ONTARIO ENERGY BOARD

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THE ONTARIO ENERGY BOARD

Ontario Power Generation Inc.

Application for payment amounts for the period from January 1, 2027 to December 31, 2031

Technical Conference held person and virtually
at 2300 Yonge Street, 25th Floor, Toronto, Ontario
on Wednesday, May 27, 2026, commencing at 9:34 a.m.

Day 1

A P P E A R A N C E S

MICHAEL MILLAR IAN RICHLER THOMAS EMINOWICZ JEFFREY SAUER MUSAB QURESHI CHRIS CINCAR TYLER DAVIDS ADA LI FIONA O'CONNELL YAROSLAV PALIY ANDREW PIETREWICZ DANA WONG TINA ZHU ZUBIN PANCHAL MUHAMMAD YUNUS ASHLEY SANASIE TINA LI	Ontario Energy Board
DALIANA COBAN ANDREA BROWN BRYAN ICYK JENNIFER VULANOVIC MELISSA LAUNDRY LORI PATCHETT AIMEE COLLIER CHARLES KEIZER ARLEN STERNBERG JONATHAN MYERS JON SILVER	OPG
SHELLEY GRICE	Association of Major Power Consumers of Ontario (AMPCO)
CLEMENT LI	Building Owners and Managers Association (BOMA)
TOM LADANYI	Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)
LAWRIE GLUCK	Consumers Council of Canada (CCC)
TOM LADANYI	Energy Probe Research Foundation

A P P E A R A N C E S

MAIA CHASE	Independent Electricity System Operator
KEITH PINTO	Keith Pinto
DANIEL VOLLMER	Minogi Corp.
SCOTT WALKER	Ontario Association of Physical Plant Administrators
COLIN FRASER BOHDAN DUMKA	The Society of United Professionals
MIKE MCLEOD	Quinte Manufacturers Association
MARK RUBENSTEIN JANE SCOTT JAY SHEPHERD	School Energy Coalition (SEC)
DAN ROSENBLUTH BAYU KIDANE	PWU
MARK GARNER	Vulnerable Energy Consumers Coalition (VECC)
COLM BOYLE	WTFN Investment Holdings LP
NICK PENDER MATT SIKSTROM MARC CHIDIAC NICOLE FABBRO MELISSA HANNON MATTHEW KIRK	Panel 1 – Hydroelectric Operations and Hydroelectric Projects and Projects and Market Renewal Program

I N D E X O F P R O C E E D I N G S

I N D E X O F P R O C E E D I N G S

U N D E R T A K I N G S

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Wednesday, May 27, 2026

--- On commencing at 9:34 a.m.

M. MILLAR: Good morning, everyone. Welcome to the technical conference for EB-2025-0297, which is the OPG payment amounts proceeding.

My name is Michael Millar. I am counsel for Board Staff. And even though I am on the dais, I am only up here because this is where all the buttons are. I am a simple public servant, and I am not a member of the Panel here in this case, but I will be your master of ceremonies for today.

I am joined by my co-counsel, Ian Richler. And we also have the case managers Thomas Eminowicz and Jeffrey Sauer. There are a number of other Staffers who will be in and out through the proceeding, some of whom are here now, but I don't think I will introduce them all now because some are here and some are not. But when they are asking questions, they will introduce themselves so everyone knows who they are.

We have a very busy schedule, so, as you know, one of the things I will be doing is encouraging people to stick to the time estimates that they have given to me. But it does look like we will comfortably fit within the time that we have allotted as long as we all do our part to work efficiently.

We are going to move to appearances in a moment, but before we do that, could I turn to Ms. Sanasie

for our land acknowledgement.

LAND ACKNOWLEDGEMENT

A. SANASIE: The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many Nations, including the Mississaugas of the Credit, the Anishinaabeg, the Chippewa, the Haudenosaunee, and the Wendat peoples. This area is now home to many diverse First Nations, Inuit, and Métis. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit.

We are grateful for the opportunity to gather and work on these lands and recognize our shared responsibility to support and be good stewards of them.

M. MILLAR: Thank you, Ms. Sanasie.

Unless there are any preliminary matters that we need to address -- I suppose I should mention folks will have seen Procedural Order Number 7 yesterday which asks that the parties and OEB Staff get together to discuss a possible schedule for maybe an additional technical conference with certain experts.

What I am proposing we do -- and I had a very quick chat with Ms. Coban this morning -- is we start with some offline discussions about that, perhaps on our break or over lunch or what have you, and then when we arrive at some consensus, hopefully we will be able to address that directly on the record

because you will have seen that the Panel was going to find out about this through reviewing the transcripts. So everyone will have seen that, but I think we can deal with that later today or in the days to come.

So unless there is anything further, I propose to do appearances. And I will start with you, Ms. Coban.

APPEARANCES

D. COBAN: Good morning. Daliana Coban, counsel for the Applicants. I will be sitting here with the hydroelectric panel, and then I will be joined by my colleagues for the remaining panels, Mr. Keizer and Mr. Myers and Mr. Sternberg. With me today I have Saba Zadeh VP of regulatory affairs at OPG.

And, Mr. Millar, is this a good time to introduce the Panel to the room?

M. MILLAR: Yeah, why don't we do that.

D. COBAN: Perfect. Thank you. I will pass it over to you, Mr. Pender, to introduce yourself and your colleagues. Thank you.

N. PENDER: Good morning. Good morning. My name is Nick Pender, senior vice president of Renewable Generation and Energy Markets. I will hand it over to my colleague, Mr. Sikstrom.

M. SIKSTROM: I am Matt Sikstrom. I'm a project director for our Renewable Generation Major Project Group.

N. FABBRO: Good morning. My name is Nicole Fabbro. I'm the vice president of regional operations.

M. CHIDIAC: Good morning. I am Marc Chidiac. I am vice president of energy markets.

M. HANNON: Good morning. I am Melissa Hannon, vice president of finance.

M. KIRK: Morning. Matthew Kirk. Director of regulatory affairs.

M. MILLAR: I will just ask the court reporter, did you get all the spellings for that, or do you already have the names? Do you need anything further from the witness panel to identify them? We are trying to get some actual nametags down which hopefully will help. I just want to make sure you have the spellings of the names.

--- (Court reporter confirmation)

M. MILLAR: Great, thank you very much.

Back to you, Ms. Coban. Are you finished?

D. COBAN: All done.

M. MILLAR: Okay. Thank you. We will go around the room. For members of Staff, I don't think you need to introduce yourselves right now. We will do that when you are -- when it is your turn for questioning. *

But I will start with you, Mr. Rubenstein.

M. RUBENSTEIN: Good morning. Mark Rubenstein, counsel for School Energy Coalition, and I will be

joined throughout the technical conference by SEC consultant Jane Scott and also SEC counsel Jay Shepherd.

M. MILLAR: Thank you, Mr. Rubenstein. And good morning, Ms. Scott.

Mr. Buonarguro?

M. BUONARGURO: Good morning. Michael Buonarguro. I am counsel with the Consumers Council of Canada. Also joining me throughout the tech conference in the proceeding will be Lawrie Gluck, consultant for Consumers Council of Canada.

M. MILLAR: Thank you very much.

Is there anyone else in the room? Okay. Not seeing -- normally I have a list of people and I do a role call for those who are online, but I am actually not sure who is here today, so this may be a little bit of a free-for-all. I am going to start with people I actually see on the screen.

So, Mr. Walker, could I turn to you.

S. WALKER: Good morning, Mr. Millar. It is Scott Walker for OAPPA.

M. MILLAR: Good morning.

Mr. McLeod?

M. MCLEOD: Good morning. It is Mike McLeod for the Quinte Manufacturers Association.

M. MILLAR: Good morning.

Mr. Rosenbluth?

D. ROSENBLUTH: Good morning. Dan Rosenbluth,

counsel for the Power Workers' Union, and I am joined somewhere here by our colleague Bayu Kidane. I will be in and out during the procedures but obviously will be careful to ensure I am here at my scheduled times.

M. MILLAR: Great, thank you. And do keep -- we have circulated the schedule, as people have seen. That is, of course, subject to change. Times may compress, occasionally get longer here and there, so don't assume everything in the schedule is set in stone. It is re-released at the end of every day. But, you know, if it says 3:40, don't assume it will be exactly 3:40. But thank you. Good morning. Welcome.

Mr. Boyle?

C. BOYLE: Good morning. Colm Boyle, and I am here on behalf of WTFN Investment Holdings LP.

M. MILLAR: Good morning.

Ms. Grice?

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

M. MILLAR: Mr. Ladanyi?

T. LADANYI: Good morning. My name is Tom Ladanyi. I am an independent consultant representing two intervenors, the Coalition of Concerned Manufacturers and Businesses of Canada, which is a group of more than 400 manufacturers and businesses

mainly located in Ontario. I also represent Energy Probe Research Foundation, a public interest group that has been active in OEB proceedings since the 1980s.

I do not plan to ask any questions during the technical conference because I expect that other intervenors will cover any areas that are of concern to CCMBC and Energy Probe.

M. MILLAR: Thank you, Mr. Ladanyi.

Mr. Li?

C. LI: Good morning. Clement Li. I am here on behalf of Building Owners and Managers Association of Toronto.

M. MILLAR: Thank you, Mr. Li.

Could I ask folks who have already introduced themselves to go off camera. That way, people who haven't gone yet will pop up, and I can see who they are. Thanks very much.

Mr. Garner?

M. GARNER: I am Mark Garner. I am a consultant for the Vulnerable Energy Consumers Coalition or VECC.

M. MILLAR: Thank you. Good morning.

Mr. Pinto?

K. PINTO: I am Keith Pinto. I am an independent intervenor.

M. MILLAR: Mr. Vollmer?

D. VOLLMER: Good morning. Daniel Vollmer,

counsel for Minogi Corp.

M. MILLAR: Good morning.

I do not see anyone else on my screen. Is there anyone else who has joined us virtually who wishes to make an appearance?

C. FRASER: Colin Fraser here for the Society. For some reason, my camera won't turn on. I am not sure.

M. MILLAR: Okay.

C. FRASER: So I will work on that.

I will also be joined by Bohdan Dumka, and we will be sort of trading on and off over the term of the technical conference.

M. MILLAR: Okay. Good morning, Mr. Fraser.

Anyone else? Okay. Hearing no more appearances, I can turn to you again, Ms. Coban. Did you wish to introduce your witnesses again, or is there any preliminary remarks? Or can we get straight to the questions?

D. COBAN: Let's get right to it.

M. MILLAR: Efficiency. I love it.

Okay. Mr. Walker, you are the lucky person who was voluntold to go first, so over to you.

EXAMINATION BY S. WALKER:

S. WALKER: Well, thank you. Good morning, everyone. My name is Scott Walker, and I am OAPPA's consultant in this very complex application.

Some of you may not know this, but hydroelectric

generation holds a very special place in my technical heart having spent some of my early years in hands-on exposure to the Ottawa River assets and then having had executive management oversight of the Rankine Generating Station while she was still a functioning generating facility, which was before they turned her into a museum, which admittedly I still find quite unsettling.

So I do want to thank Panel 1 for being here, for providing us with the opportunity to more fully and openly explore some of the issues.

However, in re-reading the evidence and numerous of your IRRs these last few days, I have somehow managed to ask the majority of the -- answer the majority of the questions that I had originally intended you, so therefore, I should be well under my time allotment this morning.

So if I could just beg your indulgence to better help me understand a few items that are not yet fully aligning in my mind. And if I could ask that Exhibit A1, Tab 2, Schedule 2, page 4 of 10 be brought up for reference, please. Starting there at line 9.13. Yeah. Maybe if you can bring that up so the whole thing is shown. Awesome. Thank you.

There is a lot of verbiage here. And so, broadly, are you effectively saying in this paragraph that you want to be compensated based on the difference between your actual 5-minute hydroelectric

production in real time versus the committed day-ahead forecast at the real-time locational market price? Do I have that correct?

M. CHIDIAC: Mr. Walker, could you please repeat the question.

S. WALKER: Fair enough. Okay. Are you effectively saying that you expect to be compensated based on the difference between your actual 5-minute hydraulic production versus what you pre-committed in the day-ahead forecast at the real-time locational market price?

M. CHIDIAC: The intent is for OPG to be paid for its real-time production in the market. This paragraph describes the interaction between the day-ahead and real-time interaction; however, OPG's proposal is to be paid on its real-time production in the market.

S. WALKER: All of it at the real-time locational marginal price?

M. CHIDIAC: That is incorrect. It would be at OPG's prescribed amount for regulated hydro.

S. WALKER: Okay. So you are looking to be basically compensated for your full production; is that correct?

M. CHIDIAC: I am not sure what you mean by "full production," but we are looking to be compensated for our real-time production in the market.

S. WALKER: Okay. I just -- because the last part of that paragraph says "multiplied by the real-time locational marginal price." Why is that important?

M. CHIDIAC: That refers to an adjustment required in the market that was introduced by the IESO's market renewal program where there could be differences in either production or payments from day-ahead and the real-time. And this describes the adjustment to revenues to reflect that OPG will be paid based on its real-time production.

S. WALKER: As would be different from the prescribed regulated price; do I have that right?

M. CHIDIAC: No. It would be at the -- well, the adjustment is not at the prescribed regulated price, but the net payment to OPG would be at the prescribed regulated price.

S. WALKER: Okay. So you are currently being compensated for all production at the regulated price; is that correct?

M. CHIDIAC: At a high level, yes.

S. WALKER: Okay.

M. KIRK: Mr. Walker, can I just add one item. This is Matthew Kirk speaking. If we can just scroll up a tiny bit, I just want to make sure we are looking at the page the same way.

So in paragraph 12 there, this is what is establishing the base regulated payment amount that

we are proposing the regulated hydro facilities will receive, and then what you are discussing with Mr. Chidiac is the hydro incentive mechanism adjustment. I just want to make sure that we are understanding that point.

S. WALKER: Okay. So this is -- sorry. This is incentive-based compensation that is in excess of what you have forecasted on a day-ahead basis; do I have that right?

M. CHIDIAC: Mr. Walker, it is Marc Chidiac here again. So, yes, this is in reference to the hydroelectric incentive mechanism which is described in evidence in E121. So there is an incentive for OPG to earn incremental revenues in the market. And there are two incentive; one is a day-ahead incentive, and one is a one-time incentive.

S. WALKER: Okay.

M. CHIDIAC: Actually, the incentive can go either way. So it could be a benefit to OPG or it could be a cost to OPG if assets are not optimized appropriately.

S. WALKER: That was a question I had. Thank you for answering that.

So would this additional in-real-time market revenue be collected as a separate revenue possibly requiring a new IESO tracking code? Or is it just, like, a gross adjustment to your monthly GA OEMP payments.

M. CHIDIAC: It is paid out as a separate code by the IESO.

S. WALKER: Okay. Thank you.

I mean, you know, it is fair to say that you reasonably expect to be compensated for asset performance and productivity in excess of your day-ahead commitments. So the challenge I am having is how I reconcile these extra performance earnings against your ask for an X factor in the custom price cap IR equation.

I am sorry, and to be more pointed, is there not the potential for double-counting the performance while this real-time market incentive is in play?

M. KIRK: In terms of the X factor, Mr. Walker -- - and sorry, this is Matthew Kirk speaking again -- the proposal is in Exhibit A1-3-2, Section 2 -- 2.3.2. Sorry. That is page 11, Lori.

And it is obviously a long section. I won't go into great detail, unless you'd like, Mr. Walker, of course. But there is two components of the X factor based on studies conducted by London Economics; one is a benchmarking study, and the other is a total factor productivity study. And the results of that study are what determines the X factor that we have proposed to include as part of our rate-setting mechanism.

S. WALKER: Right. And, as you are showing there on the screen, your productivity factor is

effectively zero. Is that because of this additional revenue you are earning in the real-time market?

M. KIRK: No, it is not driven by the revenue. Productivity specifically is based on the TFP study that is industry-based. So, generally speaking, when you see, like, the negative .4 or negative .1 percent there, it is suggesting that more inputs are required to get to the same level of output, and it is -- it is fully in the study documentation of LEI, but it looks at not just OPG but the hydroelectric industry as a whole.

S. WALKER: Okay. Thank you. I mean, straight up, I do see the potential here for double-counting. I am not sure how to reconcile that, so fair enough.

So my next couple of questions are relatively straightforward. And just for context, my client is very concerned not only by the total cost of the commodity rate, but also, they have a very profound interest in how it is being allocated. But does it matter to OPG how the IESO allocates your monthly remittances between the OEMP and the global adjustment, for example?

M. CHIDIAC: Can you clarify what you mean, "matter to OPG"?

S. WALKER: I mean you just get a remittance advice at the end of the month from the IESO. Does it really matter to you how much revenue is collected from the real -- real-time market versus the global

adjustment?

M. CHIDIAC: Well, also acting as a load -- as exposure in the market to the global adjustment. But from a revenue perspective, how we are paid, I don't think it really matters from what bucket it is coming from.

S. WALKER: Okay. I think I know the answer to this, but nothing about the IRM price cap mechanism that you are suggesting is really going to change how the global adjustment payments are made. So, i.e. the difference between your OEMP revenue as made up by the difference in the global adjustment, you know, factoring in your production, of course; is that a fair statement?

M. CHIDIAC: That is a fair statement, but I will note that hydro has a very small impact to the global adjustment.

S. WALKER: Understood. Understood. Okay. Well, that is terrific. Those are all of my questions. Thank you, Panel. Thank you, Mr. Millar.

M. MILLAR: Thank you, Mr. Walker.

We are going to turn to Staff, but before we do, Mr. Boyle, are you there? There was something you wished to address.

C. BOYLE: Good morning, Mr. Millar. WTFN filed a letter yesterday with written questions that I am hoping to get marked as an undertaking in this proceeding that is in anticipation of avoiding my

oral questioning so...

M. MILLAR: Yeah. And, Ms. Coban, did you receive that letter, and are you prepared to take an undertaking?

D. COBAN: Yes, we are. Thank you.

M. MILLAR: Okay. So, Mr. Boyle, so this is Undertaking JT-1.1, and it is questions filed by WTFN on May 26th?

C. BOYLE: Correct, yeah.

M. MILLAR: Okay. Is that sufficient, Ms. Coban?

D. COBAN: Yes.

M. MILLAR: Okay. Great. So that is JT-1.1.

UNDERTAKING JT-1.1: QUESTIONS FILED BY WTFN ON MAY 26

M. MILLAR: Mr. Vollmer, did you file something as well?

D. VOLLMER: Yes. Thank you. Minogi filed a similar letter with a list of questions on last Thursday, I believe. We would also like that entered as an undertaking.

M. MILLAR: Ms. Coban?

D. COBAN: Yes, that is fine.

M. MILLAR: Okay. Great. So that is same thing for Minogi, JT-1.2.

UNDERTAKING JT-1.2: QUESTIONS FILED BY MINOGI ON MAY 21

M. MILLAR: Is that all, Mr. Boyle and Vollmer?

C. BOYLE: That is it for me.

D. VOLLMER: Yes.

M. MILLAR: Okay. Thank you.

We are going to move to some questions from OEB Staff. We have a number of staffers who will be asking questions. Up first, we have Mr. Cincar, who I see on the screen.

EXAMINATION BY C. CINCAR:

C. CINCAR: Thank you. My name is Chris Cincar, and my first set of questions relate to the SBG variance account.

My first question specifically relates to E1-Staff-148. And in that IR response, OPG noted under "identical market conditions," it is not necessarily the case that a CMSC payment in the legacy market would map to an instance of local SBG spill in the renewed market. OEB Staff had intended the questions in E1-Staff-148 to be more precise in asking about only constrained-off CMSC payments rather than CMSC payments in general, which also includes constrained-on, and we also intended to exclude CMSCs paid to nuclear. Does limiting it to only constrained-off CMSC payments and also limiting those payments to base load hydroelectric change OPG's response in relation to mapping to local SBG-related spill?

M. CHIDIAC: No, it would not change our response. It would be consistent, as in the legacy market, there was both a constrained and

unconstrained schedule where we were able to decipher the difference between the two. And the renewed market, that mechanism no longer exists. So although there would be likely significant overlap, we can't do an exact one-to-one comparison between the two.

C. CINCAR: Okay. Under identical market conditions, can OPG please explain under what circumstances OPG would be compensated for local spill in the renewed market but -- and OPG hydroelectric generator would not have received the constrained-off payment in the legacy market, and, as you noted, they would not necessarily map?

M. CHIDIAC: So sorry. Just to clarify, are you asking for examples of in the renewed market versus the legacy market of constrained-off events?

C. CINCAR: Yeah. Well, in the renewed market, you would be compensated for local SBG, and so what cases would that happen but -- and if it was a legacy market, you would not have received constrained-off payment. So, yes, I was looking for examples.

M. CHIDIAC: Well, the intent -- I am not exactly clear on your line of questioning here, but the intent of the revisions of the SBGVA for EB2023 was to capture both global and local spill events. So what was previously recovered as CMSCs in the legacy market will now be recovered through the SBGVA. Only a subset of those constrained-off events would be recovered through the SBGVA.

C. CINCAR: Yeah, well, local -- yeah, it was excluded before, and now it is included. Okay.

I have an undertaking request. As noted, the questions were intended to be more precise. Could OPG please undertake to revise Chart 1 CMSC payments received and amounts recorded in SBGVA in E1-Staff-148 by replacing CMSC payments with only constrained-off CMSC payments, and limit it to OPG's hydroelectric base load facilities.

M. CHIDIAC: Yes, we can take that undertaking. So just to confirm, you want to update the row in Chart 1, the CMSC row just to show constrained-off events for regulated hydro?

C. CINCAR: Yes, please.

M. CHIDIAC: We can do that.

C. CINCAR: Thank you.

M. MILLAR: That is JT-1.3.

UNDERTAKING JT-1.3: REVISE Chart 1 CMSC PAYMENTS RECEIVED AND AMOUNTS RECORDED IN SBGVA IN E1-STAFF-148 BY REPLACING CMSC PAYMENTS WITH ONLY CONSTRAINED-OFF CMSC PAYMENTS, LIMITED TO OPG'S HYDROELECTRIC BASE LOAD FACILITIES

C. CINCAR: Okay. My next SBG variance account-related questions will focus on E1-Staff-149; however, I will also be making reference to E1-ED-011, but only for comparison purposes.

In E1-Staff-149, OPG notes the change in methodology to reflect renewed market does not result

in overcompensation in relation to SBGVA variance account entries. During the legacy market years, it was determined that the appropriate compensation was determined using a methodology that involved SBG due to market constraints being one of the four categories that OPG intentionally excluded from the SBG variance account, as explained in the application.

However, OPG notes that SBG, due to market constraints, is now included as part of the revised methodology used to determine the variance account entries. If OPG was being appropriately compensated for SBG with market constraints excluded in the legacy market years, can you please clarify how additional SBGVA entries associated with including market constraints under the -- under the revised methodology does not result in incremental compensation for SBG.

M. CHIDIAC: So I touched on this a little bit earlier in the response, but with the change to the renewed market, OPG's proposal is to recover both global and local spill through the SBGVA. Local spill in the legacy market was recovered through CMSCs or congestion settlement management credits. So there was a recovery mechanism for those amounts through the IESO market previously, but that no longer exists in the renewed market.

C. CINCAR: Okay. Thank you.

OPG also noted in E1-Staff-149 that if the legacy market ran in parallel with the renewed market, OPG expects a meaningful overlap of instances where it experiences local spill in the presence of market constraints; however, given the multitude of sources of differences unconstrained and in-constrained run, OPG does not believe the two volume amounts will be equal. Would OPG be able to quantify meaningful overlap? For example, would that be over 95 percent or some other percentage, as OEB Staff is uncertain how material loads versus differences between unconstrained and constrained are.

M. CHIDIAC: Unfortunately, we are not able to quantify that amount without having access to the IESO's dispatch algorithm.

C. CINCAR: Okay. OEB Staff also requested historic analysis related to taking down the volume of spill due to four categories that were excluded from SBGVA entries; water conveyance constraints, production capability, market constraints, contractual obligations. In E1-Staff-149 OPG provided a table with historical spill amounts by category for the years 2019 to 2023.

In OPG's response to E1-ED-011, OPG provided total foregone production due to SBG, along with SBGVA entries, for 2016 to 2025. So one set, it was the 2023, and the other was the 2025. Given OPG did not provide spill for the four categories for 2024

and 2025, can you please confirm they were excluded from the SBGVA entries in those years.

M. CHIDIAC: Yes. I can confirm, as per the methodologies, they would have excluded for 2024 and 2025. But I will caveat that in 2025 on May 1st, the market renewal program went live, and post-May 1st, there is no longer -- market constraints are no longer removed from the spill amounts because they are no longer quantifiable in the market.

C. CINCAR: Okay. I have another undertaking request. Is OPG able to expand the table in E1-Staff-149 with the four excluded categories to align with the years in the chart in E1-ED-011, which was for the years 2016 to 2025, and also add a new row with total foregone production that includes the spill amounts for those four excluded categories?

M. CHIDIAC: So just to confirm, you are looking to extend the table to 2024 and 2025 for those four categories?

C. CINCAR: Yeah, to match the same years from 2016 to 2025 that were reflected in E1-ED-011.

M. CHIDIAC: We can take that on a best-efforts basis.

M. MILLAR: We will call that JT-1.4. I actually can't see the evidence reference here, so, Mr. Cincar, or -- would the witness just please repeat what the undertaking is for.

M. CHIDIAC: Okay. It is to update the Chart 1

in E1-Staff-149 to include 2024 and 2025.

C. CINCAR: And go back to 2016.

M. CHIDIAC: Oh, sorry. And going back to 2016.

M. MILLAR: Okay. That is JT-1.4. Thank you.

UNDERTAKING JT-1.4: UPDATE Chart 1 IN E1-STAFF-149 TO INCLUDE 2024 AND 2025, GOING BACK TO 2016

C. CINCAR: And one more question. Now that market prices now include congestion in the renewed market, when congestion is negative, would that be an indicator of local SBG spill?

M. CHIDIAC: Yes, it could be a potential indicator of local SBG spill.

C. CINCAR: Thank you.

Okay. My next set of questions -- I am moving on from SBG, and my next set of questions relate to the HIM and the removal of the revenue sharing above the threshold. And I will be referencing E1-Staff-146.

In that OPG response, E1-Staff-146, OPG confirmed changing the designation of the PGS to energy storage facility would essentially result in an implementation of option for OPG's SBG study since both would result in the exemption from transmission network service charges.

OPG also indicated that option 1 provided the strongest incentive in terms of [indiscernible] production.

OEB Staff asked in E1-Staff-146 if PGS was

treated as an energy storage facility, would option 3 in OPG's study eliminating HIM revenue sharing above the threshold still provide an incremental incentive to OPG time shift production.

Before I get into my specific questions, can OPG please first confirm that the PGS is no longer paying transmission rates due to the EB 2022-0325 decision which exempted energy storage facilities from paying transmission charges.

M. CHIDIAC: That is correct.

C. CINCAR: And does OPG agree that if two options were implemented that are intended to achieve the same outcome, benefit associated with the second option that is implemented would be lower than it would as a stand-alone option? For example, if OPG got the GRC exemption under option 2 in the SBGVA study and subsequently got the variable load charges exemption under option 1 in that study, would OPG agree that the benefits associated with option 1 would be lower than those currently reflected in the study that was filed?

M. CHIDIAC: Sorry. I was -- had a hard time following that line of questioning. Could you please repeat the question.

C. CINCAR: Okay. Say OPG got the GRC exemption under option 2 in the study and subsequently got the variable load charge exemption under option 1 in the same study. Would OPG agree that the benefits

associated with option 1 that was subsequently implicated would be lower than the benefits reflected in the SBG study that was filed?

M. CHIDIAC: Sorry. Are you asking if we got the GRC exemption, which is option 2, and then applied option 1, which is the load charge exemption, if that benefit would be lower?

C. CINCAR: Yes. If that benefit would be lower than it would be as a stand-alone option in the study that was filed.

M. CHIDIAC: No, the -- if you can combine the two, the benefit would be greater. And that was -- that was --

C. CINCAR: It would be additive? Just add up the --

M. CHIDIAC: It is not directly additive, but the benefit increases.

C. CINCAR: But it would be lower, right, than -- this second option that is implemented would not realize the same level of benefits that you affected in the study, is my question. Since you have achieved some of those benefits with the other option.

M. CHIDIAC: I wouldn't want to -- so I don't want to speculate on results without running through the modelling and understanding your question in more detail.

C. CINCAR: Okay. Staff asked if eliminating

HIM revenue sharing above the threshold still provided an incremental incentive, how material would it be if the PGS is exempt from transmission charges, which we now know they are.

OPG's response noted it would provide an additional incentive and added OPG cannot conclude how material that additional incentive would be.

The question is, is OPG able to advise approximately how much of the time shifting of production and elimination of HIM revenue sharing would have incentives as a stand-alone option; would already be realized due to the PGS avoiding network service charges due to the storage designation as OPG is -- as OEB Staff assumes that there is a limit in terms of how much OPG can time shift?

M. CHIDIAC: So is your question is there an upper limit on how much the PGS can time shift?

C. CINCAR: I guess is -- like, how much of the time shifting of production that HIM revenue sharing above the threshold would have -- like, in the study it didn't reflect OPG's storage being exempt from paying transmission rates. And that was essentially option 1.

So if elimination of the revenue sharing was -- I guess to what extent would the shifting of production be reduced that would be associated with HIM revenue sharing above the threshold as a result of PGS being exempt now from the network service

charge?

M. CHIDIAC: So as we have commented in the IR response, we are not able to quantify and measure the benefit.

The HIM sharing results in -- essentially, it dilutes the incentive because it creates a larger economic barrier from utilization of the PGS, and that could be exemplified in the SBGVA study. So if we could pull up Exhibit E1-2-1, Attachment 1, page 21 of 36, HIM. Thank you, Lori.

So Chart 9, you can see in both scenarios the required price spread to utilize the PGS.

So in scenario 1, which assumes 50 percent sharing above the threshold, that would require a price spread between the on peak and off peak of $14.90. And in a no HIM sharing scenario, that spread is only $8.20, so almost 80 percent lower in a no sharing scenario, which would result in incremental utilization of the PGS if we had not shared the HIM revenues above the threshold.

C. CINCAR: Okay. Thank you.

Given OPG's finding in the SBGVA study that elimination of variable load charges under option 1 would increase the price spread required to economically cycle the PGS and allow the PGS to operate in up mode at all hours of the day, how does OPG expect its HIM revenue forecast and SBG variance account balance to change from what was filed in the

pre-filed evidence given that PGS is no longer paying transmission charges, they represent the variable -- represent the bulk of the variable load charges under option 1?

M. CHIDIAC: So we have not updated our analysis to demonstrate the impact of the energy storage designation of the PGS. But I would expect the results would be similar -- similar to the option 1 that was provided in the SBGVA study, which is included in the Chart 2 on page 11 of 36 in the same attachment.

C. CINCAR: So it would be essentially the same as option 1?

M. CHIDIAC: Not as -- I think a little bit lower because we have not excluded all load charges with the designation of the PGS. It only eliminates the network service charge, which is about two-thirds of the load charges. There is still IESO administrative charges that we will incur. But I think directionally, the results would be similar and -- but a bit lower than what is described here in Chart 2.

C. CINCAR: Can you please undertake to redo that analysis, reflecting the, I guess, reality now with the PGS no longer paying transmission charges.

D. COBAN: Mr. Cincar, that sounds like an onerous analysis to undertake within the context of this process. So at this time, we are not prepared

to do that.

C. CINCAR: Okay. Okay. We'll basically reflect option 1, then -- or consider it to be essentially the same as option 1.

Okay. My final question is related to HIM revenues, and I will be referring to G1-Staff-242 and G1-CCC-096.

In G1-CCC-096 OPG included a table setting out actual HIM revenues. For 2025, you are able to conclude -- include actual revenues to replace the forecast in the application, and actual revenues increased by over $20 million to 49.7 million in 2025 compared to 2024. That followed HIM revenues increasing by close to 15 million the previous year. It's therefore now two consecutive years of significant increases, with the larger increase in 2025.

Can OPG please explain the key factors contributing to those significant increases in HIM revenues over the last two years after many years of being flat and the substantial difference from OPG's forecast for 2025, which was $39.2 million lower at 10.5 million?

M. CHIDIAC: We endeavoured to respond to that question in Staff 242, part A, in terms of how volatility drives up HIM revenues. And I would say 2024 and especially 2025 were analogous years in terms of whether -- so we saw in 2025 a very hot

summer followed by a cold winter, and that drove up quite a bit of volatility in the market. So that is generally what resulted in the higher HIM revenues in those years.

But, again, if you look in the chart in CCC-96, Chart 1, for the most part from 2016 to 2023, our revenues were below 20 million. So 2024 and 2025 were really standout years largely driven by abnormal weather. And from a forecast perspective, our forecast for the HIM is based on weather normal conditions, which is why you might see a more tempered forecast.

As well, we assume that the 3,000 megawatts of battery storage assets coming online in the IESO market by 2028 will significantly reduce price volatility in the Ontario market, which will limit our ability to earn incremental HIM revenue.

C. CINCAR: Isn't much of that storage already in operation like Oneida? I think you included Oneida in that.

M. CHIDIAC: Correct. Oneida is a 300-megawatt facility, and there are 3,000 megawatts coming online. So by the end of '25, there was maybe 300 megawatts of battery storage online; and by the end of '28, we will have 3,000. So only about 10 percent were online by the end of 2025.

C. CINCAR: How does this new information related to actual HIM revenues for 2025 impact OPG's

HIM revenue forecast of 17.8 million for 2027 given OPG indicated in G1-Staff-242 that the HIM revenue forecast is based on the annual average over five years before the IR term?

M. CHIDIAC: Sorry, that is not correct. The forecast is not based on the annual average. I think the comment in the IR response was the forecast of 17.4 million was very close to the five-year average, but the forecast is derived based on our modelling methodology which is both described in E-1-21 and H1-1-1.

So to confirm, it is a model that -- for the HIM forecast in 2027.

C. CINCAR: You have had two years of major increases now, and this might be the new normal, what you are referring to as abnormal weather now that we are seeing. So I am not sure how -- are you basically -- how are you taking what happened in 2025 into account?

M. CHIDIAC: Well, I am not going to speculate on what weather is going to look like for the five years, but as I mentioned before, we take a weather normal approach which takes into account some volatility in weather but not the extremes. So I would say the aberrations in 2024 would have been included in our weather forecast, which will drive the HIM; however, the 2025 amounts were -- weather data was not available at the time of submitting the

forecast, so those would not be included.

But, again, as -- our modelling uses weather normal, and that is the most appropriate mechanism to forecast the revenues moving forward.

C. CINCAR: Okay. Thank you. That was my final question. Thank you for the clarifications and agreeing to my undertaking requests.

M. MILLAR: Thank you, Mr. Cincar.

We will move, Mr. Eminowicz, to you now. Thanks.

EXAMINATION BY T. EMINOWICZ:

T. EMINOWICZ: Good morning, witness panel. I am Thomas Eminowicz, and I am a senior advisor with Ontario Energy Board Staff. The questions that I will be asking right now relate to the hydroelectric capital plan, so these are high level, kind of general questions. I am generally interested in understanding some of the project classifications or the vocabulary that OPG used in the evidence when describing and substantiating the basis for the work that OPG performs and plans to perform on hydroelectric assets.

If we could please start with interrogatory response to D1-PWU-001. Thank you.

So this is an interrogatory that requests some clarity on definitions on some of the project types. And we can see in Chart 1, there are generally, seems like, four categories; refurbishments,

redevelopments, rehabilitation, and expansion. And the response here points to other sections, sections in Exhibit F1. So I would just like to confirm kind of the understanding of what these kind of types of projects mean.

So refurbishments in Exhibit F1-1-1, Section 3.2. I will just continue slowly here as we get it on the screen. So it looks, at least the way it is presented here in Section 3.2.1, that refurbishments and overhauls are kind of generally grouped together.

So I guess my first kind of basic question is, is it fair to understand that these kind of happen together, or could they happen independently of each other?

N. PENDER: They can happen together. So one is an OM&A type of project, and one is a capital type of project. So depending on the investment, they can be separate.

But for the capital work, typically there is always a component of OM&A included in there. We can give you further detail if necessary.

T. EMINOWICZ: Thank you. You are kind of already getting ahead.

So I guess is there any sort of, like, generalization, or is it just -- like, the decision to do one or the other or the timing, it is just -- it is so varied that you wouldn't really generalize between overhauls and refurbishments on units?

D. COBAN: Maybe you could just -- for my purpose as well, just help us understand what you mean by "generalize."

T. EMINOWICZ: Well, I see that the section kind of groups them together, and so I am just wondering, when there is a project that OPG undertakes, is it fair to say that overhauls and refurbishments happen together? Or could there be overhauls that are done independent of refurbishments? And I am just wondering -- like, I am not trying to ask for exhaustive details. I am just wondering, generally, does one happen without the other? And if they do, like, how does OPG decide to do an overhaul versus a refurbishment on a unit?

N. PENDER: So our decision on a project is fundamentally driven by asset condition, and given the asset condition, that will set a scope of work. That set scope of work has defined criteria for treatment for the type of money, whether it is OM&A or capital. So there is some fairly clear rules around delineation of, when we are doing major work on a unit, what is considered OM&A work and what is considered capital work.

T. EMINOWICZ: And is there, like, a general kind of summary of how that decision is made already on the record? I assume it is; I just can't recall, to my memory so...

N. PENDER: It is on record. We have a

capitalization policy which details the specific breakdown, if you -- we can find the reference to that, if that is helpful.

T. EMINOWICZ: I think control F1 "capitalization policy" should be good.

So just because I am trying to wrap my head around the different terms, I just want to confirm I have a common understanding of this type of work that I can kind of have in the same place as the other types of work.

So is it fair to say that the overhaul work, the OM&A work, is about sustaining the assets and that refurbishment work is about extending the life of the equipment and may also increase the ability or, like, the potential for production? And so I am kind of looking at, I think, lines 10 through 15 on the next page, I think it is.

N. PENDER: That is where I would direct you to the definition. That was where I would look for treatment of what OM&A gives you and treatment of what capital gives you, lines 10 through line 15.

T. EMINOWICZ: Perfect. Thank you so much.

And so now in Section 3.2.2, we have redevelopment, and so this is another section that has a helpful, straightforward definition right at the start of the section that identifies that this is primarily about -- or entirely about extending the life of existing assets; is that fair?

N. PENDER: I would use the word "primary goal," but you are correct, lines 2 and 3 define what we mean by "redevelopments."

T. EMINOWICZ: And so is it fair that the core kind of distinction from a refurbishment is that we are talking about, like, a collection of assets? Like, I see the word "population of assets," so would this be kind of, like, on a station level as opposed to on a unit level; is that fair?

N. PENDER: Could you give me the reference? Sorry. I don't see the word "population."

T. EMINOWICZ: It is -- so Section 3.2.2 on line 3 says:

> "Necessary to address a population of deteriorated or otherwise end-of-life assets." (as read)

N. PENDER: Thank you. Yes. So we can -- I think when we are referring to the word "definition," we are talking specifically about specific deteriorated or end-of-life assets as detailed. So, yes, there are a number of stations in that category, which that is the population.

T. EMINOWICZ: And just conceptually, could there be, like, a refurbishment -- could a redevelopment include refurbishment work, but it is just there is more of it, like more assets?

N. PENDER: I will hand to my colleague Mr. Sikstrom to give you a further definition.

M. SIKSTROM: Yeah, as is mentioned in Section 3.2.2 there, it could include the replacement of a significant portion of generating station equipment. It could also include the replacement of existing civil infrastructure as well.

T. EMINOWICZ: Thank you. And that kind of note on civil infrastructure, is that -- like, are redevelopment projects generally also including civil infrastructure, or is it just kind of -- like, this example mentions it, but civil work is not necessarily common or general to redevelopment projects?

M. SIKSTROM: They may include civil work. It depends on the condition of the assets at the particular facility.

T. EMINOWICZ: Thank you.

So the next kind of category that was mentioned in the interrogatory was rehabilitations, and so this is -- was referenced to section 3.2.4 or 3.2.5. Luckily, they are kind of together. And so for this kind of group or the use of the word "rehabilitation," it is more of a description of projects, so this is kind of what I was trying to kind of help myself understand.

Is -- in terms of, like, a generalization, I see on line 17, for example, there is mention of, like, canal wall deterioration. And then on lines 25 and 26, for Abitibi Canyon, we have, like, concrete

structures, and line 30 again, concrete deterioration. Is it -- is it fair to generalize that a rehabilitation project is more about addressing deterioration on -- yeah, I will stop there. Is it about, like, deterioration, addressing that?

N. FABBRO: As we identify in the section that you have referenced correctly, so F1-1-1, page 9 of 36, section 3.2.3.1, we identify, under the section referred to as "concrete and dam restoration and rehabilitation projects," that this is to address concrete deterioration through rehabilitation and restoration projects.

T. EMINOWICZ: Thank you very much. And on -- oh, thank you. I see it.

And so on page 15 of that exhibit, which I think is a continuation of the description of the Abitibi Canyon project, on page 15 at line 3, it makes reference to upstream concrete rehabilitation. I just wanted to confirm my understanding that what this -- what we take to mean from this is that this rehabilitation project is not limited to the generating station structure itself, like, there is other structures further up the river?

M. SIKSTROM: In the context you are pointing to in line 3 on page 15, upstream concrete rehabilitation refers to the upstream side of the dam, so there is a downstream side of the dam and an

upstream side of the Abitibi Canyon dam.

T. EMINOWICZ: Thank you. That is very helpful for understanding.

And so, I mean, it is already on the screen, but the last one I wanted to ask about was just to confirm so you have kind of everything kind of grouped together nicely.

For expansion projects, I see here on line 8 towards the end of the line that it seems that an expansion project can be generalized to increase the generation at an existing facility, so is it fair that this is, like, adding something new, like new assets to an existing generating station?

M. SIKSTROM: In terms of the reference in 3.2.6, the expansion opportunity we have is Chats Falls, and that does include the potential to add a new unit to that existing generating station.

T. EMINOWICZ: And so if I just wanted to understand generally, like, an expansion project, is that it? Like, is that the -- like, is that representative of what an expansion project is, or could there be an expansion project that is not characterized by the description of the Chats Falls expansion?

M. SIKSTROM: Expansion projects look to add new generating capacity to existing facilities.

T. EMINOWICZ: Perfect. Thank you so much.

I don't know if it is necessary, but back at the

interrogatory response to PWU-001, in the narrative that accompanies the table, just before it, it says that these categories are kind of descriptions for the purposes of organizing the projects for presentation. And I just wanted to understand, within kind of the general business planning of your capital plan, are there, like -- like, do these definitions, these categories, like, do they matter in the business planning process to the people who are making decisions? I am just trying to understand that element of it.

N. PENDER: I will answer in two parts. I think, to your point, does it matter, we are trying to be clear, so our objective is to deal with asset condition. So we are trying to define as closely as we can what we mean by what that project is. So this description is just a helpful category to explain it. In the business planning process, we use that to communicate what is in our plan.

But, again, a refurbishment, a redevelopment, a rehabilitation, an expansion, different themes going on there. So, again, primarily, if it is linked to asset condition, that is one set of things. If it is an expansion, that is not really linked to an asset condition. That is linked to new potential. So we try and use this as a descriptor in our business plans.

T. EMINOWICZ: Thank you.

And so to try and kind of summarize, there is a common understanding between, like, you know, the people doing the work, the engineers assessing the work, the people planning, the people approving the work; there is a common understanding of what these kind of categories generally mean to them in kind of their own context?

N. PENDER: I can't answer what people understand, but I can say what we define them as. We are quite clear. We do our best to define the categories. As to a common understanding, I don't know what individuals think personally.

T. EMINOWICZ: Perfect. Thank you so much. That is definitely sufficient for what I am trying to ask.

Okay. So the next kind of place I would like to go to is the interrogatory response to D1-Staff-61, please. So in this interrogatory, OEB Staff asked about kind of the criteria for determining eligibility for a project for the capacity refurbishment variance account and then identified five projects as examples. And so I would like to start off just very generally.

Is there a particular, like, part of the organization or a particular kind of group that is responsible for determining or, like, labelling if a project is eligible for this variance account?

M. HANNON: So it is Melissa Hannon. We do it

as a team effort. So we work with the line to determine the scope of the project. The finance team sits down, reviews the -- either the scope, discussions, the business case, and then we work with our regulatory finance team to determine if it is eligible.

T. EMINOWICZ: And just generally, like, kind of when does that happen in the life of a project? Like, does it -- does the project get assessed for CRVA eligibility, like, when the business cases are being developed for the first time, when the business plan is being developed, after the project is done? Like, I am just trying to understand when that kind of characteristic is determined.

M. HANNON: So we do flag it during the business planning process, but as the project progresses through the phases and the scope is more defined, that decision can change.

T. EMINOWICZ: Thank you.

So I would like to ask -- and I guess we can scroll down to the response for part B, sub 3, where there is this Chenaux Limerick Island project. Just for the purposes of the transcript, there is a reference to Exhibit D-1, Tab 1, Schedule 2. I don't think we need to go there unless the Panel would like to. But I am just kind -- if we could please start with what is the kind of general function of, I guess, Limerick Island or the stuff that is

associated with it?

N. PENDER: So we define it in line 25. It is a sluice gate, and a sluice gate allows water to be passed through a structure.

T. EMINOWICZ: Okay. So there is -- there is, like, a water control dam associated with this island?

N. PENDER: Correct.

T. EMINOWICZ: And -- okay. And then the equipment that is being worked on here are sluice gates, and so this is for water control; is that correct?

N. PENDER: Yeah, so it is -- the sluice gates are necessary to regulate the water to the downstream of the Chenaux generating station, line 27.

T. EMINOWICZ: And so there is no generating units on the Limerick Island control dam; is that correct?

N. PENDER: Subject to check, I don't think so.

T. EMINOWICZ: Thank you.

The other question I wanted to ask was about the next one that is listed here, the Silver Falls surge tank replacement. Can you please explain how or if the surge tank itself is related to generating units.

N. FABBRO: This is Nicole Fabbro speaking. To answer your question, I will reference, on the same page, line items 30 through to 32. So a surge tank is a protective device that manages water pressure

fluctuations and ensures steady water flow to the turbines. It also serves as infrastructure protection from excessive pressure surges like a damaged penstocks and associated structures.

T. EMINOWICZ: So is it -- does water flow through it to go to the generating units at Silver Falls, or is it something associated with the thing that flows water to the generating unit?

N. PENDER: So the purpose of the Silver Falls surge tank, it is to manage water pressure, so en route to the station, so ensures a steady flow of water. So you can think about it as part of the fuel route to the station.

T. EMINOWICZ: So if its -- if its function is to manage pressure, is it OPG's view that -- or description that it also manages the flow? Like, are those distinct things?

N. PENDER: I am not sure your definition of "water flow." I -- the way I would characterize it is it is part of the apparatus to safely supply water from upstream to the station through a penstock. Part of that process is to control for water pressure in that penstock, and that is the function that this surge tank provides. So I would say it is part of the system to -- part of the water conveyance system to supply fuel to the station.

T. EMINOWICZ: Thank you so much.

So the next interrogatory response I would like

to go to, please, is D1-Staff-66. And I think we can go to Chart 1, which identifies some assets and some associated projects. So I would like to ask about the bottom two rows here where we have road upgrades and road maintenance for the Otter Rapids G2 refurbishment and the G2 overhaul.

And I guess the first thing I would like to understand is the road upgrades that are listed as capital. When -- I guess when this capital work is complete and there is an in-service addition associated with the road upgrades, is OPG able to just generalize, like, what asset gets that in-service addition? Like, is the road an asset, or is there some other asset that has its -- that, like, takes in this in-service addition?

N. PENDER: It is a road. So it is just a --

T. EMINOWICZ: I guess I mean in terms of accounting. Like, if you have an in-service addition to an asset or an asset account, would this go to, like, a road asset, the generating station asset, the generating unit asset?

M. HANNON: I can answer that. So the road was actually capitalized under project 82543, but when we put it into service, it did go into its own asset class as a road.

T. EMINOWICZ: Thank you.

And there is -- there is more than one generating unit overhaul and refurbishment, I guess,

groups of work happening at Otter Rapids, right, like, if -- at exhibit -- the actual Exhibit D1-1-2, Table 1, which lists the projects with business case summaries, there is a project for Otter G2, and then there is, further down at line 20 of the table, a project for Otter G1. So there is multiple, like, Otter G1 -- Otter generating unit works happening over time; right?

N. PENDER: Correct.

T. EMINOWICZ: And I think if we zoom in on lines 10 and 20, I think at line -- yeah, line 10, there is also a camp project. So this is just -- very generally, like, the Otter G2 work, is that complete?

N. PENDER: The project is still open.

T. EMINOWICZ: Okay. And then I think on line 10, there is a -- like, a camp project. Again, generally, only if you know it off the top of your head, is that project complete or is it still ongoing?

N. PENDER: I would have to confirm whether the PIR has been complete.

T. EMINOWICZ: That is good enough for this. Thank you. No need to confirm.

So I would like to ask about, I guess, the details of this -- these overhauls. So the business case summaries are filed under Exhibit D1-1-2, and then Attachment 1, Tab 9, if my notes are correct,

would be the business case summary for the work on Otter G2?

N. PENDER: This is correct.

T. EMINOWICZ: And I just wanted to, I guess -- first, see on the screen in the recommendation there is a couple bullet points with dashes. The middle one, kind of in the middle of the page, identifies costs for road maintenance and construction camp operations and maintenance.

And I am just curious if you could -- at the highest level, like, what kind of work is or was this on the Otter G2 project?

N. PENDER: So if we -- you are right, bullet number 4:

> "Additional costs for discovery work during execution, additional costs for road maintenance, construction camp operations and maintenance due to schedule extension." (as read)

So what we are really calling out here is the road has to be maintained. So this is -- if you can think of it like a gravel road, those roads have to be maintained after weather conditions. So there is a continuous activity to regrade to make them passable. So when we talk about road maintenance, that is the component we are talking to. I think grading, in your mind, that is a good proxy.

For construction camp operations and

maintenance, that is the staffing of the camp. So when we say "camp," I don't know what you imagine, but it is modular buildings connected together with heat and light and a kitchen. So it has to have security, staffing, et cetera. So that is the -- the cost associated with that is what we talk about operation and maintenance camp costs, as opposed to the capital costs, which are putting the camp on site, so the modular construction, the utilities, et cetera.

T. EMINOWICZ: Thank you. And, Mr. Millar, I am almost done.

If we go to the previous Tab, I believe that is the business case summary for the other Otter. I think it is G1. And if we just focus on the same kind of recommendation section, there is again a note about:

> "Ongoing maintenance and operating costs for the camp and the road." (as read)

Do we see that?

N. PENDER: I see it around bullet 3.

T. EMINOWICZ: Yes. And so, again, just in general terms, is this the same kind of work as in the other business case summary?

N. PENDER: So my conceptual model just to help frame it is we will -- we have built a camp, and then that camp will operate, for the purposes of the refurbishment, at Otter Rapids, and we will go from

one unit to the next to the next.

So effectively, there is costs for the first unit. And then when that unit is completed, there will be costs for the second unit associated with running the camp and running the road. Because, again, people are using that road every day for the purposes of the refurbishment project.

T. EMINOWICZ: And are the camp and road used, like, more generally, or are these, like -- is this a new camp you built only for the refurbishment and then it gets dismantled? Similarly for the roads, required only for the refurbishment, and then it goes out of service after the refurbishments are complete?

N. PENDER: I would deal with it in two categories.

The camp is modular in nature, so the design of that is for the purposes of once this project has finished and other projects which it may be used in that vicinity, there is a choice, an ability to relocate it. So this is very common.

Just to set what Otter Rapids is, it is about 230 kilometres north of Timmins. So it is not a downtown location. It is not accessible. So that is why we have the camp there.

As for the road, we are bringing in equipment to site for the refurbishment project. So that road will remain in situ after the closure of the activity. But to bring in the componentry we need

to, there is large, heavy equipment that needs to come in, which is why there is expenditure on the road.

T. EMINOWICZ: Thank you.

N. PENDER: And for safety reasons.

T. EMINOWICZ: Thank you. I guess generally, like, if I see, you know, projects individualized for generating units and I see common elements, I am just kind of curious how does OPG determine whether, you know, these common elements of a camp and a road should be put into individual, like, generator unit projects as opposed to just having a separate project for the camp and the roads?

N. PENDER: I can't really talk about generally. I can talk about specifically. So in this construct, there is a geography. There is a program and a schedule. So the -- let's call it the Otter Rapids setup camp road refurbishment, that is a bundle of work. We treated it in the most sensible way, we thought.

If we look at other projects, we can talk about those. I can't really generalize because the nature of our assets, they are very different in different locations. So I wouldn't like to give you a false opinion through a generalization.

T. EMINOWICZ: Thank you.

And I guess just taking us back to kind of the interrogatory where this started about CRVA

eligibility. When OPG undertakes the assessment, is it -- is it limited or constrained to the resolution of the project, or does OPG ever consider whether certain components of a project are CRVA eligible and certain other components may be not eligible for the capacity refurbishment variance account?

M. HANNON: We would look at the scope individually to determine the CRVA eligibility.

T. EMINOWICZ: So just to repeat it back, you evaluate a project, and you look at the scope of the project and look at the major line items and evaluate each item of the project for eligibility?

M. HANNON: If there is unusual things in the project, we would do that. With this one, we determined that the road and the camp were part of that refurbishment. We wouldn't have been doing them if we had not done that refurbishment project.

T. EMINOWICZ: Do you have any example from either this application -- just generally, an example of a project that was part of the capacity refurbishment variance account where a component of that project was excluded from the variance account treatment?

D. COBAN: I think we might just be getting beyond the scope of what this panel can deal with. Questions around the eligibility and how that all works would be best suited for the last panel.

T. EMINOWICZ: Okay. Panel 4 knows what is

coming. Those are all my questions.

D. COBAN: Thank you.

M. MILLAR: Thank you, Mr. Eminowicz. We are going to take our morning break, and then we will turn to Mr. Paliy. So it is about 5 after 11:00. Let us come back at 11:20. And then we will probably sit for about an hour or so before lunch. It is scheduled for noon, but I think I may push that out a little bit. So we will see you all in about 15 minutes.

--- Recess taken at 11:04 a.m.

--- Upon resuming at 11:22 a.m.

M. MILLAR: Welcome back, everybody. Christopher, are you there? Okay. It looks like everyone is back, and we are ready to go. I am going to turn it over to Mr. Paliy.

EXAMINATION BY Y. PALIY:

Y. PALIY: Thank you, Mike. Yaroslav Paliy here for OEB Staff.

My first question is centered around exploring the asset condition and remaining useful life of major assets. So can we please go to the interrogatory response to Exhibit D1-Staff-059 in Exhibit L. Thank you.

So as part of interrogatory D1-Staff-059, part B, OEB Staff requested, among other things, the range of remaining useful life of major assets for all the hydroelectric capital projects with a budget of over

$30 million that have a planned in-service date after January 1st, 2027.

OPG's reply to this interrogatory pointed to Exhibit L, D1-SEC-041 for this information. Can we please now go to the OPG interrogatory response found in Exhibit L, D1-SEC-041. Thank you.

As per the OPG interrogatory response found in this exhibit, part A, page 2, starting at line 14 -- thank you -- OPG states that:

> "OPG's asset management process does not quantify a range of remaining useful life." (as read)

With that in mind, can we please go to Exhibit D1-1-2, Attachment 1, Tab 24, project 86386.

D. COBAN: Could you please repeat the reference.

Y. PALIY: Yes. Exhibit D1-1-2, Attachment 1, Tab 24. It is the Kakabeka Falls generating station redevelopment project. Thank you.

On page 2 of this business case summary, paragraph 4, it states that:

> "The estimated remaining life on the 100-years-old turbine generator system was assessed in 2021 to be approximately five years." (as read)

So my question is, given that OPG was able to estimate the remaining life on the turbine generator system for the Kakabeka Falls generating station redevelopment project, can OPG estimate the range of

remaining useful life at the time of project start for all the other projects and major assets in scope found in Exhibit L, D1-SEC-049, Attachment 3?

N. FABBRO: As you have identified in D1-SEC-041, page 2 of 3, I would like to refer you to line items 15 and 16. So, Ms. Patchett, that's D1-SEC-041, page 2 of 3. And specifically line items 15 and 16.

This is Nicole Fabbro speaking.

So we identify in the prior statement that:

> "OPG's asset management process does not quantify a range of remaining useful life, and the degradation of the health of a hydroelectric asset, which influences the time before an investment may be required, is unique to its operating environment." (as read)

In response to your request, I will start by setting a little bit of context. We have 54 hydroelectric stations, regulated hydro stations, and 207 units. Those units, as we have identified in our evidence, range in terms of age. So some can be quite significant in age, some can be relatively new.

The way that we assess the condition of an asset is based on a variety of factors, and it would be extremely challenging to accurately predict the range of remaining useful life of the assets in these stations.

Y. PALIY: Thank you for that.

So my question goes back to the Kakabeka Falls generating station project. So how was OPG able to determine remaining useful life on that -- on those units?

M. SIKSTROM: Matt Sikstrom speaking here.

The remaining useful life that is -- or approximate five years that is mentioned in this BCS was based on an assessment report which was done as part of the project.

Y. PALIY: So does OPG already have these -- this data, then, for all the other projects?

N. FABBRO: In reference to Mr. Sikstrom's remarks, that KGS report was specifically prepared for that project. And to answer your question, there is a variety of different assessment documentation that supports the projects listed in Attachment 3 of SEC-41.

Y. PALIY: Okay. Thank you.

So my question also is a follow-up question to that. Is it possible to provide the range of remaining useful life for all the projects in Attachment 3 to SEC-041?

D. COBAN: I believe that question has already been answered by the witness.

Y. PALIY: So it is possible, but it would take a lot of work?

D. COBAN: Well, I think the answer, if we were listening carefully to it, is that there is a variety

of factors that go into the assessment, and that information is available for the one project you mentioned because the specific report was undertaken.

Y. PALIY: Okay. Thank you.

So just to build on this question, we noticed that throughout the business case summaries in Exhibit D1, OPG sometimes indicates that an asset has reached the end of its expected service life. For example, can we please go to the BCS for the Coniston and Stinson GS redevelopment project found in Exhibit D1-1-2, Attachment 1, Tab 5, page 2, the "business needs" section.

So here in the first paragraph, it states that the generating station has reached the end of its expected service life. So my question is if OPG knows the expected service life of an asset, can OPG determine the remaining useful life at the time of the project start from the expected service life which is known and the age of the asset that is known?

M. SIKSTROM: With respect to the Coniston and Stinson redevelopment project, the generating station was deemed to be end-of-life because the units are no longer able to fulfill their function to produce generating power at the facility.

Y. PALIY: Right. So let me just, I guess, ask that question again.

If we know what the expected service life of a

station is -- like, let me rephrase. Does OPG know and have the data on what the expected service life is of each station?

S. ZADEH: I think the answer you are hearing is it is not a numerical exercise. So you were referencing two dates. It is not simply a numerical exercise to be able to make that determination.

Y. PALIY: Okay. Thank you.

Okay. I will move on to the next question, then, that explores the asset condition at the time of project start. Could we please go to the OPG interrogatory response found in Exhibit L, D1-SEC-041, and part C of the response. Thank you.

So as part of this response, OPG provided a summary of the major equipment and scope and the health assessment ratings of each of those assets for the allocated regulated hydroelectric capital and OM&A projects of the total project cost of over $30 million. In note 4 to this attachment, OPG states that the equipment and health monitoring process described in part A of the interrogatory response is live, meaning the condition of the assets is updated following the completion of project and maintain, refurbish, or replace components.

For completed projects in Attachment 3, the condition of the assets reflects the current status. Condition of the assets at the time of project start are documented in each project's business case

summary; however, for completed projects in Attachment 3, OEB Staff are unable to find a health impact condition rating of most major assets in project scope at the time of project start in each project's business case summary at the same level of detail as provided for the post-project condition of assets in Exhibit L, D1-SEC-041, Attachment 3.

For example, can we please go to Attachment 3, page 3, and find the 83495 R.H. Saunders generating station G9 capital refurbishment project. Thank you.

So under the condition of major assets, the listed major assets are the generator, turbine, turbine regulating equipment, and all of the related components. It is listed that all of these major assets and their components are in good condition post-project completion. However, in Exhibit D1-1-2, Attachment 1, Tab 15, Project 83495, which is this project, the business case summary lists the major issues but does not assign a health impact condition for the generator, turbine, turbine regulating equipment, and all of the related components at the time of project start.

So my question is would OPG be able to update Exhibit L, D1-SEC-041, Attachment 3, for all completed projects that include the health impact condition rating of major assets and project scope at the time of project start at the same level of detail as is already provided for the post-project condition

of assets in Exhibit L, D1-SEC-041, Attachment 3.

N. FABBRO: This is Nicole Fabbro speaking. In response to your question, some of the projects in D1-SEC-41, Attachment 3, as you have noted, have been completed. And in some cases, these projects have been initiated a number of years back, let's say, you know, potentially as far as five years or more. In our evidence, we identify that we have transitioned to a new method of monitoring the health of our assets. It is referred to as the E-health system monitoring.

And so to answer your question specifically, in some cases, the projects that have been completed would not have been -- the condition of those assets would not have been put into that new software, which is effectively what you see reflected on the page today. So to answer your question more completely, no, I cannot provide you the condition of the assets as it is presented in this attachment for the projects that have been completed.

Y. PALIY: Thank you.

So alternatively, could you provide a similar type of asset condition for those completed projects and all of its assets based on the previous reports before this system -- before this new system was implemented?

D. COBAN: So why don't we do this: Why don't we take away your request and consider if something

can be provided on a best-efforts basis. If we can, we will; if not, we will explain why we can't.

Y. PALIY: Okay. Thank you.

M. MILLAR: So we won't mark that as an undertaking now. Just in respect of timing, is this something you can consider over the lunch break, or I guess you will just let us know when you --

D. COBAN: Let's give it an undertaking so the record is clear.

M. MILLAR: Okay.

D. COBAN: And we will -- if we can't do it, we will explain --

M. MILLAR: Understood.

D. COBAN: -- in the undertaking.

M. MILLAR: So let's call it JT-1.5. And, Ms. Coban or Mr. Paliy, what is being undertaken?

Y. PALIY: We would like to see the condition of assets for the completed project based on, I guess, a -- not based on the health condition assessment ratings, but on anything comparable for all projects and SEC-41, Attachment 3.

D. COBAN: On a best-efforts basis --

M. MILLAR: Understood.

D. COBAN: -- for the completed projects. Thank you.

M. MILLAR: Okay. JT- 1.5.

UNDERTAKING JT-1.5: PROVIDE THE CONDITION OF ASSETS FOR THE COMPLETED PROJECT BASED ON

ANYTHING COMPARABLE TO THE HEALTH CONDITION ASSESSMENT RATINGS FOR ALL PROJECTS AND SEC-41, ATTACHMENT 3

Y. PALIY: Thank you.

Next question also has to do with SEC-041 and examines the assets in good and fair condition [indiscernible] -- OEB Staff notes that in LD1-SEC-41, Attachment 3, there are several examples of assets in good or fair condition being replaced or refurbished.

For example, if we scroll to page 4 of Attachment 3, we can see the Coniston and Stinson GS redevelopment project. So for the Stinson generating station in the far-right column, it shows that the condition of the rotor is good and the scope of the work entails a new installation.

There are two other examples that would show assets in good or fair condition being either replaced or refurbished. So if we can scroll to page 5 of this attachment, we can see the Otter G1 capital upgrade project. It would be Project 82542, Otter G1 capital upgrade. Thank you. So here we can see that the current condition of the stator is fair and the scope of the work entails a refurbishment.

And if we can keep going to page 8 of Attachment 3, for the Sir Adam Beck 2 G18/G17 refurbishment project -- sorry. Thank you -- it states that the condition of the stator is fair and the scope of work

entails a new installation. So my first question is why do assets in good and fair condition get replaced or refurbished if the -- in general, yeah, what happens, why -- well, why do these assets get replaced if they are in good or fair condition?

N. FABBRO: I will begin by answering your question in a broad sense and then perhaps provide an example. So broadly speaking, as identified in D1-SEC-041 at page 2 of 3, Chart 1, the intention is to complete work on assets before they get into a poor or unacceptable condition; however, there are circumstances in which when we go in to do a unit refurbishment where there is a component, a subcomponent, let's say, of a broader assembly that is deemed to be in poor or unacceptable condition.

And as a result, in the effort to replace that specific component, it may necessitate a broader replacement or redesign of neighbouring components. And in some cases, yes, that may require that an asset that is deemed to be in fair condition may need to be replaced as a result of the broader configuration of that component. There are also other considerations that we take into account when planning and scoping unit refurbishments. And one in particular is the potential for concealed conditions.

And as we plan a project, based on engineering expertise and judgment and history of past failures, we will apply that to do what we feel is prudent to

mitigate risks, what we call "in outage" or while that unit is undergoing a major refurbishment. And in some cases, that may necessitate the replacement of that asset.

Y. PALIY: Okay. Thank you for that.

Just a follow-up question on your explanation. So how does OPG determine what type of work, whether it is a new installation or refurbishment, should be done based on these health impact condition ratings?

N. FABBRO: So in response to your question, if you reference Chart 1 in D1-SEC-41, page 2 of 3, the ratings provided are a guidance or an indicator of equipment health, as we have identified. And based on these ratings, engineering in conjunction with plant staff will determine appropriate short-term and long-term mitigating actions to address conditions or risks. And based on that, that plan, whether it be short-term mitigation or long-term mitigation, in the case of long-term mitigation, may require or necessitate a greater degree of investment or a greater action plan, for example. And that determination is what initiates, in many cases, the start of a project.

So to be a bit more complete in my answer, if we refer to D2 or D -- just one second here. It would be D2-1-1, page 4 of 13, Section 3.2.1. Thank you. So we identify in lines 17 through 20 that we conduct asset reviews on reliability, health, and

obsolescence, and these reviews will produce a health report or condition assessment, and these assessments are what contribute to the recommendations to request capital or OM&A expenditure funding for project needs.

Y. PALIY: Thank you.

Could we just quickly go back to that Table 1 health impact condition ratings that we had on the screen for SEC-041. I noticed here for the condition description of fair and good that it doesn't state any mitigation actions required, you know, when you compare it to the unacceptable and poor condition descriptions. Is that -- and as I mentioned in the previous examples, we did see work done on assets that do have fair -- that were in fair and good condition. So is this just based on, like, the overall project like you described? Like, this -- this isn't, like, a religious chart that you have to follow?

N. FABBRO: Engineering will provide an assessment of equipment health; however, because in a unit refurbishment or overhaul, there are a number of components that we look at and do our best to maximize or be as efficient as we can with the work that we complete during that -- that project or during that outage, there could be reasons in which, from a project risk perspective, we may elect to do work on assets that are considered in fair condition

for the reasons I previously stated.

Y. PALIY: Okay. Thank you.

Could we please go to page 4 of this Attachment 3, please, for the G20/G19 refurbishment project. Perfect. Thank you. So we note in this attachment, it appears that certain major assets such as the rotor and hydro turbine are not in the same condition between the pairs of units being refurbished for the Sir Adam Beck GS refurbishment projects on units G20, G19, G18 and G17, and G14 and G13.

So, for example, on this page here on the -- for the G20/G19 refurbishment project, here it states that the current condition of the rotor is poor for the G19 unit and good for the G20 unit, and the current condition of the hydro turbine is poor for the G19 unit and fair for the G20 unit.

Next, if we can please pull up Exhibit D1-1-2, page 17. Perfect. There, the G20/G19 refurbishment project. So this -- so the question I am asking is also related to G18 and G17 and G14 and G13, but I am not going -- I am not going to ask to pull those up because the references are the same across all of the three projects. So we note -- we note that all these projects are being done in pairs due to being closely connected electrically. The units share a common transformer bank, high-voltage line, high-voltage disconnect, and medium-voltage isolated phase bus, as well as protection and controls equipment. All three

of these projects include the replacement of electrical common balance of plant in the scope of work, which is described in the business case summaries, such as in Exhibit D1-1-2, Attachment 1, Tab 41, in the description of the preferred alternative. Thank you.

So just to help us understand the benefits of combining these units together when the condition of certain assets are different, we would like to ask, how many outage days does OPG estimate as the result of replacement of electrical common balance plant of work for each of the G20, G19, G18, G17, and G14, G13 projects?

N. FABBRO: I do not have that information in front of me today.

Y. PALIY: Is that something that can be provided?

D. COBAN: Maybe you could help us understand why that is relevant, the number of outage days.

Y. PALIY: Well, the reason we are asking is because we understand that one of the reasons why these assets -- why these projects are being done in pairs is because they are closely connected electrically, and this -- these projects include the replacement of these electrical common balance of plant assets. So we are trying to understand if there will be a difference in the number of outage days if these projects are done together versus

separately.

D. COBAN: We can take that away to consider your request. I think there might be a premise baked into your question that we need to clarify as part of the response. But on a best efforts, we can take that away to consider. And if we think the premise of the question is not appropriate, we will explain why in the response.

M. MILLAR: We will call that JT-1.6.

Y. PALIY: Thank you.

UNDERTAKING JT-1.6: ADVISE HOW MANY OUTAGE DAYS OPG ESTIMATES AS THE RESULT OF REPLACEMENT OF ELECTRICAL COMMON BALANCE PLANT OF WORK FOR EACH OF THE G20, G19, G18, G17, G14, AND G13 PROJECTS

Y. PALIY: The next question explores the probability of failure of assets. Can we please go to Attachment 2, the Engineering Risk Assessment Program, renewable generation procedure in Exhibit L, D1-SEC-041, page 8, Section 1.222 "probability of consequence selections". Thank you.

So here, OPG describes the probability of consequence as:

> "A likelihood of the entire sequence of events that shall happen for a particularly undesirable result or consequence to occur. Before selecting the probability of consequence, the anticipated equipment failure or -- and resulting consequence to be evaluated

should be clearly defined." (as read)

So my question is, does OPG have a probability of failure for all projects and major assets listed in Exhibit L, D1-SEC-41, Attachment 3?

N. FABBRO: I cannot confirm, based on the information I have in front of me today, definitively that a probability of consequence of failure has been completed for every single component listed for every single project in Attachment 3 of D1-SEC-041.

Y. PALIY: Would it be possible to take it back and provide information for any of the projects or as much as you can?

N. FABBRO: On a best-efforts basis, we can undertake to provide you a representative sample of some of the analysis or the risk assessment that may have been completed to form the determination of scope for one of the projects listed in D1-SEC-0 41, Attachment 3.

Y. PALIY: I am just considering the magnitude of projects and the impact on ratepayers. I think we would prefer if it could be done for all the projects in that attachment. And to make it easier, if we can meet halfway, maybe the probability of consequence can be done on the major assets and not all of its components. Would that work?

D. COBAN: I think the scope of what you are looking for is quite extensive. So we are prepared to do that on an example basis so that you can

understand how it works, but to undertake to do that for all the projects, even if we scope it down to a major component, is a significant undertaking amount of work, and we are not able to do that here within the timelines.

Y. PALIY: Okay. Thank you.

In that instance, can we please ask you to prioritize the importance of the project in the example that you give us. So something with the highest cost or -- just use your discretion to give us the most relevant example, please.

D. COBAN: We will use our discretion to give you a meaningful example.

Y. PALIY: Thank you.

M. MILLAR: We will call it JT-1.7.

Mr. Paliy, could you just repeat for the record what the undertaking is for, to the best of your recollection, just to make sure we are all on the same page?

Y. PALIY: Thank you, Mr. Millar. We are looking for a probability of failure for any relevant and important project that OPG can provide us with as an example of how it is assessed and how it is -- and how we can use it to analyze certain issues.

D. COBAN: That is fine.

Y. PALIY: Thank you.

UNDERTAKING JT-1.7: PROVIDE A PROBABILITY OF FAILURE FOR ANY RELEVANT AND IMPORTANT PROJECT

THAT OPG CAN PROVIDE AS AN EXAMPLE OF HOW IT IS ASSESSED AND HOW IT CAN BE USED TO ANALYZE CERTAIN ISSUES

Y. PALIY: My next question explores equivalent forced outage rates and availability for generating stations. Can we go it the interrogatory response found in Exhibit L, D-1-Staff-060. Thank you.

So in this exhibit, OPG provided the actual and target hydroelectric availability and equivalent forced outage rate, or EFOR, for the Alexander GS and the Manitou Falls GS for the 2016 to 2024 period and the EFOR and availability trends for these units as compared to the other units at the respective stations.

On page 2, part C of the interrogatory response, OPG stated that although the Alexander GS station has five units, refurbishments are only required for Alexander GS G1, G2, and G3 based on their condition.

OPG also stated that for Alexander GS, over the 2016 to 2024 historic period, availability trends for units G1, G2, and G3 were generally consistent with each other and aligned the with performance of units G4 and G5.

Similarly, historical EFOR results for G1, G2, and G3 followed comparable trends and were overall in line with those of G4 and G5.

So my first question is, what condition are units G4 and G5 in?

N. FABBRO: I don't have that information with me today.

Y. PALIY: Could that be taken back and provided later?

D. COBAN: Yes, we can do that.

M. MILLAR: JT-1.8.

Y. PALIY: Thank you.

Just a follow-up question to that. I don't know if you have this information as well. But when will units G4 and G5 be refurbished?

N. FABBRO: I also don't have that information with me today.

Y. PALIY: Could we add that to the undertaking?

D. COBAN: Yes, we can just roll it into 1.8.

Y. PALIY: Thank you.

UNDERTAKING JT-1.8: ADVISE WHAT CONDITION ALEXANDER GS UNITS G4 AND G5 ARE IN AND WHEN THEY WILL BE REFURBISHED

Y. PALIY: The next question is, can OPG please help me understand what is the relationship between availability and EFOR trends and asset condition.

N. PENDER: So I will start with the availability and EFOR relationship.

So availability is the total availability of the station measured on a time basis weighted by megawatts. EFOR is a subset of that. It is -- a equivalent forced outage rate is the definition of EFOR, so it is a subset of the overall availability.

Within availability, there is planned outages, unplanned outages, EFOR. So there is a number of criteria that sits underneath there.

The relationship of that to underlying asset condition, there is not a direct comparable or a linear relationship between one and the other. It depends on the context of the unit, the function of the unit in the market, and the role it serves.

So, again, just at a broad perspective, we have lots of units across the province. They vary in from new to very old, so think over 100 years old. So it really depends on the function of the unit in the market and how it runs. So if we narrow the question, perhaps we could get to something substantive.

Y. PALIY: Okay. Thank you.

So is it acceptable to see a unit in good condition with poor, say, EFOR and availability trends? Is that something that is commonly seen?

N. PENDER: Sorry. Can you repeat the question? I want to make sure I have understood the question.

Y. PALIY: Yes. If there is a generating station, for example --

--- (Court reporter interjection re microphone)

N. PENDER: Sorry. Can you -- can you just repeat the question or just clarify it?

Y. PALIY: Yes, thank you.

Can a generating station or -- be in a good

condition but show, you know, a negative or bad availability and EFOR trends?

D. COBAN: I think I am struggling with your question and the premise of it because, as we heard and we can see in SEC 41, condition is not assessed at the station level, it is assessed with respect to the components. So could you maybe clarify your question? Because I think there is a faulty premise in there that, you know, might confuse the record.

Y. PALIY: We are interested in the condition of the assets that drive the work of the project. So -- and we are trying to compare the overall station condition to its availability and EFOR trends.

N. PENDER: If I could refer you to F1-1-1, page 24, chart 7 -- or chart -- actually, let's start with Chart 6 on page 22. Okay. So this looks at -- okay, give it a second.

We can see on Chart 6 a sample of individual stations and then the fleet as a whole at the bottom where it says "all 54 regulated hydroelectric stations."

You can see in this chart here, we list out the actual and target availability for a station, and that is at a station level. And a station comprises of units that sit underneath of that.

So to my colleague's point a moment ago, when we are looking at projects, we assess at unit level, we don't assess at a generic level, but we track

availability for a station at a station level.

So let's take a station example. Sir Adam Beck 2, that is 16 units. So the -- if we look on the sheet here, third row, Sir Adam Beck 2 GS, that is the composite of 16 units' worth of availability. So the underlying asset condition will vary, as we have just established, on a unit-by-unit basis. And under that unit-by-unit basis, there will be kind of subsystem and subcomponents.

So to your -- if I recall your question correctly, if we are trying to link asset condition to availability, it is not a straight pass through in the relationship between them because of how all the subsystems tier together. Your overall premise, though, is not unreasonable that a poor -- assets in poorer condition could have lower availability.

To your point on EFOR, which is a forced component, that is a particular subset of unavailability which is related to being unplanned in nature. So, again, the relationship you are drawing is somewhat broad. Again, if we want to zoom in, we can be very specific, but we are dealing with lots of units and lots of subcomponents, and I wouldn't want to draw a generalization even though it might be tempting.

Y. PALIY: Thank you for that. Do you want to do lunch now, or should I continue?

M. MILLAR: How much time do you have left, Mr.

Paliy?

Y. PALIY: I have four more questions, probably around half an hour.

M. MILLAR: Okay. We may need to -- why don't we take our break, and we can see where we are from there.

Okay, let's take our break now. Let's come back at 1:05.

--- Recess taken at 12:07 p.m.

--- Upon resuming at 1:04 p.m.

M. MILLAR: Good afternoon, everyone. Welcome back to the afternoon session of day 1 of the technical conference for OPG.

Mr. Paliy, I will hand it back over to you.

Y. PALIY: Thank you, Mr. Millar.

So for this next question, I would like to explore the Sir Adam Beck Canal Rehabilitation Project Deferral. So can we please go to Exhibit D1-1-2, Tab 42, Project 89252. Thank you. If we scroll down to page 3, please, of the business case summary. Okay. Thank you.

On page 3 of this business case summary:

> "OPG states that the Sir Adam Beck 1 Canal Rehabilitation Project began under Project 82771, which funded condition assessments and various project management activities, including the development of an initial overall cost estimate and technical specification. The

project was deferred in 2020 following a risk analysis that confirmed that the canal conditions could sustain this delay. As per the plan upon project deferral, a team was reassembled to explore restarting the project in 2024." (as read)

On page 1 of this business case summary, it states that the project was restarted in June of 2024.

Can we please now go to Exhibit L, D1-Staff-075. Thank you.

So for this interrogatory, OEB Staff asked how long did the 2020 risk analysis indicate that the canal could sustain a delay in rehabilitation and if any more recent analyses have been performed, and if so, how long did these analyses indicate that a delay could be sustained?

In part A of its response, OPG replied that a specific timeline wasn't provided in the 2019 risk analysis, indicating that the canal could sustain a delay in rehabilitation and that no further recent risk analysis has been conducted. So my question is, given that there was no timeline provided in the 2019 risk analysis and there was no further recent risk analysis performed, how did OPG determine the need to restart the project in 2024?

M. SIKSTROM: So as indicated in the IR response D1-Staff-075, there isn't -- the next condition

assessment is planned for 2030. And although the canal assessment that was done in 2020 indicated that there wasn't a firm timeline, it did highlight that degradation of the canal will continue, and eventually it will need to be rehabilitated. So this project was restarted in 2024 with the scope of preparing for the eventual rehabilitation of the canal.

Y. PALIY: Thank you for that.

My next question explores unallocated projects. So can we please go to Exhibit L, D1-Staff-064. Perfect.

In Exhibit L, D1-Staff-064, Attachment 1 -- I don't know if you can pull up the attachment to this, please, Attachment 1. It was an Excel file. Perfect. Thank you.

So in this attachment, OPG provided the estimated total cost and potential in-service year for each of the unallocated projects found in Exhibit D1-1-2, tables 5A and 5B, which is all of these projects that we see in front of us. OPG also stated as part of their interrogatory response that -- we can go back to the exhibit. Yeah, perfect. Thank you.

So OPG stated that with the introduction of the longer-term business horizons of up to seven years, the renewable generation business unit has aligned the management of its capital and OM&A project

portfolio with that of the rest of the company and implemented the use of unallocated portfolio funding. The use of this unallocated portfolio in business planning was approved by the OPG Board of directors.

Can we please go to Exhibit D1-1-2, Table 4. Thank you.

In Table 4 OPG shows the yearly in-service capital additions by prescribed facility category, which includes categories for allocated and unallocated projects. So my request is can OPG please provide a yearly breakdown of the unallocated projects that contribute to the forecast in-service capital additions for 2027 to 2031 seen in lines 27, 30, 32, 33, 34, 35 in Exhibit D1-1-2, Table 4.

M. HANNON: If you can please turn to IR F1-AMPCO-91. Thank you. And then scroll down. So in this IR, there are charts in here that identified both the unallocated and allocated projects for that table.

Y. PALIY: That is great. I just can't see the unallocated projects. Is that lower down in the reply?

M. HANNON: It is Chart 4. It shows your unallocated.

Y. PALIY: Okay. Okay. That is good. Thank you.

Can OPG please confirm when the OPG Board of Directors approved the use of unallocated portfolio

in business planning for the renewable generation business unit and when did OPG start implementing it in their business planning.

M. HANNON: The unallocated portfolio has always been part of the RG business plan. But because this is a seven-year business plan, it's substantially larger than it has ever been.

Y. PALIY: What year did it start, the use of this unallocated portfolio?

M. HANNON: So I don't have that in front of me.

Y. PALIY: Oh, is that something that we -- you could check and get back to us with?

D. COBAN: Maybe you could just help us understand how -- what is the relevance of knowing when it started.

Y. PALIY: I think we think it speaks to the way that OPG kind of plans capital projects, and we are trying to understand and, I guess, compare to the last time the OEB kind of undertook a review of a capital plan. So we understand that these unallocated projects were not really a thing during the last cost of service proceeding, so we would like to understand when -- when OPG as a business started using unallocated projects. And just stating that, like, the RG business uses this is a bit ambiguous to us because we understand there have been reorgs, so we are looking for, like, a -- even just a year or, like, a business plan that started using this idea.

D. COBAN: Okay. We will undertake to consider your request, and if we can provide an answer, we will; and if not, we will explain the basis for the refusal.

Y. PALIY: Thank you.

M. MILLAR: JT-1.9.

UNDERTAKING JT-1.9: CONFIRM WHEN THE OPG BOARD OF DIRECTORS APPROVED THE USE OF UNALLOCATED PORTFOLIO IN BUSINESS PLANNING FOR THE RENEWABLE GENERATION BUSINESS UNIT AND WHEN OPG STARTED IMPLEMENTING IT IN THEIR BUSINESS PLANNING

Y. PALIY: All right. Thank you.

My next question explores the cost variance between the RH Saunders G12 and G16 units. So can we please go to Exhibit L, D1-Staff-068. Thank you.

So in this exhibit, OPG provided the difference in cost and in the project scope between the RH Saunders GS G9, G12, and G16 refurbishment projects. On page 2 OPG states that RH Saunders GS unit G16 is the third unit to undergo capital refurbishment and the second CWC unit to undergo a refurbishment as part of the RH Saunders GS refurbishment program.

The cost and scope for Unit G16 incorporated lessons learned gathered from both Unit G9 and Unit G12 up until Q4 2025 when the full execution BCS for Unit 16 was approved. Unit G16 and Unit G12 are both CWC units with the same scope of work as per Chart 1, scope comparison summary, major components on page 3

of this reply.

OPG also provided a cost breakdown per unit in Chart 3 on page 5. OEB Staff note that the Unit G16 refurbishment incorporated lessons learned gathered from both Unit G9 and Unit G12 refurbishments and had the same scope of work as the G12 refurbishment and yet cost $18.9 million more than the G12 refurbishment.

Can OPG please undertake to provide a narrative that describes the main drivers of the difference in cost between the G16 and G12 refurbishment by category as seen in Chart 3, cost breakdown per unit, on page 5 of this interrogatory response.

N. PENDER: Sorry. Just to refer back to Chart 3, you want to see the cost breakdown that is in Chart 3?

Y. PALIY: Yeah, just -- we would like to see an explanation narrative of these differences in cost.

N. PENDER: So it is the narrative around the detailed items, the project management and engineering, through interest to substantiate the 30.4 to the 49.3, if I am --

Y. PALIY: That is right.

N. PENDER: We can do this.

M. MILLAR: That is JT-1.10.

UNDERTAKING JT-1.10: PROVIDE A NARRATIVE THAT DESCRIBES THE MAIN DRIVERS OF THE DIFFERENCE IN COST BETWEEN THE G16 AND G12 REFURBISHMENT BY

CATEGORY AS SEEN IN CHART 3, COST BREAKDOWN PER UNIT, ON PAGE 5 OF THE INTERROGATORY RESPONSE

Y. PALIY: Thank you.

The next question explores the cost variance in the Chenaux Limerick Island superstructure gate hoist project. Can we please go to Exhibit L, D1-Staff-316. Thank you.

In this exhibit, OPG explained that this project neither has a superseding business case summary nor is in recovery, so they did not provide the cost variance for this project. The BCS filed in Exhibit D1-1-2, Attachment 1, Tab 19, identified an increase in cost between the Gate 2 definition phase and Gate 3 execution phase from 11.4 million to 32.7 million. We can pull up that business case summary, please, just for really quick reference. Thank you. So it is just that first line -- sorry -- that second paragraph that states that the total project cost is now at 32 million versus the 11 million in the previous release.

If we can just go back to the interrogatory response now. Thank you. So in this interrogatory response, OPG explained this cost increase is a natural progression as the project continued to solidify scope, complete detailed design, and refine cost estimates throughout the planning process. As described in the business case summary in Exhibit D1-1-2, total project cost at execution phase includes a

revision to the sluice gates control standard, power supply replacement, addition of stair towers, enclosed hoist house, and logistical considerations at the interprovincial bridge.

Can OPG please provide a quantitative reconciliation from the $11.4 million found in the Gate 2 definition phase to the $32.7 million cost found in the Gate 3 execution phase by major cost category and by driver. Can you please identify which scope elements were known or foreseeable at Gate 2 versus identified later, and can you please explain whether the increase was driven mainly by scope additions or estimate class maturity, EPC pricing, access or logistics, market escalation, or contingency.

N. PENDER: So I think you are calling out the natural progression of our project maturity as we come through the phase of maturity from the Gate 2 through to a Gate 3. So we expect our scope matures, et cetera, to -- and estimates to be refined. This is just part of the natural progression.

If you are asking to do a specific breakdown as per the way we have approached G9 and G16 in the aforementioned reference via those high-level cost categories, we would be willing to detail that between a Gate 2 and a Gate 3 for this limerick project.

Y. PALIY: That would be great. Thank you.

M. MILLAR: That is JT-1.11.

UNDERTAKING JT-1.11: PROVIDE A QUANTITATIVE RECONCILIATION FOR THE CHENAUX LIMERICK ISLAND SUPERSTRUCTURE PROJECT FROM THE $11.4 MILLION GATE 2 DEFINITION PHASE ESTIMATE TO THE $32.7 MILLION GATE 3 EXECUTION PHASE ESTIMATE, BY MAJOR COST CATEGORY AND DRIVER, AND IDENTIFY WHICH SCOPE ELEMENTS WERE KNOWN OR FORESEEABLE AT GATE 2 VERSUS IDENTIFIED LATER, AND EXPLAIN WHETHER THE INCREASE WAS DRIVEN PRIMARILY BY SCOPE ADDITIONS, ESTIMATE CLASS MATURITY, EPC PRICING, ACCESS/LOGISTICS, MARKET ESCALATION, OR CONTINGENCY

Y. PALIY: Those are all the questions I have. Thank you so much for your time.

M. MILLAR: Thank you, Mr. Paliy.

I think, Ms. Li, it is over to you now.

Y. PALIY: Yeah, we are just going to do a quick swap at the front here.

M. MILLAR: Okay. Very good.

EXAMINATION BY A. LI:

A. LI: My name is Ada Li. I am an analyst with the Ontario Energy Board, and my questions are primarily related to the hydroelectric production forecast. Can we go to interrogatory response E1-Staff-140.

So according to the scorecard, the definition of "hydroelectric availability" is the percentage of the

generating potential that could have been provided after considering outages and de-rates regardless of fuel availability. So can OPG confirm that outages and de-rates are the only factors considered in this metric?

N. PENDER: If I could direct you to F1-Staff-170, we give -- maybe let's start on page 5 -- sorry -- page 2 of 5. Yes, Staff-170, please. And we will start at line 18.

So we give a description here of what is included in availability. So the components to derive availability is one, minus the incapability factor. And the incapability factor is a function of planned outages, equivalent planned de-rate hours, forced outage hours, and equivalent forced de-rate hours divided by the time period.

So I would happily -- if you repeat your question, I can answer the specific elements, but these are the specific elements in the incapability factor to which I think you were referring.

A. LI: Yeah, thanks. This confirms it.

So the question was can OPG confirm that outages and de-rates are the only factor that is considered in this metric?

N. PENDER: As per this calculation, that is an incorrect premise. It is planned outage hours, equivalent planned de-rate hours, forced outage hours, and equivalent forced de-rate hours.

A. LI: Okay. I understand. Thank you.

Can we go to Exhibit F1-1-1, Chart 6 and 7. So Chart 6 shows the historical hydroelectric availability from the year 2016 to 2024, and Chart 7, if you scroll down, shows the target availability from 2025 to 2031. Can OPG confirm whether the target availability in Chart 7 in this case is the same as the forecast availability used in determining the hydroelectric production forecast?

M. CHIDIAC: So it would not be the same, and the availability used in the production forecast is described in Staff-140. When you think about production and availability, you have to consider fuel availability, which is water for hydroelectric stations. And as we described in E1-1-1, production is highly tied to the availability of water.

So you could theoretically have outages that don't impact your production because you wouldn't have otherwise had water to generate so the numbers are different, but the numbers used in the production forecast are included in the Staff-140 response.

A. LI: Okay. So the availability used in the forecast is the one shown in 140, Staff-140. Okay. Thanks.

T. EMINOWICZ: So can OPG provide, like, an availability table similar to what is in F1-1 that reflects the actual production forecast for 2027? Is that possible?

M. CHIDIAC: It is possible. I am just thinking about the level of effort required and the timeline available to us, so I think --

T. EMINOWICZ: The top five stations by production.

M. CHIDIAC: I think we will take it back on a best efforts --

T. EMINOWICZ: Yeah, we are not asking for, like, every single station in the forecast.

M. CHIDIAC: It requires calculation because there isn't an explicit availability used in the production forecast. It is a function of outages that are planned in the forecast, right. And then I think from there, we have to reverse-calculate what the availability would look like.

T. EMINOWICZ: Yeah, we are trying to understand how the production forecast relates to these metrics, so on a best-effort basis, if by the level of production there is a few top stations that account for the majority, I think that would be sufficient for what we are asking.

M. CHIDIAC: Okay. Yeah, so I think we could take that back as an undertaking to describe the availability used in the production forecast for the top five generating stations.

T. EMINOWICZ: Sorry, Mr. Chidiac, we understand from Staff-140 that availability isn't, like, used in the production forecast. We are trying to compare, I

guess, what would be the output of a production forecast to compare it to the availability metrics we see in the chart of Exhibit F1. So just to be clear, we are not asking about kind of, like, an input of availability to the product forecast, but the result, like, the output.

M. CHIDIAC: Understood, yeah. And we will endeavour to provide that.

T. EMINOWICZ: Thank you.

M. MILLAR: JT-1.12.

UNDERTAKING JT-1.12: PROVIDE AN AVAILABILITY TABLE SIMILAR TO WHAT IS EXHIBIT F1-1-1 THAT REFLECTS THE ACTUAL PRODUCTION FORECAST FOR 2027 FOR THE TOP FIVE STATIONS BY PRODUCTION

A. LI: Moving on to interrogatory response E1-Staff-137. If you can go to part D of the answer. So for context, this interrogatory is focused on understanding the difference in the forecast methodology between EB-2013-0321 and EB-2025-0297.

Can OPG confirm the following numbers: The impact of unplanned outage spill is 0.19 terawatt hour for test year 2027, non-SBGVA eligible market spill is 0.63 terawatt hour, condensed mode operation load is 0.08 terawatt hour, and the spill occurred outside SBG conditions and not associated with scheduling down is 0.16 terawatt hour for test year 2027?

M. CHIDIAC: That is correct.

A. LI: Thank you.

So do you accept, subject to check, that the sum of all these numbers is 1.06 terawatt hour?

M. CHIDIAC: Subject to check, yes.

A. LI: Regarding the fourth paragraph in response F, can you please explain what is causing the spill that "occurred outside SBG conditions and not associated with a market event"? Specifically, what does this mean operationally for OPG?

M. CHIDIAC: Well, in terms of what it means operational for OPG is that we had economic offers to generate our facility, and due to some market condition, we were not able to generate and the -- that was not reflected in the shadow price at the time. So it resulted in foregone production to OPG.

A. LI: Can you confirm that the cause is unclear to the spill that is referenced here?

M. CHIDIAC: Are we referencing -- which paragraph are we referencing?

A. LI: So --

M. CHIDIAC: Lines 1 to 10?

A. LI: Yes.

M. CHIDIAC: So, sorry, could you repeat your question?

A. LI: So for the spill that is in line 2 and line 3, what is the cause of this spill that occurred outside SBG conditions but also was not directly associated with scheduling down?

M. CHIDIAC: So it wouldn't be reflective of market outcome or dispatch from the IESO. There are multiple potential causes for these types of events. They could be IESO manual or verbal dispatches. It could be IESO respecting constraint violations. There are a multitude of events that could cause this.

A. LI: Thank you.

So using the above-mentioned value of 1.06 terawatt hour as the sum of all adjustments and comparing it to the currently-proposed 2027 test year forecast of 32.5 terawatt hour, the total 2027 production forecast would increase to 33.56 terawatt hour if the original EB-2013 method was applied.

Does it mean that if the EB-2013-0321 forecast model had been used to produce the 2027 production forecast, it would have been 33.56 terawatt hour? Can OPG confirm this?

M. CHIDIAC: I would frame it more so the adjustments we have made to the production forecast for EB-2025 and in terms of the totality of those numbers are the 1. -- I don't remember the number you quoted, but 1.02 terawatt hours.

A. LI: Thank you.

Can we go to interrogatory response Staff-007, Table A1. So this a list of in-service capacity by generating stations between now and the end of 2031 according to the capital plan.

So staff conducted an analysis of the amount increase between the current application and the year 2031 and identified five stations that are key contributors to the capacity increase. So, for example, for Otter Rapids, Otter Rapids has a capacity increase of around 11.6 percent. Does it -- does this seem right to OPG?

N. PENDER: In the response in Chart 1, I count a few more stations than the ones you noted there. So I think you -- how many -- I think you said there were five?

A. LI: Five. So list them all is Otter Rapids, Otto Holden, R.H. Saunders, and Sir Adam Beck 1 and 2.

N. PENDER: That is a subset of the increases. I agree with that.

A. LI: And Otter Rapids has a capacity increase of 11.6 percent? Around?

N. PENDER: I haven't done the math. It goes from 182.4 to 203.5, so I make that 21.1 percent. So in a range-bound way, your answer doesn't seem unreasonable.

A. LI: So in OPG's view, is this increase in capacity a material impact to production?

N. PENDER: Can you define "material" for me, please.

A. LI: So it would result in a change, an increase in production due to capacity.

N. PENDER: So can I just take a step back? So let's think about what capacity is. So capacity is generating potential, and generating potential gives you the opportunity to have higher production. Again, because these are hydro plants, they are subject to water, of being a key constraint of how much water is received in the river or the system. So making a direct linear comparison between capacity and production isn't the right mental model in this context.

EXAMINATION BY T. EMINOWICZ:

T. EMINOWICZ: I guess what we are asking does -- would OPG consider this increase that we are talking about for Otter Rapids to be material?

N. PENDER: We can provide the net change in the production. Again, your material and my material, I don't know -- if you can be specific, I might be able to guide you. We are adding 21.1 megawatts of capability over the rate period, so that is being layered in over the next period of time. So this is what will happen by 2031.

T. EMINOWICZ: In the interest of time, I will try and make sure I understand what you are offering.

So is OPG offering to attempt to quantify the production impact of that capacity increase? Like, could you compare it, for example, to the 2027 forecast, the incremental production of that capacity increase?

N. PENDER: You have just made the question considerably harder.

T. EMINOWICZ: I didn't understand exactly what you were offering.

N. PENDER: So I can't go back and remodel '27 because life moves on, things change. What we can do is give you a best-efforts estimate of what happens to this 21 megawatts in the future. I can't go back and say what happened in 2027, had I had 21 extra megawatts, what could have happened there. That is beyond our capability to do that.

T. EMINOWICZ: Sorry, Mr. Pender, just to clarify, I was asking in the context of the 2027 production forecast that is proposed for the hydroelectric payment amounts. Like, the forecast. I am just confused because you -- it seemed like you were talking about the past. I am sorry if I am tired.

D. COBAN: I think we are all getting a little confused. What I understood is that we cannot reconstruct the 2027 forecast to account for this increase in production. That is what I understood from your testimony, Mr. Pender. If that is incorrect, please do set us straight on that.

N. PENDER: That is where I was going.

T. EMINOWICZ: We will take whatever you are offering. Thank you.

M. MILLAR: I am unclear. Is there any

undertaking here or...

M. CHIDIAC: So just to confirm the ask, you are seeking to quantify the benefit of the capacity increase at Otter Rapids in 2027 from a -- the benefit to the production forecast?

T. EMINOWICZ: That sounds about right.

M. CHIDIAC: On a best-efforts basis, we will seek to provide that.

M. MILLAR: That is JT-1.13.

UNDERTAKING JT-1.13: QUANTIFY THE BENEFIT TO THE PRODUCTION FORECAST OF THE CAPACITY INCREASE AT Otter Rapids IN 2027

A. LI: So continuing on -- oh, okay. Thank you.

T. EMINOWICZ: Okay. So thank you.

So I just have a couple more questions also related to the production forecast. So this is, for the benefit of the transcript, Thomas Eminowicz, senior advisor, OEB Staff.

If I can start, please, this conversation with interrogatory response to E1-SEC-128. And so this is an interrogatory that identifies outages. I am not interested in the specific outages; rather, what I am interested in is the general concept of what OPG as a market participant kind of provides to the IESO in terms of production information.

And so it is -- I guess I will start off by confirming that, as a market participant, OPG

provides information to the IESO, for example, related to outages and future production?

M. CHIDIAC: I can confirm we provide outage information to the IESO as per the IESO market rules. We do not provide production information to the IESO -- or production forecasts, I should say.

T. EMINOWICZ: It is OEB Staff's understanding that under the market rules, to support the IESO's planning documents such as the reliability outlook or annual reliability assessments, market participants provide information to support those IESO undertakings?

M. CHIDIAC: That is correct. That is generally outage information and availability and capacity factors, that type of information.

T. EMINOWICZ: Does that information also provide, like, production like megawatt hours over a future period?

M. CHIDIAC: I don't believe so, but I am not positive.

T. EMINOWICZ: So OEB Staff understands that the IESO has, at minimum, an annual process where market participants provide information to the IESO to support the reliability outlook, and I believe the IESO references a Form 1230. And in our -- just for the transcript, I see nodding heads, at least one.

If you are able to -- like, isn't there a megawatt hour component to that information that

market participants provide to the IESO?

M. CHIDIAC: I think that is something we could check at break and get back to you on. I don't know off the top of my head.

T. EMINOWICZ: So it is our understanding that this type of information would support, like, for example, the IESO reliability outlook and would contain at least some view of future production that the IESO uses for the reliability outlook. So, for example, there is production information by fuel type that is provided in those reports and supporting tables. And it is OEB Staff's understanding that that information comes directly from market participants, that the IESO wouldn't come up with their own megawatt hour forecasts to support their reliability outlook.

And so what I am asking is if OPG could provide for some sort of -- I assume that this is a future outlook of at least 18 months because that is the term of the reliability outlook, and from the information on the IESO website, this, at minimum, has to be provided on April 1st annually with any subsequent updates afterwards. And we are asking if OPG would provide the production forecasts that were supplied to the IESO under these market rules.

D. COBAN: I think one of the things we maybe asked Mr. Chidiac to speak to is if this data that you are providing to the IESO is on a combined basis

in terms of prescribed assets and non-prescribed assets. I think that will -- you know, from looking to get information that is submitted on a combined basis and includes assets that are with -- outside of the scope of this proceeding, obviously we have some concerns with that.

T. EMINOWICZ: Understandable. It is our understanding that this is a document that the IESO receives from market participants on a facility basis. So we would not expect or request any information related to non-regulated stations.

D. COBAN: I think at most we can do right now is take this away at the break and see what can be done. So not prepared to give you an undertaking on it because I think there is some clarification that might be required at the break in terms of this particular set of information you are referencing.

T. EMINOWICZ: Thank you.

Sorry, just give me a moment to calibrate as I am planning to scrub time here.

Okay. Final kind of set of questions for me on this topic. If we could go to E1-Staff-136, part C, please. And so in the question -- or in the interrogatory, OEB Staff requests OPG to confirm that the 2027 production forecast would be the basis for the water conditions variance account for the entire term.

And then in the response, OPG confirms this.

And so I would like to kind of build on Ms. Li's question about the upgrades or improvement to the production forecast, and I would just like to generally confirm whether any of those upgrades that were discussed with Ms. Li are affected by water flow. Like, do changes in water flow affect any of those items that were discussed with Ms. Li?

M. CHIDIAC: Yes, any production increase resulting from capacity or efficiency increases would be impacted by water flow.

T. EMINOWICZ: Okay. Thank you.

And then the other thing that Ms. Li kind of asked about was capacity increases. And so I would like to confirm OEB Staff's understanding that under the water conditions variance account, for example, how we discussed Otter Rapids, if there is an actual increase in the capacity of a hydroelectric generating station but that is not reflected in the production forecast, that underlies the water conditions variance account, is it correct that the variance account is agnostic to that change; like, it can't capture that variance?

M. CHIDIAC: I would agree with that statement.

T. EMINOWICZ: Thank you.

And then the other variance account that is listed here is the surplus base load generation variance account. So, again, in the most general terms at the resolution I just asked, if there is a -

- if there is an increase in the capacity of a generating station, would this variance account capture it or would it be equally agnostic as the water conditions variance account?

M. CHIDIAC: The SBGVA methodology would capture those increases just based on due to different methodologies and used in terms of calculating those amounts.

T. EMINOWICZ: Thank you.

The third item that is kind of listed in the response is the changes of laws deferral account. And, again, trying to just understand at a general basic level, how could -- how could changes in law affect or be an input into the production forecast?

M. KIRK: Can we turn up Exhibit H1-1-1, page 61. And I am not sure if you need this reference, Mr. Eminowicz, but we do give an example in Exhibit H about potential change in law. Sorry. I will wait for this to come up. That is perfect. Thanks.

So you can see on line 16, there is some discussion around potential changes to *Endangered Species Act*, and continuing on from line 25, potential changes there. And through that discussion, this is potential impacts on OPG-regulated hydro stations, and there could be some potential impacts on production in that case.

T. EMINOWICZ: Thank you very much. That is all that I have.

M. MILLAR: I think we are moving -- thank you, Mr. Eminowicz.

We are moving now to Ms. Zhu, who I see there. Tina, would you mind introducing yourself. I am not sure if the court reporter has caught that yet.

EXAMINATION BY T. ZHU:

T. ZHU: Thank you, Mr. Millar. My name is Tina Zhu. I am a senior advisor at the Ontario Energy Board. I have a few questions. They are relating to the hydroelectric FTEs and the project OM&A.

First, could we pull up F1-Staff-164, please. So in the preamble of the interrogatory, OPG states that hydroelectric overhaul projects are typically required every 25 to 30 years.

And now could we move to interrogatory response Chart 1. So on the chart, it is showing the overhaul project OM&A spending. The spending is showing an upward trend since 2021, and the trend is keep going all the way to 2027, so it is going for seven years so far.

My first question, could you explain what is the time duration for OPG to complete this round of overhaul projects? Because it has been going for seven years, and it is happening every 25 years. So we want to understand the pacing of your overhaul projects.

N. PENDER: If I could refer you to D1-1-2 -- sorry -- yeah, sorry -- D1-Staff-311, please. Yeah,

that is D1-Staff-311. My apologies. So if I just refer you to lines 9 and 10, we describe overhauls are typically required every 25 to 30 years. So -- and we do this at a planning horizon to sustain the reliable operation of turbine generator equipment and related systems. This is in line with effectively what you will see in industry guidance from external third parties, CEATI. That is typically the planning horizon when you think about hydro assets.

So when you look at the fleet and you look at the nature of the program, we have 207 units operating across the province in over 50 stations. In this rate period we have coming up, we are doing roughly 53 units. So just sort of rough math, we are doing about a quarter of the fleet. So this is a rate case of seven years.

So, again, just to kind of extrapolate it out a little bit, if we are doing a quarter of the fleet in seven years, you could make a reasonable assumption you would do the entirety of the fleet over, let's call it, 28 years, 30 years for convenience. So we are entering a phase of refurbishment, but in reality, if our objective is to sustain the reliable operation of turbine generator equipment and related systems, effectively, the cyclical nature of this investment is -- should continue.

So the question of when does it start and when does it stop is somewhat of a moot point. There will

be periods of more activity and periods of less activity, but I don't think I could say, on date X, it started; on day Y, it stops. It is somewhat continuous in nature.

T. ZHU: Thank you for the explanation. Because OPG doesn't provide the project OM&A details beyond 2027.

So based on your response, I do want to better understand if you anticipate the overhaul project OM&A continue to show a high spending trend in 2028 all the way to 2031, because this relates to the fundamental overhaul, the hydroelectric payment impact.

N. PENDER: I will pass to my colleague Ms. Hannon.

M. HANNON: Thank you. If you can refer to IR A1-SEC-012, it provides the total project OM&A for '27 to '31.

T. ZHU: So thank you for pointing this out because I guess my question was more specific about the overhaul project OM&A. I believe here is the high-level project OM&A, yeah. But if this is the level that you provide, I understand. Thank you.

Okay. And now could we continue with the same interrogatory, so that is F1-Staff-164. I want to look at Chart 2. So the Chart 2 is showing the refurbishment project OM&A spending. As we can see on the chart, the spending was very immaterial up

until 2025. And if you move to the next page, please. So suddenly in 2026 and 2027, OPG is anticipating an increase in refurbishment project OM&A.

In the same interrogatory response, OPG responded that for the removal costs to remove the existing assets, they are treated as OM&A costs. So I do want to understand if you could clarify the reason for refurbishment project OM&A increase in 2026 and 2027 is due to the increasing of the removal costs of the existing hydro assets.

M. HANNON: That is correct.

T. ZHU: Could you further explain compared to prior years, say, between 2025 to 2026, it is only one-year difference, but why within the one year, the removal costs that would be treated as OM&A in refurbishment projects suddenly increases for over ten times?

M. HANNON: So the significant increase that you see in 2026 and '27 is directly tied to the execution phase of our major refurbishment project. So when they start the execution, that is when the demolition and everything starts. So currently in '24/'25, we are in the planning, we are in the development stages of most of our larger refurbishments, where the bigger dollars start towards the end of this year and into 2026.

T. ZHU: Thank you for the explanation. Because

I do understand that the hydroelectric business has started refurbishment work since 2021.

But if we look at the actual refurbishment project OM&A, the spending was very small from 2021 all the way to 2025. Would that mean in the prior years, there was no project moved to execution phase of the refurbishment project work?

M. HANNON: No, that is not correct. There would have been definitely projects that were in execution. The cost would have just been minimal.

T. ZHU: Yeah, so I think that is part of the question that I wasn't sure, prior year versus now versus a year later, why the asset removal costs suddenly increased so much. Would you be able to clarify whether there is a portion to do with the labour cost increase or anything to do beyond the workload itself, like, any market factors here?

M. HANNON: No. I wouldn't say that labour is a component of it. It is more the amount of removal that we are doing. So as we are going into these large refurbishments, for example, the Sir Adam Beck, where we are doing significant refurbishments or redevelopments, we are removing a significant portion of that equipment.

T. ZHU: Thank you.

And now I want to look at F1-Staff-174, please. So in this interrogatory, originally the OEB Staff was asking if OPG could provide a breakdown between

the inflationary factor and the workload factor that could explain the project OM&A escalation year over year. So in the interrogatory response, OPG is saying that the project OM&A costs attributable to market inflationary-related impacts cannot be isolated.

So based on OPG's response, I further explored your pre-filed evidence from Exhibit A2, Tab 2, Schedule 1, Attachment 2. And page 10, please. I think I will say that again. So that is Exhibit A2, Tab 2, Schedule 1, Attachment 2, page 10.

So on the page 10, the table showing inflation assumptions on the right side, funding area OM&A, OPG is saying that the inflation is indexing based on existing contracts or supplier estimates or 4.5 percent if estimate is not available.

So based on the assumptions that OPG made in the business plan versus the interrogatory response in Staff-174, I want to further clarify how OPG determined the 4.5 percent as the project OM&A escalation and how much of the regulated hydroelectric project OM&A escalation year over year is based on the 4.5 percent versus it is based on the existing supplier or contractor's estimate.

M. HANNON: I think I get what you are asking. Okay. So the 4.5 percent escalation for procurement was provided through an analysis that was done through our supply chain team. 4.5 was determined to

be a reasonable estimate across the board.

If you do look at IR F1-Staff-177, it does speak to very specific indices that are impacted in the renewable generation equipment procurement. This percentage has been applied in a business plan on our purchase services. Our labour has been done separately. So I don't have in front of me the breakdown specifically between labour or procurement material, et cetera.

T. ZHU: Thank you for the answer.

And now I have a couple of more questions. They are to do with the FTEs.

First, could we go F1-Staff-172, please. In the interrogatory response, OPG is saying that the 2025 budget versus actual regulated hydroelectric regular and the no-regular FTE, that the actual is lower than budget by 98.4.

My first question, could you provide which job functions are currently understaffed and what is the impact to 2026 and the 2027 business plan due to the actual FTE behind budget. Specifically, I want to understand, for those jobs that are currently under-budgeted, understaffed, are they mainly to do with the jobs in the day-to-day operation at the hydro station or they are to do with the project works that hydro business is picking up over the last few years? Thank you.

M. HANNON: Thank you. I will start, and then I

will pass it over to Mr. Pender to finish it up.

So out of the 98 FTEs that we are under for 2025, approximately 20 of those FTEs relate to base OM&A work. Out of that 20 FTE, there is about 18 that were under in the engineering job family specifically. The remaining 78 FTEs that we are under is in our capital -- both project OM&A and our capital portfolio. A lot of that was intentional. Some of our project timing and schedules were delayed and deferred; therefore, we made the intentional decision to hold off on bringing in those FTEs until the projects were fully up and running.

So I will pass it on to Mr. Pender now to speak to -- I think your second part of the question was the work program. Thank you.

N. PENDER: So I think Ms. Hannon has described the capital impact, so roughly 60 FTE, so call it two-thirds. From a base perspective, really in two areas, it has had an impact. We talked about predominantly in engineering is where the underage is, and that is really on our equipment reliability program. So we talked this morning about equipment health monitoring, E-health, ELCM, and providing support to stations. We have not -- we have focused on our largest stations at the outset, and really the slight temporary delay receipt of those staff is just slowed up the rollout to other station sets.

So predominantly from an operations perspective,

it has had an impact in what we call our excellence plan, which is really a set of criteria in our business of how we are focusing on getting better, and that -- the reference for that is F1-SEC-151. We don't need to go there, but I just wanted to just put it on the record. So really, it is really about our drive for excellence. Just some of the challenges of bringing in the engineering staff means we haven't done it quite as quickly as we would have hoped.

T. ZHU: And thank you for that answer. Because now it is near the 2026, and OPG filed in the pre-filed evidence of its original 2027 plan in the OM&A FTEs and the capital FTEs.

As an undertaking request, would it be possible for OPG to provide an updated 2027 FTE plan breakdown into the OM&A FTE and the capital FTE that would incorporate the reality that the actual FTEs currently at the hydroelectric business is below the original budget and the original plan?

M. HANNON: Can I just clarify your ask? Is it to restate what you are believing we should change our plan to, or is it giving you what we have as of today?

T. ZHU: So since the last time we heard from OPG, that was the time where you replied the interrogatory --

M. HANNON: Right.

T. ZHU: -- at that time, the actual FTE was

still behind the 2025 budget. And because now we are halfway through 2026, so I believe it will take time for OPG to hire FTEs that will be able to reach the original level that you guys budgeted as 2026 and what you planned for 2027.

According to our conversation just happened now, it seems that OPG is potentially holding back some of the hirings until later when it is mature.

So based on all these conversations, I am wondering if it is necessary for OPG to provide an updated 2027 plan for the hydroelectric FTEs into the OM&A FTE and the capital FTE that reflects the reality.

S. ZADEH: Ms. Hannon, maybe I can offer -- perhaps we can take an undertaking to explain how we are going to catch up or expand further on the explanation that you and Mr. Pender provided, and perhaps we can give maybe a current view on the current FTE levels. But I don't believe a reforecast of the 2027 amounts we will be doing.

T. ZHU: Okay. Thank you. I think that is a reasonable undertaking. Thank you.

M. MILLAR: That will be JT-1.14.

UNDERTAKING JT-1.14: PROVIDE AN EXPLANATION OF HOW OPG EXPECTS HYDROELECTRIC FTE LEVELS TO CATCH UP TO THE BUDGETED 2026 AND PLANNED 2027 LEVELS, INCLUDING CURRENT HYDROELECTRIC OM&A AND CAPITAL FTE LEVELS

T. ZHU: And I have last two questions.

Could we go F1-CCMBC-002, please. I want to look at part A of the response. It is showing that regular staff in capital increased by 188.6 FTEs.

In my understanding, capital FTEs work for projects, and the projects are defined as temporary in nature. And if this is the case, could you explain why the 188.6 FTEs were hired as regular FTEs if that means OPG's intention is these additional capital FTEs will be kept in the hydroelectric business on an ongoing basis after the project work concludes?

M. HANNON: So it was decided to bring in these 188.6 FTEs full-time because, as Mr. Pender mentioned before, we are starting on a very long refurbishment program where we have regular full-time FTEs. The benefit that can be provided from using the same staff on sequential units is deemed to be more beneficial than bringing in temporary employees that turn over every two years.

T. ZHU: Could you elaborate when you say OPG is anticipating a long term of refurbishment work, so how long that time duration will look like?

N. PENDER: Maybe we could refer back to the record 30 minutes ago where we talked about the construct of when the program starts and finishes. I said it is very hard to define when it starts and when it finishes. It is somewhat continuous in

nature.

We talked about we are doing roughly a quarter of the fleet in the next rate period. And we extrapolated from that that if we do a quarter in, let's say, sort of seven years, it is not unreasonable to say in about 30 years, we would do the whole fleet. And then we talked around the planning guidance from CEATI and the U.S. Army Corps of Engineers that about 25 to 30 years is a sensible planning horizon for refurbishments.

To build off Ms. Hannon's question, it is reasonable to assume, subject to asset condition, as we spoke about earlier, that we would be in a cycle of refurbishments. And, again, we are really doing that to -- if we refer to evidence here on page -- line 34, our core objective is to sustain 1,500 megawatts of the existing regulated hydroelectric fleet from a capacity perspective and add an incremental sort of approximately 50 megawatts.

So on the assumption that we are going to meet that strategic objective, it is a reasonable supposition that having regular FTE, we think, is a more prudent way of driving our efficiency in our projects over time as opposed to having temporary FTE who will cycle through more regularly.

T. ZHU: So thank you so much for the explanation.

In the same response, it is showing that the

OM&A regular FTEs increased by 173.3. In the response the narrative, OPG is saying that -- it is on the third paragraph of the response -- it says the 173.3 increase reflects the addition of personnel across project management, operation, maintenance, engineering, as well as address the recommendations from the auditor general's 2022 value for money audit.

My first question, could you explain how many of the 173.3 FTE increase is supported by the auditor general's 2022 value for money audit?

N. PENDER: I can't do it specifically because I don't have the information to hand, but I would happily give you generalizations if that is helpful.

T. ZHU: So why not -- if we could take it as an undertaking request. If you could provide the specific section from the 2022 value for money audit report that is showing that the recommendation is OPG needs to add certain personnel into the hydroelectric business to support its ongoing operation, since like that, if that is possible.

N. PENDER: So we can turn to the auditor general report and look at the recommendation, but that report does not specify a specific number of FTE to go and do an activity. So that wasn't a recommendation from the AG.

There was a recommendation to address a backlog and work deferral. We can pull up if needs be to go

and look at the specific recommendation. But it wouldn't give you the exact number of FTE required do that. That would have been a decision from within the business to meet the requirements of that recommendation.

T. ZHU: I see. So the recommendation is a general recommendation, then OPG came up with its own analysis and hired so many FTEs coming on board.

So is it possible that, as an undertaking, you could provide more reasonings on how you determined that you needed to hire 173.3 FTEs as OM&A and 188.4 FTEs as capital over the last few years that would be able to address the recommendations saying that OPG needs to catch up with the backlogs?

N. PENDER: So the auditor general came in in 2022. They did a 2024 follow-up, a check-in. We haven't completed the five-year review of that process with the auditor general. So I will leave it to our counsel to guide whether we can answer this question.

D. COBAN: If I understood your question specifically, you are looking for a more detailed explanation of the FTE increases that you took us through and sort of how they are connected to the auditor general's recommendations of being able to implement those recommendations. I think subject to the qualification that some of that work is ongoing, we can on a best efforts undertake to provide

additional explanation.

T. ZHU: So I think right now -- because we are determining payments for the next five years, so we want to get enough information and the evidence that is supporting the FTEs that you put in the plan in 2027. And that plan is built on what was the actual FTE that is building up over the years; right?

D. COBAN: Understood. So you are looking for not just the auditor general but sort of a more fulsome explanation of all the drivers behind those FTEs?

T. ZHU: Yes, please.

D. COBAN: Yes.

M. MILLAR: That is JT-1.15.

UNDERTAKING JT-1.15: ADVISE HOW OPG DETERMINED WHETHER THEY NEEDED TO HIRE 173.3 FTES AS OM&A AND 188.4 FTES AS CAPITAL OVER THE LAST FEW YEARS

T. ZHU: And that is all of my questions. Thank you so much.

M. MILLAR: Thank you.

I think we are almost done, but I think one question got punted away from this panel and then perhaps punted back to Mr. Eminowicz. So over to you.

EXAMINATION BY T. EMINOWICZ:

T. EMINOWICZ: Thomas Eminowicz, Ontario Energy Board Staff.

Yes, so with the benefit of side discussion, I am back. So I have been asked to revisit my question that I was having with the Panel about the details of some projects and the components of refurbishment projects.

So I think, especially for me, to help kind of jog my memory, if we could please go to Exhibit D1-1-2, Attachment 1, Tab 8. This should be the Otter Rapids G1 overhaul and refurbishment. And in the recommendations section for this project, we were generally talking about maintenance and operating costs relating to the Otter camp and the road.

And so I guess to kind of pick up where we left off, I just wanted to confirm how common is it for a project to overhaul and refurbish a generating unit like this, as an example, to include work that is not directly related to the actual, like, generating equipment.

N. PENDER: I am not sure I can answer how common, but I can give you some context. So Otter Rapids is, as we discussed earlier, broadly in the middle of nowhere. So if we want to bring large equipment to site, you either choose road or rail or water. The only option here is road or flying it in.

So a prerequisite for doing this refurbishment work, we are talking about heavy engineered equipment that is heavy and bulky. So to commence that work, there will be activities required to enable staff to

get to site, equipment to get to site, provision of health and safety requirements. So in the case of Otter Rapids, this is the camp, the road, the staff; they are all necessary to undertake the refurbishment.

T. EMINOWICZ: Yes, thank you. That is certainly helping my memory.

And so what I think I had kind of asked as a follow-up was relating it back to the eligibility of a project for the capacity refurbishment variance account, and I thought I had understood that the assessment at the very least could or generally is done kind of at a detailed level where components of the project could be assessed for whether it is eligible for variance account treatment.

And I had asked for some sort of summary or identification of the projects in the IR term, so in 2027 to 2031, where there would be examples of subcomponents, where certain portions of a CRVA-eligible project may not have, like, those certain subcomponents eligible for variance account treatment.

So I assumed I was asking for an undertaking for the period, and if there was none in the period, I was asking for just any general example to understand how that happens.

M. HANNON: Thank you. So I don't have that in front of me, so I will have to get back to you on

that.

Typically what we would do is look at the scope of the project and then determine the eligibility. For many of the projects that are in our plan currently, they are unallocated, right, so the scope hasn't been fully defined, and we are just taking it as a general assumption that it is eligible. I can take that back, though, for you and get an answer.

T. EMINOWICZ: Yeah, thank you. I am just looking for examples of projects to just illustrate how that comes about.

M. HANNON: Thank you.

M. MILLAR: The undertaking is JT-1.16. Could we have a recitation again of what the undertaking is for?

T. EMINOWICZ: Yeah. I was asking for examples of projects that are identified as eligible for capacity refurbishment variance account treatment where there are components of the project that are not eligible for variance account treatment. And if there are none in the proposed term or the plan that is presented, just any example from the past if there is nothing that is easy or available in the future term.

M. MILLAR: Okay.

UNDERTAKING JT-1.16: PROVIDE EXAMPLES OF PROJECTS THAT ARE IDENTIFIED AS ELIGIBLE FOR CAPACITY REFURBISHMENT VARIANCE ACCOUNT

TREATMENT WHERE THERE ARE COMPONENTS OF THE PROJECT THAT ARE NOT ELIGIBLE FOR VARIANCE ACCOUNT TREATMENT, AND IF THERE ARE NONE IN THE PROPOSED TERM, PROVIDE ANY EXAMPLE FROM THE PAST

T. EMINOWICZ: And so the kind of follow-up that I had on that was related to just the idea of the generality, as Mr. Pender was explaining, the beautiful yet remote part of the province where Otter Rapids is.

In Exhibit D1-1-2, Table 1, which is where we have kind of, like, the list of projects, we have, I think, almost or just over $4 billion of capital expenditures summarized, I think -- that is Column I, as in "India."

And then in Column M, as in "Michael," there is, I think, almost $2.5 billion of capital in-service additions for these projects.

And I was just wondering if OPG would be able to somehow give a sense of the proportions of, like, these amounts where there is project work but where the actual tasks are not directly related to generating equipment.

N. PENDER: So I will kind of take a step back. So we talked around Aguasabon this morning, if I recall. That is a surge tank to supply water to the generating facility to undertake its intended purpose to generate power. We have got dams that hold water to provide fuel to the stations to create power. I

think you can see where I am going.

There is a system involved with generating power. So there is a turbine, and it has equipment, electrical, that allows it to be distributed out. So, for me, if we want this product, this product has a certain system requirement to have fuel, do it safely, leave site. So our work to do that is predicated on the function of power generation. That is the business we are in. So I think we -- to draw a distinction to say, That is power generating, That is not power generating, is a highly subjective perspective. So I am not sure how to be helpful in your question.

T. EMINOWICZ: Well, maybe if it is easier to just focus on the work that is easily attributable to the generating equipment, however your judgment would interpret applicability to -- so, for me, generating equipment is equipment that is used to generate and then inject electricity into the IESO system. So, like, a road, even though it is necessary for the project to get -- to bring the equipment, the road itself is not equipment required to generate energy and inject it into the grid.

N. PENDER: I would a hundred percent agree with you. Can I give you an alternative terms of reference? To maintain that station and to have it providing electricity into the grid, I need to get people to site. How I choose to get people to site

is one of cost prudency. There are multiple ways to transport people. Road is a fairly economic means to transport people to a site. So we can -- there is delineations of directness in the orders of magnitude, how far you go back. And I feel like I am being difficult; I am really not.

I am just trying to understand, where do you -- where do you cap the system at this is power generation, and this is something else linked to safety systems, public safety systems, regulatory systems, environmental systems all for the purpose of power generation, because that is the game we are in. The delineation is a real problem for me.

T. EMINOWICZ: I would leave it to your judgment of how to delineate, like, the physical thing that is used to generate and convey energy. I will just leave it at that. Up to you if you think that is an undertaking you can take, or I will just drop it.

D. COBAN: No. I don't think it is a proper undertaking on the exchange we had. You know, OPG's position is that the work is eligible for CRVA. If in the course of a detailed assessment, something is identified as not being eligible, as Ms. Hannon called out, you know, that will be brought forward in the normal course. But to try to delineate at this point in time on some kind of distinction, I think, would be unhelpful.

T. EMINOWICZ: Thank you. That is all for me.

Thank you.

M. MILLAR: Thank you, Mr. Eminowicz. And I think that is it for staff.

We will take our afternoon break now for 15 minutes, so until, say, 2:55 or so, and then, Mr. Rubenstein, you are up. Okay. Thank you.

--- Recess taken at 2:39 p.m.

--- Upon resuming at 2:55 p.m.

M. MILLAR: I see everyone is back, so let's get started again. Good afternoon, everyone. We are moving now to School Energy Coalition. I believe it is actually you, Ms. Scott, who is going to be doing most of the questions?

J. SCOTT: Yes, I am. Can you hear me okay?

M. MILLAR: I can hear you, so over to you.

EXAMINATION BY J. SCOTT:

J. SCOTT: Thank you. Though staff did cover some of our questions, I would like to return to D1-SEC-041, if we could. And in the response, part A says:

> "OPG assesses asset condition through its equipment health monitoring process for the hydroelectric system, structures, and components provided in Attachment 1." (as read)

And Attachment 1 is a health monitoring and reporting procedure. And then in part C of this response, it states:

> "Condition assessments are documented in

multiple ways. Historically, this has at times included plant-level assessments that address a broad range of equipment and were not prepared for project-specific decisionmaking." (as read)

So maybe if we could go to that Attachment 1 and page 8 of 23. And under "report generation and format," it refers to these plant-level health reports. So maybe can you explain what these reports entail, and if not for project-specific decisionmaking, then what are these reports for?

N. FABBRO: This is Nicole Fabbro. In response to your question, the plant-level health -- plant-level health reports essentially would be a summation of the assessment of condition of major components inside of the plant and as part of this new process that we are in varying stages of implementation. On an annual basis, the engineering team will sit down with the plant leadership staff and review, based on a myriad of information, an assessment of the health of the major components of the plant.

With that being said, I would like to distinguish that engineering will provide an assessment of asset condition, and based on that asset condition, the engineering will also recommend short-term and long-term mitigating actions. And as I have -- or as I have noted previously on the record, based on those actions, in some cases, a greater investment may be required to address the

asset, the asset condition. This is, at times, distinct and separate from a project-based risk assessment.

And I also noted in prior discussions earlier today that at times, in order to manage some potential project risks, decisions need to be made around the appropriate scope of work to be included in a particular project. So that would be my best response on how to delineate between the two.

J. SCOTT: So -- and on that same page, it talks about these reports being provided to the regulator, so I am assuming the regulator is the Ontario Energy Board, or is it referring to some other regulator?

N. FABBRO: I do not have the list of the regulatory bodies that is referenced in page 8 of 23 in Attachment 1 in front of me.

J. SCOTT: Well, what we are going to ask for is that -- could you provide us with a plant-level health report for the stations related to the renewable generation projects greater than 30 million, both for those projects that have been completed before the work was done and the impending projects.

N. FABBRO: As I have noted previously, we are in varying stages of implementation of the health monitoring and reporting software; however, what I can provide is a representative example or sample of what a plant health committee, I guess, slide deck

would look like, and that would be in reference to one of the projects listed in SEC-41, Attachment 3.

J. SCOTT: Okay. Well, maybe if you could -- if for the projects that are listed in Attachment 3 where you have that information, provide it to us. I guess because the -- like, you know, you have provided us with Attachment 3, but it is very -- in some -- well, it is very high level. In some cases, you know, the condition of the stator is poor to good, which doesn't really tell us.

D. COBAN: Sorry, Ms. Scott. Just trying to get some instructions here. I think, as we heard from Ms. Fabbro, we can provide you a representative sample, but at this time, we are not prepared to go through that entire list there and sort of go through it and figure out what is and isn't available. So we will give you a sample so that you can look at the rigour of the information, but not able to do the whole thing.

M. RUBENSTEIN: Sorry. Why not? If -- just to be clear, these are for project -- these are for the plants where, as I understood the evidence, because you are implementing this, you will have it for some plants and not others; is that my understanding?

N. FABBRO: That is correct. As I noted previously, some of these projects were initiated before we implemented this new live system, if you will. And as a result, I cannot confirm that a full

plant health condition assessment in the new system is available for every single project listed in Attachment 3.

M. RUBENSTEIN: Yeah, sure. And I guess the question -- the undertaking we are asking for is for the projects that Ms. Scott discussed on that table where you have those reports are available to provide them. I mean, a representative sample is not really that -- sample is not --

--- Off record discussion

M. MILLAR: Ms. Coban, do you want to try to summarize the undertaking?

D. COBAN: Sure. For the information in SEC-41, we will provide a representative sample of the health condition report, and we will consider if we are able to provide anything further than that sample, and if we can, we will; and if we cannot, we will explain the basis for the refusal.

M. MILLAR: It is JT-1.17.

M. RUBENSTEIN: And just so the record is clear, the request at the second part there that SEC is seeking is the plant-level health reports that do exist for all of those projects.

UNDERTAKING JT-1.17: PROVIDE A REPRESENTATIVE SAMPLE OF THE HEALTH CONDITION REPORT IN REGARDS TO SEC-41 AS WELL AS THE PLANT-LEVEL HEALTH REPORTS THAT EXIST FOR ALL OF THOSE PROJECTS

J. SCOTT: So the dates on this procedure are

PDF creation date of the -- of 2021/12/01 and a compliance date of September 1st, 2022. So is this the first version of this procedure?

N. FABBRO: I do not have that information in front of me.

J. SCOTT: If you could undertake to tell us. Because my second part of the question is, was this produced in relationship with -- as a result of the auditor general's value for money audit and in response to the recommendation that said OPG did not always assess the conditions of its hydroelectric stations and address engineering recommendations on a timely manner?

N. FABBRO: Again, similarly, I cannot confirm or deny any relation to the auditor general report in the institution of this process at this time.

J. SCOTT: Can you undertake to tell us if there were previous versions of this procedure?

N. FABBRO: Yes, I can undertake to provide confirmation of any prior versions of this health monitoring and reporting procedure.

M. MILLAR: That is JT-1.18.

UNDERTAKING JT-1.18: PROVIDE CONFIRMATION OF ANY PRIOR VERSIONS OF THE HEALTH MONITORING AND REPORTING PROCEDURE, AND PROVIDE AN ASSESSMENT OF THE STATUS OF THE PCA COMPLETION FOR ALL 54 HYDROELECTRIC STATIONS TODAY FOR REGULATED HYDRO

J. SCOTT: Thank you.

So the -- in the follow-up to the auditor general's report, it said -- it -- OPG stated that they had reviewed the completion dates of the plant condition assessments for all 66. The legacy auditor general had reviewed that and found that approximately 20 percent did not have planned condition assessments completed in the last ten years. Do all 66 of the stations have PCAs done now?

N. FABBRO: Again, unfortunately, I do not have direct confirmation in front of me as to completion of a PCA for all 66 hydroelectric stations.

J. SCOTT: Maybe we could add that to the previous undertaking?

N. FABBRO: I can undertake to provide an assessment of the status of the PCA completion for all 66 hydroelectric stations today for regulated hydro.

J. SCOTT: Thank you. Yes, yes, yes.

So Attachment 3, staff asked about when assets that were rated as fair or good were replaced, and you did respond with the reasons why there may be reasons for doing that. Just take this one step further. Is -- does OPG have a process where they can cost the sort of cost benefit of replacing fair to good assets under a sort of global outage versus maybe doing it later on?

N. FABBRO: What I can confirm is as part of the project management process that we follow and as part

of the early phases of planning a project, as with any project, we will assess risks associated with the overall project. And one of those risks may be concealed conditions or the risk of finding a greater degree than perhaps what we could have planned for. And that process that we follow to further define the total scope of the project is provided in D2-1-1.

In addition, I would like to highlight -- and if we could please go to D1-Staff-311, please. And if we could specifically go to starting at line item 37. Thank you. So in this undertaking -- or sorry. In this interrogatory response, we provide a series of factors that are considered as we move into the planning of a turbine generator unit overhaul or refurbishment. And we identify assessment of risks and a series of bullets on page 3 of 5, lines 3 through 12. So these risks, as I mentioned, are assessed as part of the project planning process by a combination of engineering as well as plant staff and project management staff.

J. SCOTT: So does that include the risk of replacing perfectly good assets? I understand I saw the concealed -- I understand the concealed condition, but the idea of replacing a good -- an asset in good condition that didn't need replacing and the increased cost of doing that early?

N. FABBRO: The project teams in conjunction with support from engineering would assess the risks

versus the benefits of making that decision as part of the overall project scope.

J. SCOTT: Okay. Maybe could we ask for one of the projects, and maybe the Coniston Stinson project back on that -- the Attachment 3, if you could sort of provide us with a breakdown of the costs between fair to good assets being replaced versus poor or unacceptable assets being replaced.

M. SIKSTROM: I think part of that comparison is already done in the business case for the Coniston Stinson project in Exhibit D1-1-2, Attachment 1, Tab 5. So in that BCS, it presents a number of different alternatives. So the preferred alternative is highlighted there with new DIVE units, which is a type of turbine and generator units, and also compares that to alternative 4, which is redevelopment of both sites with new Saxo units.

So as part of that description, it compares how the new technology, which would necessitate replacing some of the equipment in the SEC-41 attachment that may be rated fair, with new equipment is due, in part, to this new -- the new technology that is being installed at this site. And the cost benefit of doing so is highlighted between those two alternatives.

J. SCOTT: So does that include replacing the power transformers which were rated good?

M. SIKSTROM: That is correct. The existing

power transformers weren't compatible with the new DIVE-Turbine technology.

J. SCOTT: Okay. Well, we will have a look at that, and thank you for that response.

I have some questions related to prioritization of projects, so if we can go to D1-SEC-43. And in that, when we asked about the Renewable Generation Turbine Generator Refurbishment Program, and we referred to D2-1-1. And so looking at page 4 of 13 of D2-1-1, under "project selection and prioritization," and it says:

> "Produce a prioritized list of candidate projects for inclusion in the business plan within unallocated capital projects and project OM&A subject to the business planning approval process." (as read)

So could you explain how allocated capital projects fit into, then, the prioritization process?

M. SIKSTROM: So as we conduct the prioritization process as part of our business planning function, projects that already have a business case approved in the form of allocated projects, they are at the top of the prioritization list. Essentially, they are our must-do within our prioritization process.

J. SCOTT: Okay. I did actually see that in -- because you did also refer us to -- I think it is Staff-311, and I was going to ask about how -- so if

you -- if a project that has a business case approved, that must -- how -- could you not then approve more than the funds that are available? I am -- I guess I am -- within the projects that are approved, how do you prioritize within those?

M. SIKSTROM: The projects that already have a business case approved are prioritized first, and then remaining capital is then prioritized amongst the unallocated projects.

J. SCOTT: If there is a capital envelope for a certain year, the ones with approved with business cases go first. Is there a risk that that is going to be more than the capital envelope?

I guess my question is, is there a master list of all the projects and a prioritization of all of those projects?

M. SIKSTROM: I guess there were two parts to your question there, Ms. Scott.

The first part with the scenario where if we had a capital envelope that was less than our allocated portfolio, then we would work with our allocated portfolio to manage it within our capital envelope.

And your second question related to is there -- do we have a list of projects. We do provide in our evidence a list of the allocated and unallocated projects.

J. SCOTT: But as far as I can see, there is not a -- they are not ranked in a certain order.

Maybe I can ask this in another way. My understanding is you are using the Copperleaf 55 program.

M. SIKSTROM: That is correct.

J. SCOTT: Is that --

So based on experience from other, you know, distribution -- utilities -- distribution utilities is the Copperleaf 55 produces a score, and they can provide us with a list that has a score for each project. Are you able to produce something similar to that?

M. SIKSTROM: So Copperleaf is used to help us value our potential investments, and we -- it is used to help us prioritize, as you said, our selection of unallocated projects.

So we did provide that list of unallocated projects along with their score in IR D2-AMPCO-22. Lori, perhaps you can bring it up.

J. SCOTT: Is that the value framework one? Yes.

M. SIKSTROM: Yeah.

J. SCOTT: And that was going to be my -- one -- another question is, is the Copperleaf score the same as the value framework?

M. SIKSTROM: The Copperleaf tool -- we apply our value framework and use the Copperleaf tool to help perform those calculations to come up with that asset and investment net value that is highlighted in

the table that we use to help us prioritize our unallocated investments.

J. SCOTT: But only the unallocated investments? The allocated ones have an approved business case, and they go first; is that what -- that is what you are saying?

M. SIKSTROM: Yes. In case of -- in the case of the projects that have an approved business case, they are prioritized, and they don't form part of the list that we provided in Attachment 1.

J. SCOTT: So maybe could we pull up the AMPCO-22 spreadsheet just so that I can make sure that I understand what the numbers are saying.

So there is a net benefit -- maybe someone could make that just a little bit bigger so we can look at it. And go to the far right. Yeah.

So there is a net benefit score and a -- in dollars and a cost in dollars; correct?

M. SIKSTROM: Yeah, the net benefit score is really a value, the value of -- a summation of the value of the mitigated risks with the cost of the investment netted out.

J. SCOTT: Okay. Is that similar to a Copperleaf score, then, that net benefit score?

M. SIKSTROM: Yeah, that net benefit score, that is the score that we look at to help us prioritize our unallocated portfolio.

But I should add just for context, like, we do

use Copperleaf as a tool, and these scores, to help us prioritize. But we do take into consideration other constraints that we highlight in more detail in D2-AMPCO-23, resourcing, scheduling considerations, environmental requirements, and so on and so forth. So the score does kind of form our foundation for our prioritization, the unallocated portfolio, but there are other considerations as well.

J. SCOTT: Okay. Thank you very much.

If we can maybe move to -- well, I don't know if we need to pull it up, but A1-CCC-009 in Attachment 11 is the Renewable Generation Turbine Generator Overhaul Program. And that was an internal -- as I understand, an internal audit of that program. And it referred to RG-PROCOP-001, a hydroelectric optimization procedure document. Has that been completed?

M. SIKSTROM: Could we just scroll down to which page and line you are referring to in this attachment?

J. SCOTT: Let me -- I don't have the page. It was in one of the recommendations. If you just scroll through that document. Key findings...

I am sorry, I don't have the page. I don't know which -- well, in - actually, if you go to A1-4-1, Attachment 4, which was a summary of the internal audits. And it says:

"Management will continue to develop the

hydroelectric optimization procedure document."
(as read)

M. SIKSTROM: Sorry, Lori, would you mind just scrolling down --

J. SCOTT: Yeah. Attachment 4, page 38 of 89. No, that is not...

There. Yes, right there. "Management will continue" at the top of the page.

M. SIKSTROM: Could you just scroll up one page, please, Lori, just so I can see. Sorry, just scroll down again, Lori. I am just trying to find the one response.

D. COBAN: Ms. Scott, just because we have been trying to dig up the references, would you mind just restating your question so we have that before us.

J. SCOTT: Has that procedure been completed, and, if so, is there a copy on the record, or could you provide one if there is not?

D. COBAN: And just for our clarity, Ms. Scott, we had started on this exchange talking about the overhaul program, but I believe this audit that you are taking us to now is related to a different topic. I just want to make sure we are not getting confused.

J. SCOTT: This is on the Turbine Generator Overhaul Program and prior --

D. COBAN: No. The audit you pointed us to is on the generation revenue planning. So the reference you are pointing us to is related to a different

scope.

J. SCOTT: Sorry, page -- no, I am sorry. Yeah. That was -- well, I am -- just I am still looking for the RG-PROCOP-001, hydroelectric optimization procedure document, is what I was looking for.

D. COBAN: I think without a reference, it is hard for us to really understand if that is an undertaking we can give you. So perhaps you can come back to us with that reference, and we will consider the undertaking.

J. SCOTT: Okay. I will do that, then.

D. COBAN: Thank you.

J. SCOTT: Okay. If we look at the summaries of the internal audits, and specifically related to maintenance and work orders. So in the internal audit, I think 20-19, renewable generation and power marketing asset management and maintenance follow-up, the finding was that a significant number of maintenance work order tasks remain backlogged.

And the 22-11, there was a -- there was a statement saying there is no formal documented plan to reduce work order task backlogs. And there was a similar recommendation in the 2022 audit -- auditor general's recommendation number 3, action item 1. So in that 2022 auditor general's recommendation number 3, the back load of work orders was 9,500 at the end of 2021.

So my question is, can we get an update on that?

But related to that, my understanding, there is -- and the nuclear benchmarking annual report includes tracking of the back load of maintenance work orders. Is there something similar for hydroelectric that tracks the maintenance work orders and where -- the status of them?

N. PENDER: Can I just verify recommendation number 3 from the AG report was to deal with Ontario Power Generation and IESO? Can you just give me the reference, please. I am just trying to track it down.

J. SCOTT: Yeah. I am -- and I am looking at -- this is F1-AMPCO-090, the follow-up on the 2022 performance audit. And recommendation number 4 was:

> "To better monitor, track, and complete maintenance work on its hydroelectric generation fleet." (as read)

And that is where the reference to the back load was approximately 9,500 work orders at the end of 2021.

So there is no page numbers on this. It is just -- it is item 3:

> "The aging of hydroelectric stations and equipment has led to a continuous backlog of work orders which could result in increased maintenance cost." (as read)

N. PENDER: So I have just gone to the AG follow-up report from 2024.

J. SCOTT: Mm-hmm. Right. So then -- yes.

N. PENDER: And there was a recommendation 4 on page 7 of 23, action item 1.

J. SCOTT: Right. That is the page I was looking at, yes.

N. PENDER: So -- and I think it -- yeah. It references a legacy position as of 2021, some 9,500 work orders. The account from here was that recommendation 4, action item 1 fully implemented, and so we have reviewed and revised our work management procedures to ensure appropriate work prioritization and completion by due dates.

And then it lists a couple of examples around work management, master data procedure was revised in June 2023.

And then the bullet below around work management, assessing, planning, and scheduling procedure was revised in February 2024, and I note that the AG had classified this as fully implemented.

J. SCOTT: Right, but my question was, is there an update on the number of the backlog of -- the number of maintenance work orders, and if -- a backlog, if it still exists or not?

N. PENDER: This is something I don't [indiscernible] something we could undertake to provide.

J. SCOTT: So there is no -- there is no equivalent report to this, as part of the

hydroelectric annual report or anything, that includes tracking of the back load of maintenance work orders?

N. PENDER: We have established a methodology to track status, and that was -- that was how -- well, I can't go into exactly how the AG made its fully implemented assessment, but we provided enough information to close out this action item.

J. SCOTT: But you -- so you cannot provide the number of -- the backlog of maintenance work orders for hydroelectric at this time?

N. PENDER: I don't have it to hand, no.

J. SCOTT: Can you undertake to provide that?

N. PENDER: For sure, yeah. We can undertake to provide the volume of backlog of work orders within the context of recommendation 4, action item 1, which is fully implemented, yes.

J. SCOTT: Great. Thank you.

I. RICHLER: It is -- for the record, it is Ian Richler, I have taken over for Michael Millar as moderator, and we will note that as Undertaking JT-1.19.

J. SCOTT: Thank you.

UNDERTAKING JT-1.19: PROVIDE THE VOLUME OF BACKLOG OF WORK ORDERS WITHIN THE CONTEXT OF RECOMMENDATION 4, ACTION ITEM 1

J. SCOTT: I just have a couple of questions about opening rate base for hydroelectric. And we

don't have to pull these ones up, but there are a number of IR responses that confirm that the Timmins building expansion and the Dymond machine shop were common capital and therefore part of the asset service fee.

So -- but just to confirm, that doesn't change the 2027 hydroelectric capital expenditures; they are still 880.9 million as shown in D1-1-1, Table 2?

M. HANNON: That's correct.

J. SCOTT: And so there hasn't been any update to the rate base for hydroelectric for 2027, if I understand correctly?

M. HANNON: There would not be, no. Those two projects were coming into service post-2027.

J. SCOTT: Okay. B1-SEC-028, Attachment 1, which was one of the motion IRRs -- IR responses, and it is an Excel spreadsheet, shows the conversion from Capex to in-service capital. If we could pull that up. It is an Excel spreadsheet.

If you just scroll down a little, there is a line called "reconciling differences," which I understand -- maybe you can explain what that line is for.

M. HANNON: Sorry, can you repeat that? You went a little blurry there.

J. SCOTT: There is Capex and then in-service, and there is a line at the bottom, "reconciling differences." I don't know, is that related to CWIP?

Or what is that line representing?

M. HANNON: That line is representing all capital expenditures that do not go into service during this period.

J. SCOTT: But there is a line in service 2032 or later, so it's --

M. HANNON: Yeah, so it is essentially -- if you look at our narrative, there was about 126 million that we called out that is included in our capital that never goes into service. That is what that line represents.

J. SCOTT: And so how -- maybe you can explain that a bit more. Why does it never go into service?

M. HANNON: There were a few projects that we identified that had included contingency on their unallocated amounts in their capital expenditure. The directions were that those were -- that contingency was not to be put into service because we couldn't validate that it was going to be spent. So that caused the discrepancy of 126 million with no impact to the rate.

J. SCOTT: Okay. And so -- it was that spreadsheet. But -- so if I sum up line 15 for 2027 on that spreadsheet and get 836.5 and 6 million --

I. RICHLER: Ms. Scott, you're -- you're -- sorry. It is Ian --

J. SCOTT: -- million is in service --

I. RICHLER: Jane, it is Ian. You are -- you

are breaking up a bit. I think the sound -- the -- we are having a bit of a tech issue. Maybe you could just repeat the question, please.

J. SCOTT: Sorry.

So if I sum up the line of capital additions for 2027 and get something lower than what is shown in the total capital additions on other -- sort of another table, can I assume that that is the differences before 2022?

M. HANNON: Yes, you are correct.

J. SCOTT: Okay. Thank you.

Now, I am not sure that this Panel is the place to ask this, but I will. H1-Staff-260, Attachment 3, Table 1D, which, again, is part of the motion IR responses. It is an Excel spreadsheet again. So it is H1-Staff-260, Attachment 3, Table 1D. Yeah, Table 1D.

So there is a note 6, and that is stating that the line is the total capital additions. So -- and we talked a bit about this before, about only some projects being eligible for CRVA only applies to a subset of the project. So can you explain how -- why the total capital is used in this calculation?

M. KIRK: Yeah, Ms. Scott, this question ultimately will probably be better suited for Panel 4. But at a high level, I can tell you that the reference to total capital is in relation to threshold methodology that we use for clearing the

hydroelectric CRVA over a five-year period.

J. SCOTT: Okay. I did read about that, but I maybe wanted a bit more explanation. But maybe I will save that for Panel 4. Thank you.

Now, I did have some questions about one of the projects that exceeded 10 percent of its first execution business case summary from Project 82089. There is a number of references. I don't know if we need to pull them all up. But if the business case, Exhibit D1-1-2, Attachment 1, Tab 6 -- I don't know. Are we getting that pulled up, or, I mean, I can proceed without it?

So my understanding, the initial execution release of 136.5 million and project over variance, so it was really baseline distribution of 145 million. And then my understanding -- then the superseding business case summary increased it to 167.5. So an increase of 31 million or 22.77 percent.

Now, there is a project change form -- 016, Attachment 5.

I. RICHLER: Sorry. Jane, it is Ian again. We have a really poor -- we have a really poor connection, and you keep breaking up.

J. SCOTT: Oh, sorry.

I. RICHLER: The only -- the only troubleshooting trick I know is to maybe try turning off your camera which can sometimes take up some

bandwidth. So can I --

J. SCOTT: Okay.

I. RICHLER: Can I ask you to do that, and we will see if it improves at all. Thanks.

J. SCOTT: Okay.

I. RICHLER: But just go back 30 seconds because we didn't hear any of that.

J. SCOTT: Sorry.

Okay. There is a project change form, D1-AMPCO-016, Attachment 5. And in that, there is a change in budget for project management. And my understanding, it says:

"Added 0.25 a person --" (as read)

We can see that:

"-- and an increase of 1.1 million." (as read)

So I was hoping someone could explain that to me.

M. SIKSTROM: So, Ms. Scott, the addition as per the change description in that attachment, we added an additional 0.25 FTE to the project team, which was -- which would trigger the contingency change amount.

J. SCOTT: Maybe that is -- so if -- if you could just blow that up a bit. Do we have the change -- my understanding, there was one project manager, one project engineer, and one senior business development officer, and then the new budget is for one project manager, one project engineer, one senior project engineer, and 0.25 of a senior business

development. So I read that to be an increase of 0.25?

M. SIKSTROM: That is correct.

J. SCOTT: And -- but that -- but the budget increased by 1.1 million?

M. SIKSTROM: There may have been some other details that went into building that contingency draw amount that is noted in the attachment, Ms. Scott, but I don't have them in front of me.

J. SCOTT: Can I get an undertaking to provide further information on that?

M. SIKSTROM: Yeah, we can take an undertaking to, on a best-efforts basis, rationalize what went into that contingency drawdown amount that is noted in that.

J. SCOTT: Thank you.

I. RICHLER: Let's record that as Undertaking JT-1.20.

UNDERTAKING JT-1.20: RATIONALIZE WHAT WENT INTO THE CONTINGENCY DRAWDOWN AMOUNT THAT IS NOTED IN D1-AMPCO-016

J. SCOTT: So if we go to D1-AMPCO-013, the project closure report for this project.

D. COBAN: Can we just have that reference one more time, Ms. Scott, please.

J. SCOTT: Yeah, D1-AMPCO-013, Attachment 3. And I can't see -- I can't see the page number, but just scroll down to the next page, yeah. So at the

top there, and it says:

"The project was completed successfully. Project was completed with an actual cost of 167.2 million under the approved budget of 167.5." (as read)

But, as we saw earlier, the actual original execution release was 136.5.

So my question, I guess, is how -- why is this considered a success in that it came in under budget but the budget was updated; compared to its original budget, it was overspent?

M. SIKSTROM: So the key to identifying this project as completed successfully is related to the fact that the 167.5 million was an approved budget, and the project cost did not go over the approved budget. So acknowledging that there was an over variance in a superseding release, but as part of our project management process, the changes that merited that those two documents and those two approvals were justified in changes in the conditions of the project, and that is how we concluded that the project completed successfully.

J. SCOTT: Okay.

I think I am -- I have used up my time, my part of SEC's time, so I will turn it over to my colleague Mr. Rubenstein. Maybe if there is any time left at the end after he has asked his questions, I might ask a few more, but...

EXAMINATION BY M. RUBENSTEIN:

M. RUBENSTEIN: Thank you very much, Panel. I just have a couple areas that I would like to discuss with you, and I want to follow up on the discussion about unallocated projects and allocated projects and how the budgeting works.

And at a high level, as I understood from your answers to OEB Staff and Ms. Scott, there is an annual -- or over multi-years, there is annual budgets. You have allocated projects, which are those that have an approved business case. And then you have a certain amount of the budget that is unallocated that you then run a prioritization process and that you essentially draw from -- you draw from to then select projects, then, I assume, also then have to go through the business case process, and then they become allocated. Is that, at a high level, how this works?

M. SIKSTROM: In general, yes, we have a capital budget that we figure out every -- determine every year. There are certain projects that are classified as must-do, as you alluded to, and then after those have been prioritized, the remaining investments, we prioritize with the help of Copperleaf and the AINV and other constraints to maximize the value as much as we can within the constraints of our unallocated portfolio.

M. RUBENSTEIN: So when you select a project or

a prioritization process now for the -- what I am calling sort of bringing up projects from the list, the unallocated list, presumably, then, they also have to go through a business case process; correct?

M. SIKSTROM: Yes. Once one of the potential investments that is one of the unallocated investments -- when it reaches the milestone to go into a Gate 1, it turns into a project and then proceeds through the project management process with our various gates to get to execution.

M. RUBENSTEIN: Like, do you do any -- what type of work is then done for the purposes of getting a project onto the list, the candidate investment list?

M. SIKSTROM: In terms of identifying potential investments, they follow our asset management process that we describe in Exhibit D2-1-1. And so when investments are identified, we then score them using our value framework with the help of Copperleaf to come up with that net benefit score that helps us prioritize our unallocated investments to be included in our business plan.

M. RUBENSTEIN: Now, in the business cases, often you will see alternatives, and I don't just mean do-nothing alternatives. There will be some alternative solution to the issue. Do I have that right?

M. SIKSTROM: Yes. Alternatives are often identified in our business case.

M. RUBENSTEIN: Now, that is at the business case, but now we are -- before we get to the business case, we are entering in investments into the -- into Copperleaf. Is there multiple candidate investments for each of those alternatives, or is -- you have already -- or you are making that selection, and then the project enters Copperleaf?

M. SIKSTROM: So the potential investments address the asset condition and the associated risks, and working with our engineering group and our operations group, they identified short-term and long-term mitigating actions. And those recommended mitigated actions are which we translate into potential investments in Copperleaf. So each Copperleaf -- our preferred investment, as what you are kind of talking about, that is the one that we score in Copperleaf for that particular investment.

M. RUBENSTEIN: So I will just give you a hypothetical. Just sort of at an abstract layer, there is sort of a -- there is a potential issue, and you have two options; one is a more expensive upfront investment, but it will last longer, so to speak, or a -- you know, a less costly investment, but obviously it will last -- the solution will be shorter in duration, right. Those are two alternatives. Something like that, sometimes you see in your business case.

I want to understand, for the purposes of the

Copperleaf, are both of those put in, or are you making a determination over some analysis of which one of those is preferable and it enters Copperleaf?

M. SIKSTROM: The alternative that is entered in Copperleaf, there is -- it is the -- this is the alternative of that investment to address that asset condition or risk. The -- that selection of the alternative we put into Copperleaf is based on the discussion with engineering and operations. Once the project or a potential investment proceeds into the project management process, we do review those other alternatives or potential other alternatives in -- through the project management process as well and the BCSs that you talked about earlier.

M. RUBENSTEIN: So you look at it twice, so to speak? Once is sort of scored through the value framework, and then at the -- once you have sort of selected the project from the list to be allocated and you go through the BCS process, you look at it again?

M. SIKSTROM: When potential investments are identified, the scope is very preliminary. And so as the scope and cost and other mature through the project management process, alternatives are often assessed and -- to ensure we have selected the preferred alternative, which may have been refined through -- as you progress through Gate 1 and Gate 3, that scope and details are often refined.

M. RUBENSTEIN: Okay.

Now, with respect to the list of projects, I think, as you mentioned, in D2-AMPCO-22, I think it is Attachment 1, there is the list of the value framework outputs. And I believe those correspond to the list -- or supposed to or some variation of the list of unallocated projects; do I have that right?

M. SIKSTROM: Yes. The list in Attachment 1, D2-AMPCO-22, this is a list of the unallocated projects that were included in our business plan.

M. RUBENSTEIN: But the list that was prioritized to get to that was longer; do I have that right? Or is that every potential candidate investment?

M. SIKSTROM: We have potential investments that were not included in this list.

M. RUBENSTEIN: And can you provide a revised version of this table with all of the investments and then indicating which ones are in the list that is in the application and which were not, which were obviously not selected for whatever reason?

D. COBAN: No, we are not able to provide that. I think we looked at this issue as part of AMPCO-23 in the resolution of our motions, Mr. Rubenstein.

M. RUBENSTEIN: Well, I am just understanding from this what I -- look, I am understanding from today's discussion how this works, and I was not clear at the time. So the list is -- as I understood

here, there is a larger list of potential investments that you have done some work on, which you haven't selected, and I am not sure -- and so I am going to ask if that can be produced.

D. COBAN: No.

M. RUBENSTEIN: And what is the basis of that?

D. COBAN: Well, the first basis is that we understand to have resolved this issue through the resolution of AMPCO-23.

And the second basis is that investments which did not make it into the plan we don't believe are relevant because, ultimately, they don't form part of what we are considering here today.

M. RUBENSTEIN: And you don't think understanding which projects you obviously didn't chose -- helps inform; doesn't help inform the prudence of the projects you are planning to do? What you have selected, what you have not, and why those were not selected through your process? That confuses me.

D. COBAN: I think you are free to ask the witness question around how that determination is made. And certainly when it comes to the allocated projects, we have detailed evidence on the record as to the valuation of alternatives with respect to many of those projects, and so we believe the record is complete and sufficient to allow the evaluation of prudence.

M. RUBENSTEIN: Well, let me ask you this: Is it based on -- is it going -- is what sits underneath the projects that were not selected, do they have -- is it just simply based on their net benefit scores are lower than those on this table?

M. SIKSTROM: No. As we talk about in Exhibit D2-1-1, net benefit, or AINV, performs the basis for our prioritization, but we also apply constraints -- whether it be resourcing, scheduling, environmental constraint, as examples -- that could inform how we prioritize those potential investments into our business plan.

M. RUBENSTEIN: So there are projects that would have higher net benefit scores than the projects that are on this list?

M. SIKSTROM: Potentially. But they -- how we prioritize our unallocated potential investments are based on -- those constraints would have to be taken into consideration as some of those constraints determine the executability of the selection of unallocated potential investments that we added.

M. RUBENSTEIN: Well, let me ask this -- let me ask the question a bit differently. Can you provide a list of all of the projects that were part of the longer list that you -- that had higher net benefit scores and why they were not selected ultimately?

D. COBAN: No. I think the witness has explained that the selection of projects is not just

on the basis of the net score. There is other considerations that go with that, and we are not prepared to provide anything beyond what is included here in the application that ultimately doesn't form part of the amounts we are here to --

M. RUBENSTEIN: Yeah. Just to be clear, my question was -- and to provide the reasons why I think there was some discussion of sort of, here are the types of reasons, but the specific reasons.

D. COBAN: No. We maintain the refusal.

M. RUBENSTEIN: Now, let me just ask about the overall budget, how that is determined. Because if you go look, as I understand, there is an overall budget set that includes the allocated and the non-allocated. It is not clear to me from the evidence how that overall number is determined. Can you help me?

N. PENDER: So if we turn to A2-2-1, page 18, line 10. Yeah, okay, this is good.

So line 10. So starting at the top level, so the OPG business planning and budgeting process, line 9, is a:

> "[...] decentralized annual process undertaken with a consistent top-down framework of strategic objectives, resource guidelines, and costing assumptions." (as read)

So within this framework, individual businesses, such as ours in hydro in this case, set strategic and

performance objectives to identify a plan and the work required to achieve these objectives.

So we approach it in two ways. One is the top-down kind of global OPG perspective. Me from the hydro, we -- as we kind of established, we are condition-based. So when we talk about SEC-41, that is the foundational elements of identifying the work that we need to do, and then we set a plan in and around that to meet those kind of global capital objectives.

Now, we don't work in a vacuum. And our core objective is really, as a business, to maintain availability and reliability, and it is really to manage within -- manage the bottom-up requirements within the kind of top-down scope of the business.

M. RUBENSTEIN: So you have a capital budget, which is allocated or non-allocated, that you are seeking approval for the regulated business for the five years, they have very specific numbers, in which a sizable amount is obviously unallocated. You don't even know which of the specific projects in the list you are going to do. So it is just not clear to me how you pick -- how those specific numbers are determined.

Why is it not $10 million more? Or $40 million less? That is the type of question.

N. PENDER: I will refer you to D2-AMPCO-023. So line 37, please. This is D2-AMPCO-23? Yeah?

Okay.

Yeah, sorry, I have just updated the reference. Let's start on line 25, please.

So when we talk about the unallocated portfolio, these are potential starts or potential future starts. As my colleague, Mr. Sikstrom, has mentioned, it is selected and prioritized through our asset management process described in D2-1-1, Section 3.2. Now, we recognize these haven't been fully scoped, and they are based on Class 5 estimates.

Now, as we review this portfolio, from time to time, we may change what sits on this portfolio based on a prioritized basis, but we use the combination of the unallocated and unknown top-down requirements allocated projects for which we have confirmed BCSs really to build together our kind of capital and OM&A request. So that starts as the foundation into the business planning process.

M. RUBENSTEIN: Can I ask -- move on to a different topic. Can I ask you to go to F1-SEC-152.

In this interrogatory we had asked OPG for each historic or current continuous improvement or productivity initiative for the hydroelectric business, to provide for each year between 2016 and 2024 certain information, quantified information.

And you say at line 29:

> "OPG is unable to attribute discrete cost savings or isolate incremental production

increases to individual initiatives, as overall performance reflects the interacting effects of multiple initiatives, external conditions, and operational factors that together drive the aggregate outcome." (as read)

Do you see that?

So just so I can understand, when I look through the list that you have provided here, which ones are focused on reducing cost? Is it really just the organizational realignment one?

N. PENDER: No. I would say it is broader than those you have characterized. So when we think about cost, I think there is the efficiency with which the business operates.

So on page 2 of 4, we have detailed what I am going to call two sets of safety initiatives. One is what we probably recognize as conventional worker safety, and, for me, that is really about driving down the level of incidences to our people. And having a good, strong safety culture has the net effect of driving efficiency within our business. So if we have a safety event or people get injured, that takes time away from doing work to address the impact of it.

And our safety performance has radically improved in recent times. So we have set the strongest TRIF metrics in our history in the last three years. So, for me, that would be just one

example of driving for excellence and kind of continuous improvements.

M. RUBENSTEIN: I don't disagree. Safety is incredibly important. I recognize, obviously, there is a cost implication for an unsafe environment but -- so let me just put aside safety for a moment or safety-related and non-safety. Is the -- regional realignment, is that the only one that is just -- it is cost focused?

N. PENDER: So I would then probably draw your attention to equipment, reliability, and maintenance. So I think you are going at what I would kind of call headline cost, whereas I was the business leader and focused on within business cost and how can I drive an efficient -- an effective business.

So one of the key areas I'd draw your eye to would be on page 3 of 4, line 11, equipment failure reviews. So we spent a lot of time talking about equipment reliability, and so instituting, from 2020, a focus on forced outage causes to inform business and operational decisions, in my mind, is a direct driver to how much cost we consume as a business to produce our product. Really strengthening that cross-functional ownership between equipment reliability, as my colleague Ms. Fabbro mentioned earlier on, plant health committee meetings, and really trying to drive down how we manage equipment condition, risk mitigation, and failure reviews. And

you can see that in our performance.

So, to me, in each case, it is really driving through the cost of production in the business. I can give you further examples if helpful.

M. RUBENSTEIN: But as I understand, as you mentioned in the beginning, we -- there is -- you can't quantify the cost impact of any of it.

N. PENDER: I can't isolate independently one variable because we run it as a business, we don't run it as a series of independent variables. So the aggregate outcome produces our RRR scorecard, equipment -- you know, availability, cost performance, safety performance. But to isolate one individual component and attribute it solely to that, it is a combination of factors. So that is -- it is just not how we run the business.

M. RUBENSTEIN: Now, in any of the individual initiatives, do they have KPIs that talk about cost, that are specific to cost?

N. PENDER: Yeah. Can I draw you to SEC-150, Attachment 2. So this is what we call our excellence plan. And so what I have drawn out from there is I have drawn an example from people. I have drawn an example from, third column, plant, about maximizing equipment performance.

But if I draw your eye to "measures of success" on the bottom, these are all measures of success of the performance [indiscernible]. Translating that

directly into your question, the efficiency with which we achieve -- take your choice of any one of those, that really translates, for me, into our unit production cost. Do this well, we will be run as an efficient business.

M. RUBENSTEIN: So these are the metrics, the KPIs that you have for any of the initiatives that you are showing on the screen?

N. PENDER: These are the measures of success.

M. RUBENSTEIN: And I don't see any that have a target of cost saving. Just as a reference. Not to -- just because it is cross panels. For example -- which I will take the nuclear folks to -- they reference in an audit report that one of the KPIs of one of the initiatives that they talked about has s cost. The measure was about, you know, annual maintenance cost savings. There is nothing like that for the hydro business?

N. PENDER: Not in -- we run -- so the way we run hydro is somewhat different than nuclear business. So comparables -- I am going to extrapolate comparables to industry and hydro are somewhat difficult due to the nature of the business.

So we have performance targets. That doesn't say we have performance targets in the business. And if we can talk about our benchmarking, so our cost performance, I can direct you to there in terms of how we bench relative to others. So we do have

targets. I have just drawn you to the measures of success, but I haven't given you the targets that sit underneath it.

M. RUBENSTEIN: The targets are not specifically cost-based?

N. PENDER: So if I refer you to Exhibit F1-1, page 29, Chart 11. So this is our -- thank you, Lori. So on line 6 here, Chart 11, this is our unit energy cost forecast, and this sits under the section of hydroelectric cost effectiveness. So we have cost targets which are a function of cost to run the business divided by measures of generation.

M. RUBENSTEIN: Sure. But not at a productivity continuous improvement level? That is the question I was asking. I take it from what you showed me, you don't have any for any of the initiatives?

N. PENDER: They are inherent in our cost. But to your question, directly and explicitly, not as you framed.

M. RUBENSTEIN: Okay. Thank you.

And just my last question -- I assume it is going to be for undertaking, it is on a different topic. Can I ask you to go to E1-SEC-132.

In this IR we asked for underlying calculation included in Chart 6 in the pre-filed evidence, and you provide some information -- underlying information on the second page. And so the problem I am having is reconciling the information on Chart 6

with the cost information in Chart 1 in this interrogatory.

So, for example, Chart 6 in 2026 has payment to non-OPG supply generator at negative 46 million, and I am simply unclear and I can't figure out which combination of costs that are shown here reconcile with the 46 million.

And I assume it is import cost, non-OPG gas cost, wind costs, potentially OPG gas costs, if we are talking about regulated, but I get different numbers. So I was asking you -- so by way of undertaking, can you reconcile Chart 1 in this interrogatory and Chart 6 in the evidence?

M. CHIDIAC: So essentially just looking to map out the costs from Chart 6, how we showed them here in SEC-132 --

M. RUBENSTEIN: Yes.

M. CHIDIAC: And -- what components are included in each line item?

M. RUBENSTEIN: Yes.

M. CHIDIAC: Yes, we can undertake to provide that.

I. RICHLER: That will be JT-1.21.

M. RUBENSTEIN: And if they don't reconcile, why.

M. CHIDIAC: Sure.

UNDERTAKING JT-1.21: RECONCILE CHART 1 IN E1-SEC-132 AND CHART 6 IN THE EVIDENCE E1-2-1

I. RICHLER: Thank you, Mr. Rubenstein.

Ms. Scott, I think you said you might have some follow-up?

J. SCOTT: Actually, I will just ask one on that F1-SEC-150 that you just had up, the attachment -- the strategy and excellence plan. Yeah. At the bottom, it says:

> "Right-click on the table and select drill through." (as read)

Could you provide us with a copy that actually has that drill through?

N. PENDER: So this is from our Power BI. And so just to clarify, your question is you are interested in what we call the GDAR, which is the gap driver action result?

J. SCOTT: Yes. Not knowing exactly what it was, it just -- my understanding was it was going to provide more information on a specific -- on specific objectives.

N. PENDER: Yeah, on a best-efforts basis, we will provide the relevant GDAR for the strategy and excellence plan for renewable generation 2026-2028.

J. SCOTT: Thank you.

I. RICHLER: JT-1.22.

UNDERTAKING JT-1.22: PROVIDE THE RELEVANT GDAR FOR THE STRATEGY AND EXCELLENCE PLAN FOR RENEWABLE GENERATION 2026-2028

I. RICHLER: Anything else, Ms. Scott?

J. SCOTT: If -- is there still time? Yes?

I. RICHLER: Not really. We are supposed to break now. Do you have much more?

J. SCOTT: No. I am fine. Thank you.

I. RICHLER: Okay.

So let's call it a day, and we will be back here tomorrow morning at 9:30. Thanks, everyone.

--- Whereupon the proceeding adjourned at 4:30 p.m. to resume Thursday, May 28, 2026, at 9:30 a.m.