh, sorry. You --

R. BASSINDALE: What we can provide is the number of stations we will have remaining in service that are for an EKV by the end of 2031. That is what we can provide.

S. GRICE: Okay. And then no -- no vision about what sort of timeframe you are going to take to address those?

R. BASSINDALE: So for some of the areas, we haven't even started an investment plan long term yet so --

S. GRICE: Okay. Okay. Okay. That is fine. Thank you.

R. DHILLON: I will mark that as Undertaking JT-

1.27.

UNDERTAKING JT-1.27: PROVIDE THE NUMBER OF STATIONS REMAINING IN SERVICE THAT ARE FOR AN EKV BY THE END OF 2031

S. GRICE: Okay.

And then 4-AMPCO-64, please. So I am looking at the response in part C, which the table is filled in on page 2. And just in the last column there, you provide the number of projects delivered that were greater than 10 percent of the planned cost and greater than $100,000, and you've -- you show that there are 1,617 projects.

I wondered if you could provide the dollar amount that equates to the overrun as it is described there related to those 1,617 projects?

M. WITTEMUND: Ms. Grice, just so I understand, in aggregate, the total value?

S. GRICE: Yes, in aggregate.

M. WITTEMUND: Yes, we can do that.

S. GRICE: Thank you.

R. DHILLON: I will mark that as Undertaking JT-1.28.

UNDERTAKING JT-1.28: PROVIDE THE DOLLAR AMOUNT THAT EQUATES TO THE OVERRUN RELATED TO THE 1,617 PROJECTS

S. GRICE: Okay.

And then I just have a question, just with staying in this interrogatory. If we can go back a

page. I just want to look at the response to part B.

Okay. We will start with where you talk about the cost performance index, and then you say that the actual project costs are measured as a ratio of actual to planned cost to determine the CPI. I just -- I just want to clarify. So then if a ratio is 1 or less, that is a good thing. It means the project came in under budget. I just want to make sure I am understanding this CPI correctly. It came -- sorry. It came in at or under budget?

M. WITTEMUND: Yeah. So if the ratio is under 1, then the actual cost of the project versus planned came in under budget.

S. GRICE: Okay. Just wanting to make sure --

M. WITTEMUND: Yes, that is correct.

S. GRICE: -- I had that correct.

And then same thing with schedule, the SPI. Can we just go to the next page, please. I just want to make sure here too that this metric is the percentage of projects which are completed within 90 days either before or after the anticipated finish date. So can you just explain, just in the same basis as CPI, what -- that -- is the -- the ratio 1 and less for a project that is on time? Or is it simply a percentage?

M. WITTEMUND: Sorry, Ms. Grice, can you just clarify that? I am just trying to understand again.

S. GRICE: Okay.

M. WITTEMUND: Yeah.

S. GRICE: Actually, if you can tell me sort of what the SPI looks like. That is -- instead of me guessing. That is what I am looking for.

M. WITTEMUND: Yes. The SPI is a ratio of the schedule, so it is scheduled performance index. It is the scheduled -- the date of the project as compared to the actual completion date of the project.

S. GRICE: So if the project is late, what does the ratio look like?

M. WITTEMUND: So, Ms. Grice, just for clarification, so the SPI metric is the percentage of projects which we completed within 90 days before or after the anticipated finish date.

So in column 2 there, we have stated that 2,059 projects were delivered within 90 days of the finished project date.

S. GRICE: So then the SPI would be 2,059 divided by 5,534? No. Sorry, I am just trying to understand how to calculate the SPI.

M. WITTEMUND: Okay. What we can do is we will take that back and provide that to you. We will provide a written, more informative response on that one, if that is okay.

S. GRICE: Okay. That would be great. Thank you very much.

M. WITTEMUND: Yeah.

R. DHILLON: Ms. Grice, can you just repeat that undertaking, please?

S. GRICE: Yes. To provide a response on how the SPI is calculated. Which is the scheduled performance index.

R. DHILLON: I will mark that as Undertaking JT-1.29.

UNDERTAKING JT-1.29: PROVIDE A RESPONSE ON HOW THE SPI IS CALCULATED

S. GRICE: Thank you. And those are all of my questions. Thank you very much.

R. DHILLON: Next we have Energy Probe. I believe that is Mr. Ladanyi.

T. LADANYI: Yes. I am here.

R. DHILLON: Thank you. Go ahead.

CROSS-EXAMINATION BY T. LADANYI

T. LADANYI: So as I introduced myself this morning, I mentioned that I am representing two intervenors, Energy Probe and the Coalition of Concerned Manufacturers and Businesses of Canada, CCMBC, and they are sharing my services to reduce regulatory costs.

Now, in the schedule, it shows that Energy Probe is -- questions are first for 20 minutes, and CCMBC questions are second for 15, but I will reverse that. I will start with CCMBC, if you don't mind.

So can you turn to 4-CCMBC-3. Thank you.

And in that question, I asked about the apparent

contradiction between the claim of prudently managing costs and the claim of increasing backlog of deteriorated assets. And you provided an answer. And I am just going to point you to the bottom of the page of that answer, and the last sentence on that page says:

> "OM&A per customer increased by only 1.4 percent annually over the period and was 16 percent lower than the Alectra Utilities' peer group."[as read]

Which peer group is that?

If you don't know, we can have an undertaking. It is not that important. I am just interested in what the source of that reference is.

T. WASIK: That is acceptable. We will undertake to provide the source of the peer group.

R. DHILLON: I will mark that as Undertaking JT-1.30.

UNDERTAKING JT-1.30: ADVISE WHAT PEER GROUP IS REFERENCED IN THE RESPONSE AT 4-CCMBC-3 AND ADVISE WHETHER ALECTRA DECIDED CONSCIOUSLY TO SPEND LESS OR WHETHER THEY ARE BEING CONSTRAINED FROM SPENDING MORE ON OM&A BECAUSE THEY DID NOT HAVE ENOUGH MONEY

T. LADANYI: And trying to understand that answer in general, I won't read it to you, but are you stating that you would have spent more on maintenance if you had more money, or did you

consciously decide not to spend as much on maintenance as the peer group?

T. WASIK: Mr. Ladanyi, I think the context of that question is to demonstrate efficient and prudent cost management relative to our peer group.

T. LADANYI: So as I understand your answer right now, it was your conscious decision to not spend as much on maintenance as the peer group did?

J. BUTLER: Mr. Ladanyi, I just want to clarify. You stated you are asking about our spend, and what I am hearing is total spend relative to the peer group that we will define in that undertaking, but I think the cost referring to is a per customer cost. So even though our per customer cost may be higher or lower than the peer group, it does not necessarily reflect the higher or lower overall spend, so I am not -- you may need to rephrase that question.

T. LADANYI: Well, I am trying to understand the answer, but if you can -- you can actually rephrase your answer and you can qualify it and say, it is only per customer, and we actually spent in total more than the peer group, but because we have more customers, when you divide it by number of customers, per customer number is different. But it is up to you how you answer it.

Actually, you can also have an undertaking on that one as well if this -- I don't want it to take too much time with these. I have quite a few other

questions.

R. BASSINDALE: Sorry, Mr. Ladanyi, what specifically was your question in that statement you made?

T. LADANYI: The question was really about the decisionmaking that Alectra has made. Have you decided consciously to spend less, or are you actually being constrained from spending more on OM&A because you did not have enough money?

You can answer in writing if you want to. You don't have to answer now if you don't want to. If you prefer to answer in writing, I am fine with that.

R. BASSINDALE: We will take that as part of the previous undertaking.

T. LADANYI: Very good. Thank you.

So now can you turn to 2A-EP-6. I am still on CCMBC questions. It is 2A-EP-6, Energy Probe 6. Yeah, down. Okay. And go to the next page, please. And there is a link to the capacity information map.

You are familiar of -- there is a capacity information map, I know that Alectra participated in it, and there is a lot of interesting information there. So can you actually click on that link, and we can see the map on the screen, please.

So you see it has got two selections there: available load capacity and available DER hosting capacity. So I am going to ask some questions about the data centres. So I assume that data centres are

actually loads. Is that right? They are not DERs?

T. WASIK: That is correct.

T. LADANYI: Could you click on "available load capacity" and have it come up on the screen, please. And now could you zoom into the Alectra service area or service territory?

Just in general, I would say in the area north of Toronto, that is the easiest, I am going throughout the territory. I am just going to ask you some general questions. Again, zoom some more until it comes up. Keep zooming. Keep zooming. Keep going. There it is. Now we are in business. Okay.

So can you tell me what the colours are, or are we just going to use the legend on the side? Is anybody on the panel familiar with the colours?

T. WASIK: We can speak to the best that we can about the legend, but I believe that it is -- the legend explains what the available load capacity and MVA ratings are as per the OEB requirements.

T. LADANYI: All right. Very good. Actually, and I don't need too many details. These are just general questions.

So from what I gather, let's say if a data centre wants to locate in an area where there is insufficient capacity, what would you do? Would you tell them to -- don't go there, or would you actually try to provide them with capacity? What would happen?

T. WASIK: Well, Mr. Ladanyi, it doesn't really work that way. We don't advise load centres where to go look. What typically happens is a customer approaches us with a specific site and address in mind, and they are asking for specific information about what would it take to provide electrical connections at those particular sites and locations.

T. LADANYI: So then you would inform them. And if you go back to my interrogatory for a second. We will return to a map in a minute. Okay. Just a minute. So if you go to the previous page, to the bottom. And there, you explain how you used the distribution system code to calculate the contribution that is required.

So if a data centre wants to locate in a location where there is insufficient capacity, you would do a calculation that would show what would be required to bring sufficient capacity to that location. Is that what you would we doing? And that would be in part of this, what you describe here at the bottom of the page?

T. WASIK: So, Mr. Ladanyi, there is a little bit of a different sequence that I would like to maybe clarify. If a data centre was to approach Alectra with a specific site and address and ask us if there is available capacity to connect, we would review that and complete that study.

Depending on the size of the data centre and

depending on the magnitude of the connection, it may follow different particular approach, and we may have to be required to do a system impact assessment, we would have to go through a significant amount of planning.

Each particular site is done case-by-case. So there isn't, you know, a general approach that we take with data centres because they can vary in significant magnitude connections as well as requirements.

I think that is also an important part of it. It is not just capacity. Data centres are also seeking specific power quality, redundancy, and other technical matters that are requested of Alectra by the customer.

T. LADANYI: So then you would calculate what deposit is required. Is that right? And then you would tell the customer how much money they have to give you, and then I guess things are going to start happening, and you keep the deposit on your books. And I think in a previous question this morning, we saw how much deposit you have, and you have a bunch of deposits for 2027. That is fine.

And you talk about a connection horizon, and a connection horizon is a essentially prior to the revenue horizon. So connection horizon would be, let's say, three or four years might lapse before the data centre is actually operating. So that would be

the connection horizon. And then the revenue horizon is after the data centre starts operating and starts paying you revenues. Would that be right?

T. WASIK: So a couple clarifications, Mr. Ladanyi. The connection horizon is effective from the point of connection and energization, which is also when the revenue horizon starts, not from the point of construction.

T. LADANYI: So for data centres, revenue horizon starts on day 1 of the connection horizon. But connection horizon is five years, so then what happens with the remaining years of the connection horizon? Nothing? Or it doesn't have any significance?

Because I am trying to get this, and I think maybe you can answer it. Suppose the data centre does not actually start operating for another five years, maybe it doesn't start operating for six years. What happens then? Do they forego their deposit? Can you explain what would happen if they do not actually start operating for quite some time after they have been connected?

D. FAIRCHILD: Yeah. In that example that you provided where a data centre comes to Alectra, we go through the process and offer to connect, economic model is established, and once that project is constructed and energized, the window -- the time starts ticking for both the connection horizon and

the revenue horizon. They start at the same point.

If for some reason that data centre chooses to delay any part of their load ramp-up schedule, and it falls outside of the five years, yeah, very much, you know, that -- you know, it is quite possible they would have to -- they would have to pay back, you know, whatever, you know, line of credit, letter of credit on deposit that we have. So they do that have right, though, for that five-year window.

T. LADANYI: Now, if the data centre wants to locate and they can -- could you go back to the map, please. Yeah. And let's say in the green area. I understand the green area, this is most capacity. And I guess you are actually assigning capacity to customers on a first come, first serve basis.

So if a data centre comes and takes up a lot of that capacity in the green area, are they charged a contribution, or is this -- because there is no incremental cost to you for a building new facilities. Or are they charged nothing?

D. FAIRCHILD: The treatment of data centres is a similar treatment for all of our other customers. If a customer comes along and we refer to them as "lies along customer," meaning there is already available capacity, a front to their property, they have access to it, like any other customer, on a first come, first served basis.

T. LADANYI: And they are not treated in any way

differently than, let's say, members of CCMBC, who are essentially medium and small manufacturers in the commercial establishments? They are treated just the same way? There is no special provision for data centres?

D. FAIRCHILD: There are no special provisions for data centres.

T. LADANYI: Now, in terms of the spare capacity, and maybe this is kind of a subject for argument or the discussion, the spare capacity exists because some other customers have paid for assets to provide the spare capacity. Is a new customer -- and that would actually not just be data centre -- are they required to -- essentially may pay some contribution to the customers who already provided this capacity, or it is you are not really taking -- looking after it that way?

D. FAIRCHILD: No. You are correct in your thinking, is if there is a system expansion and customer A pays for that system expansion and someone comes along within a five-year period, there is a mechanism to provide a rebate from the second customer to the first customer.

T. LADANYI: And that is covered in appendix I of the distribution system code; would that be right? I think it is kind of discussed there, appendix I, which is just the capacity allocation model, or you're not familiar -- I don't want to test your

knowledge that way.

D. FAIRCHILD: Yeah, it is -- I don't believe it is at appendix I, but it is definitely covered in --

T. LADANYI: Okay.

D. FAIRCHILD: The distribution system code talks about factoring in things like when they connect, where they connect, and the time within that five years that they connect. So they look at those three factors.

T. LADANYI: Okay. Thank you.

Now I am going to go to Energy Probe questions, and we are still staying on the -- on the map. So if you can go back -- so try to look at this, you know, let's say, record this in your memory, and now go back to the selection on the first, let's say, screen of the capacity information map, and we will select the DER selection.

Go back. Go back some more. Back, back. And -- no. Go back the other way. Yes, to the -- to the very -- all the way to the -- there. Yeah, now go back some more. No. You are going the wrong way. So you can select DER capacity. It has got a separate selection button. There, the one at the bottom. See, available DER hosting capacity. Okay.

And now let's go zooming back to Alectra service territory. And you can see here the DER hosting capacity is very different than the load capacity. Can you tell me why they are so different?

J. BUTLER: Yes. The -- excuse me. The connection of a load is very different than the connection of a DER, which is essentially an injection into the system or a deferral. Many of the limitations for the DERs is -- is there is a thermal or a -- or a short-circuit constraint, and that is really what this is looking at.

From a technical standpoint, it deals with the protection and controls of the system and show the protections in place, which were generally designed for one-way downward flow, can they handle multiple injections of -- into the system?

You know, so a system was originally designed for one-way power flow, cannot handle multiple injections, so multi-injections.

T. LADANYI: Yes. That is my understanding. I am actually -- so you are agreeing, what I expected.

J. BUTLER: Yes. So --

T. LADANYI: So do you have DER management systems in place, and let's say in the red area, you actually don't have it, or are you dealing with just protection equipment? Because I understand from other proceedings with other utilities that to protect the distributor from problems that might be caused by DERs, you'll need ADMS, which is advanced distribution management systems; FLISR, which is fault, location, isolation, and service restoration system; and volt wire optimization to control voltage

and reactive power. Is that your understanding too?

J. BUTLER: Yes. As the penetration -- initially when DER penetration is very low, these systems are generally not needed, but the deployment or development of these systems allows a greater penetration of DER onto the system.

T. LADANYI: And you are actually installing these systems, or you have these systems throughout, or are you in the process of installing these systems, or have you installed them everywhere?

J. BUTLER: Just for clarification, I think we need to be a little bit more succinct in what you are defining as "systems." You know, Alectra has done a lot of investments in distribution automation. We are upgrading protection and control systems throughout our service territory.

And if you -- and I don't -- we don't need to pull it up, but appendix B14 talks about enabling resiliency in modernization, so there is a section in there on some of our plans moving forward to develop, you know, more ADMS and DSO-type capabilities. That is outlined in appendix B14. But there -- on those systems, DSO and ADMS, it is still very early stages for Alectra.

T. LADANYI: So they are needed for DER customers that export power to the grid, but all customers will be paying for it, according to your plans; is that right?

J. BUTLER: These systems -- and, again, we need to be careful that we don't be too broad with our definition of "systems." The protection and control systems we are putting in place at our stations that are upgrades, they -- they assist in the enabling of DER, but they actually have -- that is not the primary driver. There is many benefits that we are doing this for in the operation, the safe operation and reliable operation, of our distribution system. That is the driver for those.

With the IT systems themselves, they are multiple benefits. So I don't think it is a fair assertion that that investment is being done -- you know, paid for by the entire rate base when it is only benefiting a small number of customers. I don't quite think that is an accurate statement.

T. LADANYI: Actually, I agree with you, it has got other benefits, but they are -- you would not need it, need these systems, if it wasn't for DERs that export into the grid, otherwise you wouldn't need it. There would be no rush to installing. You could install them over many years. But the systems have, obviously, many features, and I have discussed this in other proceedings and discussions, but I will accept what you are saying.

So if you receive an application for a DER connection for an area with inadequate capacity, what do you do? So in a red area there, for example, in

Markham.

J. BUTLER: Generally, in -- in -- I can -- let me find the reference. It's -- fortunately, Alectra is generally not constrained. I think it is ED 12, has got the reference for it. Let me just check. Yes. So if you go to ED-12 and table 2, which is on page 2, you can see that -- oh, sorry. I will wait for it to come up.

Okay. So that table there, you can see, you know, we have a relatively small number of stations. There is only two stations that are Alectra-owned stations that have constraints, and these are generally short-circuit constraints and -- so TS is owned by Hydro One. There is a number of stations there that are constrained, and it only represents 6 percent of our total customer -- customer base.

So, you know, when we are talking about red or constrained areas for Alectra, it is a very small percentage of our customer base. But saying that, at present, we do not have a lot of the ability to overcome some of the short-circuit constraints we have. So there is not a lot of good solutions we have. We are exploring those, but at present, we don't have a great solution.

So if you are one of those 6 percent of our customers, we don't have -- we don't have a lot of solutions for you right now. We may not be able to connect you.

R. DHILLON: Mr. Ladanyi, just as a reminder, we have ten minutes remaining.

T. LADANYI: Ten minutes remaining, you said. Okay. I will try to be quick. I am going to drop a bunch of questions.

And let's go to 2A-EP-8, Energy Probe 8. And there, in your answer -- keep going down so we can see the answer. There, you talk about the increased volumes, about the DER connections contribute to work volumes, and you name them, and some of them are actually capital costs, and some are maintenance costs, operating costs.

And I asked you a question. I said, is increasing work volumes different for exporting or non-exporting DERs? And you surprised me. You said, no, there were -- the increase in work volumes is not different for exporting versus non-exporting DERs. And I thought, if you -- for example, if I install on my home rooftop panels, I have no intention of exporting any power to any utility, they are only for my own use, what -- how would that increase your work volume?

J. BUTLER: Sorry. I am just trying to understand the full context of the question. Your question is the difference in work volume between exporting and non-exporting DERs? That's --

T. LADANYI: Yes, it is. Yeah.

J. BUTLER: And your example is an installation

of -- I think -- did you say solar on your home that is not injecting, so you are just load displacing?

T. LADANYI: Exactly. It just reduces the amount of electricity I would be using. I don't have -- I understand to export, you require an inverter and some other equipment. I would not have an inverter. I would not have any intention of ever exporting power into the grid. Why would that increase your workload?

J. BUTLER: I think we are saying it does not change our workload; correct?

T. LADANYI: Well, that is what you said. You said the same workload whether you were exporting or not exporting.

J. BUTLER: Yes. So --

T. LADANYI: And I am telling you I don't understand that.

J. BUTLER: So in your example where you are connecting solar onto your house, there really -- so initially, the assessment of it, there is no difference whether you are injecting or not injecting. It is still a short-circuit consideration that we have to take into account, and is the system able to handle that short-circuit injection?

And even if you don't inject, the impact assessment has -- does not take that into account. It assumes full injection because it is a theoretical possibility, and we have to design for that. So

there is no difference in the assessment.

And in actual operations, yeah, you are not injecting back in, but there still needs to be protection and control equipment so that if, you know, the circuit trips out and it detects a lack of voltage, it drops the solar out. So there is still extra equipment required there.

And that equipment actually is on your side -- or the customer's side, customer responsibility, so it does not change the cost or the work volume for Alectra. So that is the context in which we answer that question.

T. LADANYI: So is that -- isn't that dependent also if there is a bidirectional meter? So let's say if customer has a bidirectional meter, they can export into the grid, or if they do not have this bidirectional meters, they can't; would that be right?

J. BUTLER: Correct. You need a bidirectional meter if you are feeding back into the grid. And with the new electronic meters, I apologize. I am not personally aware of if our standard residential meter is -- can be programmed to be bidirectional or if it may require a meter change. I would have to -- if you need that answer, I can get it for you. But that is -- you know, the electronic meters are -- it is pretty easy to program to be bidirectional. So it may require a meter change, but that is a pretty,

pretty minor operation and minimal cost involved in that.

T. LADANYI: So apart from what we just talked about, once the customer in injecting -- or rather, like, exporting customer is connected to the grid, there are additional costs. And I am trying to explore whether -- where these costs are and whether these customers are charged for them.

And so the question is after DERs are connected and in service, does Alectra incur incremental costs dealing with them, for example, such as billing and settlement -- from billing and settlement perspective, customers who export to the grid impose higher cost as it requires additional activity such as billing function, data capture, review time, and settlement with the ISO; would you agree with that?

J. BUTLER: The business process in billing and settlement for someone -- you know, the example of a residential household with solar that injects, it is different from a house that does not have solar, but -- so it is a different process, yes, but the overall cost difference between the two processes would not be material, so there would not be any material difference in cost, although, yes, it is a different process.

T. LADANYI: So how about customers who have nothing? And this is what I understand, Alectra is the largest distributor in Ontario with about a

million customers, and you are projecting to have in five years 9,569.5 connected DERs, and -- or not 0.5. I misread that -- 9,569 DERs, and you currently have, I understand, 6,000 and something.

So that is actually less than 1 percent of your customers will have DERs, and they are going to be imposing all these costs that the other, let's say, 99 percent of the customers will not be imposing. They will not be making you spend this money. Should these DER owners not be charged incremental costs that they are imposing on the distribution system?

J. BUTLER: So I don't agree with your assertion that we are imposing incremental costs. I thought we just kind of walked through where I showed that there is no real incremental costs. And any costs associated with the initial installation of the DER is at the cost of the customer. We recover that cost from the customer. So I don't believe that the rate base in general is covering the cost or subsidizing, if you will, DER customers connecting to the grid -- to our system.

T. LADANYI: Just a second. I think I am at the end. I just wanted to ask a question. And this is actually in relation to -- and you don't have to look it up. It is in relation to the distribution system code. And it is section 3.1.5. And it says:

> "For non-residential customers other than micro-embedded generation facilities customers,

a distributor may define a basic connection by rate class and recover the cost of connection either as a part of its revenue requirement or through a basic connection charge to the customer."[as read]

So this is in the May 5th version of the distribution system code on page 52. You don't have it to bring it up.

I want to ask you, what is your policy? Do you actually charge everything in the cost of connection, or do you recover it somehow through revenue requirement? And you can take an undertaking on that as well.

J. BUTLER: No, we recover the cost of connection from the customer.

D. FAIRCHILD: That is true. We fully recover the cost for the connection from the customer. But as per the distribution connection code, there is a basic allowance for residential customers that is applied.

T. LADANYI: Okay. Thank you, Panel. These are all my questions.

R. DHILLON: Thank you. The time is 4:30. And next is PWU, and I will hand it over to you, Mr. Rosenbluth.

CROSS-EXAMINATION BY D. ROSENBLUTH

D. ROSENBLUTH: Thank you. I can -- I have about -- I think I have 20 minutes -- sorry, 20

minutes scheduled. I am only actually going to be a couple of minutes. I have revised my notes. So I will get right into it.

I would like to go, please, to 3.1-PWU-1A. And so there is a reference here to a deferral. I am on line 1 of page 2:

> "This approach resulted in the deferral of certain medium- and long-term investments."[as read]

Et cetera.

Is it possible to receive a table or summary showing -- or sorry. I am actually -- the reference is at line 2:

> "Secondly, Alectra sought to attain incremental capital funding through multiple applications."[as read]

In relation to those ICM requests, is it possible to provide a table showing the comparison between the amounts requested by way of ICM applications in each of these five proceedings versus what was approved?

T. WASIK: Yes, we can provide that.

D. ROSENBLUTH: Thank you.

R. DHILLON: I will mark that as Undertaking JT-1.31.

UNDERTAKING JT-1.31: PROVIDE A TABLE SHOWING THE COMPARISON BETWEEN THE AMOUNTS REQUESTED BY WAY OF ICM APPLICATIONS IN EACH OF THE FIVE

PROCEEDINGS VERSUS WHAT WAS APPROVED

D. ROSENBLUTH: Coming back to line 1, there was a discussion of the deferral of certain investments. And then actually just at the bottom of the page 1, it says that this occurred -- this deferral occurs at the expense of those investment needs.

Is it possible to quantify this in any more detail? For example, to quantify the extent to which these medium-, long-term investments are being deferred, first of all?

H. IBRAHIM: It is not possible to quantify the value of the deferrals. As mentioned in the response, we were optimizing on yearly basis, deferring the need. And, again, those deferrals were at -- were cost at the time, and the cost wouldn't be relevant unless we go back and update everything, which is not reasonable.

D. ROSENBLUTH: Right. I am just trying to get a sense of the scale here. When you say that the approach resulted in the deferral of certain investments, I guess I am just trying to understand, are you saying it is not possible to put a number on the total amount of investment spending that has been deferred as a result of insufficient capital?

H. IBRAHIM: That is correct.

D. ROSENBLUTH: Okay. Pivoting slightly, we were just talking about the deferral, but the flip side of that as discussed here is that this happens

at the expense of the medium- and long-term investment needs.

So leaving aside amount of capital investment deferred, in terms of the impacts of that, clearly Alectra is of the view that it has an impact. I think that is what it is saying here. Are you able to, whether it is numerically or narratively, give us more information about that?

H. IBRAHIM: We will have to take this one back to see what -- how can we quantify the deferral. Again, it will be on best-efforts basis. And we will have to qualify the work with caveats and assumptions. Again, it will be on best-efforts basis.

D. ROSENBLUTH: Thank you. And I guess as part of that, like I said, I am interested in understanding it both numerically and, I suppose I would put it, narratively in the sense of what are the types of -- what areas of the business are being impacted and how. Certainly if we can understand that quantitatively, that is great. But if not, you know, your best estimates or assumptions just to provide us all with a better understanding of that would be helpful. So I will just leave that there and treat that as part of the existing undertaking, I think.

R. DHILLON: I will mark that as undertaking JT-1.32.

D. ROSENBLUTH: Thank you.

UNDERTAKING JT-1.32: PROVIDE INFORMATION ON THE NUMERICAL AND NARRATIVE IMPACTS OF DEFERRED CAPITAL INVESTMENT ON THE BUSINESS

D. ROSENBLUTH: Those are all my questions for today. Thank you very much.

R. DHILLON: Thank you, Mr. Rosenbluth. Next we have OAPPA, Mr. Walker, and the time now is 4:37.

CROSS-EXAMINATION BY S. WALKER

S. WALKER: Thank you. Good afternoon, Panel. Sorry. While we are pulling up 1-AMPCO-4, could I ask for an undertaking associated with the information you just provided to Mr. Ladanyi under 2A-EP-8 question C, the number of DERs that you are reporting in your answer differ from those reported in your DSP, specifically 2A, tab 1, schedule 1, 5.2.1, page 19.

There is a difference between the capacity and the number of installed units. Could you reconcile that for me?

J. BUTLER: Yes, we can take that undertaking.

S. WALKER: Awesome. Thank you.

R. DHILLON: I will mark that undertaking as JT-1.33.

UNDERTAKING JT-1.33: RECONCILE THE DIFFERENCE IN THE NUMBER OF DERS REPORTED IN 2A-EP-8 QUESTION C AND THOSE REPORTED IN THE DSP, 2A, TAB 1, SCHEDULE 1, 5.2.1, PAGE 19

S. WALKER: So I am trying to get a bit of an understanding in terms of, you know, Mr. Garner referred to it earlier today, the sense of system hardening that is happening and the contributions that DER and load displacement generation provide to the system kind of innately.

I know there is a lot of money that is being asked for in terms of the information technology to deal with DERs over the coming period. And in referencing 1-AMPCO-4 here, I see that your SAIDI and CAIDI performance measures are improving pretty dramatically from the beginning of the last rate period from 2019 through.

In your evidence you filed, you know, by the end of 2023, you had -- I am going to get this number not quite correct -- 6,300 DERs installed in the system, 340-some-odd megawatts of capacity.

I guess maybe I should ask you a general question. I know that a lot of the SAIDI and CAIDI numbers stem from outage -- equipment failures that are precipitated by age and stress and strain that are put on it. Mr. Butler, you had referred to, in your address to Mr. Ladanyi, about how the system was designed for one-way flows. And so the benefit of the DER, obviously, is that it helps with that problem, and it eases system constraints, et cetera.

So it is a bit of a generalized question, but based on sort of the improvement SAIDI and CAIDI

numbers, how much of that is due to the DERs of the load displacement generation generally? Have you reviewed that?

J. BUTLER: Yes, Mr. Walker, I just want to clarify we are talking SAIDI and SAIFI here, not CAIDI but --

S. WALKER: Sorry.

J. BUTLER: Yeah, it is cool.

But at this point, actually, again, for a number of different operational safety reasons, when the system power is lost, a breaker opens at a breaker, any DERs connected also disconnect. So the reliability improvements -- and they are improving, but if you note 2025, we got worse. So it is -- you know, we regressed last year. But that is not due to DERs or load displacement generation.

S. WALKER: My question was more around it provides support for existing equipment that might not wear and tear on it necessarily the way it would if the DERs, if the load displacement generations weren't necessarily in the system.

J. BUTLER: I am not sure it has an impact on -- it is dropping load overall. So I could say from an overall loading perspective, it will, you know, bring the load down, and so there is an effect of that as well. But I don't know if it is at a material level yet. I don't think it is at a material level yet.

S. WALKER: Okay. Maybe a little bit further on

this line, could I ask you to pull up 2A-SEC-29B.

So I was impressed by this. Clearly, power systems design and software have moved a long way since I ever last looked at it. I see how you have been able to actually break down the SAIDI and the SAIFI numbers based on capital installations and their contribution to that.

Within the context of the fact that, you know, you have -- you are installing DERs, you have looked at installing DERs, is there a possibility of evaluating through your software, through your modelling, the contribution that DERs might have in terms of improving your SAIDI and your SAIFI numbers?

J. BUTLER: Mr. Walker, at this time, with the systems we have -- and, really, there is -- especially on, like, the large volume of DERs we have are -- like, with the micro-fits and that, we have no visibility of their operation, of when they are operating and when they are not operating. So just given the relative granularity and access to information we have, I don't see it feasible being able to make that calculation at this point in time.

S. WALKER: Yeah. Fair enough. I wasn't sure that it could be, but I thought that I would ask. I mean, you speak a fair amount of it in your system plan about how it is a significant part of improving your reliability and the system moving forward. I was just wondering if you had started to think about

how you are quantifying that and how that is maybe having some impact on existing operating and maintenance or capital expenditures.

J. BUTLER: No. Alectra views DERs as an important component of the overall solution for the grid going forward, but we haven't been able to quantify that at this point.

S. WALKER: Okay. Fair enough. Thank you.

Relatedly, if I could trouble you to pull up -- well, actually, let's just stay here, 2A-SEC-28. And the answer to A on the next page, I guess. I have the wrong reference, my apologies. Could we go to 2A-SEC-63. And the next page, please. The section that talks about reactive power a little bit further down.

D. COBAN: Can you give us a page number, please?

S. WALKER: Yeah, I am sorry, I didn't actually write it down. Sorry. The basic gist here is that you have reactive capital renewal projects approximating, you know, $179 million over the current 2019 to 2024 period.

Is there any element of the reactive capital program that is being obviated moving forward by the installation of DERs?

And I need to ask a silly question. When we are talking about reactive capital, we are talking about the installation of capacitors, basically. Is that

correct?

J. BUTLER: No. Sorry. In this context, reactive capital is replacing things that have failed in service.

S. WALKER: Oh, okay. Fair enough. So it is a responsive, poles are down, equipment has failed.

J. BUTLER: Correct.

S. WALKER: My complete misunderstanding.

J. BUTLER: Yeah, yeah.

S. WALKER: Yeah. I am sorry for that misunderstanding. I have no further questions. Thank you, Panel.

R. DHILLON: Thank you, Mr. Walker.

Next we have BOMA, and that is Mr. Li. I will turn it over to you; however, Mr. Li, BOMA is scheduled for about twenty minutes, 10 minutes today and 10 minutes tomorrow morning. Do you anticipate that you will be able to finish a few minutes past 5:00 today?

C. LI: Yes, I think so. It is -- yeah. The worst would be, like, 5 minutes after 5. I hope that's okay. Like, 20 minutes also.

R. DHILLON: Thank you, Mr. Li.

CROSS-EXAMINATION BY C. LI

C. LI: Okay. Just give me one second here. Sorry.

Okay. Well, good afternoon. My name is Clement Li. I am representing Building Owners and Managers

Association of Toronto. I suspect some of my questions probably touch both Panel 1 and Panel 4, but I will go ahead and ask this panel now, and, of course, stop me and let me know if it is more appropriate to save this question for Panel 4, but, anyway.

Actually, you know what, before I start with my regular question, I want to have a quick follow-up question regarding your earlier exchange with Mr. Harper regarding building electrification.

During the exchange, you guys were looking at your evidence. Let's turn there, table 5-3 -- I am sorry -- table 5.3.1. It is actually in Exhibit 2A, tab 1, schedule 1, page 91. And that is, yeah, table 5.3.1. I just want to make sure that I understand correctly what you said during the exchange. So -- there we go. Yes, yes. There we go. Okay.

So you mentioned that in the last category, even though it is listed as transportation and electrification, the driver is really all transportation. Because how I understand what you said is building education only impacts your winter peak, and you expect in 2031, your system in the winter still has enough capacity to handle all the load growth of building amplification; do I understand it correctly?

T. WASIK: Yes, that is correct.

C. LI: Okay. Okay.

So having said that, I am going to take you to another exhibit. Having said that, if you go to evidence, Exhibit 2A, tab 1, schedule 1, appendix J, there are two figures there. Go to figure 22 and 23 there just together. Sorry. I don't have the page number there, but...

Okay. Okay. So -- so that is okay. So these are winter -- these are winter planning system forecasts, I guess, and one is 1-in-2, and where the correction was, I guess one is 1-to-10. It doesn't matter.

So my question is the additional load from building electrification is due here, right, in these numbers, even though it is not triggering any, I say, capital investment, but the load is still included as part of, like, whatever is shown here? Let's say, for example, in 2031, medium scenario, you have, like, 50 whatever, 57, something like that, 5,700 megawatt, so the electrification -- the additional electrification load is included; it is just not triggering investment; is -- do I understand it correctly?

T. WASIK: That is correct.

C. LI: Okay. Okay. I just want to make sure that I understand correctly.

So let's go back to my first original question, so that is BOMA Number 1, the IR response. But let's not go there because in part A and part B, your

response refer me to SEC-26. So let's go to -- sorry -- let's go to SEC-26. If you go to page 2, table 1, and -- there we go. Yes -- and you list all the assumptions, right, between the two forecasts -- one is -- I call that the billing -- the charge determined forecast is on the right-hand side, and then the left-hand side is the system peak forecast rate. Okay.

So the first thing I noticed is the CDM impact is missing in this table. Now, I understand, in the same IR in your response in part E, that you mentioned that you use different methodologies to estimate impact of CDM in these two forecasts. In the charge-determined forecast, you do not really have a separate CDM variable, and you stated that the historical usage captures the trend, and so you don't really need a separate CDM variable. But if you go to -- but then in your system -- planning system forecast, you do have explicitly -- explicitly, you have the CDM impact there.

So if you turn to your evidence again, Exhibit 2A, tab 1, schedule 1, appendix J, back to where we were, figure 12. Figure 12. Sorry. There we go. There we go. Okay. So I can see that clearly by, again, 2031, the impact of CDM is a reduction of 200 megawatt on your planning forecast; is it correct?

T. WASIK: Yes, that is correct.

C. LI: Okay. All right.

So how does this compare to what is included in your charge determined forecast? Like, did you try to compare, or are you telling me that there is no way to compare because really -- because it is not modelled separately?

T. WASIK: So, Mr. Li, I can speak to the methodology upon how the CDM impacts were included in the non-coincidental system peak forecast, but I can't speak to the energy efficiency and CDM as was done by the Itron contractor for the customer and billing revenue.

But what I can tell you from the perspective of inclusion into the system peak forecast is that we followed the methodology as laid out by the Ontario Energy Board's load forecasting guideline, and we incorporated the CDM peak demand reductions as presented to us by the IESO and incorporated that into our forecast.

C. LI: Yeah, I understand that.

But I guess my question is how -- I know you cannot speak to it. So how does it work? Like, do I wait until Panel 4, or --

D. COBAN: Well, actually --

C. LI: -- who can speak to that?

D. COBAN: Yeah, Mr. Li, questions for Itron with respect to their models, we have agreed that we are just going to deal with those by way of undertaking. So if you would like to --

C. LI: Okay.

D. COBAN: -- submit that in writing, we can introduce those on the record once we receive them from you.

C. LI: Oh, so it has to be -- I cannot just trigger an undertaking here; it has to be in writing?

D. COBAN: We can record it here. That is fine.

C. LI: Yeah, yeah. Can we do that? Because that is my question, right?

D. COBAN: Yeah.

C. LI: So my question is -- well, you already explained basically how you do it in the system, the planning forecast when it comes to CDM impact, and I understand that.

My question is how does it compare to the one that is included in the charge determined forecast? Did you do the comparison? If you did, is it about 200 megawatt? Is it about the same in terms of the magnitude? Can you do that comparison for me as part of an undertaking? That is the CDM impact in the charge determined forecast.

D. COBAN: Okay. We'll give that --

C. LI: In terms of megawatt.

D. COBAN: -- an undertaking number, and just to be clear, you know, we will take that away and consider if we can provide what you are looking for here, obviously recognizing we have to coordinate with Itron on this.

C. LI: Okay. All right. Thank you. Thank you. Okay.

R. DHILLON: I will write that down as Undertaking JT-1.34.

UNDERTAKING JT-1.34: PROVIDE, IF AVAILABLE, A COMPARISON OF THE CDM IMPACTS INCLUDED IN THE NON COINCIDENTAL SYSTEM PEAK FORECAST AND THOSE INCLUDED IN THE CHARGE DETERMINED FORECAST, INCLUDING THE MAGNITUDE OF THE IMPACTS

C. LI: Okay.

Let's scroll down to -- sorry. Let's scroll down to BOMA, the same IR, but part C. After reading the response, it is still unclear to me --

J. MYERS: Sorry, Mr. Li. Which IR? We are in an SEC one.

C. LI: I'm sorry. BOMA -- oh, this is back to BOMA part C. This is the IRR --

J. MYERS: BOMA 1?

C. LI: -- BOMA Number 1 -- BOMA Number 1, part C.

J. MYERS: Thank you.

C. LI: Yes. Yeah.

Okay. So we are talking about AI and data centre and all that stuff here, right. So it is still unclear to me what is the assumptions when it comes to that load in the two separate forecasts. On one hand, if I read the first part, it sounds like you are telling me that the data centre or 425

megawatt increase -- that is how I quoted -- is indeed included in the charge determined forecast.

But on the other hand, if I read the rest of the response, it sounds like you are telling me that you are including less because of all the uncertainty of this kind of load. Can you clarify? Is it about -- because in the planning forecast, I see you -- clearly it's quoting 425 megawatt increase. But can you clarify in the charge determined forecast what is included?

D. COBAN: I don't think this panel can speak to the revenue forecast, Mr. Li.

C. LI: Oh, okay. So -- so can we -- can we sort of roll it into the undertaking for Itron, our friends at Itron?

D. COBAN: Why don't we just give it a fresh undertaking number so we don't get confused.

C. LI: Okay. So this will be the impact of data centre and AI and cloud computing, how does it compare to the 425 megawatt impact as listed -- as in the planning forecast? In the charge determined forecast, what is it? What is the number? How does it compare to the 425 megawatt?

D. COBAN: Okay. That is fine. Thank you.

R. DHILLON: I will mark that.

C. LI: Thank you. Thank you.

R. DHILLON: Sorry. I am just going to mark that as Undertaking JT-1.35.

UNDERTAKING JT-1.35: ADVISE HOW THE IMPACT OF THE DATA CENTRE, AI, AND CLOUD COMPUTING LOAD IN THE CHARGE DETERMINED FORECAST COMPARES WITH THE 425 MEGAWATT IMPACT AS LISTED IN THE PLANNING FORECAST

C. LI: Thank you.

Now, if you go to -- now, this is an overall -- after asking all these questions, then -- then it is sort of an overall -- so -- so can you please go to evidence, Exhibit 2A, tab 1, schedule 1, appendix J, same place, but this time, go to figure 19 and figure 23. So -- okay.

So figure 19 is the summer peak that includes everything. When I say "everything," I mean, like, CDM and EV and all that. And then figure 23 is the winter peak that includes everything but is -- for winter, is more specific, is medium decarbonization scenario. And I think both of them are 1-in-2 where the correction lies. It doesn't really matter. But --

So -- so you have to trust me on this one because I did some calculations. When I look at these two figures, for summer, between 2024 and 2031, looking at the numbers, the compound annual growth rate for the summer peak in figure 19 is 3.2 percent. And then for the winter, if I do the same thing, it is 4.2 percent. So they grow at probably 3 -- 3 to 4 percent, both of them.

So I sense that it probably is going to go to Itron again. But then when I go to the other evidence, Exhibit 3, tab 1, schedule 1, attachment 3-1, which is also OEB appendix 2ID, if you go there, I am sure it is going to be Itron. I am sorry. If you go to column AB to AF, that is where it shows the percentage -- year-over-year percentage change. And I am looking at two specific tables; one is the demand table, and the other one is the consumption table.

If you scroll down -- because I think you've started with actual, and the bottom is the -- you have to go back to the left-hand side to see the label of the table, then there is, like, the weather-corrected -- yes, weather-normalized -- I am sorry -- weather-normalized consumption and demand table, right.

And if you scroll to the right now where the growth rate is, like, go back to column AB. Okay. There we go. In the -- again, you know, you have to -- you have to -- subject to check, I guess, because when I did some -- well, you can look at it. In the demand table, the annual growth rate, they are pretty low.

And I sum it up -- I know it is not right, but I sum it up because you are missing residential class and the GS less than 50KW class because they are both energy billed.

So -- but if you just sum it up, the annual growth rate for the same period, 2024 to 2031, is, like, half a percent. But then I said, this is not -- this is not fair, because I am not including residential and GS50KW. So I used the consumption table as a proxy. So if I do that and sum up everything, the total load growth, again, annual growth rate for the same period, is, like, 1.5 percent.

So that is my question.

So in the -- in the other part, the planning forecast, winter and summer, we are looking at 3.2 -- 4.2 percent annual growth rate, but if we look at the charge determined, then it is growing at -- whatever, 0.5 or 1.5 percent growth.

Is that what you expected when you look at it? Did you -- did you do a comparison? Does it make sense? I understand that, obviously, these two forecasts have different assumptions and purposes, but many things are common or consistent. So is it what you expected, or can this panel comment on that? Did you guys have an internal discussion about this?

D. COBAN: I think, Mr. Li, this panel can speak to you about the system planning forecast and the basis for that. I think this kind of reconciliation you are trying to do here with the live models is -- you know, we are sort of challenged by, first of all, following your thread on it and then, second, given

the kind of detail you need.

So I might suggest we just punt this to Panel 4. If they can assist you, they will; and if not, it will be something we have to take away as part of a Panel 4 undertaking.

C. LI: Right. Can I actually -- now that I think about it, can I -- it just dawned on me. Maybe it would be really helpful if I can draw an undertaking to sort of summarize this question that I have so far.

If you go back to the SEC-26 table, you know, where it actually lists the difference in terms of assumptions between the two forecasts. So if you go to page 2, table 1, yeah, there. Do you think it is possible to expand this table? First of all, I need to add category. I need to add CDM. I also need to add AI or data centre as additional roles.

But then on top of just listing the assumptions, can you also have the demand too, the volume or the percentage growth rate and the rationale why they are different, like, to sort of sum up all my questions in a way today, right? It is all about this.

Is this a difference between charge demand forecast and the planning forecast? The assumptions are here already, but then I missed two categories, CDM, and then you have the AI data centre and then the percentage annual growth rate in the period 2024 to '31, or if you want to do '26, that is fine,

whatever, around there, and megawatt difference and then the rationale behind it, why they are different. Is it something that you can do as an undertaking?

D. COBAN: Sure. We will take that undertaking. There was a lot to follow in your exchange, so, you know, we will need to kind of review the transcript and make sure we are clear on this. But just so --

C. LI: I am happy to -- I am happy to jump on a call and maybe offline just explain what it --

D. COBAN: Yeah.

C. LI: Yeah, yeah.

D. COBAN: We want to make sure all the parties have access to the same information.

C. LI: Yeah, yeah. Oh, okay.

D. COBAN: So if you want to put it in writing and send it to us, that is helpful, and then we will make sure it is entered on the record exactly as you intended. I am just mindful that we are at 5:00 p.m., it has been a long day. You know, I don't want to miss anything.

C. LI: Sorry. You know what, I will submit it. I will submit it, then, as an undertaking. Why don't we leave the previous undertaking, and then I will submit a new one, and if I feel that it can replace the other one, then I will go ahead and mention that. But I definitely will draft a new undertaking to cover what I just said, this new table. That is okay. I will do that.

J. MYERS: So are we withdrawing JT-1.35?

C. LI: No. No. I don't think so. Not yet.

J. MYERS: Okay.

C. LI: Oh, I am sorry, which one is which? I lost track. In terms of -- because I -- I had two so far, is it correct, undertakings?

D. COBAN: Yes. You had JT-1.34 related to CDM reconciliation.

C. LI: Right.

D. COBAN: And then JT-1.35 related to data centres.

C. LI: Let's leave them, and I will draft a new one. When I draft it, I will tell you whether I want to withdraw those two. But let's leave them for now. Is that okay?

J. MYERS: That is fine.

C. LI: Okay. Okay. That is all the questions I have for today.

R. DHILLON: Thank you, Mr. Li.

That concludes Day 1 of the technical conference. Thank you to the panelists and to the participants. We will continue the technical conference tomorrow at 9:30, and we will adjourn for today. Thank you.

--- Whereupon matter adjourned at 5:10 p.m., to resume Friday, March 6th, 2026, at 9:30 a.m.