

ONTARIO ENERGY BOARD

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| FILE NO.: | EB‑2013-0321 |  |
| VOLUME:DATE: | Technical ConferenceApril 22, 2014 |  |

EB-2013-0321

**THE ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the Ontario Energy Board Act,

1998, S. O. 1998, c. 15, Schedule B;

**AND IN THE MATTER OF** an application by Ontario

Power Generation Inc. pursuant to section 78.1 of the Ontario Energy Board Act, 1998 for an order or orders determining payment amounts for the output of certain of its generating facilities.

Technical conference held at 2300 Yonge Street,

25th Floor, Toronto, Ontario,

on Tuesday, April 22nd, 2014,

commencing at 9:29 a.m.

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TECHNICAL CONFERENCE

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BAYU KIDANE Power Workers Union (PWU)

RICHARD STEPHENSON

LARRY SCHWARTZ Energy Probe Research Foundation

MARK RUBENSTEIN School Energy Coalition (SEC)

MARK GARNER

RANDY AIKEN London Property Management Association (LPMA)

JAMES WIGHTMAN Vulnerable Energy Consumers Coalition (VECC)

DAVID CROCKER Association of Major Power

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VINCE DeROSE Canadian Manufacturers and Exporters (CME)

PIPPA FEINSTEIN Lake Ontario Waterkeeper

JACK GIBBONS Environmental Defence

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 Tuesday, April 22, 2014

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

 MR. MILLAR: Good morning, everyone. I think we will get started.

 Welcome to the technical conference in the OPG payments application. My name is Michael Millar. I am counsel for Board Staff. I will be acting, I suppose, as a facilitator for this session, or a ringmaster, perhaps. As all of you will know, I don't represent the Board Panel in anything today and I don't have any power to make any rulings or anything of that type.

I understand today no one has expressed any need to go in camera for any questions. If you do have to go in camera, you should tell us as quickly as possible, because we have to make arrangements for that, but I understand nobody does.

 We have a busy couple of days. We have circulated a draft schedule, so we will do our best to stick with that, or we will start with that, in any event.

 I will do appearances, and then, Mr. Smith, I understand you had some brief opening remarks, and then we can get straight to the questions?

 MR. SMITH: Yes. Thank you.

 **APPEARANCES:**

 MR. MILLAR: Okay. For appearances I'll start with me. My name is Michael Millar, and I will just introduce the staff that will be participating in the conference.

We have Violet Binette beside me, and over on the table there we have Richard Battista.

Keith Ritchie will be joining us. He is not in the room right now. Ben Baksh also will be joining us.

Duncan Skinner is here, Rusty Chute, and Ted Antonopoulos.

 MR. SMITH: Crawford Smith, appearing as counsel to OPG, and with me are Colin Anderson and Andrew Barrett.

 MR. POCH: Hi. David Poch, appearing as counsel for Green Energy Coalition, GEC.

 MS. GIRVAN: Julie Girvan, consultant to the Consumers Council of Canada.

 MR. ZACHER: Glenn Zacher, counsel for the IESO, and with me is Jessica Savage.

 MR. MILLAR: I think you have to turn on your microphone, sir. If you press -- there's a green button there, and when it lights up your mic is on.

 MR. TOLMIE: Ron Tolmie, Sustainability Journal.

 MR. MILLAR: Welcome. Thank you.

 MR. KIDANE: Bayu Kidane, consultant for the

Power Workers Union.

 MR. SCHWARTZ: Larry Schwartz, consultant to Energy Probe Research Foundation.

 MR. RUBENSTEIN: Mark Rubenstein, counsel for the School Energy Coalition.

 MR. AIKEN: Randy Aiken, consultant for the London Property Management Association.

 MR. WIGHTMAN: James Wightman for VECC.

 MR. CROCKER: David Crocker for AMPCO. I am with -- David Crocker for AMPCO. I am with Hamza Mortage and Shelley Grice.

 MR. DeROSE: Good morning. Vince DeRose on behalf of CME.

 MR. MILLAR: Okay. Thank you.

 Mr. Smith?

 **OPENING STATEMENT BY MR. SMITH:**

 MR. SMITH: Thank you, Mr. Millar.

 As Ms. Binette indicated yesterday, OPG is going to be producing through this technical conference four witness panels, covering, in order, the following areas: Hydro, nuclear, the Darlington refurbishment, and corporate

matters. The panels represent, so people understand, a

cross-section of the witnesses OPG intends or will likely call at the hearing, but obviously not all of the witnesses, nor all of the panels.

 We've scheduled people today according to the schedule that was circulated yesterday. In order to move efficiently, we do have some tech help with us today, so in order to move efficiently through the questioning, and recognizing the breadth of the materials the panels have been asked to cover, I am going to ask parties to please identify, in advance of your question, the issue that the question is directed towards and the interrogatory that is in issue, and that will allow us the opportunity to pull it up on the screen. And if people, once they have done that, can just bear with us as we call it up for everyone's benefit.

 I gather from Mr. Millar's comment at the outset that we don't intend to go in camera, but if there are, as it develops, questions in relation to confidential material, it probably makes sense to hold those until the very end of the particular panel's questioning so that we can go in camera in an orderly way.

 And lastly, just from OPG's perspective, of course, this is a technical conference and we're here to help answer questions of clarification, but it is not, from our perspective, a cross-examination. People will have ample opportunity, no doubt, to do that at a later time.

 By way of introduction, we have with us, from my far left, Bill Wilbur; to his right, Mario Mazza; to his right, Chris Young; and then finally, nearest to us, Rick Everdell. And just by way of brief overview, I expect that the individuals on my left, Rick and Chris, will be speaking to the Niagara Tunnel, we have Mario for hydro, and Bill to deal with the hydroelectric incentive mechanism, broadly speaking.

 Subject to that, I gather we're ready for the technical conference to begin.

 MR. MILLAR: Thank you, Mr. Smith.

 We had put together a draft Schedule. A minor change for this morning. The IESO has suggested they go first, and there's been agreement from Mr. Crocker that he can be bumped to second. So, Mr. Zacher, could I turn it to you?

 **QUESTIONS BY MR. ZACHER:**

 MR. ZACHER: Thanks, Mr. Millar.

So my questions are going to be, I believe, directed at Mr. Wilbur. They're with regards to the hydro incentive mechanism.

I just sort of preface my questions to say that the IESO is generally supportive of hydro incentive mechanism; in fact, thinks that it is essential for both the currently regulated facilities and also for the newly regulated facilities, in order to ensure that they're sufficiently price-responsive and incented to time-shift generation from off-peak to on-peak periods, and that this is important for operability and for market efficiency purposes.

 And so the purpose of the IESO's questions is really just to clarify how the operation of OPG's facilities, in particular the newly prescribed facilities, will operate under the proposed new enhanced hydro incentive mechanism and to ensure that that is a robust enough mechanism to encourage these facilities to continue to be price-responsive the way that they are today, or that they

largely are today.

 So with that said, Mr. Wilbur, if I could just start off and ask you some general questions about how the operating characteristics of the currently regulated hydro facilities compare to the newly regulated facilities.

 In one of the interrogatories -- and I don't think I need refer you to it, but OPG was good enough to characterize the newly regulated facilities in terms of whether they're peaking, run-of-river, or intermediate, and I wonder if you could just start off by explaining how you would characterize the currently regulated facilities, which I understand broadly break down into the Beck facility, DeCew Falls, and Saunders.

 MR. WILBUR: Sure. The Saunders facility and the DeCew facility we would characterize as run-of-river, and the Beck facility we would characterize as intermediate.

 MR. ZACHER: And in terms of the ability to store water and to time-shift generation from off-peak to on-peak periods, can you comment on the ability of those three facilities to do that?

 MR. WILBUR: Yes. As is stated in the Board Staff interrogatory on this topic, which is Board Staff 196, we provided a definition for each of the three types of facilities that we use to characterize them.

 So run-of-river has a minimal forebay storage.

 MR. MILLAR: Mr. Wilbur, can you identify the issue number when you discuss the interrogatory number?

 MR. WILBUR: Sure. That's Issue No. 9.7, and the interrogatory was Board Staff 196.

 MR. MILLAR: Thank you.

 MR. ZACHER: Sorry, had you finished?

 MR. WILBUR: No, I am not finished. In our response to that, we had indicated that a run-of-river station has -- typically has minimal forebay storage and an intermediate station has a moderate amount of storage.

 MR. ZACHER: Okay. So of the currently regulated facilities, the only facility that really has ability to store and to time-shift would be Beck; is that fair?

MR. WILBUR: It has significantly more than Saunders and DeCew, but Saunders and DeCew do have some ability to time-shift.

 MR. ZACHER: And of the Beck facility, I think it's –- correct me if I am wrong, but it is in the neighbourhood

of 2,100 megawatts. Are all of those megawatts capable of being stored and time-shifted, or only a portion?

 I understand that there is probably some amount of water that you have to continuously run over the falls, and so that can't be stored and diverted.

 MR. WILBUR: That is correct. So there is a minimum amount of generation that is always required from the Beck facility, and that amount will change depending on conditions -- change from hour to hour, day to day, depending on conditions. And the remainder is able to time-shift.

 MR. ZACHER: Can you put a number on it? Of the 2,100

megawatts, what, roughly ,can be time-shifted and what can't be?

 MR. WILBUR: I would say something on the order of 700 megawatts, typically. So it can be larger than that, can be smaller than that, depending on conditions.

 MR. ZACHER: So turning to the newly regulated facilities, and you can refer to the interrogatories if it is helpful. But I just sort of looked at it, did some rough math, and determined that there is about 3,000 megawatts, thereabouts, of newly regulated hydro facilities, and somewhere in the neighbourhood of 2,200 would be either intermediate or peaking; is that fair?

 MR. WILBUR: I haven't added that up, so I can't confirm your numbers. But I can say that from the list we have shown in table 1 of the interrogatory, Board Staff 196, most of the plants that are listed there are run-of-river.

There is a few peaking plants, but I guess I would characterize it as there is more time-shifting capability in all of the newly regulated plants together than there is at the Beck facility.

 MR. ZACHER: Okay. And I am not sure it is necessary to go through it, but in your evidence you identified the newly regulated facilities and identified them in both the megawatt capacity and then, I think in answers to the interrogatories, whether they were peaking, intermediate or run-of-river.

 So in any event, the ones that have been characterized as peaking or intermediate, you say have the ability to store water and time shift?

 MR. WILBUR: That's correct.

 MR. ZACHER: Okay. And those facilities, how do they

compare to the time-shifting ability of the Beck facility? Do they have greater or lesser ability to store water and to time-shift generation?

 MR. WILBUR: Well, as I said, taken all together, the total of the time-shifting ability of the newly regulated facilities would be considerably greater than that of Beck.

 MR. ZACHER: Is that just because the megawatts are greater, or because the operating characteristics of the facilities are different?

 MR. WILBUR: Mainly because the megawatts are greater.

 MR. ZACHER: Okay. Is there any differences in terms of the operating characteristics, in terms of the ability to store over a period of days, as opposed to a shorter storage horizon?

 MR. WILBUR: There is -- some of the peaking facilities in the newly regulated do have longer-term storage, longer than Beck.

 But the Beck storage can be used over a few days, as opposed to just one day as well. So it is not limited to just one day.

 MR. ZACHER: Can I just ask you to turn up -- there is a report of Mr. Hamal, Exhibit E1, tab 2, schedule 1, attachment 1.

 MR. WILBUR: I have that.

 MR. ZACHER: If you just turn to page 3 --

 MR. SMITH: Sorry, can we just wait until it comes up on the screen?

 MR. ZACHER: I think we need to look at attachment 1. Yes, that's it, so page 3.

 So, Mr. Wilbur, right at the top of page 3, Mr. Hamal says:

"The Newly Regulated hydroelectric facilities are typically dispatchable and have significant ability to store water and shift energy across time. Their operating characteristics contrasted with the previously regulated hydroelectric

facilities. Among the units historically covered by HIM, the vast majority of storage capacity was associated with the PGS at Beck which can efficiently time-shift hydro generation on a daily basis, but does not provide longer term storage capacity."

 So I just want to understand what the significance of the contrast is. Why is it that the newly regulated facilities have some greater ability to time-shift?

 MR. WILBUR: They have -- generally, they have larger storages, so the reservoirs are considerably larger than the PGS reservoir. And at times their inflows are sufficiently small that flow into that reservoir, so that there is a relatively small amount of energy that can be produced from those facilities. And then there is

an ability to sometimes wait a week or more before actually

generating from that facility.

 So that allows a significant time period over which the time-shifting can occur.

 MR. ZACHER: So the currently regulated assets, including Beck, have been subject to this hydro incentive

mechanism for the past couple of years, including this sort of 50/50 sharing mechanism.

 And now OPG is proposing that the newly regulated facilities also be subject to this mechanism, albeit with some changes.

 Do you expect the responsiveness, price responsiveness and time-shifting ability of the newly regulated facilities to be the same, or to be more responsive than the previously regulated facilities?

 MR. WILBUR: We don't anticipate any change in the

responsiveness of these facilities under the mechanism that we have proposed here.

 MR. ZACHER: They're not going to be more responsive or less responsive, but just the same?

 MR. WILBUR: That is correct.

 MR. ZACHER: Have you done any modelling or analysis? I am just trying to understand what the reason for that view is.

 MR. WILBUR: The reason is that this mechanism provides an incentive to follow the market price signals. And that is currently the signal we use, that we follow with those resources right now.

 Those resources are only paid from the market right now, and so we follow market price to earn the maximum revenue we can from those facilities.

 MR. ZACHER: Okay. But that principle aside, have you done any sort of study or analysis?

 MR. WILBUR: No, we have not.

 MR. ZACHER: Okay. So my understanding of the change from the current incentive mechanism to the enhanced incentive mechanism is that at a high level, really the only difference is that it will eliminate the unintended consequences of incentive payments during surplus base load generation spill; is that right?

 MR. WILBUR: That is correct.

 MR. ZACHER: Okay. And so with regards to the currently regulated facilities, does OPG expect any change in their operation, in particular their ability to time-shift, as compared to how they operate under the current hydro mechanism?

 MR. WILBUR: No, we do not expect any change.

 MR. ZACHER: Okay. And that is because the sharing mechanism, 50/50, remains the same, and your view is that incentive isn't in any way dampened by the elimination of this unintended spill payment or the removal of the revenue offset?

 MR. WILBUR: That is correct.

 MR. ZACHER: Okay. With respect to the newly regulated facilities, I take it that currently they're fully exposed to the hourly Ontario energy price?

 MR. WILBUR: They are.

 MR. ZACHER: And so they're currently incented to shift generation from low-priced off-peak hours to on-peak high-priced hours?

 MR. WILBUR: Correct.

 MR. ZACHER: Okay. And OPG's found that under the current system, that is a robust and strong incentive?

 MR. WILBUR: That is a strong incentive.

 MR. ZACHER: Okay. And do you expect that incentive to be reduced as the result of the proposed eHIM, which I take it sort of reduces the upside reward to OPG from currently 100 percent of the differential between the off-peak and the on-peak price, to a 50/50 sharing?

 MR. WILBUR: As I said earlier, we anticipate -- with the incentive mechanism as we have proposed, we do not anticipate any changes in our behaviour for the newly regulated or the currently regulated facilities.

 MR. ZACHER: And can I just ask you to turn up Exhibit L, tab 5-4, schedule 11?

 MR. WILBUR: Is that the interrogatory?

 MR. ZACHER: Yes. Yes, it is the IESO Interrogatory No. 4.

 MR. WILBUR: No. 4, was that?

 MR. ZACHER: That's right. So, Mr. Wilbur, if you look at the answer there to (a), OPG says:

"The higher the level of incentive to OPG, the greater the degree of potential costs and risks that OPG would be willing to assume to time-shift production."

And what I am just trying to understand is, as I take it, the -- under the current -- under the proposed structure, OPG's downside risk is reduced, because you are guaranteed the regulated rate as compared to whatever the off-peak HOEP price was currently.

 And the upside award is also reduced. Instead of getting 100 percent of the difference between -- of the price differential, you only get 50 percent.

 And so I take it, all things being equal, you are going to be less incented going forward to time-shift this generation from off-peak to on-peak?

 MR. WILBUR: Well, as we said in the response, the higher the level of incentive will allow us to take -- to take slightly more risk and potentially do more time-shifting. But given the incentive that we have proposed, we don't anticipate any change from what we do now.

 MR. ZACHER: But what you're saying, if you were to -- if OPG was to receive 100 percent of the price differential as opposed to 50/50, all things being equal, that would lead you -- that would induce you to time-shift more, right?

 MR. WILBUR: There is a potential that we could take more risks with our time-shifting, yes.

 MR. ZACHER: And so won't the proposed mechanism mean that OPG's newly prescribed assets are going to be less responsive to price and less incented to time-shift?

 MR. WILBUR: No. As I've said, we do not -- we do not intend to make any change to the way these facilities operate, on the way they operate currently under the proposal that we have before the Board here.

 MR. ZACHER: And that's because there still is some market inducement to shift generation?

 MR. WILBUR: There is. Yes.

 MR. ZACHER: Okay. And again, have you done any sort of analysis or studying to sort of -- to support that proposition?

 MR. SMITH: That question has been asked.

 MR. ZACHER: Well, I asked the question with regards to the currently prescribed assets, but this is with regards to the newly prescribed assets that haven't been subject to this.

 MR. SMITH: I don't agree with that.

 MR. WILBUR: Can you repeat the question, please, Glenn?

 MR. ZACHER: I am not sure if your counsel will allow you to answer it, but...

[Laughter]

 MR. SMITH: No.

 MR. ZACHER: Okay. In an answer to an interrogatory from the IESO, Mr. Wilbur, OPG indicated that a number of factors, including operational, environmental considerations, safety, equipment, protection requirements, affect operational decisions in terms of the dispatch of hydro facilities.

 Can you just elaborate on that a little bit more?

 MR. WILBUR: Sure. I think probably a simple one --

 MR. SMITH: Sorry. Sorry. Mr. Zacher, can I just ask you for the interrogatory reference?

 MR. ZACHER: Yes, I apologize. It is Exhibit L, Issue 5.4, Schedule 11, and it is Question No. 1.

 MR. MAZZA: Can you repeat the reference again, please?

 MR. ZACHER: Sure. It is Exhibit L, tab 5.3, Schedule 11. Sorry, Mr. Wilbur, sorry, just the paragraph at the very bottom, where it is talking about the various operational parameters, so if you could just elaborate on how those factors go into OPG's operation decisions.

 MR. WILBUR: Sure. Yes. So what we're talking about there is the operational constraints with which we have to operate these plants.

And maybe a simple -- the simplest example might be the elevation requirements in the forebay, so the reservoir behind the dam. There are limits on the levels that the water can be in that reservoir. So there is a high limit based on dam safety and possibly other factors, and there is a low limit based on equipment protection for the generator.

 So when we're making a decision as to when to run energy out of that plant, a very large consideration is what the level is in the forebay at any given time, and we have to operate the plant such that the forebay level will not go above the maximum or below the minimum.

 We also listed environmental considerations. That would be -- there's often requirements for a minimum flow to be run through the dam for certain hours of the day, or all hours of the day, sometimes for weeks at a time, for various environmental reasons; fish spawn would be a good example.

 So that would mean that we would have some generation

running at all those times to pass that minimum flow requirement.

So that would limit the amount of time-shifting that could be done during those times from that facility.

 Another example, another one listed there was transmission and system constraints. So we put our offers into the IESO's market to try and achieve the dispatch we would like to happen.

But there are some other things going on in the power system that might prevent our unit from generating when we intended it to generate. So we won't always get the dispatch we're looking for, and might not be able to time-shift to the best priced hour that we were looking to do.

 MR. ZACHER: Just a couple of more questions.

In this application, OPG is seeking cost recovery for a number of hydro projects or upgrades, and the question is: Will any of these projects affect operational flexibility of the facilities, either improve operational flexibility or degrade operational flexibility, in terms of manoeuvrability?

 MR. MAZZA: Okay. I will answer that one. For that

question, it is basically the assets -- we're keeping the assets basically in there as much as possible in their present condition, sustaining the asset. So we don't expect anything different.

 MR. ZACHER: But no sort of improvements are being made in regards to sort of equipment limitations, or anything of that nature?

 MR. MAZZA: There will be improvements, if there's a

business case for it, like runner upgrades.

 MR. ZACHER: But nothing is planned?

 MR. MAZZA: There are some plans there, but they're more from a production point of view, instead of a time-shifting point of view.

 MR. ZACHER: Mr. Wilbur, if I could just ask you to turn to Exhibit L, tab 5.3 -- I'm sorry, tab 5.4. This is schedule 11, and it is the IESO's IR, Question No. 3.

 Mr. Wilbur, OPG indicated it did not propose an alternate operational driver during the evaluation of the alternatives to the eHIM.

 And my question is: Would OPG agree that under different incentive mechanisms, OPG's operation of its facilities would be different? Or put another way, why didn't you consider other operating profiles?

 MR. WILBUR: If I can refer to our evidence, to Exhibit E-1, tab 2, schedule 1, page 11, table 4 –- page 11. That's it, Table 4.

So this is where we summarize the analysis of the different potential incentive mechanisms that we did look at.

 And what we can see from the first three different

alternatives that we looked at, they all exhibited a high

correlation between the amount of the incentive payout and the amount of time-shifting that we do. And we're proposing that that is what we want. We want to -- if you want to incent us to time-shift, then this high correlation here would make sense.

 One alternative has a low correlation. So if we were to look at -- if we were to look at that alternative, the IM alternative, that one would likely induce a different behaviour because the correlation is not high, but the other three all do induce a correlation.

So that's the only driver that we looked at, basically a market -- that is the closest. Those three alternatives provide the closest to a market price driver, which is what the IESO wants.

 MR. ZACHER: Okay. Just give me a moment.

 Those are all of my questions. Thanks very much.

 MR. MILLAR: Thank you, Mr. Zacher.

Mr. Crocker?

**QUESTIONS BY MR. CROCKER:**

 MR. CROCKER: Thank you.

I am going to ask my questions or pose my questions to the Board -- I'm sorry, to the panel at large, and you can decide among you who you think is most appropriate to answer them.

 I have a couple of questions, general questions at the

beginning. I don't know whether this is the right panel. I am sure your counsel will advise both you and me whether you are the right panel or not, and if you are not, where I should be asking the question.

 I am looking at Exhibit L, tab 1, schedule 1. It is Board Staff Question 002.

 MR. SMITH: Unless the question is specifically addressed to hydro, this would normally, Mr. Crocker, go to the corporate panel, which would be the last panel we're intending to call.

 MR. CROCKER: Okay. I have another general question without any specific reference.

OPG has filed electronic copies of interrogatories, and hard copies were delivered in binders, and it seems to us that not all of the IRs have been included in the electronic version.

And is that -- two questions, I guess. Is that your understanding? And secondly, if we're correct, are you going to marry the two at some point?

MR. ANDERSON: Certainly that was not the intention, and this is the first that I'd heard that specific IRs may have been omitted.

Can I ask a question of you? Were they confidential IRs? Because in that case, they would not be included.

 MR. CROCKER: No, I don't believe they were. At the break, we will give you the detail of what we're talking about, and then --

 MR. ANDERSON: That would be good, because we certainly did not do it knowingly.

MR. CROCKER: Okay. My reference is Exhibit B-2, tab 3, schedule 1, table 2.

 MR. MAZZA: Could you please repeat the exhibit?

 MR. CROCKER: Yes. D-2, tab 3, schedule 1, table 2. That's fine.

 My question is in respect to Northeast Plant Group, so line number 7. And the forecast in-service additions are 12.3 million; do you see that?

 MR. MAZZA: Yes.

 MR. CROCKER: Okay. If we go over the page to -- once again with the Northeast Plant Group, the actual in-service addition is -- or additions are 3.9 -- sorry, 30.9 million. Do you see what we're talking about?

 MR. ANDERSON: Sorry, is there a reference for the next table that you referred to?

 MR. CROCKER: I'm sorry. It's Exhibit L -- it was over my page. Exhibit L, tab 1, schedule 1. Once again, it is Staff 002, attachment 1, table 2. Okay?

The Northeast Plant Group, the actual in-service --

 MR. SMITH: Sorry, just so that we're clear, you are looking at attachment 1, table 2; is that correct?

 MR. CROCKER: Yes. The actual in-service additions are 30.9 million. I wonder whether you could please explain the increase. It is a big increase.

 MR. MAZZA: I can't explain it here without looking at the detail. One might be a forecast, and the other one might -- are they both actuals? Can it be...

 MR. CROCKER: No. The first is a forecast, the second is an actual.

 MR. MAZZA: I don't know the answer to that.

 MR. CROCKER: Okay. Can I, I guess, get an undertaking that you will provide the answer, please?

 MR. SMITH: Yes, we will do that.

 MR. MAZZA: Yes, we will do that.

 MR. MILLAR: JT1.1, and that's to provide an explanation between the difference in the forecast and the actuals for the northeast plant group for 2013; is that correct?

 MR. SMITH: In-service additions.

 MR. MILLAR: In-service additions, I'm sorry, yes.

 MR. SMITH: Yes.

 MR. MILLAR: Thank you.

**UNDERTAKING NO. JT1.1: TO PROVIDE AN EXPLANATION OF THE DIFFERENCE IN FORECAST AND ACTUALS FOR IN-SERVICE ADDITIONS FOR THE NORTHEAST PLANT GROUP FOR 2013.**

 MR. CROCKER: I have some questions about the Niagara Tunnel, Issue 4.5. I am referring to Exhibit D-1, tab 2, schedule 1, and I am at page 25 of 145. And I am in -- I am looking at the last paragraph on that page.

 MR. SMITH: B-1, tab 2, schedule 1, page 25?

 MR. CROCKER: D as in "David."

 MR. SMITH: Sorry. D-1, tab 2, schedule 1, page 25.

 MR. CROCKER: I am just waiting for the screen. I will ask the question and then the screen -- they will catch up. I am reading at line 28:

"OPG has approved payment of a $600,000 honorarium to each unsuccessful firm submitting a conforming proposal."

 My instincts are to ask you how I put myself in the

position to -- but I won't ask that question. The question I will ask is why such a high payment is made. That's my first question. What allows for such a high payment, or -- without putting a value judgment on it -- a payment of that amount?

 MR. EVERDELL: Yes. The amount for the honorarium was determined based on the market conditions at the time, recommendation. And it is actually tied, I think, to the

expected price of the bids -- or the proposals. So that was based on our engineer's estimate of the cost of the project at that time, cost of the design-build agreement.

 MR. CROCKER: So did it relate to what your estimate was of what it cost the unsuccessful bidder to put together the bid? Is that what you're saying?

 MR. EVERDELL: Yes. It is -- it partially offsets the expected cost of the bidders to put together their proposals. It wouldn't likely fully compensate them.

 MR. CROCKER: Okay. Is it a standard approach that OPG has for unsuccessful bidders?

 MR. EVERDELL: I believe that this -- I think this was the first time that we had actually applied that. But it is a fairly standard practice in -- for owners bidding on large-value work that requires a considerable amount of -- this is for design-build contracts, where it requires a significant amount of work by the firms that are putting in proposals to produce a compliant proposal.

 MR. CROCKER: Is that amount of money -- that is, the 600,000 times two -- the 1.2 million included in the Niagara Tunnel project costs?

 MR. EVERDELL: Yes.

 MR. CROCKER: I am at now Exhibit D-1, tab 2, schedule 1, and I am at page 136 of 145 this time.

 MR. MAZZA: Could you please repeat that?

 MR. CROCKER: Yes. D-1, tab 2, schedule 1 -- I think that's where we were -- page 136 of 145.

 MR. MAZZA: Could you pull those up, because they're not in --

 MR. ANDERSON: It's the Niagara Tunnel exhibit.

 MR. MAZZA: Okay.

 MR. CROCKER: So the heading is 13.2, appendix B, "Summary of geological investigations"/

 MR. MAZZA: Yes.

 MR. CROCKER: You say at line 3:

"Beginning in 1983, extensive geotechnical investigations were undertaken during concept and

definition phases for the expansion of OPG's Niagara hydroelectric facilities, which at the time contemplated two additional tunnels and the new underground generating station, Beck 3."

 If you go over the page -- once again this is over my page, so we're --

 MR. ANDERSON: Less helpful.

 MR. CROCKER: Yes, I know. I will tell you where we are. Exhibit D-1, tab 2, schedule 1, page 7 of 45.

So if you go back to page 7, what I want you to do for me, if you could, please, is to tell me where the boreholes –- okay. I'm sorry.

 Tell me where the two tunnels which you originally

proposed were aligned, as compared to the one that's depicted in that figure on page 7.

 MR. EVERDELL: Okay. The two tunnels that were planned were directly below the existing tunnels through the city of Niagara Falls, following the same corridor.

 So they would deviate; in the north end, they would be in a similar location to where the red line is shown for the Niagara Tunnel.

 And then they would actually be directly underneath the Beck 2 tunnels that are shown on there as dotted blue lines --

 MR. CROCKER: Right.

 MR. EVERDELL: -- through the city of Niagara Falls.

Then again, they deviate slightly at the upstream end, near the intake at the south end, in order to arrive at the new intake locations.

 So, you know, it was essentially the same corridor as the existing tunnels.

 MR. CROCKER: Okay. As I understand it -- and I am not sure where the reference is, but this is 10.2 kilometres in length. Is that your understanding?

 MR. EVERDELL: The new tunnel, Niagara Tunnel, is 10.2

kilometres long.

 MR. CROCKER: Right. Can you tell me how much of that is in Queenston shale?

 MR. EVERDELL: With the realignment of the tunnel -- initially, it was supposed to be about 80 percent of that length, about eight kilometres, would have been in Queenston shale. With the realignment of the tunnel that was required because of the difficult subsurface conditions, the final configuration has about three kilometres in the Queenstown shale, instead of eight.

 MR. CROCKER: Okay. I would like to go back to page 136 again, please.

 At line 15 of that page, you say that:

"The geotechnical investigations were carried out in stages, and included a total of 59 boreholes and geotechnical test adit."

 I am going to ask you -– "adit" will come in again. What is an adit?

 MR. EVERDELL: An adit is a small tunnel done for geotechnical investigations. And it is not done for all projects, but it was done on this project.

 MR. CROCKER: Probably should have looked at the brackets just following. A "small test tunnel"; that should have been my clue.

 MR. EVERDELL: Okay.

 MR. CROCKER: All right. We couldn't find anything in any of the material which showed us where the boreholes were. Have we missed something? Where can we find a diagram which describes where the boreholes were -- were put, placed, dug?

 MR. EVERDELL: The boreholes were located along the tunnel alignment, as well as in the underground power house or the different power house locations that were under consideration at the time of the concept and definition phase work.

 We, I am sure, can provide a drawing that shows the

location.

 I think, though, in the geotechnical report that was

provided with the evidence, there may be a drawing there that shows that.

 MR. CROCKER: I don't think it is there. We couldn't find it, in any event.

 MR. EVERDELL: Yes. In the geotechnical base line report, there's a -- there are plans that show both a plan view as well as a cross-section along the tunnel, that indicates where the different boreholes are, or were.

 MR. CROCKER: Will you -- at the break once again, if you can find that in the material and point us to it, great. And if not, will you undertake to provide that to us?

 MR. SMITH: Yes, we will do that.

 MR. MILLAR: We will only take an undertaking if necessary, so I will wait for an update.

 MR. CROCKER: Okay. I'm on page 137, then, and I am at line 23. You say:

"After contract award, STRABAG drilled seven additional boreholes."

 Can you tell me when those boreholes were drilled?

 MR. EVERDELL: They were drilled in -- after contract award, which was in August of 2005. They were drilled after that time, probably in late 2005 or early 2006.

 MR. CROCKER: Once again, can you provide us with a drawing so that we can locate those boreholes?

 MR. EVERDELL: I don't believe that is in the evidence now, so we could provide that drawing, I'm sure.

 MR. SMITH: Yes, we will do that.

 MR. MILLAR: JT1.2.

**UNDERTAKING NO. JT1.2: TO PROVIDE A DRAWING SHOWING LOCATION OF SEVEN ADDITIONAL BOREHOLES DRILLED AFTER CONTRACT AWARD.**

 MR. CROCKER: And how did STRABAG's proposed alignment

compare to the concept alignment?

 MR. EVERDELL: I believe that's in the evidence. I am not exactly sure of the reference, but STRABAG's alignment is higher than the concept alignment, so not as deep into the Queenston shale as OPG's concept alignment.

 I think it is about 40 meters or 50 meters

higher than the concept alignment that OPG had put in the RFP documents, and this is in the area underneath the Buried Saint David's Gorge.

 MR. CROCKER: Once again at the break, if you could locate that, great. If not, then an undertaking to provide it.

 MR. SMITH: Sorry, to provide what? I mean, you have the answer that it was 40 meters higher than had been in the RFP document.

 MR. CROCKER: Okay. Thank you. That's fine.

I am at page 138 of that section. I have questions with respect to the chart that you provide, and it may very well be in the same diagram that either you will find or have undertaken to provide.

 But can you -- is it possible to identify the boreholes that provided rock cores from Queenston shale? You said you've drilled five boreholes in Buried Saint David's Gorge, drilled 25 boreholes, et cetera, et cetera.

 I just need you to identify the borehole numbers that

provided the raw cores. I don't expect that you will be able to do that off the top of your head.

 MR. EVERDELL: The drawing that I was referring to, the profile along the tunnel route, would show how deep all of the boreholes are.

 MR. CROCKER: That's what I thought.

 MR. EVERDELL: But my recollection is that essentially all of the boreholes went into the Queenston shale, which was our target formation. With our need to go below the Buried Saint David's Gorge, we knew that we needed to excavate the tunnel in the Queenston shale formation, so that was the target formation, and the boreholes essentially all went into that formation.

 MR. CROCKER: And would that diagram also identify the boreholes where in situ stress measurements were done?

 MR. EVERDELL: The diagram probably doesn't show that, but I think there are diagrams. I think the reference is the geotechnical baseline report that has illustrations of those locations as well.

 MR. CROCKER: And do you believe that is in here? Because I don't think it is.

 MR. EVERDELL: Yes. It was attached to the design-build agreement, which was provided on a CD, not hard copies, I believe, to all of the participants.

 MR. CROCKER: Okay. I don't know whether we have one or not, but if we don't, we will get one.

 And the third question and the fourth question, I have the same sort of general questions that you're, I'm sure, going to direct me to the same thing, but let's find out.

 I want you to identify the boreholes where piezometers were installed.

 MR. EVERDELL: We have that information. I'm not sure whether that's included on those drawings that I referred to or not, but they were spread along the tunnel route, as well as -- and in the proposed power house location.

 MR. CROCKER: Once again, maybe we can -- we will check at the break and see where we can get that information.

 I am at now page 77 of the same document.

 MR. SMITH: Sorry, Mr. Crocker, I missed the reference.

 MR. CROCKER: 77. Is there a longitudinal section of this alignment that has been produced?

 MR. EVERDELL: Yes, this -- the figure that is shown here, called "Vertical tunnel realignment," is the longitudinal section in an illustrative manner. We have a more detailed plan that was part of the evidence, I believe.

 MR. CROCKER: Sorry. My question wasn't clear. Do you have a diagram like this of the original tunnel alignment?

 MR. EVERDELL: We do have, yes. It was not included in the evidence.

 MR. CROCKER: Could we have that so that we can compare the two, please?

 MR. EVERDELL: Yes. Essentially on that, though, basically this lower portion in the Queenston shale under the Buried Saint David's Gorge continues along at that same level and then slopes up at the intake on the same slope as shown on this diagram. So there is not very much difference.

 MR. CROCKER: Okay. If you could provide that, that would be helpful.

 MR. EVERDELL: Okay.

 MR. MILLAR: JT1.3.

 MR. SMITH: Yes, we will do that.

**UNDERTAKING NO. JT1.3: TO PROVIDE A DIAGRAM OF THE ORIGINAL TUNNEL ALIGNMENT.**

 MR. CROCKER: I can give you the reference, but I am not sure it is important. If we need it we can go back to it.

 Why did you not -- why did OPG not undertake any geotechnical investigations after 1993?

 MR. EVERDELL: We believed that we had done enough investigations by that time, and further investigations were not to be fruitful.

We had spent quite a bit of money as well in the concept and definition phases on the investigations, as well as the environmental assessment and engineering work that had been done.

 The project was parked, essentially, at that time, and brought forward again later on.

 MR. CROCKER: Okay. But your alignment changed; correct?

 MR. EVERDELL: The alignment changed partway through the execution of the design-build agreement, based on differing or more challenging conditions for excavating the tunnel in the Queenston shale formation.

 MR. CROCKER: But you didn't do any -- in response to the design change, you didn't do any additional geotechnical investigations?

 MR. EVERDELL: No. The boreholes go from the surface down to the tunnel horizon that we were expecting to drill. So we had already drilled through all of those other formations and tested them.

 We also had the information from the construction of the Beck 2 tunnels, which were done in the 1950s at a higher level in some of the formations above where the new tunnel was being driven. So we had lots of information on that alignment as well.

 MR. CROCKER: Let me ask you a question about the design change. As I understand it, you originally proposed two tunnels; correct?

 MR. EVERDELL: Correct.

 MR. CROCKER: And then you changed that to a single tunnel?

 MR. EVERDELL: Correct. The environmental assessment

approval was for two tunnels and the underground power house that was planned, as well as transmission improvements. This was Ontario Hydro's submission back in 1991.

 But -- and the approval that we got on the environmental assessment allows us to stage the project, and so the Niagara Tunnel project ended up being the first stage of the entire project. So the one tunnel that was built was the same size as both of the two tunnels that were proposed in the environmental assessment.

 MR. CROCKER: And what about its location? Was it -- you tell me. What about its location?

 MR. EVERDELL: Well, the original location -- the location in the environmental assessment was similar to what we went out with the RFP, which had two tunnels -- or, sorry, it had one tunnel underneath one of the existing two tunnels, and the second tunnel could have been built adjacent to that at some time in the future.

 With the realignment, the new tunnel, the Niagara Tunnel, is now shifted out from underneath of the existing tunnels and it goes underneath Stanley Avenue.

 So we would have to -- there is likely room for a fourth tunnel, should we ever have the economics to do that, business case to do it. But we would like -- we would have to then acquire additional property rights, likely, in order to accommodate the fourth tunnel.

 MR. CROCKER: Can you go back to the shift and tell me in what direction was the shift and how far?

 MR. EVERDELL: The shift was towards the Niagara River out from under the existing tunnels. And if you look at that figure that you talked about, or you had before --

 MR. CROCKER: Page 77?

 MR. EVERDELL: Page 77? No, no. Not that one. There was a plan view. I think it was page 7 that...

 MR. YOUNG: Yes, page 7.

 MR. EVERDELL: It shows -- the blue lines on that are the existing tunnels, the blue dotted lines. And the red line is the Niagara Tunnel. So the shift is about 100 metres to the -- towards the Niagara River.

 MR. CROCKER: Mm-hmm. Okay. My diagram is black and white, but I will --

 MR. EVERDELL: Sorry.

 MR. CROCKER: That's all right. No, I think I know which lines you are talking about. Okay. Thank you.

 And I assume from the evidence, the written evidence and yours this morning, that you didn't think that it was necessary with that shift to do more bore-holing, more bore work?

 MR. SMITH: He has already answered that question, Mr. Crocker.

 MR. CROCKER: Well, it was a very general answer originally. This is a much more specific question.

 MR. SMITH: Covered by your earlier question.

MR. CROCKER: Am I to take that that it's a no, that you refuse to allow him to answer the question? It's a pretty simple question.

 MR. SMITH: I am telling you've already asked a question about why further geological testing was not done after 1993, and he has answered that question.

 MR. CROCKER: That's fine. We will decide what to do with your approach. Thanks.

 MR. SMITH: No doubt.

 MR. MILLAR: Mr. Crocker, you are down to about 10 minutes or so; just a time check.

 MR. CROCKER: I am not going to go to the reference because it will take more time than the question is worth, I think.

But you say that the -- my question is: Are the two tunnels at the same depth as the Niagara Tunnel project -- I'm sorry, the Sir Adam Beck 2 tunnels the same as -- all right. I will give you the reference. I'm sorry.

 MR. EVERDELL: There was an interrogatory response, actually, that addresses that.

 MR. MAZZA: Staff 160.

 MR. EVERDELL: Staff 160, and it basically describes the location of the Niagara Tunnel relative to the Beck 2 tunnels. The Beck 2 tunnels are higher than the Niagara Tunnel.

 MR. CROCKER: Okay.

 MR. EVERDELL: And they don't go into the Queenston shale formation.

 MR. CROCKER: My reference is Exhibit L, tab 4.4, schedule 2. This is AMPCO Interrogatory 16, and I am at page 3 of 3.

And in (g), you say -- in answer to (g), you say:

"OPG considers that 100 percent of the variance relative to the originally approved budget of $985.2 million is due to the more adverse subsurface conditions."

 And my question is: What is the market value of the Niagara Tunnel? Do you know?

[Witness panel confers]

 MR. EVERDELL: No, we don't have an answer to that question.

 MR. CROCKER: Can you provide it?

 MR. SMITH: No, we cannot.

MR. CROCKER: No, you cannot? Or no, you will not?

 MR. SMITH: No, we will not. Mr. Crocker, are you aware of a market value? I am not aware of the tunnel being proposed for sale, and I am not aware of a market for 10.4-kilometre hydroelectric tunnels.

Is there information you can point us to that would assist in that calculation?

 MR. CROCKER: Well, can you go over the -- I guess back to page 2 of 3 of where we are in this? And can you

explain to me (e), your answer to the (e) part of the question, STRABAG's response, GBR-B, ILF consult, et cetera? I don't understand it. If you could explain it to me, please?

 MR. SMITH: Just a moment, Mr. Crocker.

 MR. EVERDELL: The way the RFP --

 MR. SMITH: Sorry, just one moment. What aspect of the response would you like clarification in relation to?

 MR. CROCKER: I don't understand the -- all right. Let's leave it as it is. Somebody else can explain to me what you meant. Has GBR-C been filed?

 MR. EVERDELL: Yes, as part of the design-build agreement. It is one of the appendices in the design-build agreement; appendix 5.4, I believe it is.

 MR. CROCKER: Okay. Can you go, please, to F-5-6–1? So this is Exhibit F-5, and we're at tab 6, schedule 1, and my question is on page 27, or relates to something you have said on page 27.

 MR. ANDERSON: Could we get the page number, again, Mr. Crocker?

 MR. CROCKER: Page 27.

 MR. ANDERSON: Thank you.

 MR. CROCKER: This is an expert report by -- I think it is an expert report by Robert Ilsley --

 MR. SMITH: Roger Ilsley.

 MR. EVERDELL: Yes.

MR. CROCKER: Okay. About two-thirds of the way down, you say, under the heading "Insufficient stand-up time":

"The DRB indicated that there was a serious misunderstanding between the parties with respect to the anticipated rock conditions and rock behaviour at the time of the contract..."

Et cetera. What was the misunderstanding and –- well, describe to me what the misunderstanding was, first of all.

 MR. SMITH: I believe there is an interrogatory that deals with this.

 MR. ANDERSON: I believe that if you look to Exhibit L, 4.4, Staff 22, part (c) --

 MR. EVERDELL: Thank you.

 MR. CROCKER: The questions I have are going to be more detailed than what was described in that interrogatory, but you can go ahead and turn to it, if you'd like.

 MR. SMITH: Well, we should turn it up.

 MR. EVERDELL: Sorry, was that Staff 21?

 MR. SMITH: Staff 22.

 MR. EVERDELL: So in this interrogatory, Staff 22, page 3 of 4, about three-quarters of the way down the page, it describes that the misunderstanding had to do with the expected behaviour of the rock during the tunnel excavation.

 MR. CROCKER: Well, tell me what OPG's position with respect to the issue was. Who was at fault for the -- for not knowing the subsurface condition?

 MR. EVERDELL: The geotechnical baseline describes the agreed conditions that -- what we contractually agreed to with the contractor of the rock underground that the tunnel would be going through.

 So it was -- the way the geotechnical baseline was

established, OPG produced a draft geotechnical baseline report, GBR-A. The contractor responded to that as part of the proposal process, GBR-B, and then it was negotiated from that, the final elements, GBR-C, that became part of the design-build agreement. So it was a joint geotechnical baseline established through that process.

 MR. CROCKER: But you still haven't told me what OPG's position with respect to this misunderstanding was.

 MR. SMITH: I am not sure --

 MR. EVERDELL: OPG's position was that the contractor had changed its means and methods of construction after the award of the contract, and our position was that that had led to the breakdown of the tunnel crown as the tunnel was being excavated.

 MR. CROCKER: Thank you. That is what I wanted.

 MR. MILLAR: You are getting close to the end of your time, Mr. Crocker. How many questions do you have left?

 MR. CROCKER: I have a bit left. This is supposed to be -- this is supposed to be a discovery. It is supposed to shorten the hearing, ultimately.

 MR. MILLAR: No, I am just asking you. So let's keep moving.

 MR. CROCKER: Yes, thanks.

 I am at Issue 5.1. Originally, OPG --

 MR. SMITH: Sorry, do you have an evidence reference, Mr. Crocker?

 MR. CROCKER: Yes. I was going to ask some preliminary questions, but eventually we're going to have to get to it anyway. Exhibit N-1, tab 1, schedule 1.

 That exhibit indicates that -- a change in the 2014 forecast of one terawatt-hour and for 2015 an increase of 0.8 terawatt-hours as a result of higher flows. The increases are associated with the previous facilities.

 MR. ANDERSON: Sir, it would be very helpful if you had a page reference for us.

 MR. CROCKER: Sorry. I guess the page reference is 20.

MR. ANDERSON: Thanks.

 MR. CROCKER: 2013 is higher than -- was higher than forecast. 2014 and '15 are proposed to be higher. Okay?

My question -- that was the background.

My question is this: What does the increase in 2013 have on the -- on 2014 and 2015?

 MR. MAZZA: Really, the increase in 2013 was mostly related to the Niagara Tunnel coming in early. So when we did the forecast for this business plan, we had already incorporated the tunnel in the '14 and '15 forecast, based on the flows of the time. And as mentioned in the evidence here, we did update that with a more recent forecast based on the more recent water flows.

 MR. CROCKER: And is it based on anticipated higher flows in the Niagara and the St. Lawrence Rivers? Is that what it is based on?

 MR. MAZZA: Compared to the original business plan that the evidence is based on.

 MR. CROCKER: So does 2013 actuals have any impact on your production forecast for 2014?

 MR. MAZZA: Well, we do a reassessment, yes. We did a reassessment of water flows in 2013.

 MR. CROCKER: Okay. And so tell me what the impact was.

 MR. MAZZA: There is a general increase in water flows compared to the previous forecast. That's the impact.

 I think if you refer to page 16 of that evidence, you will see the explanation, part of the explanation, there.

 MR. CROCKER: Okay.

 MR. MAZZA: If you go to line 18 and 19 of that. You will also find part of an answer in AMPCO Interrogatory 23, to that part of the question.

 MR. CROCKER: Can we go to F-1, tab 4, schedule 1? I'm sorry, it is Issue 6.1, and it is OM&A, hydroelectric. F-1, tab 4, schedule 1, page 3.

 MR. MAZZA: Page 3?

 MR. CROCKER: Yes.

 MR. SMITH: Just wait until we pull it up.

 MR. CROCKER: Okay. I apologize. The question relates to -- so could you read for your own information so that you put into context the question I am going to ask you, if you could read the paragraph beginning at line 14 and ending at line 23? And then my questions relate to Exhibit L, tab 6.1, Schedule 2. It is AMPCO Interrogatory No. 34. The questions are there, (a), (b) and (c).

 And in (c), you say:

"Vital information supporting the application was not available until 2013."

 Can you tell me, please, what that vital information was? And then I want to explore with you a bit of timing.

 MR. EVERDELL: I was looking for the reference, but basically, the work that was missing in 2013 before the application was made was the actual flow test for the tunnel, the actual performance of the tunnel, how much water it was capable of delivering.

And also earlier in 2013, the revised model of the energy output estimates for the Sir Adam Beck complex was also finalized.

 MR. CROCKER: When was that information available? I am just trying to put together the timing of the application and when the information was available, and why wasn't it available.

 MR. EVERDELL: The response to the interrogatory -- so the model, the revised model for average annual energy output was finalized and approved in March of 2013, and the flow capacity test for the Niagara Tunnel was completed in July of 2013.

 MR. CROCKER: And when was this application submitted?

 MR. EVERDELL: It was shortly thereafter. I believe it was in August.

 MR. CROCKER: Okay. I have nothing further. Thanks.

 MR. MILLAR: Thank you, Mr. Crocker.

What I would like to do is go to Mr. DeRose now, who I understand is going to be a little bit shorter than he had originally anticipated. And then we will go to a break.

**QUESTIONS BY MR. DeROSE:**

MR. DeROSE: Thank you.

 Panel, my questions are entirely focussed on Issue 5.4, and they have actually been shortened because of the assistance of the IESO's questioning that we started off with today.

 If I can start with -- and again, it is under Issue 5.4, the IESO Interrogatory No. 4. I would like to just sort of follow up on something that Mr. Zacher asked. This is Exhibit L, tab 5.4, schedule 11, IESO 4, page 1 of 1. And what I would like to follow up on is (a).

Mr. Zacher asked you about whether your operations would be changed if the incentive was greater, if the sharing was something other than 50/50. And the answer in (a) is:

"The higher the level of incentive to OPG, the greater the degree of potential costs and risks that OPG would be willing to assume to time-shift production."

 Could you describe for us what the potential costs and risks are that exist? What are the steps or actions that you could undertake that you are currently not, because you don't have the incentive to do so?

 MR. WILBUR: Let me just -- I think we discussed in evidence what these costs and risks are, and I am just going to take a moment to look that reference up.

 MR. DeROSE: That's fine. Thank you.

 MR. WILBUR: Without being able to find the reference --

 MR. DeROSE: Perhaps we could do this, if it helps. One of two things -- and I will refer to Mr. Smith. Either you could simply give us the reference after the break, or, to the extent that you can describe it to us now, that would be fine.

Alternatively, we are right on the precipice of a break. I look to Mr. Millar; if we want to take the break now and you could get back to us afterwards. I am in the panel's hands, I guess.

 MR. SMITH: They have been going for an hour and a half. Let's take 10 minutes now and come back at 20 after or quarter after.

 MR. MILLAR: We will take 15 minutes, and 15 minutes only, which, I guess, gets us back at 22 minutes after 11:00.

 [Laughter]

 MR. MILLAR: Mr. Smith, can you have your panel ready at that time?

 MR. SMITH: Yes.

 MR. MILLAR: And, Mr. DeRose, you will be here, and then Mr. Wightman is after Mr. DeRose.

Thank you.

 --- Recess taken at 11:07 a.m.

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

 MR. MILLAR: Welcome back, everyone. I think we will get started again.

 Mr. DeRose?

 MR. DeROSE: Thank you.

 So before the break, panel, I had asked with respect to IESO Interrogatory No. 4 if you could identify what the potential costs and risks that are available that OPG would consider or may be willing to assume if there was a higher level of incentive.

You were going to look for the reference in the evidence and take us through that.

 MR. WILBUR: I was, and I was mistaken on the reference in the evidence.

 MR. DeROSE: That makes me feel better, because I hadn't seen it either, so...

 MR. WILBUR: Now, there is -- I will refer you to IESO Interrogatory No. 1, which we did talk about earlier in the IESO.

 So regarding the risks, a number of those are mentioned, the operational considerations, environmental, so actually, this is...

 MR. DeROSE: Now, but those risks exist regardless of what the incentive is. Those risks exist whether the incentive is 50/50 or 90/10; correct?

 MR. WILBUR: They do.

 MR. DeROSE: Okay. And so I guess what I am trying to understand -- or let me put it this way. The response, (a) response to Interrogatory No. 4, what I took from that is that there are additional steps or additional actions, things that OPG could undertake, if it had a higher incentive to do so.

And that's what I would like to understand. What are those steps or actions that OPG could undertake if it elected to do so with the higher level of incentive?

 MR. WILBUR: Sure. I can provide two examples.

 MR. DeROSE: Okay.

 MR. WILBUR: One is related to operation of the PGS facility at Beck. So there are costs associated, direct costs associated with operating that facility.

 The -- it requires more energy to pump water into the reservoir than you get when you generate out of the reservoir. So there is efficiency losses associated with using that facility.

 So you need a sufficient expected price differential between the low-value period and the high-value period in order to undertake use of that facility.

 MR. DeROSE: So would there be times that right now you elect not to pump water because the incentive is only 50/50? It is not high enough to do so?

 MR. WILBUR: We would be willing to -- so there's -- there is some uncertainty around exactly what that cost is, the precise value of that cost. So we will build in some margin to ensure that we are going to recover the costs when we do that. And if the incentive was higher, we could refine that margin.

 MR. DeROSE: Okay. And so that's one example. What was the other? You said there were two.

 MR. WILBUR: The other one was related to the -- more typically to the currently unregulated facilities, the newly regulated facilities, and there are times when the price -- if a price differential is significant enough, we could operate the unit during the high-value periods in a -- to get more energy out, but it is a less efficient method of operation. So --

 MR. DeROSE: And under your current proposed incentive, would it be OPG's position that you wouldn't do so?

 MR. WILBUR: I wouldn't say that we wouldn't do so. But we would have greater incentive to do that more with a higher incentive.

 MR. DeROSE: Okay. Thank you for that.

 The second follow-up question actually relates to IESO No. 2. Again, this is all in Issue 5.4. So it is 5.4,

schedule 11, IESO No. 2.

And in this response -- sorry, it is just coming up on the screen -- you identified certain direction and guidance that you relied upon when you proposed changes to the HIM.

 And my question relates to the first bullet:

"Direction for OPG to review consumer benefit estimations, including the global adjustment payments."

Could you explain how your review of consumer benefit estimations related to your changes to the HIM?

 The rest of the bullets, I can tell you, I could see were directly related to the HIM, to your incentive mechanism, but could you explain the first bullet?

 MR. WILBUR: I think that is referring to the analysis we did to determine that the HIM is still the appropriate incentive, which, if I can refer you to --

 MR. DeROSE: But how does that relate to benefit estimations?

 MR. WILBUR: The benefit -- that's where we're estimating the benefit to the consumer of doing this time-shifting.

 MR. DeROSE: Okay. Thank you for that.

 Now, if I can turn you, again under Issue 5.4, to CME No. 7, and in this interrogatory we asked you to prepare four tables showing illustrative incentive payments under the four alternative payment mechanisms.

 My questions -- I am only going to ask questions with respect to the current HIM and the enhanced HIM. I am not going to ask any questions on the other two, but if you can turn to page -- my questions are going to be on page 2 and page 3 of that IR.

 Now, first of all, on page 2, which shows the two cases for the HIM, I just want to make sure that I understand what the incentives would be produced.

 So in case 1, you have the 2,500. That is the incentive that would be paid under the HIM; correct?

 MR. WILBUR: That is correct.

 MR. DeROSE: Okay. And in case 2, the incentive would be 1,250?

 MR. WILBUR: Paid under the HIM, yes.

 MR. DeROSE: Okay. Now, if we then turn to page 3, just to understand the difference, first of all, under case 1, while it shows -- while under the total it shows 2,500 under HIM, there is a note that says:

"Note: There is no incentive payment adjustment in case 1 because there is no SBG spill."

Can you explain that statement to me?

 MR. WILBUR: Yes. So in case 1, we were able to time-shift 50 megawatts from periods of low value to periods of high value, as shown in the output column of that table under case 1.

 MR. DeROSE: Okay.

 MR. WILBUR: So -- and there was no spill incurred.

 MR. DeROSE: And so under that scenario it would produce the same as your current incentive mechanism?

 MR. WILBUR: That's correct.

 MR. DeROSE: And then case 2 shows what happens when there is SBG spill concurrently or in the same time period; is that correct?

 MR. WILBUR: That's correct.

 MR. DeROSE: And so the way that the numbers have worked out is that the SBG spill is equivalent to the incentive; is that correct?

 MR. WILBUR: That's correct. That's the intent.

 MR. DeROSE: Now, in terms of -- can I then take you to -- thank you for that clarification. That's helpful.

 Again, Issue 5.4, I would like to just ask a question about SEC Interrogatory 69. And in your response you provide a table, which shows for 2013 what the payments would be under your -- first of all, am I right that this is based on actuals for 2013?

 MR. WILBUR: That is correct.

 MR. DeROSE: Okay. And so under the current mechanism, you have 18.1 million. Under the enhanced, it would be 10 million.

 Am I right that the difference between the 8.1 million, the difference between the current existing mechanism and the enhanced, is that there would have been SBG, the equivalent of the 8.1 million? That's the difference?

 MR. WILBUR: That's correct.

 MR. DeROSE: Okay. Thank you.

 My final question is this. These numbers are based on your previously regulated hydroelectric assets. Do you expect -- in your proposed newly regulated assets, do you expect that the SBG will be -- is SBG, the way that you run the new facilities, going to be more or less, generally speaking, than your previously regulated facilities?

Can you speak to that at all, or is it something that cannot be predicted year by year?

 MR. WILBUR: I don't think we could generalize a response to that. I mean, there are -- we do undertake, or have undertaken SBG spill at many of our facilities, so Beck being the only one in the previously regulated category, but a number of the facilities in the newly regulated category.

 MR. DeROSE: Maybe I will put it differently. This morning with Mr. Zacher, you talked about the enhancements of the new facilities and the fact that Beck has certain time limitations that you have to use in a certain period of time; you can't store it as long.

 Is it a fair conclusion for a layperson like me that if you can store the water longer in your new facilities, that that would potentially lead to less SBG?

 MR. WILBUR: It might lead to less SBG spill at that facility, yes.

 MR. DeROSE: Okay.

 MR. WILBUR: Yes.

 MR. DeROSE: Thank you. Those are all of my questions on this issue.

 MR. MILLAR: Thank you, Mr. DeRose.

Mr. Wightman?

**QUESTIONS BY MR. WIGHTMAN:**

MR. WIGHTMAN: Thank you, Mr. Millar.

James Wightman on behalf of VECC. Good morning, panel. Just a couple of questions.

If you could turn up L-5.4, schedule 15, PWU 009, page 1? The first page; that's right.

Just looking under (b) on this page, in the preamble, and just going down to the last sentence, it says:

"In 2014, customers would achieve 34 million in benefits, while OPG would benefit by 11 million, 18 million eHIM payment, less incremental cost of 7 million."

And that, of course, is an extract from your evidence, as you can see.

 Do I have it right that you expect incremental costs of 7 million for 2014, and about the same for 2015, with respect to this time-shifting incremental cost?

 MR. WILBUR: That is correct.

 MR. WIGHTMAN: Okay. If you then turn to your prefiled evidence -- and it is E-1, tab 2, schedule 1, attachment 1 -- on page 8 of 25, there is a table. Yes, table 2.

Now, this table is labelled "OPG costs

incurred from time-shifting at PGS," and it shows 7 million for 2014 in total OPG costs and 6 -- but I think it is rounding -- for 2015.

 Are those the total incremental costs, or just the PGS costs?

 MR. WILBUR: Those are just the PGS costs.

 MR. WIGHTMAN: Well, then why would you have just removed from the first, from the preamble noted in the PWU thing, that you would get 18 million less incremental costs of 7 million?

And you've just said that those are all of your incremental costs; now you say those are just the PGS costs.

 MR. WILBUR: First of all, the preamble in PWU Interrogatory No. 9, that is from Cliff Hamal's evidence, which we were looking at in -- that is what attachment 1 is that we're looking at, the supporting evidence provided by Cliff Hamal.

 MR. WIGHTMAN: But the numbers are still the same, and it says incremental costs of 7 million in 2014.

 MR. WILBUR: Yes. I am not understanding what the question is.

 MR. WIGHTMAN: What I want to know is if your total

incremental costs that you will incur under your eHIM proposal are 7 million or not for 2014 and 2015. And if they're more, I would like to know how much they are, and a breakdown.

 MR. WILBUR: That is the total.

 MR. WIGHTMAN: So that is not just PGS? It is your run-of-river and your intermediate, everything, incremental costs?

 MR. WILBUR: I don't think we estimated the costs at the currently non-regulated facilities.

 MR. WIGHTMAN: Okay. That's good.

 Now, you have estimated -- let's call them 7 and 7 in this table 2 that is up there. So you have a pretty good idea, I guess, of the costs. You know, they're not going to be 4 million or 12, you don't think. You know, 7 million and 7 million?

 MR. WILBUR: That's a forecast based on the best available information at the time, so --

 MR. WIGHTMAN: Have your forecasts in the past been good with respect to the incremental costs?

 MR. WILBUR: I don't have that information.

 MR. WIGHTMAN: Okay. Well, while we're on that, do you happen to know -- because I couldn't find this anywhere, and maybe I just missed it -- but what the incremental costs in 2013 were for time-shifting, or in 2012?

 MR. WILBUR: No, I don't have that information.

 MR. WIGHTMAN: Could you find it, or produce it?

 MR. SMITH: Yes, we will do that.

 MR. MILLAR: J T1.4, which is to provide the incremental costs of time-shifting for 2012 and 2013?

 MR. WIGHTMAN: Yes. Thank you.

**UNDERTAKING NO. JT1.4: TO PROVIDE THE INCREMENTAL COSTS OF TIME-SHIFTING FOR 2012 AND 2013.**

 MR. WIGHTMAN: Okay. Just a couple of more things, then. Let me just ask you something on that, and then one more question.

 You say you need an incentive, and we will take your word for that. Now, if your costs were 7 million and you received an incentive payment net, but it is not net of costs, of 9.1 million, that would be a 2.1 million return, 30 percent, in one year on your 7 million. But you want 11 million more.

Is a 30 percent return on a one-year incurring costs of 7 million not enough?

 MR. SMITH: Sorry, is there a question of clarification that you require, Mr. Wightman? Or is this an argument you propose to make at a later date?

 MR. WIGHTMAN: No, I am just asking if they wouldn't

consider that a good return. That's all.

 MR. SMITH: Well, I think you have what OPG's proposal is in the evidence already.

 MR. WIGHTMAN: Yes, I have their proposal. Thank you.

I think I have just got one more thing to cover, then.

 You were talking earlier about the correlation of the

incentive payments and with the time-shifting. And it was, I think, table 4, E-1, tab 2, S-1, page 11 that was discussed earlier today. And at page 11 is where it was discussed in that exhibit.

There was the table with the high and the low correlations and the SBG. Okay. All right.

 Well, we don't have it up? But I was going to go back to the previous page, and fortunately I have written down what it says.

The previous page, page 10, and I will just read this for you and I just would like you to explain it, because I got a little confused when I heard it this morning.

 On page 10, when you're talking about this assessment, this correlation assessment, you say for the purposes -- lines 16 and 17, yes.

"For the purposes of this assessment, the use of generation facilities under each alternative for any given set of market prices is assumed to be the same."

Now, that sounds like you're going to -- you would use the things the same, no matter what, for each facility. So I just got confused as to how this relates to the correlation matrix on the next page, because it looks like it is not doing anything, but I am sure that is not correct.

 MR. WILBUR: So what we're saying is the time-shifting from periods of low value to periods of high value that occurred in the scenarios that looked where these different alternatives were analyzed, that time-shifting is the same in each case.

 MR. WIGHTMAN: Okay?

 MR. WILBUR: What the table illustrates is how the payout differs in each of those -- under each of those different incentive mechanisms.

 MR. WIGHTMAN: Okay. Well, I guess all I'm asking is: If you're going to assume the behaviour is the same with different payouts, how -- does this give us an assessment of how an incentive would work?

 MR. WILBUR: It gives an idea of which of these incentives gives the best incentive or incents the proper behaviour, follows market prices.

 MR. WIGHTMAN: Okay. Thank you, panel. Those are my questions.

 MR. MILLAR: Thank you, Mr. Wightman.

 Mr. Rubenstein?

 **QUESTIONS BY MR. RUBENSTEIN:**

 MR. RUBENSTEIN: Thank you very much, panel. If I could ask you to turn up PWU No. 2, this is L-4.2, 15, PWU 2. If I could take you to your response in number (b).

 And in the response to number (b), OPG states in part that:

"Major components of hydroelectric generating stations are managed per OPG's asset management program."

I'm wondering if you could talk to me sort of just generally about what is OPG's asset management program with respect to hydroelectric generating stations.

 MR. MAZZA: Yes. I will first refer you to some of the evidence where we point to that, and... just give me a second here.

 MR. RUBENSTEIN: Are you referring to Exhibit A-2, tab 2, schedule 1 --

 MR. MAZZA: Yes. It's an attachment.

 MR. RUBENSTEIN: -- attachment 4?

 MR. MAZZA: Yes, it's an attachment to the exhibit, where we discuss --

 MR. RUBENSTEIN: Asset management and project review process, if that is familiar.

 MR. MAZZA: Yes.

 MR. RUBENSTEIN: I just -- the reason I asked the question is in that attachment, is that -- would that be the entirety of the asset management program outline that OPG has? Is there any more formal document that is used internally to determine the asset management program for hydroelectric generating stations?

 MR. MAZZA: That is a summary of the asset management program. There is, as part of the corporate evidence, some discussion around how we tie into the corporate asset management program.

But basically, we use a portfolio concept, as mentioned in the evidence, and we have asset classes because of the number of assets or facilities that we have; we have a little bit more granularity around the asset classes that we mention in the evidence.

 MR. RUBENSTEIN: All right. Thank you very much.

 You don't need to turn this up, and this is probably more for Mr. Smith, but this is -- with respect to Mr. Ilsley's report, I couldn't find in the evidence a CV for him. I was wondering if that could be provided.

 MR. SMITH: We can provide one, if it is not in the record already.

 MR. MILLAR: Assuming it is not, I will give it an

undertaking. JT1.5.

**UNDERTAKING NO. JT1.5: TO PROVIDE CV OF ROGER ILSLEY.**

 MR. RUBENSTEIN: Thank you very much.

 If I could turn to Staff 28, this is L-4.5, 1, Staff 28, if I could turn to the chart.

Is OPG able to provide this chart with an additional column that would show the original estimated capital costs?

 MR. SMITH: Sorry, Mr. Rubenstein, I'm not sure I am understanding. Are you asking for -- this is a table that shows actual costs over time.

 MR. RUBENSTEIN: Yes. And I was wondering -- there is a "Total" column at the end, estimated capital costs to complete, and I was wondering if OPG is able to provide a separate column which would be -- which would essentially, using those cost description categories, provide the original cost estimates, so there could be a comparison per cost description line item.

 MR. SMITH: Well, just so I understand, there wouldn't be an actual -- because there is only one set of actuals.

 Are you asking is there a chart that shows the budget adding up to 985 million, broken down by these categories?

 MR. RUBENSTEIN: Yes.

 MR. SMITH: I will ask Mr. Everdell if there is such a document.

 MR. EVERDELL: Yes, we have that information. It would be from the original business case, and the breakdown wouldn't be into all these categories. Some of these were basically added under the amended design-build agreement for cost categories that weren't part of the original agreement.

MR. RUBENSTEIN: All right. Can you provide this chart with an added column which would show the forecasted -- sorry, the forecasted costs at that time? And if there are certain elements which clearly, because they were added later, they would not be included?

 MR. SMITH: Rather than make work, why don't we point you to the original business case estimate that contains the information Mr. Everdell just referred to.

 MR. MILLAR: Is that sufficient, Mr. Rubenstein?

 MR. RUBENSTEIN: Sorry, I thought -- well, I would like to see it. I don't -- when I reviewed it, it wasn't sufficient. It didn't have it to this granularity. That is the question.

 MR. SMITH: But we don't have it to that level of granularity.

 MR. RUBENSTEIN: Well, that's not exactly what Mr. Everdell said. He said that there were certain cost items that were added later based on the amended agreement. So I would assume that was based on changes that had to be undertaken.

MR. SMITH: All right. Well, we will review the business case summary and will let you know our position.

 MR. RUBENSTEIN: All right.

 MR. MILLAR: I will mark that as an undertaking and we will see what comes back from it; it is JT1.6.

Mr. Smith, what are you undertaking to do?

 MR. SMITH: Review the business case scenario to determine whether or not we have the information reflected on whatever this interrogatory is, tab 4.2, schedule 15, PWU -- sorry. It is 4.5, schedule 1, Staff 28, page 2 of 2.

 MR. MILLAR: Thank you.

**UNDERTAKING NO. JT1.6: TO REVIEW THE BUSINESS CASE SCENARIO TO DETERMINE WHETHER OPG HAS INFORMATION REFLECTED IN TAB 4.5, SCHEDULE 1, STAFF 28, PAGE 2 OF 2.**

 MR. MILLAR: Thank you.

 MR. RUBENSTEIN: Panel, I just want to talk generally about the production forecast.

I was wondering has there been any effect, because of the unusually cold winter that we have had, on the production forecast actuals versus what you forecasted for, say, January to the end of March?

 MR. MAZZA: It is too early to predict what the impact would be. We're still early in the year and the -- you know, the fresh -- it is evolving. So there really isn't any reforecast done at this stage.

 MR. RUBENSTEIN: But based on your monthly forecasts, are you seeing, for the beginning part of January, actuals higher than what you had forecasted?

 MR. MAZZA: They are a little higher.

 MR. RUBENSTEIN: Are you able to provide the first quarter actual forecast versus your forecasted forecasts?

 MR. SMITH: Yes, we can do that.

 MR. MILLAR: JT1.7.

**UNDERTAKING NO. JT1.7: TO PROVIDE Q1 2014 PRODUCTION ACTUAL VERSUS FORECAST NUMBERS.**

 MR. RUBENSTEIN: If I could take you to IESO No. 5 --

 MR. MILLAR: Issue number?

 MR. RUBENSTEIN: Sorry, this is 5.4, schedule 11, IESO 5. In fact, it may not even be important to turn it up. I just wanted to talk about the X factor with respect to the incentive mechanism.

 My understanding of the X factor is it is supposed to represent the customer cost reduction.

 MR. WILBUR: It ensures that OPG's enhanced HIM revenue is equal to half of the expected customer cost reduction.

 MR. RUBENSTEIN: And my understanding is that number, the X factor number, was based on the reduction in payments to gas-fired generators, the increase in the GRC costs, and the increase in the export revenues. Those were the three

components?

 MR. WILBUR: Those are the three main components in the consumer cost reduction.

 MR. RUBENSTEIN: Can you just explain to me, for each of those, how you have forecasted those amounts? So we will start with the reduction in payment to gas-fired generators.

 MR. WILBUR: So I need to turn to the evidence, to Exhibit E-1, tab 2, schedule 1, and table number 2 on page 7.

 The table indicates the amounts for the categories that you are asking about, and there's text on the previous page, page 6, which provides a bit of response as to what those are. But I will go into a bit more detail.

 So the first category, the reduction in payments to gas-fired generators, is basically the -- when we generate additional energy from time-shifted hydroelectric in periods of high value when the gas-fired generators are running, the gas-fired generators will produce less. They will operate at reduced output.

 And the amount shown there is -- that's the cost of the gas, the natural gas associated with that reduced output. The consumers have to pay the cost of the gas that those gas generators consume. So if they burn less gas, the consumers pay less for gas.

 MR. RUBENSTEIN: And can I ask you how you came to the

number? How do you determine what the reduction in the costs of the natural gas would be?

 MR. WILBUR: We have a forecast model that we use to

determine this, and that -- and the numbers come from the

difference between two runs of that forecast model. So in one run, we are doing the time -- we are doing time-shifting as incented by the HIM.

 And in the other run, the other run is a much flatter

profile. We're doing much less time-shifting.

 MR. RUBENSTEIN: What are the inputs to the model? I am -- I mean, I understand the calculation that you are making, but you're making certain assumptions.

 MR. WILBUR: Correct. So the input -- there are many inputs to the model. So this model is a comprehensive forecast of Ontario's power system, as well as the neighbouring regions.

 It has information -- it has all of the detailed information about OPG's generation in Ontario. It has assumptions about non-OPG generation in Ontario, based on publicly available information.

And we have assumptions about generation in the surrounding areas, based on information that we purchase.

 MR. RUBENSTEIN: So is the model -- it is an internal model to OPG?

 MR. WILBUR: It is an internal model, yes.

 MR. RUBENSTEIN: Okay. Thank you very much.

The third item is the increase in export revenues. Can you explain the methodology behind the forecast?

 MR. WILBUR: Well, again, the methodology is -- as I said, the comprehensive forecast model, which includes modelling the neighbouring regions determines -- forecasts an amount of exports and imports that occur.

 And whether -- and in the two cases that I mentioned, whether we're doing time-shifting or not doing time-shifting, those imports and exports are different. And this line represents that difference.

 MR. RUBENSTEIN: Okay. Thank you very much.

If I could take you now to -- this is Issue 6.1, AMPCO 34.

 I am sort of summarizing the interrogatory, but you were asked about the Regulation 124.02 process and the timing, and essentially OPG says it is unable to forecast when it expects the MNR to provide the information, but you don't expect that it will happen within the test year.

 Can I -- can you help me understand why you believe it is going to take so long?

 MR. MAZZA: Yes. We have also applied for this holiday exemption from some other facilities, and it has taken quite an extensive period of time to get the holiday. So we're basing it on that.

 MR. RUBENSTEIN: Now, if the MNR makes a decision, say in 2016 -- if I remember reading from another interrogatory that that decision would be retroactive to the date that the facilities come into operation, am I right?

 MR. MAZZA: This is our understanding, if you read the

regulation.

 MR. RUBENSTEIN: All right. Would that amount -- if in 2016, the MNR gives the approval and it is retroactive to 2014 and 2015, the test period, would that amount be credited to ratepayers?

 MR. SMITH: We will take an undertaking to advise you of OPG's position.

 MR. MILLAR: JT1.8.

**UNDERTAKING NO. JT1.8: TO ADVISE OF OPG'S POSITION RE: WHETHER AN MNR-APPROVED AMOUNT WOULD BE CREDITED TO RATEPAYERS AND HOW THAT CREDIT WOULD WORK WITHIN A POTENTIAL HYDROELECTRIC IRM.**

 MR. RUBENSTEIN: If I could just ask sort of one more question, you will probably want to work it into the undertaking.

 I would also ask: How would that work, if OPG is expecting to credit that to ratepayers? How would that work within a potential hydroelectric IRM?

 MR. SMITH: Well, sure, we can consider that. I don't think we know the answer, but we can certainly consider what we don't know.

 MR. MILLAR: So that will be wrapped up in the same

undertaking?

 MR. SMITH: Yes.

 MR. RUBENSTEIN: If I could take you to SEC 84, this is 6.2.17.SEC84. In the interrogatory, we asked you to sort of provide the reports or the documents with respect to three benchmarking studies that OPG refers to in its evidence.

And OPG essentially says they don't have any reports that were prepared specific to OPG's hydroelectric facilities by third parties as contemplated by the interrogatories.

 I was wondering, what format do you receive the information for these three benchmarking surveys or studies?

MR. MAZZA: Well, the information that we get is masked. So we have data, data and spreadsheets, and basically that information is masked, so you don't know which utility relates to what piece of information.

 MR. RUBENSTEIN: But you receive -- they come in a spreadsheet format, essentially?

 MR. MAZZA: Basically a spreadsheet format.

 MR. RUBENSTEIN: And are you able to provide those spreadsheets?

 MR. MAZZA: As mentioned, the information is confidential. We would have to get approval from the different benchmarking companies to release any information.

MR. RUBENSTEIN: Can you please provide those spreadsheets?

 MR. SMITH: No, we're not going to do that.

 MR. RUBENSTEIN: Thank you. Those are my questions.

 MR. MILLAR: Thank you, Mr. Rubenstein.

 I think we are moving to Staff now, and we will start with Mr. Battista.

 **QUESTIONS BY BOARD STAFF:**

 MR. BATTISTA: I guess it is afternoon now, so good afternoon, panel. I would like to take you to Exhibit L, tab 4.2, Staff 19.

 MR. SMITH: Before we go to Staff, I take it Sustainability Journal doesn't have any questions, then?

 MR. MILLAR: Yes, Mr. Tolmie, can you confirm you don't have questions for this panel?

 MR. TOLMIE: Yes.

 MR. MILLAR: Yes, that's correct.

 MR. SMITH: Thank you.

 MR. BATTISTA: And if you are able to double-screen, the other exhibit would be Exhibit D-1, 1, 2, attachment 1, tab 10.

 This interrogatory had asked for some explanation for the increase to 2014 and 2015 when the average expenditures for the newly regulated was in the range of 70 million, and then there is a pop to 90 million in '14 and '15.

 The answer refers to the Ranney Falls project, which is -- increases production, and that most of the increase is accounted for that. And it referred to the business case, which is attachment 1, tab 10.

I notice that in the business case, it seemed that the project was going to start in 2013 in a big way, and 2014. Yet the plan as provided in this application has it delayed a year. I was wondering what was the cause of the delay. If you look, the --

 MR. MAZZA: Well, first, I just want to mention that these are just cash flows that don't enter into the test period. So this project really doesn't take into account the extra energy or the in-service costs associated, so that they're not really part of the test period. They were provided for information purposes on what the plans there are.

 MR. BATTISTA: Right. But would you know why it would be delayed for a whole year?

 MR. MAZZA: Yes. We are working -- there are various regulations that we would have to -- and agreements that we would have to put in place in order for this project to go along, one of them being that it is on a federal waterway, so we have to work with the Trent-Severn Waterway to get approvals not only on the project but also on exemptions related to their version of the GRC.

 So those are in progress, and they are taking longer.

 MR. BATTISTA: Okay. If you go to the bottom of page 1 in attachment 1, you will notice that -- I didn't realize this, but this was a FIT -- pre, I guess, regulation, this would have been a FIT program.

And does that mean, if you go to that paragraph above the table, you would be receiving 13.3 cents per kilowatt-hour for that production?

 MR. MAZZA: Yes. At the time it was contemplated to be part of a FIT. What we would get is in question, because the FIT program has changed. So some of this information is no longer relevant.

 MR. BATTISTA: Right. So as a regulated -- if this facility now is regulated, are you still getting FIT revenues from it?

 MR. SMITH: No.

 MR. BATTISTA: Who answered that, sorry?

 MR. SMITH: I did.

 MR. BATTISTA: Okay. And does this also tell us that this is only economic at 13 cents per kilowatt-hour?

 MR. MAZZA: No. The FIT number that you see there is what's been established, you know, by the OPA. And we are working to make the project more economic.

 MR. BATTISTA: Would you undertake to provide what the revenue requirement is in the test year for this project that is supposed to go into service in the test year?

 MR. SMITH: There is no revenue requirement. It is not coming into service during the test period.

 MR. BATTISTA: Oh, when is it coming into service?

 MR. SMITH: After the test period.

 MR. BATTISTA: Oh, 2016?

 MR. SMITH: Yes, or later.

 MR. BATTISTA: Okay. I would like to take you to Exhibit L, tab 4.4, schedule 1, Staff 20. This has to do with the Niagara Tunnel project.

And an option, of course, with the project, once it was apparent that 900 million wouldn't suffice, was that it would cost $100 million to mothball it.

 As an identification amount, the 100 million, under your paradigm, what is the variability of accuracy of that number?

You know, a definition phase, it is more accurate, but at the very beginning of the process, could this number be 30 million, 40 million? What is your percentage, plus or minus? I have forgotten it.

 MR. EVERDELL: I don't have that detail with me today.

 MR. BATTISTA: Could you provide that in an undertaking?

MR. SMITH: Yes, we will do that.

 MR. MILLAR: J T1.9.

**UNDERTAKING NO. JT1.9: TO QUANTIFY THE ACCURACY OF THE $100 MILLION ESTIMATE FOR CANCELLATION OF THE NIAGARA TUNNEL PROJECT.**

 MR. BATTISTA: I would like to take you to Exhibit L, tab 4.4, schedule 1, Staff 24, page 2.

 This interrogatory asked you to prepare a LUEC which would be related to mothballing the tunnel. And it is noted that under (c), the last bullet -- I think the LUEC provided in the table beneath that includes replacement energy.

Would you please do a LUEC, but without the replacement energy? So it would just be the costs incurred to date of 400 million plus 100 million, or some lower amount for close-up costs. Would you be prepared to do that?

 MR. SMITH: Sorry, I am not sure I understand the question.

 MR. BATTISTA: Well, what this is trying to do is to see what the sunk cost is of the investment of $500 million, and then if you were to shut it down there would be a cost to be paid.

So you could create a LUEC for that, an equivalent to a LUEC. So just strip out from the 11 cents the -- because my understanding in the answer is that you have included the costs, but you have also included the fact that you had to purchase -- the system would have to purchase replacement energy for the energy that is not available because the tunnel is inoperative. Or did I misread that?

 MR. MILLAR: I think the request is to calculate the LUEC taking out the replacement energy costs.

 MR. BATTISTA: Yes.

 MR. SMITH: As at 2009?

 MR. BATTISTA: Right.

 MR. SMITH: Well, I guess I would ask the panel whether this can be done.

 MR. MAZZA: We would have to --

 MR. MILLAR: Microphone.

 MR. MAZZA: The finance panel may be able to answer that question. We can get back to you, after I check with some of the people.

 MR. SMITH: Well, why don't we park the question and we will -- you can ask it again when we come up to the corporate panel?

 MR. BATTISTA: Okay. Could you please go to Exhibit L, tab 4.5, schedule 17, section 37? Maybe you don't have to call it up.

 This is the site inspection report on fall of ground, and it says:

"The presence of water-filled unsealed exploration drill hole advanced through the Queenston formation has led to the deterioration of the rock mass by a process of weathering and swelling over the last 18 to 25 years."

 MR. ANDERSON: Mr. Battista, can you give us a reference from which you are reading?

 MR. BATTISTA: It is Exhibit L, tab 4.5, schedule 17, SEC 37, attachment 1, at page 5, under the paragraph heading "1.4: Note, item 1."

 MR. ANDERSON: Thank you.

 MR. BATTISTA: I was just wondering whether STRABAG, your contractor, was aware of the location of this exploratory drill hole.

 MR. EVERDELL: Yes, they were aware of the location of that borehole.

 MR. BATTISTA: So they just drilled through it, and that caused the over-break?

 MR. EVERDELL: They drilled in close proximity to that borehole, yes, or they bored the tunnel in close proximity to that borehole.

 MR. BATTISTA: That would have been prudent?

 MR. SMITH: Sorry, is there a question there?

 MR. BATTISTA: Yes. Would that be a prudent thing to do?

 MR. SMITH: Obviously our view is that yes, it was.

 MR. BATTISTA: Even though you had a fall as a result?

 MR. SMITH: Yes.

 MR. BATTISTA: Okay. That's it for me.

 MR. MILLAR: Mr. Chute, you had some questions?

 MR. CHUTE: Yes. Issue 5.4, the eHIM, the reference is E1-2-1, pages 5 to 7, the Cliff Hamal analysis that was an attachment, I believe. And I am referring to section 4.1, which deals with the calculation of the customer cost changes.

 I will preface my remarks by saying that I may mention PGS specifically, but I am referring generically to all of the units when I say "PGS," so that includes the newly regulated with forebays.

 Section 4-1 deals with the calculation of the customer cost changes as a result of using a simulation model that OPG maintains, and you have described that previously.

 I think there were some previous questions on some of the inputs to that model. But in my experience with simulation models, they're quite sensitive to input assumptions and changes to variables based on what a view of the future may be, since you are doing a forecast.

 Generally, you don't report point estimates, generally; you report bands with probabilities around them for outputs.

 But in section 4.1, you have a table 1, and you have point estimates of 30 million and 27 million in 2014-2015 for the consumer cost reductions -- I think 36 million in both years.

 Can you tell me what would be the most relevant input

assumptions to your model which would have an impact on the level of these consumer cost reductions -- primarily, the payments to gas generators and increased export revenues?

 MR. WILBUR: I am not sure that I could indicate the most relevant of those inputs, because there are a lot of relevant inputs.

 Specifically to the line 1 of that table, referring to the gas-fired generators, obviously the price of gas is the most significant part of that particular line item. So we have a forecast for natural gas prices going forward.

But I would also point out, referring to your words on the point estimate, this is actually the difference between two forecast runs and it's not a point estimate from one of those forecast runs.

 So those assumptions that you are referring to that are assumptions about the future are the same in both of those two forecast runs, except for the amount of time shifting that is done.

 MR. CHUTE: But you would accept, even if those forecasts were the same, if you had a different forecast you would get a different -- difference between those two simulations?

If you have a different forecast -- as you say, use natural gas prices -- you would get a difference. You would get a range for that estimate of reduction in payments to gas-fired generators, which would then result in a different estimate for the customer cost reductions?

 MR. WILBUR: Yes.

 MR. CHUTE: Okay. When was the analysis prepared that is supported by the evidence?

 MR. WILBUR: This was based on our business plan 2013, done in late 2012.

 MR. CHUTE: Okay. So it is a view of the world from late 2012, looking out to 2015?

 MR. WILBUR: Correct, yes.

 MR. CHUTE: Just to follow up, did you do any sensitivity analysis on, you know, some of the major inputs for your simulation model, so that you’d know how things would react if the future were different than what you were thinking in 2012?

 MR. WILBUR: No, we did not, because this is the forecast we used for our business plan. That's our best estimate of the future conditions.

 MR. CHUTE: Well, based on your experience of how the world has changed over the last three years -- two years since 2012 to, say, first quarter this year, and what we know, how do you think these estimates of consumer cost reductions would move?

 MR. WILBUR: I am unable to speculate the answer to that.

 MR. CHUTE: Okay. My next set of questions deal with the IESO Interrogatory 005.

 MR. MILLAR: What is the issue number?

 MR. CHUTE: Same issue, 5.4. I refer to response sub-number (a) or sub-letter (a), and I quote:

"A different forecast of customer cost reduction less than or greater than 36 million would result in the recalculated X factor."

 And then the next sentence says:

"The X factor is a static value with no adjustment planned throughout the test period."

 So you have a static X factor throughout the test period based on the analysis done in 2012, which may have changed, or the results would have changed if you were doing that analysis now?

 MR. WILBUR: That is correct.

 MR. CHUTE: So we could have a true calculation or an actual calculation of customer cost reductions which could be somewhat different, vastly different, than what is in this analysis?

 MR. WILBUR: It could be different, and, again, different in either direction.

 MR. CHUTE: Okay. I would ask you if, based on your experience with your simulation model, has OPG ever conducted any experience [sic] that have been directed at identifying, say, an optimal level of customer cost reductions associated with the operation of, generically, the PGS, but I mean all the stations?

 MR. WILBUR: I am not aware that we have done such analysis.

 MR. CHUTE: Could you tell us if the model could be used for such an analysis?

 MR. WILBUR: I think I need to understand exactly what

analysis you're asking.

 MR. CHUTE: Well, say we were -- have an idea to maximize the customer cost reductions associated with operation of the PGS, and based on a set of input assumptions.

Would your model be able to produce that?

 MR. WILBUR: No, it would not.

 MR. CHUTE: Why not?

 MR. WILBUR: So I think what you're asking is that if we did time-shifting in a different way, would that produce more customer benefit? And could the model optimize the best way to do the time-shifting to get the most customer benefit?

 MR. CHUTE: Yes.

 MR. WILBUR: And that is not possible with this model, because one of the inputs to the model is our hydroelectric offer strategy, and it is that strategy that would be different if we were going to operate -- do time-shifting

differently.

 So the model does not take the -- how the incentive mechanism works, for instance, and come up with the best time-shifting to optimize that revenue. It doesn't do that.

It takes our existing understanding of offer strategy and uses that to forecast consumer benefit.

 MR. CHUTE: But is it true to say that regardless of

whatever incentive mechanism is in place -- eHIM, HIM, any of the other options -- those customer cost reductions would be realized anyway by operating the PGS?

 MR. WILBUR: By operating the facilities the way we operate them currently --

 MR. CHUTE: And it doesn't depend on what the incentive mechanism is? Those things flow out of that?

 MR. WILBUR: Well, except that in the previous IESO interrogatory, No. 4, we did refer to a different level of incentive would allow us to -- would cause us to take costs and risks into effect differently, and that might affect the amount of time-shifting that we do.

 MR. CHUTE: But you would still have the customer cost reductions regardless?

 MR. SMITH: Sorry, regardless of what?

 MR. CHUTE: Regardless of how you operate the PGS, you are going to have some level of customer cost reductions?

 MR. WILBUR: As long as we do some time-shifting with the PGS and the other facilities, there will be some customer benefit, yes.

 MR. CHUTE: Okay. If we can refer to SEC -- same issue, 5.4, SEC IR No. 073, page 2, this is a table that you were requested to produce as a result of this IR. I am looking at "Forecast of incentive payment," line A.

 And let's just look at the numbers there and not be worried whether it is monthly, weekly or annual. What's the source of that revenue?

 MR. WILBUR: That is the existing HIM incentive.

 MR. CHUTE: Existing HIM incentive?

 MR. WILBUR: That is without an X factor applied. Or an X factor of 1.

 MR. CHUTE: Okay. And then you have an adjustment for the SBG impact?

 MR. WILBUR: Correct.

 MR. CHUTE: And then you have an X factor sort of to reduce it so that the percent or the actual incentive payments to OPG equal the market cost reductions?

 MR. WILBUR: Equal half of the consumer benefit, yes.

 MR. CHUTE: Yes. So it is a sharing of what you see as the benefits to consumers.

 So are you saying that OPG is going to forgo those other revenues that are the result of that top line, 78 -- 96? The source of those revenues is consumers, right? Consumer payments?

 MR. WILBUR: Yes. But the consumers are paying 18 million, not 78.

 MR. CHUTE: Right. Okay. So you're saying that we should -- you would propose that you adjust this such that only 18 is paid?

 MR. WILBUR: Correct.

 MR. CHUTE: So you are going to operate the system so that only that level of revenue would be generated by eHIM?

 MR. WILBUR: If actual conditions turn out the same as our forecast, then we would -- it would generate 18 million, yes.

 MR. CHUTE: Okay. Thanks.

 MR. MILLAR: Thank you, Mr. Chute.

Ms. Binette has just a couple of questions, and then I think we're done.

 MS. BINETTE: Yes, I will be brief. I am standing between you and lunch, so...

 I have given OPG staff my references. I would like you to refer to interrogatory response under Issue 6.1, Staff 69. And this interrogatory relates to OM&A for the newly regulated hydroelectric facilities. There it is. It is on the screen.

And so the table in the interrogatory lists historical OM&A as well as the budget for 2013, and that budget was 218.3 million.

 Part (b) asked about a rationale for the test period OM&A versus historical. In that response in part (b), which is at the bottom of the page, OPG had provided an explanation for the shift in the OM&A 2012 to 2013, at least the base OM&A, and it spoke about increases to labour rates, unfilled vacancies and other organizational changes.

 So if I could ask the OPG staff to go to interrogatory

response under Issue 1, Staff 2, table 16, which I believe is page 36 of the PDF. That is Issue 1, Staff No. 2, table 16; I believe it is page 36 of the PDF.

 So while they're pulling it up, I just -– and you will see it in a moment. The actual 2013 OM&A for the newly regulated was 196.6 million. And in fact, it is almost identical to the 2012 OM&A.

 Can you explain that difference with respect to the previous interrogatory, where there were reasons given for the increase but these didn't materialize? Can you explain that?

 MR. MAZZA: As we mentioned in the response to 69, a

portion of the underage in 2013 was related to unfilled

vacancies. There was a plan to fill certain vacancies that didn't materialize, so that is part of it. That is really one of the major items.

And the other one was the business transformation initiative, where there has been a reallocation of some of the staff to the corporate groups; we referred to some of that in the corporate evidence.

 MS. BINETTE: This wasn't factored in, in the forecast?

 MR. MAZZA: Not in the forecast of 2013 -- the forecast that this filing is based on, because that was -- that was done similar to the energy production forecast and other forecasts in 2012, before we knew exactly how BT would evolve.

 MS. BINETTE: The timing of that forecast, the -- for that forecast, wasn't it May of 2013?

 MR. MAZZA: There was an update done to the Board in May, yes.

 MS. BINETTE: And my understanding was business

transformation was in 2012, or it was initiated in 2012?

 MR. MAZZA: The process did start in 2011, actually, the whole process of business transformation, yes.

 MS. BINETTE: Okay. So if I could ask staff to turn up interrogatory response Issue 6.2, Schools 84, which I believe is page 2,123 of the PDF. Thank you.

So this interrogatory relates to hydroelectric benchmarking and EUCG, Navigant and CEA. My interest is in the OM&A unit energy cost.

At the bottom of that page, it says that the costs for the benchmarking are shown at the highest level of aggregation, the top level of aggregation; is that correct?

 MR. MAZZA: Yes, at the OM&A level.

 MS. BINETTE: Okay. So if we go to the second page of that interrogatory response, the second bullet says that what's been excluded, in terms of OM&A, is the gross revenue charge and water rental fees, as these aren't controllable costs; correct?

 MR. MAZZA: True.

 MS. BINETTE: Okay. So if we can go to the application, the consolidated application, which is -- I am looking at Exhibit F-1, tab 1, page 9, and I am looking at page 8,274 of the consolidated PDF.

 MR. SMITH: Sorry, what tab?

MS. BINETTE: F-1, tab 1, schedule 1, page 8,274. That table is OM&A unit energy costs.

Now, my understanding is that this is just base and project; correct?

 MR. MAZZA: This is -- it is mostly base. Projects in the benchmarking are excluded by all of the utilities.

 MS. BINETTE: Okay. But this particular table is base and project; correct?

 MR. MAZZA: No. As mentioned, this is base, mostly the base OM&A. Projects and GRC are excluded. I believe there is a note in one of the references.

 MS. BINETTE: Okay.

 MR. MAZZA: It is whatever the Navigant folks and the EUCG folks benchmark. And projects are one of the things that can fluctuate between capital and OM&A, and each utility treats them differently.

 MS. BINETTE: Okay. So it is largely base?

 MR. MAZZA: Largely base, yes.

 MS. BINETTE: But not including corporate and central?

 MR. MAZZA: There is some inclusion, if there's consistent treatment amongst the utilities to include certain corporate costs. So they do an analysis of what kind of costs could be included, to a certain level --usually to what we refer to as an SVP level, to our hydro thermal operations level.

 MS. BINETTE: You gave an acronym there; what is that?

 MR. MAZZA: Senior vice president level of our business.

 MS. BINETTE: Okay.

 MR. MAZZA: So basically it is a function of what the

benchmarking companies collect consistently from each utility.

 MS. BINETTE: Okay. I don't want to take up too much more time. Could you go to page 20 of that exhibit? That is page 8,285 of the consolidated PDF.

 This is EUCG for 20 of the hydroelectric plants and how they would stack in the benchmarking.

 So this is OM&A costs. So this OM&A, as we just spoke, then, it is largely base and some corporate and central; is that right?

 MR. MAZZA: [nods]

 MS. BINETTE: On a go-forward basis with respect to business transformation, the whole basis of this calculation would not change. So in 2015 or whatever, all of these numbers on a year-over-year basis will not be affected?

 MR. MAZZA: Going forward, you're saying?

 MS. BINETTE: Yes, with a centre-led organization, which is a result of --

 MR. MAZZA: Well, they could be affected, depending on some of the factors that drive OM&A base to either escalate or if there is any improvements to a centre-led.

So there will be an impact in the future on what the base costs are, and there will be other utilities also with different base costs as time evolves, so --

 MS. BINETTE: Mm-hmm. Is there a definition that EUCG or Navigant provides that says what falls into the OM&A to do this benchmarking? Can you provide that?

 MR. MAZZA: Yes, we can.

 MR. SMITH: Yes, we will do that.

 MR. MILLAR: JT1.10.

**UNDERTAKING NO. JT1.10: TO PROVIDE A DEFINITION FROM EUCG OR NAVIGANT OF WHAT FALLS INTO THE OM&A FOR BENCHMARKING PURPOSES.**

 MS. BINETTE: I am finished. Thank you.

 MR. MILLAR: Okay. Thank you, Ms. Binette. I think that concludes the questions for panel number 1.

 MR. SMITH: We have a number of answers to undertakings that we might as well read into the record right now.

 MR. MILLAR: If you have them prepared, that's fine.

 MR. SMITH: Maybe I will ask Mr. Anderson to read them in, and then Mr. Everdell has some references, I believe, to some AMPCO questions.

 MR. ANDERSON: In response to both JT1.2 and JT1.3, which were requesting information in respect of boreholes and locations, if I could direct you to Exhibit D-1-2-1, which is the Niagara Tunnel exhibit, attachment number 6 is the design-build agreement included on the CD that was distributed with each of the copies and also located on the website, both the Board's and OPG's websites.

 Included in the DBA is the geotechnical baseline report, and the page numbers for the longitudinal section which shows the boreholes and cross-section is pages 1,785 and 1,786.

 And the page numbers for the plan view, which shows

essentially the overhead view of where the boreholes are located, is 1,787 and 1,788.

 MR. SMITH: Mr. Everdell?

 MR. EVERDELL: Yes, there was – I’d referred to them, but you have the page numbers. It was figure 4-1, 4.2 and 4.3 are the location of the boreholes, with more detail in the Saint David's Gorge area.

 There is also figure 6.15, that provides the location of the in situ stress testing, showing which boreholes the in situ stress testing was completed in.

 And then using the same document, the geotechnical baseline report, which is part of the design-build agreement, the boreholes that had the piezometers located in them are summarized on table 6.11 in that document.

 MR. SMITH: Thank you very much. Thank you very much, panel.

 MR. EVERDELL: Can I just -- I found one more, actually, if we can address it.

 MR. SMITH: Oh. Perfect. Perfect.

 MR. EVERDELL: I forget which number it was applied to, but it was the Schools question having to do with adding a column to table -- a table in Exhibit L, 4.5-1, Staff 028, and that information that you requested is actually part of the evidence, Exhibit D1-2-1, table 8, which is on page 128.

MR. ANDERSON: And that is the response to JT1.6 that Mr. Everdell was referring to.

 MR. SMITH: Thank you.

 MR. MILLAR: Thank you, everyone. That concludes panel 1. So thank you, panel 1. You are excused.

We will return in one hour at 1:45, where we will commence with panel 2. I think up first is Mr. Stephenson. Thank you.

 --- Luncheon recess taken at 12:45 p.m.

--- On resuming at 1:45 p.m.

 MR. MILLAR: Good afternoon, everyone. Could I ask everyone to take their seats and we can get started?

Just before we start with panel 2, I wanted to address a scheduling matter. It looks like we should comfortably finish panel 2 today, but panel 3 is not ready to go until tomorrow.

By the time estimates we have, it's going to be a very full day tomorrow. So we are going to move the start time up until 9:00 a.m., and if that causes scheduling

difficulties for some people, we can switch the order of the cross-examination.

 I should also note we're moving to the west hearing room. So we won't be here; we will be in the room next door.

 Mr. Keizer, are you taking over for this session?

 MR. KEIZER: Yes, I am, Mr. Millar.

 MR. MILLAR: Would you like to introduce your panel, or do you have any preliminary matters?

 MR. KEIZER: There is one preliminary matter, I guess, relating to an undertaking that was given this morning.

 MR. MILLAR: Go ahead.

 MR. ANDERSON: In response to Undertaking JT1.1, we did some work at the break and I have the following to add to the record.

 The in-service addition variance of $18.6 million for the Northeast Plant Group is substantially related to the Matabitchuan Generating Station Penstock replacement project -– and by "substantially" I mean 16.5 million of that variance.

 This project was planned to be completed in December 2012, but was not placed in service until early 2013. The project is shown in Exhibit L-4.3.17.SEC30, table 1, line 28.

 MR. KEIZER: Just for the record, I wasn't in appearance this morning, but my name is Charles Keizer and I am counsel to OPG. I will be responsible, for this technical conference, for the nuclear panel, as well as for the Darlington refurb panel.

 So let's move on with the nuclear panel, if I could, and ask each of the witnesses to please state their name and title, and then we can get started.

 MS. CARMICHAEL: My name is Carla Carmichael. I am vice president of nuclear finance.

 MS. SWAMI: Laurie Swami, vice president, nuclear services.

 MR. WOODCROFT: James Woodcroft, director of strategic

planning and improvement.

 MR. KEIZER: Thank you, panel. We don't have any other preliminary matters, so we're good to go.

 MR. MILLAR: Thank you, Mr. Keizer.

Mr. Stephenson, I believe you are first, after which I think it is Mr. Poch.

**QUESTIONS BY MR. STEPHENSON:**

 MR. STEPHENSON: Thank you, panel. I promised Mr. Zacher I would ask this question.

On the screen in front of me, I see that you

are running Windows XP. Are you telling me that OPG is running Windows XP as their operating system?

 [Laughter]

MR. BARRETT: That's all we can afford.

 MS. SWAMI: Do you want me to answer?

 MR. STEPHENSON: Yes, I want to know. I mean, it is ridiculous.

 MS. SWAMI: Laurie Swami. Yes, that is the operating system that we're using, although during this year we will be making some changes to our systems.

 MR. STEPHENSON: And you are aware that it's not being

supported?

 MS. SWAMI: That's why we're making the changes to our

systems.

 MR. STEPHENSON: Okay. My first question is dealing with Exhibit L, tab 4.7, schedule 15, and it is the response to PWU IR No. 4.

 This was dealing with the issue of CNSC aging management regulation. Ms. Swami, you are it for this one?

 MS. SWAMI: That's correct.

 MR. STEPHENSON: Yes.

 MR. KEIZER: Whoever is the most appropriate to answer.

 MR. STEPHENSON: The answer that you gave us was that it was a draft document, and as a result of that, you didn't really -- it was, in effect, premature to get into it.

 As I understand it, the aging management Reg doc 2.6.3 was finalized by the CNSC on March 19, and I am simply asking if you can update your answer now that that document has been finalized. And you don't need to do it here.

 MS. SWAMI: Okay.

 MR. STEPHENSON: Can you do that?

 MS. SWAMI: We can certainly update the answer. However, I would just comment that we have a normal process that we go through when new regulatory documents are updated.

 We do a GAAP analysis against those documents if it's required, and when it becomes part of our licence, we would be required to follow it as a licence document. And until that takes place, we would not be required to follow it specifically.

However, the other comment I would make is the updates that the CNSC is generally making to their document set is to bring it up to a new numbering scheme in some cases, with some minor changes to the actual documentation.

 So this Reg doc 2.6.3 actually will replace RD 334,

which is the current documentation that we use for this area.

 MR. STEPHENSON: In any event, you have our question.

The second issue relates to --

 MR. POCH: Sorry to interrupt, but I was going to ask a similar question, just ask them to file the updated situation.

Can we have an undertaking so we can keep track of this?

 MR. KEIZER: That's what I was going to ask.

 MR. MILLAR: So there is an undertaking, then; it is JT1.11. What is the undertaking, Mr. Keizer or Mr. Stephenson?

 MR. STEPHENSON: It's to file CNSC Reg doc 2.6.3 as enacted, or as finalized.

 MR. MILLAR: Thank you.

**UNDERTAKING NO. JT1.11: TO FILE CNSC REG DOC 2.6.3 AS FINALIZED.**

 MR. STEPHENSON: The second issue deals with the production forecast, and if I could, the reference is Exhibit E-2, tab 1, schedule 2, table 1, and there's a second reference, Exhibit L, tab 5.5, schedule 2, which is AMPCO 27.

 This is dealing with a table which sets out the actual

losses due to planned outages for Darlington. And on the chart, it shows that the -- it is actually a pretty simple question.

 MR. KEIZER: Can we let the chart get up on the screen

there first?

 MR. STEPHENSON: It is actually the interrogatory answer that is the more helpful one, which is there is 0.84 terawatt-hours of outages revealed in that answer, as compared to zeros for the prior two years.

 And we just want to find out why. What's the explanation for a significant increase?

 MR. WOODCROFT: Can you repeat that, sorry?

 MR. MILLAR: Microphone.

 MR. STEPHENSON: Yes. Where you really want to look is in Exhibit L, tab 5.5, schedule 2, which is AMPCO 27.

 MR. WOODCROFT: Yes, I've got that one.

 MR. MILLAR: Your microphone is not on.

 MR. STEPHENSON: If you look at the production loss due to forced extension of planned outages for Darlington, and you look at the figure for 2013, it's 0.84 terawatt-hours.

 MR. WOODCROFT: Okay.

 MR. STEPHENSON: In the prior two years, it had been zero, and smaller numbers in the years before that. It is a significantly different number than in any of the prior years you show.

 We wanted to know if there's an explanation for that.

 MR. WOODCROFT: In 2013, we exhibited FEPO of approximately 20 days on both our spring outage and our fall outage at Darlington. For the previous years, there was no extension to the planned outages.

 MR. STEPHENSON: I understand that that's what the number tells me. I was looking for an explanation. Presumably, there was a reason why there was a forced extension.

 MR. WOODCROFT: The main issue in the spring outage was we had a human performance event on our IMS scrape campaign, where we inadvertently actually scraped the channel and made some damage to the channel, and we had to go back into the outage and do further inspections and replicas, to ensure we had a fitness for duty –- fitness for service properly for the CNSC.

 MR. STEPHENSON: Right.

 MR. WOODCROFT: In the fall outage, we had another human performance event where our contractor -- grinding an asbestos gasket. We had an asbestos release in the turbine hull which set back our turbine work program, and then we had some conventional site equipment repairs to do at the back end of the outage, also delaying the outage to approximately 20 days.

 MR. STEPHENSON: All right. New question, different area. I am going to skip down. It is Exhibit L, tab 6.3, schedule 15, which is PWU 17. It is the answer to question (d) as in "David," and it involves -- where's the 2013 numbers? Yeah, PWU 17. One moment.

 There it is. It is the safety performance summary. Have you got that? 2013 OPG safety performance summary? It's attachment 2, appendix A -- sorry. There's...

 My question is: I assumed this document wasn't prepared for this hearing, that there are prior years that will show us the same data; am I right about that? I am looking for historical information to compare these numbers.

 MR. KEIZER: Can you just repeat the reference again, Mr. Stephenson? Is it attachment -- is it L-6.3.15.PWU17, attachment 2?

 MR. STEPHENSON: Appendix A.

 MR. KEIZER: Appendix A, yes. Appendix A, shown on the document, appendix A.

 MR. STEPHENSON: Yes.

 MR. KEIZER: That's attachment 2 to that interrogatory. Okay.

 MR. STEPHENSON: Oh, I see. Yes. Appendix A is part of a document, as opposed to part of the reference.

 MR. KEIZER: I think.

 MS. SWAMI: So just for clarity, I am looking at OPG list 08610-001, which is in the titled blocks for OPG's document? Have I got the right reference?

 MR. STEPHENSON: No. It's on the screen.

 MR. ANDERSON: It's the last page of that interrogatory response, so there is an appendix to the attachment 2 that is entitled --

 MR. STEPHENSON: And you don't need to turn it up, I don't think. If you feel you do, by all means, but my question is actually blindingly simple.

And that is: Can you provide us with the same data for 2010, '11, and '12, so we can compare your safety performance track record relative to '13?

 MR. KEIZER: We have to see whether -- its availability and whether we can actually provide it or not. So I think --

 MR. STEPHENSON: That is exactly the answer I would expect to get, Mr. Keizer. I mean, there either is or there isn't. So you will tell us.

 MR. KEIZER: Right.

 MR. MILLAR: Will you undertake to do that?

 MR. KEIZER: Yes.

 MR. MILLAR: JT1.12.

**UNDERTAKING NO. JT1.12: TO PROVIDE SAFETY PERFORMANCE DATA FOR 2010, 2011 AND 2012, IF AVAILABLE.**

 MR. STEPHENSON: Okay. Next issue is dealing with the Goodnight benchmarking analysis. And this is PWU 21, Exhibit L, tab 6.4, schedule 15. PWU 21. And it is the answer to part (d) as in "David" that I am interested in.

 And in part (d), you tell us that there was an error in the Goodnight report because of -- because Goodnight did not update part of the report. And you will see in the last sentence it says:

"Recalculated OPG would have been closer to the benchmark by 36 FTEs."

 And first off, have you got that? Okay. My question -- what I want to find out is the extent to which you have updated or revised the charts, et cetera, in the materials to reflect this correction about the 36 FTEs.

Has that been cascaded down into a correction of the charts?

 MS. CARMICHAEL; So the answer to that question is no, we have not updated the report for that error.

 MR. STEPHENSON: Okay. And is there -- so can I just then get you to turn up just as an illustrative example -- it's Exhibit F5, tab 1, schedule 1, part (b).

 MS. CARMICHAEL: Can you repeat that, please?

 MR. STEPHENSON: Yes. F5, tab 1, schedule 1, part (b), page 24. And there is a chart there.

 MS. CARMICHAEL: Okay.

 MR. STEPHENSON: And this is -- the gap is -- and it shows two bars.

 MR. KEIZER: I am just a bit lost here on ours. We are just trying to track it down.

 MR. STEPHENSON: Page 24. It's a bar graph.

 MR. KEIZER: Okay. Thank you.

 MR. STEPHENSON: Okay. So you see the 2013 variance bar, and it's got a number of 430 in it, which I assume is an FTE number; am I right?

 MS. CARMICHAEL: Yes, it is.

 MR. STEPHENSON: Okay. Am I right that that number is out by 36?

 MS. CARMICHAEL: Yes. I would believe that is the case, because the variance to benchmark would be reduced by 36 FT --

 MR. STEPHENSON: So that should read 394?

 MS. CARMICHAEL: Yes. With your -- if your calculation is correct, yes.

 MR. STEPHENSON: Well...

 MS. CARMICHAEL: Yes.

 MR. KEIZER: I guess the question is are you asking if it is, subject to check, Mr. Stephenson, or --

 MR. STEPHENSON: Yeah, I mean, if you need to check something, you tell me. This is not -- I am not engaged in trickery here.

 MS. CARMICHAEL: Yes, so I agree with your numbers. It would be less than 430 by 36.

 MR. STEPHENSON: Okay. And then if I can get you to turn up one more document, it is in the same exhibit. It is at page 29. Now, this is going to be a challenge.

 As I understand it, this chart, if you go in the heading "Initial four-unit CANDU benchmark" -- do you see that column?

 MS. CARMICHAEL: Yes.

 MR. STEPHENSON: And there are a number of job positions there that have no entry. There's five of them, I gather?

 MS. CARMICHAEL: Yes.

 MR. STEPHENSON: I gather there was a reason why there's no numbers there. Can you help me with the reason?

 MS. CARMICHAEL: Yes, because the -- those are related to functional groups that are not adjusted by a ratio adjustment.

So if you look at the column before that, there are ratios applied to those columns that don't have any numbers under "Initial four-unit CANDU," because they're added to the second-last column called "Ratio staffing."

 So it is just a mechanism to differentiate between actual numbers and ratio-derived numbers, and then at the end of the -- they're all totalled together in the last column.

 MR. STEPHENSON: Okay. I want to try to understand whether or not there's some linkage here with another issue which is identified on this sheet, which is the 35-hour work week issue.

 You've derived some numbers coming out of these using ratios, but I wanted to understand whether or not you had -- you have adjusted some things here to deal with the 35-hour versus 40-hour work week.

 MS. CARMICHAEL: Can I just say that we did not derive these numbers? We do not prepare this report; it was a

Goodnight benchmarking report.

 MR. STEPHENSON: All right. Maybe the answer to this is -- is Goodnight showing up for the hearing? Do we know that, or do you know that?

 MR. ANDERSON: We haven't decided yet.

 MR. KEIZER: We haven't reached a conclusion one way or the other.

 MR. STEPHENSON: Okay. That's interesting. Well, maybe I can just ask the questions and you can take it back to Goodnight, and Goodnight will tell you what they will tell you.

 My question to Goodnight would be that on our review, it does not appear that for the five job areas that are blank in that benchmark column, there has been any adjustment made for the 35- versus 40-hour work week issue.

 And as a result of that, the numbers that are attributed to those five functional staffing areas don't seem to be accurate, in that -- those are the ones that appear in the column "Staffing ratio," the second from the right.

 I guess my question is now on the record. My question to you would be: Can you go back to Goodnight and ask him to provide an answer to that question?

 MS. CARMICHAEL: Yes, we can.

 MR. STEPHENSON: All right.

 MR. MILLAR: JT1.13.

**UNDERTAKING NO. JT1.13: TO CONFIRM WITH GOODNIGHT CONSULTING WHETHER ADJUSTMENTS WERE MADE TO BENCHMARKING NUMBERS FOR THE ISSUE OF 35-HOUR VERSUS 40-HOUR WORK WEEKS.**

 MR. STEPHENSON: The only other question in this area is that to the extent there are other charts or calculations in the Goodnight report, where there has been a flow-through of this error about the 36 FTEs, if they can go back and update those charts and those calculations.

 MS. CARMICHAEL: Yes, we will.

 MR. STEPHENSON: All right. Those are my questions. Thanks very much, and let's hope there is no security patches for XP coming out soon.

 MR. MILLAR: Thank you, Mr. Stephenson.

Mr. Poch?

 MR. POCH: Mr. Gibbons. Sorry, we didn't enter an

appearance for you, so maybe you could introduce yourself.

 **QUESTIONS BY MR. GIBBONS:**

 MR. GIBBONS: I'm Jack Gibbons. I am here on behalf of Environmental Defence, and I have one question for this panel. It is with reference to your response to our Interrogatory No. 15.

 MR. MILLAR: What issue number is that, Mr. Gibbons? It should state it at the top of the IR.

 MR. GIBBONS: It is 6.3.

 MR. MILLAR: Thank you.

 MR. KEIZER: Just before Mr. Gibbons proceeds, if I could just ask him. Are you, Mr. Gibbons, just going to recite the question that you -- earlier in the week, Mr. Elston, counsel for Environmental Defence, had sent a letter indicating certain areas or questions of clarification, and also the position of OPG with respect to certain aspects of interrogatories asked by Environmental Defence.

 And we're prepared to put certain things on the record with respect to that, which may -- and deal with those questions in advance.

If Mr. Gibbons is going to recite the questions as

posed in the letter relating to Question 15, then I can deal with it at the outset. That may save him some time.

 MR. GIBBONS: Fantastic.

 MR. KEIZER: So the letter, I think, was filed on the public record, so I believe it is available for everybody to see. So I am not going to recite the question again.

It related to Issue 6.3; it was Interrogatory -- 6.3, Environmental Defence Interrogatory No. 15. There were

three parts to the enquiry that they made in following up on particulars relating to operation, maintenance, administration expense relating to Pickering.

 Maybe if I can -- without reading the entirety of the questions, I could simply refer to the part questions and then people can refer to the letter on the public record to the extent that they would see how we would deal with it.

 The first relates to a clarification of certain calculations, and whether or not OPG agrees with those calculations.

 Can I actually just have one moment to confer, and then I will be able to state more clearly?

[Mr. Keizer confers with Mr. Barrett]

 MR. KEIZER: Thank you. So the quick response is with respect to part (a) of Mr. Elson's question relating to this interrogatory, and also part (b) -- both of which are related to one another since it affects the fundamental calculations in the table which he has disclosed -- that by way of undertaking OPG will provide a response to (a) and (b) as to its understanding of the calculation and whether it is doable, and any issues it has with respect to that.

 With respect to part (c), OPG will maintain its objection to its response to part (c).

 MR. MILLAR: So for (a) and (b), that will be Undertaking JT1.14, and on (c), you are maintaining the refusal?

 MR. KEIZER: Yes.

**UNDERTAKING NO. JT1.14: TO PROVIDE A WRITTEN RESPONSE TO ENVIRONMENTAL DEFENCE INTERROGATORY NO. 15, PARTS (a) AND (b).**

 MR. GIBBONS: So it is your position, Mr. Keizer, that if we want an answer to (c), we will have to bring a motion to compel the Board –- to ask the Board to compel you to answer it?

 MR. KEIZER: That is our position.

 MR. GIBBONS: Okay. Thank you. That's very clear.

 MR. MILLAR: Anything more, Mr. Gibbons?

 MR. GIBBONS: No. We have questions for the nuclear panel and the corporate panel, which are tomorrow, so I will leave now.

 MR. MILLAR: This is the nuclear panel. The Darlington panel is tomorrow.

 MR. GIBBONS: Sorry, the Darlington panel, yes. Darlington and corporate for tomorrow.

 MR. MILLAR: Thank you.

Mr. Poch?

 **QUESTIONS BY MR. POCH:**

 MR. POCH: Can we start with Exhibit L, tab 6.6, schedule 8, GEC 10? We wanted to get some better answers to a few of our questions here.

We asked you, for the results of the probabilistic safety assessment for Pickering A and B that you were required by the CNSC to provide, to remove the current hold point, which would, if it is not removed, I take it you couldn't operate past about 2015; is that correct, first of all?

 MS. SWAMI: The hold point would apply to operation for the different units as they each would achieve the 210,000 full-power hours.

 MR. POCH: Right. And that would start to restrict you as of -- within --

 MS. SWAMI: It would start to restrict in June.

 MR. POCH: Right. Okay. And your response indicated it would be available -- our information is that you have in fact completed that and filed that material with the CNSC already; correct?

 MS. SWAMI: That's correct.

 MR. POCH: Can we then get a copy filed here?

 MR. KEIZER: Sorry, just so I understand, you want the copy of the evidence filed by OPG in that proceeding?

 MR. POCH: We asked for a summary of the -- what's called the PSA, and the answer was it would be available in May, but I gather we just had it confirmed it is already available.

You're shaking your head. Perhaps you can correct my --

 MS. SWAMI: So just the technical report was filed with the CNSC. It is a strictly confidential report for security provisions.

 MR. POCH: Understood.

 MS. SWAMI: The summary document has not been finalized yet, but will be on our website in time before the May hearing.

 MR. POCH: And that's May 7th, I understand?

 MS. SWAMI: That's correct.

 MR. POCH: All right. Perhaps we can just get an undertaking, then, to file the summary document in this case once available.

 MR. KEIZER: That's fine.

 MS. BINETTE: JT1.15.

**UNDERTAKING NO. JT1.15: TO FILE PSA SUMMARY DOCUMENT ONCE AVAILABLE.**

 MR. POCH: Thank you.

 And I wanted to ask you about -- in answer to part (b), you provided us with the safety limits or the safety targets used to determine if upgrades are required. And that's in a table there.

 I provided you or counsel today with a document that has been put on the public record before the CNSC, and I will -- if necessary, we can put this into evidence when we get to the hearing, but in short, in the -- in that document -- which, for purposes of identification, is a Canadian Nuclear Safety Commission document entitled "CMD 14-H2," dated the 24th of March, 2014, and it is appendix C at table C1 -- it indicates that for Pickering A, using what they call a simple summation approach, there is a large release factor for Pickering A following the Fukushima enhancements of 1.26 times 10 to the minus 5.

 And my question was: I see in the answer you provided us that your limit is 1 times 10 to the minus 5; is my simple understanding correct, that your probabilistic risk assessment now shows that after doing the changes that have been requested of you in response to the Fukushima events, for Pickering A you still get a result which is higher than your limit?

 MR. KEIZER: So, Mr. Poch, maybe I could just stop you there. It is my understanding that this table is part of a staff -- a CIC staff report which is at issue in the proceeding before the CNSC. It is also my understanding that the creation of this table was by the CNSC staff, not by OPG, and that the calculations and the derivation, particularly the summation, is not an OPG calculation, and that is a CNSC staff calculation.

 So my concern in further examination on that number is that we're entering into territory where we're starting to deal with issues which are before the CNSC and not before this Board.

 MR. POCH: All right. Let me just make sure my understanding is correct. I appreciate it is not your evidence. I am not asking you to testify to the veracity of the -- or the derivation of those numbers. But just on the face of it, we're looking at apples and apples here, are we?

And we can come back to this if we need to in the hearing, but...

 What is referred to as an LRF 10 to the minus 5 per reactor year is the same as a large off-site release safety goal?

 MS. SWAMI: The number that you are looking at is referred to as a simple summation. This number, as you can see in the paragraph above, describes that it is biased because of the uncertainties associated with this calculation.

 OPG has proposed a method for aggregating these types of results that is not a simple summation. It is a three-year project that we will go through, and we will use international practice to develop what that should be.

 So this number is not a comparator to the numbers that are provided in GEC 10, answer (b) or "bravo."

 MR. POCH: I guess what I am really getting at for the purposes of the Ontario Energy Board's proceedings is I just looked at the CNSC documents, and there you have a number of 1.26 for Pickering A, and for Pickering B, for the sake of comparison, it's --

 MR. KEIZER: But it's not their number, Mr. Poch.

 MR. POCH: No, I know. It is the -- I'm sorry, it's the CNSC's staff's number. It is 1.26 for Pickering A; it is 0.17 for Pickering B.

 I guess my -- the question for the purpose of this proceeding is: It seems to me there is obviously an issue here, a live issue here, that you have just indicated is going to take you about three years to do an analysis to come up with a number that you are happy with; does that not mean that there remains some considerable uncertainty about either the expenditures that are going to have to be made to continue running Pickering or the ability of you to obtain release from the CNSC to continue to do so during this next few years?

 MS. SWAMI: No.

 MR. POCH: Can you tell me why?

 MS. SWAMI: As I explained, the simple summation is not the way to deal with these numbers. And therefore it is not a comparator to the limits that we have provided.

 MR. POCH: All right. Thanks. I think that is as far as we can go today with that. Let's carry on.

 In part (c) we asked you to provide your current policy document on how you consider whether upgrades are needed. You gave us a one-paragraph answer. Is there in fact a policy document that that answer is derived from?

 MS. SWAMI: No. There's not a policy-level document.

 MR. POCH: Is there a document?

 MS. SWAMI: There is a -- I believe it is a procedure-level document. I would have to check that, though.

 MR. POCH: Perhaps I could just ask for an undertaking, and would you check and provide what documentation is available that sets out where your approach is set out in writing, rather than us just getting a snippet?

 MR. KEIZER: Sorry, when you say "approaches," approaches in respect of safety upgrades, is it?

 MR. POCH: Yes. The question asked the document that -- where it indicates how OPG considers whether safety upgrades are required. I assume it is a document that discusses cost/risk trade-offs.

 MR. MILLAR: That's a yes?

 MR. KEIZER: Yes, yes.

 MR. MILLAR: JT1.16.

**UNDERTAKING NO. JT1.16: TO PROVIDE ANY DOCUMENTATION AVAILABLE THAT SETS OUT IN WRITING THE APPROACH IN RESPECT OF SAFETY UPGRADES.**

 MR. POCH: Thank you.

 MS. SWAMI: Could I clarify?

 MR. POCH: Sure.

 MR. KEIZER: Sorry, Ms. Swami wants a question of clarification.

 MS. SWAMI: Could you clarify what document you are looking for?

 MR. POCH: Well, I think I asked if there was a policy document. You said there is not a policy-level document, and I asked if there was a document, and you said yes, there was sort of operating-level documentation.

So I guess that is what we're looking for.

 MS. SWAMI: Sorry for the delay. This button seems a little stiff.

 MR. POCH: You may want to just leave it on.

 MS. SWAMI: Yes. The document that you then referred to was a cost-benefit analysis type of document?

 MR. POCH: No, I was just saying -- I am assuming that this is a document that instructs OPG how to make these decisions, including how you go about getting -- it doesn't matter what I assume.

 MR. KEIZER: Why don't we try to clarify? Why don't we seek an undertaking -- or provide an undertaking that we will look for what documentation that supports part (c) with respect to safety upgrades, and be able to report back.

 MR. POCH: Thank you. That would be helpful. I am sure you will do your best.

 I take it -- well, all right. I think your answer to part (d) is you didn't provide an action plan to the CNSC because your conclusion is your PRAs don't exceed the safety goals. That was the topic we were discussing a few minutes ago.

 I take it, though, that that is still a live question before -- the CNSC will determine in the May 7th; is that correct?

 MS. SWAMI: So OPG confirms that it does not exceed the safety goal limits as required.

 The CNSC has not identified to us that we have an exceedance of any safety goal limits either.

 MR. POCH: Well, I see that that is a matter that has been addressed in the CNSC staff paper that is going to the commission on May 7th. I assume that the commission will either accept the staff's report, or it will be at that point that if they chose to call for anything further, they would; is that correct?

 MS. SWAMI: That's correct.

 MR. POCH: All right. Thank you.

 Now, I might have to come back to this, but in answer to part (f), you said there is no action plan. So there is no required activities, therefore there is no financial impact in this rate case, in this payments case.

 And you refer there to a Staff exhibit that deals with your request to the CNSC to lift the hold point.

 In that Staff exhibit, which is for the record L-6.6.1,STAFF97, it refers to the -- to the intention to move from 210,000 hours to 247,000 hours for Pickering.

 Am I correct that you are now talking about moving to

261,000 hours for Pickering?

 MS. SWAMI: So the current business case that we have just completed is the 247,000. That's what we have underway now.

 We have another project that is looking at the potential to go to 261,000.

 MR. POCH: Right, and that's -- it -- unfortunately it has the same acronym as an older project, but it is the second FCLMP; is that correct?

 MS. SWAMI: There's two different projects. There is the fuel channel lifecycle management project, FCLM, and there is the fuel channel life extension, the FCLE project.

And the latter is the one that moves to the 261,000.

 MR. POCH: All right. I am just trying to understand. Is that something that still has to go to the CNSC for approval, that latter extension of time?

 MS. SWAMI: The project –- we’ll work through the project, and we'll be providing information to the CNSC staff on a regular basis.

 What is important is for OPG to demonstrate the fitness for service for our pressure tubes, and that will determine the life of the plant. And so we will be working through that on an ongoing basis.

 MR. POCH: And is there any further plans to go beyond

261,000 that you are looking at?

 MS. SWAMI: No, there's no plans for beyond that.

 MR. POCH: Now, one of the -- I see that one of the

proposals that was being considered to respond to the new

insights that Fukushima gave was the inclusion of a containment filtered venting system, which you have used the acronym "CFVS" for.

 Now, I understand that OPG has proposed other measures, or has provided an analysis suggesting that other measures obviate the need for that at Pickering; is that correct?

 MR. KEIZER: Sorry, are you referring to part (g) of GEC 10?

 MR. POCH: Yes, that's correct.

 MR. KEIZER: Okay.

 MS. SWAMI: So that's correct. We have done an analysis to look at whether we could upgrade our existing systems, or whether we needed to install this for Pickering, and we have determined we don't need to make the installation for Pickering.

 MR. POCH: Right. I take it that is another matter that is pending before the CNSC, approval of that alternate approach?

 MS. SWAMI: Could I just take one minute?

 MR. POCH: Sure. I took that, by the way, from that document that I provided you with this morning.

 MS. SWAMI: I'm just seeking clarification. I need to think about whether it's approval that we're seeking from the CNSC.

What we were required to do was to provide a report with our decision, and we have done that.

 MR. POCH: Okay. Whether you have been asked to -- whether there is a hold point, or whether it is simply something that is before them, potentially subject to their subsequent request, that is an issue they have not yet spoken to?

 MS. SWAMI: The hold point was specific to three matters and those are listed in our document, which you have not brought forward here.

 OPG also has a similar document, CMD 14-H 2, I believe, .1 -- but I am going by memory, so subject to check -- which would describe the requirements that we needed to fulfil. That would be a better reference in that case, but again, it is something that is before the commission.

 MR. POCH: I guess my question was -- turning to SEC

Interrogatory 52 that is L-4.8, schedule 17, SEC 52, I just note that you have ended up adding a containment filter venting system as part of the proposed work for the Darlington rebuild.

 It's a $39 million project, and I am just wondering why it is needed for the Darlington rebuild and it's not needed for Pickering.

 MS. SWAMI: As you can see in this response to 52 --

which -- I think that tomorrow's panel may be in a better position to answer.

However, if you look at lines 18 to 22, it discusses

this as a CNSC commitment. So at the time that we were looking at the environmental assessment for the Darlington refurbishment and continued operations project, this was one of the commitments that we made for that environmental assessment, and therefore it was required.

 So it is part of the consideration post-Fukushima. But the refurbishment environmental assessment actually was a commitment before Fukushima occurred.

 MR. POCH: Okay. That's fine. I guess my question is

simpler than that.

Why, if it is felt it is needed for Darlington, is it not needed for Pickering?

 MS. SWAMI: So it is a very technical answer, which I can provide. But perhaps it would be best if I provided it in a written summary.

 MR. POCH: Sure.

 MR. MILLAR: JT1.17.

**UNDERTAKING NO. JT1.17: TO EXPLAIN WHY A CONTAINMENT FILTER VENTING SYSTEM IS REQUIRED FOR DARLINGTON BUT NOT FOR PICKERING.**

 MR. POCH: Thank you.

Just for the purposes of this Board's proceeding, if it were to be required of you, the $39 million you have budgeted for Darlington, that would be an indication of the order of the magnitude at least of what it would cost to do at Pickering; is that fair?

 MS. SWAMI: I would be speculating on the cost.

 MR. POCH: That's fine. Moving on to L-6.6, schedule 8, GEC No. 9, we asked for the --

"Please indicate the impact on expected SBG..."

Surplus base load generation.

"... from the Pickering life extensions, with and without the Pickering life extensions, and with only two units' life extended."

 Your answer was:

"There is no expectation of a surplus base load generation impact on the nuclear production forecast."

 I think you have read our question D inverse [sic]. We weren't looking for the impact on nuclear production forecasts; rather, in effect, the opposite, the impact of life extension and therefore an increased production forecast or a changed forecast on surplus base load generation.

 Can you provide us with an answer to that?

 MR. KEIZER: I think that's something -- I'm not sure that it is this panel that can address that, and we would have to see whether it is even something that is predictable.

 MR. POCH: Why don't we take a -- sure. I appreciate it is -- to some extent it is a forecast, and...

 MR. KEIZER: If we could predict SBG, a lot of people would be making money on SBG, I think.

 MR. POCH: Sure. We don't know when it would be, but presumably some statistical expectation based on past experience and the time of year and when Pickering is -- you now have a schedule for when Pickering's going to be generating.

 So perhaps we could just ask for an undertaking that you could -- Mr. Keizer could take back and the appropriate panel could respond, if they're able.

 MR. KEIZER: Yes, I guess we could see if they could respond or if they're able to respond. I am not sure if the calculation is even something that can be prepared, because I don't necessarily know that in the machinations of the marketplace that there is a direct link between any one particular unit and the degree that SBG exists, you know, in the market.

 MR. POCH: Okay. I guess I was just coming at this at a very simple level.

I take it every Pickering unit that runs purchases about 7 terawatt-hours a year if it was running steady. And they're base-loaded units, so they're going to be on when -- the times of surplus base load generation, and based -- I guess what I am asking is if -- based on the previous years' experience with how often surplus base load generation occurs, how much of an impact might this have on it.

I wouldn't have thought it was that complicated.

 Obviously it can only be as accurate as history repeating itself, but we know how much you are proposing to generate from the Pickering units.

 MR. KEIZER: Yeah, I take your -- I understand that, that you know what we're going to generate. I think what we can do is take away and provide, I guess, an undertaking which says: Are we able to provide any meaningful calculation as to whether the relationship between Pickering and SBG -- my initial thought is that it's -- the ability to actually link the two may be, you know, in terms of actually cause and effect or impact, may be difficult to do, but we can look at whether it is possible to do.

 MR. POCH: Let's get an undertaking number for that, then, if I could.

 MR. MILLAR: JT1.18.

**UNDERTAKING NO. JT1.18: TO PROVIDE ANY MEANINGFUL CALCULATION THAT SHOWS THE RELATIONSHIP BETWEEN PICKERING AND SBG.**

 MR. POCH: Okay. Thank you.

 Now, in an exhibit just related to that, these last couple of issues we have been talking about, in Exhibit F2-03-03, attachment 1, tab 11 -- let me see if I can get that up on my screen.

 MR. KEIZER: Sorry, can you just repeat that again, Mr. Poch?

 MR. POCH: It would be Exhibit F2-03-03, and it is attachment 1, tab 11.

 MR. KEIZER: And I see there is some blacked-out parts. I am assuming that if we're going to speak about confidential, we'll -- you will alert us to that fact?

 MR. POCH: That's fine. We can stay with the blacked-out version unless you need otherwise. I just wanted to just confirm my understanding of this.

This is a document where you do discuss this new plan to move to 261,000 effective full-power hours rather than the 247,000; correct?

 MS. SWAMI: That's correct.

 MR. POCH: All right. And just -- I want to make sure I understand this, that the proposal is to spend -- and I can't recall where in the document I found this. I will see if I can pull it up.

Yes, on page 10 of 15, I see that that's expected to be budgeted at about $252.5 million, and that the Pickering portion would be something over 57, $57.1 million; is that correct?

Well, first let's do them one at a time, since I think the second question is more complicated.

 First of all, I see total cash flows of 252.5 million, for that further life extension? Or investigations to -- and --

 MS. CARMICHAEL: The 252 million? Yes, I see that.

 MR. POCH: Okay. And then below that there is a table which breaks it out but doesn't have the full amount. And I see it lists 57.1 costs for Pickering and 89.6 for Darlington, and that obviously doesn't add up to the 252.

 Is the difference just what's being funded by your other CANDU Owners Group partners?

 MS. CARMICHAEL: No. The 146.7 is the total of ongoing costs required to do further work throughout the years. It is the line 146.7 above, above the 252.

 MR. POCH: Oh, okay. I see. Can we just then get the number that's -- of the 252.5, can I just get the number that would be attributable to Pickering? That would be something obviously greater than 57.1?

 MS. CARMICHAEL: So the first component is R&D costs of 105.8 million, and of that, 15.6 million is related to

Pickering.

 MR. POCH: Yes, I understand. Were you stopping there or still calculating for us?

 MS. CARMICHAEL: I'm stopping there, because the 146 million is broken down below --

 MR. POCH: Okay. So --

 MS. CARMICHAEL: Those are ongoing inspection/maintenance costs throughout the years.

 MR. POCH: All right. So the total for Pickering for this shift from -- what I think is 247- to 261,000 is the sum of 15.6 plus 57.1; is that correct?

 MS. CARMICHAEL: I would have to go and confirm that, but --

 MR. POCH: Subject to check?

 MS. CARMICHAEL: Subject to check, because the bottom numbers are part of lifecycle management plans and are subject to change.

 MR. POCH: Okay. Subject to check, approximately 62, $63-million. And I take it that that does not include contingencies?

 MS. CARMICHAEL: All BCSs include contingencies.

 MR. POCH: I just read -- just under the table, it says "Project cash flows," and the second sentence is:

"The estimate at completion does not include contingency of..."

And it is blacked out, the amount, but I just thought that was applicable annotation.

 MS. CARMICHAEL: Yes. BCSs include contingency, but the estimated completion may be different. I don't know what the numbers are under this.

 MR. POCH: Okay. So the 252, for example, would include --

 MS. CARMICHAEL: Would include some component of

contingency.

 MR. POCH: Okay. Thank you.

 Now, this is a document -- I know this is a 2012 document; am I correct? It would have come out in the same year that you were doing your analysis of the net present value calculations for life extension at Pickering.

 I take it that the net present value calculations you have provided us elsewhere in the evidence, yours and OPA's, were for the move to 247,000 hours, not for this? It wouldn't include these costs or benefits?

 MS. SWAMI: That's correct.

 MR. POCH: Okay. From L6.6, schedule 8, GEC No. 6, I took it that the -- prior to this second round of projects to extend beyond 247- to 261,000 hours, Pickering 6 was to have an extended outage in 2016, and that has changed as a result of this?

 MS. SWAMI: I'm sorry, could you just tell me where you are seeing that?

 MR. POCH: The reference -- I don't have it in front of me either, unfortunately. It is L-6.6, schedule 8, GEC No. 6.

 And I'm sorry, I think I might have the wrong reference, because that just gives the total terawatt-hours.

 MR. KEIZER: We have it on the screen there now.

 MR. POCH: Yes. I'm sorry, I don't have the reference at hand. If you can't answer this, we'll have to come back to it.

 But my understanding was that as a result of this proposed further life extension, a long outage of Pickering 6 that was to have occurred in 2016 is not going to occur any more. And there would be other shifts in outages?

 MS. SWAMI: I just am trying to check, because I believe the outage that you are referring to is a unit 7 outage; is that correct?

 MR. POCH: You may be right. I know that there was a unit 7 outage which changed, to go from 210 to 257.

 MS. SWAMI: Sorry, can you repeat that? Maybe you could repeat the question.

 MR. POCH: Yes, give me one sec. I might have a reference for you here.

 Well, let's do it this way. If you turn up L-6.6, tab 2, AMPCO 53, in the table there you provided that the change in outage days in generation due to continued operations at Pickering -- I guess what I am asking is: Has that now changed because of this, assuming this new plan to go to 261 comes into being?

 MS. SWAMI: So I think what you are referring to is the units -- if I can just step back, because I want to make sure I understand the question.

 In AMPCO 53, there's a reference to unit 6, which would be shut down in May 2014 if there were no continued operation scenario. That may have been what you were referring to earlier.

 But with continued operation, that unit will continue to operate.

 Unit 7, with no continued operation, would have required lengthy life management outages.

So with 247 we have moved the -- one of those, one unit 7 outage; with 261, we would then redo our generation plan, eliminating a life management outage completely, so that we would get more generation from all of our units.

 MR. POCH: Okay. And that, I take it, is not in this table. That would be a further change?

 MS. SWAMI: That's correct. So what we've given here is the 247 business case, and the questions we looked at here were surrounding that business case.

 MR. POCH: Is it possible to get that table updated with the 261?

 MS. SWAMI: I believe we could do that. I'm not sure how long that would take to do, but I believe it could be done.

 MR. POCH: Well, I mean, I'm assuming it's going to have an impact in 2014 and 2015, both in terms of planned outage days and generation, so it is kind of central to the --

 MS. SWAMI: No, no, it's not going to be an impact in 2014 and 2015; it will be an impact in future.

 MR. POCH: Okay. That's helpful. Then it would be helpful if it is available; I don't want to put you to great work if it's not.

 MR. KEIZER: If it's not going to impact the test year, I am not sure why we're going through the work to produce it.

 MR. POCH: I think it is nevertheless relevant to this Board. We can have this argument later, but if you are doing expenditures in this year, they are going to affect

things like generation and surplus base load generation in future. I think it is relevant to the Board's consideration of expenditures that are occurring in this year.

 MS. SWAMI: Right. The bulk of the expenditures on the fuel channel life extension project are related to the

Darlington plant, and there are some benefits that Pickering will derive as a result of those expenditures.

 So it is really focussed on Darlington as opposed to

Pickering.

 What we're doing is we're getting additional -- additional life from our Pickering plant, which, from the perspective of our expenditures, is an advantage because the Pickering plant will continue to operate fully until the end of 2020 without, for instance, a life management outage on unit 7.

 MR. POCH: Okay. Well, let me ask you about -- let me ask you about that.

If you turn to GEC 7, which is tab 6, L-6.6, schedule 8, GEC 7, we were asking you there about the overall assessment of these -- this life extension going ahead.

 And my question was: If you look at the answer to (d), we were asking you about the base load demand versus base load generation, and how it would affect that. Our concern is about how this is going to affect -- one of our concerns is how this is going to affect surplus base load generation.

 You indicated there that OPA did not estimate base load generation. And then in answer to (g), you say that:

"OPA advised it did not estimate the cost or benefits of production above Ontario demand, that example the impact of potential surplus energy."

 So I am wondering where, if at all, you have account for that impact.

I'm sorry, I might have misspoke myself. It was

OPA has advised, yes.

 MR. KEIZER: Sorry, I am trying to understand the question.

 So you are asking whether OPG has accounted for it, even though it is OPA calculation?

 MR. POCH: You have indicated OPA hasn't accounted for it. That, I think, is clear from your answer; correct? That's at the bottom of page 4 of 5 of this answer.

 MS. SWAMI: That's correct.

 MR. POCH: I am wondering if OPG has anywhere analyzed the impact of these life extensions at Pickering on surplus base load generation during the period it will operate.

 MS. SWAMI: No. OPG did not consider that in its business case.

 OPG relies on the OPA and others to plan the system, and we looked at the business case with respect to our generation.

 MR. POCH: Okay. And did you -- excuse me one sec.

 In answer to part (f), we were asking you about if you had done an analysis of overall system benefit; that was part of my earlier question.

 And we were asking you specifically about the -- in your response, rather, you mention that OPA provided numbers and that system benefits can also include reductions in CO2 emissions.

 Is it your understanding that the analysis that –- well, actually you know what? Let's just move right ahead to AMPCO Exhibit 52, which is more directly on the point. That’s Exhibit L, tab 6.6, AMPCO 52.

 There, they asked you basically to explain the difference between the significantly different numbers that OPA and OPG provide for what the benefit of life extension to Pickering is.

 And your answer indicates there is a large number of assumptions, including the demand forecast, the gas price forecast, carbon price forecast, value of exports, and conservation and so on. And the main differences for the treatment of exports, valuation of carbon emissions and modelling differences.

 I took from that answer that at least you or they or maybe both included the value of carbon emissions in your analysis?

 MR. KEIZER: First, I guess the question -- do the witnesses have in front of them that interrogatory? Oh, there it is on the screen now.

 MS. SWAMI: Yes.

 MR. POCH: Yes. I am guessing this is heading towards another undertaking.

 Basically, can we get an explanation of what the actual diff -- rather than just the headings of where differences arise between you and OPA, perhaps we could get a fuller answer that would respond to my earlier question and perhaps help AMPCO too, to what the differences were in the treatment of exports, valuation of carbon emissions and modelling differences, both in terms of describing what the difference is and numerically what that accounts for.

 MS. SWAMI: So the models that are used are quite complex, and there's a number of assumptions that are included in each one of those.

 OPG is not in a position to provide a detailed breakdown of those differences. We can provide this general difference, but it is a fairly complex model that's employed for these types of calculations.

 The value -- I think the OPA does a secondary view of what we have done and uses their own modelling assumptions to look at the economic value of Pickering going forward, and concluded that it was a value, and included in that was the qualitative factors that you have somewhat described in terms of the value of Pickering.

 The long-term energy plan also describes the value of Pickering going forward, particularly during the refurbishment years.

 MR. POCH: I guess my question is simply: Did somebody put a price on carbon emissions to come up with their 100 billion or their 520 million? Did you or did OPA put a price on carbon?

 MS. SWAMI: The way that that was done in the model was through CO2 adders. I don't have the specific value of that. And I don't have the difference between OPG and --

 MR. POCH: Maybe we could just get that smaller undertaking, if my friend doesn't object.

In OPG's and OPA's assessments of the net present value of the Pickering life extensions, what value was used, if any, for carbon emissions?

 MR. MILLAR: JT1.19.

**UNDERTAKING NO. JT1.19: TO EXPLAIN THE VALUE USED, IF ANY, FOR CARBON EMISSIONS IN OPG AND OPA'S ASSESSMENTS OF NET PRESENT VALUE OF THE PICKERING LIFE EXTENSIONS.**

 MR. MILLAR: Mr. Poch, how are you doing for time? We've been going about --

 MR. POCH: I think I may be done.

 MR. MILLAR: Okay.

 MR. POCH: In fact, I know I am done.

 MR. MILLAR: I won't interrupt. Thank you very much, Mr. Poch.

 Mr. DeRose, are you next?

 MR. DeROSE: Yes. SEC has been good enough to let me jump the queue.

 **QUESTIONS BY MR. DeROSE:**

 MR. DeROSE: Panel, all of my questions are going to be directed at Issue 6.5, so this is with respect to the forecast of nuclear fuel costs, as well as the Longenecker report.

 And if I could start by having you turn up CME 8, so it is Exhibit L, tab 6.5, schedule 3, CME 8. It is five pages.

And in this interrogatory, we asked a number of questions, which at a high level were trying to get an understanding of the extent to which you could reduce your inventories and the pace at which you could reduce your inventories.

 And if I could turn you to page 4 of 5, so this is (e), you will see at the top you say that:

"Drastically reducing inventory levels was not possible, given the existing contractual commitments, and would not be consistent with a prudent inventory management approach. Other variables, such as financial and physical risk coverage limits, need to be considered."

 So if I start with the contractual commitments, because I think that is probably the easiest piece, am I right that all of your contracts did not have a termination for convenience clause or the ability to terminate for convenience? Correct?

 MS. CARMICHAEL: That's correct.

 MR. DeROSE: And so were there any, what I would describe as, off-ramp provisions, or the ability to terminate early with a set penalty?

 MS. CARMICHAEL: I would have to verify that on the long-term contracts.

 MR. DeROSE: Is that something that you -- Mr. Keizer, is that something we can have an undertaking to? And just so that I'll -- I will describe what we're looking for. Termination for convenience can have a broad meaning, or it can have a very particular, limited meaning, saying: No penalty, you can terminate with a notice provision with no cost.

 Sometimes there will also be termination provisions which have a set penalty or cost for terminating, which might not be considered termination for convenience.

 So what I am really looking for is: Was there the ability to terminate short of actually breaching the contract?

 MR. KEIZER: If I could just have a moment.

 [Mr. Keizer confers with Mr. Barrett]

 MR. KEIZER: That's fine.

 MR. MILLAR: That is an undertaking?

 MR. DeROSE: Yes, please. And, sorry, one supplemental to it. If the answer is anything other than no, there were no such provisions, if we could have the particulars of the provisions described to us.

 MR. KEIZER: Depending upon the nature of what is in there, some of those responses may have to be confidential.

 MR. DeROSE: That's fine. I think we can cross that bridge if the answer is anything other than no.

 MR. MILLAR: JT1.20.

**UNDERTAKING NO. JT1.20: TO ADVISE WHETHER THERE WAS AN ABILITY TO TERMINATE SHORT OF BREACHING THE CONTRACT, AND IF NOT, TO PROVIDE THE PARTICULARS OF THE PROVISIONS.**

 MR. DeROSE: Okay. So the first issue, which is the inability to contractually terminate early, so if we just put that aside, you then refer to other variables. And you have referred to financial and physical risk coverage limits, and you've referred to it in other interrogatories as well.

 Could you describe to me what you mean by "financial and physical risk coverage limits" in that context?

 MS. CARMICHAEL: So when we develop our procurement plan for inventory for nuclear fuels, we look at mitigating two risk factors. One would be the financial impact of cost escalation, price escalations of the market, as well as ensuring we have physical quantities on hand, and we limit our risks with regards to that.

So it is a dual risk management process.

 MR. DeROSE: Given Longenecker's recommendations or their observations about the appropriate level of fuel inventory, if we take, let's say, the physical risk coverage limits to start with, do I take it that the physical risk coverage limits that you are referring to there is essentially disagreeing with Longenecker?

Is that a different way of saying: We think it should be more?

 MS. CARMICHAEL: Actually, Longenecker reviewed our inventory limits when they came in and did their assessment, and they did suggest that we could lower our inventory limits, which we are taking action towards.

 So we have reduced our target inventory levels as a result.

 MR. DeROSE: Correct. But you have not reduced it to the levels that Longenecker had identified yet?

 MS. CARMICHAEL: Yet. And Longenecker did identify inventory targets that were, say, more aggressive for the Canadian market. So we have different supply sources, things like that.

 So we determined that there was an optimum target of 750,000 pounds.

 MR. DeROSE: Okay. And on the financial coverage limits, what you're referring to there is -- and I am trying to put it into sort of a layperson's language -- the appropriate mix of short-term and long-term contracts and fixed-price and spot market price. Is that what you mean by "financial risk coverage limits"?

 MS. CARMICHAEL: So the financial risk coverage is how many contracts we have out in the future for inventory levels at a certain price or a price mix. Does that answer your question?

 MR. DeROSE: Okay. Thank you very much.

 Now, you’ve referred to other variables, plural, and you give these two as examples.

 Are there -- other than the contractual commitments, the financial risk coverage limits and the physical risk coverage limits, are there other variables that you are aware of that would lead you to conclude that you should not be as aggressive as Longenecker had recommended, or identified as a possibility?

 MS. CARMICHAEL: Well, like I said, there is a supply risk, a higher supply risk issue for the Canadian market than the American market. So we did have to factor that into consideration, which is what we based our physical risk limit coverage on.

 MR. DeROSE: Could you explain to me what you mean by "a higher supply risk for the Canadian market than the American market"?

 MS. CARMICHAEL: So -- just give me a second.

 There is a few differences in our market and our

technology, I should say. So from a technical perspective, we do on-line fuelling in our CANDU reactors, which PWRs do not do in the US. So we have we have to have a continuous supply for our on-line fuelling process.

 The other issue is that we have a very limited supplier base for the Canadian market; basically, in some circumstances, just one supplier. Whereas in the US, because of the size of the market, they would have more competitors in the market.

 MR. DeROSE: Okay. Did you not make Longenecker aware of these differences when they were preparing their report?

 MS. CARMICHAEL: Well, they would have -- they would have known we were CANDU. I personally wasn't involved in those discussions with Longenecker. I would have to check that, but my understanding is that they did know we were a CANDU operator.

But at the same time, not being in this market, they may have not determined those as we determined them, the risks.

 MR. DeROSE: Okay. Could I then take you to –- again, it is the same issue, 6.5, to Board Staff 93? So this is Exhibit L, tab 6.5, schedule 1, Staff 93.

 I just want to make sure that I have the timeline of what's occurred, in terms of your contracting practices since the last case.

 So if we start with response (a), second paragraph, you confirm in 2010 -- so this, I am assuming, either would have been just before or just after you received the Decision from the OEB -- you made a decision not to contract until a report had been concluded; correct?

 MS. CARMICHAEL: That is correct. We suspended developing new procurement plans.

 MR. DeROSE: Okay. And the report, the external

consultant review is the Longenecker -- or the L+A report, we will refer to it as -- that you would have received in or around April of 2012.

 MS. CARMICHAEL: That is correct.

MR. DeROSE: So if I then turn you to Board Staff Interrogatory 94 -- that is the next one, page 3 of 3 -- this is where you provided a table with your contracts since 2006?

 MS. CARMICHAEL: Yes.

 MR. DeROSE: And on page 3 of 3, it is the contracts –- sorry, it starts on page 2 of 3. You will see it goes back to what is referred to as contract A that has been completed.

 And then on page 3 of 3, we have the -- so my first question is: Just in terms of the contracts H and I, those were negotiated in the third and fourth quarter of 2011. I take it that even though that was after your decision not to contract, that your previous answer was that you would suspend long-term contracting when the external consultant was reviewing, and that these two contracts were for immediate spot requirements; is that --

 MS. CARMICHAEL: We didn't -- we didn't create a new

procurement plan. We were waiting for that plan. But we still were executing based on the old plan, where needed.

 MR. DeROSE: Okay. And so then we have contract J. Would contract J have been executed pursuant to a procurement plan?

 MS. CARMICHAEL: I would assume, yes. I would have to check that, but I am pretty sure it was.

 MR. DeROSE: Okay. Could you check that? I want that by way of an undertaking for contracts J, K, L and M.

 MS. CARMICHAEL: Sure.

 MR. DeROSE: Were those contracts procured pursuant to a procurement plan?

 MS. CARMICHAEL: Yes, I could maybe give a little bit more information on that.

 In September of 2012, after the Longenecker report, Enterprise Risk Management, a supply chain organization that handles the procurement of nuclear inventories, presented a recommendation to our nuclear executive committee, and it was approved.

 So those contracts would have been based on that

presentation that happened after September 2012.

 MR. DeROSE: Okay. In that case, we don't need an undertaking; that is all that I was looking for.

 So these contracts, J, K, L and M, would have been executed after the L+A report was accepted, reviewed and was being implemented.

 So these are the procurements that we can assume were

undertaken in the context of the L+A report; is that

fair?

 MS. CARMICHAEL: That assumption is correct.

 MR. DeROSE: Okay. And so for the amounts purchased in those contracts -- so we will take, by way of example, contract J, negotiated in fourth quarter 2012, first delivery in 2013 for a four-year period, you have the quantity of the 385.

 That amount that you elected to purchase -- first of all, had you elected to reduce your inventory more aggressively? You weren't contractually obligated to buy the 385; correct?

 MS. CARMICHAEL: In Q4, 2012, before we entered into the contract, we would not have been contractually obligated.

 MR. DeROSE: So at that stage, I take it -- or is it fair for me to conclude that those contracts, J, K and L, were based on your assessment of the physical -- what you call the physical and the financial risk factors?

 MS. CARMICHAEL: Yes, based on a certain business plan for production.

 MR. DeROSE: Right. And am I also right that in entering into those contracts, OPG had made a decision that it would not reduce its inventory as aggressively as the L+A report had identified that it could be done?

 MS. CARMICHAEL: We basically said we needed to have 750,000 pounds on hand, because of the size of the delivery.

The size of the deliveries typically aren't small, and so to ensure that we were at a certain level, that if a delivery wasn't made -- because there are always risks to having deliveries made -- that we would have enough inventory on hand to continuously fuel our reactors.

 MR. DeROSE: I appreciate that. Let me try to put it a different way.

 If OPG had accepted the L+A report reduction levels as

presented by L+A -- so the very aggressive inventory

reduction -- you could have more aggressively reduced your

inventory by not purchasing as much in the contracts that were executed in 2012-2013?

MS. CARMICHAEL: It depends, because we don't just base it on inventory levels and physical limits. We also base it on price and -- price risk balancing for future prices.

 So it is not a "one or the other"; it is a "both" in terms of contracting. To ensure we have contracts out in the future with set prices to mitigate the risk of rising costs, we would enter into contracts too for that purpose.

 MR. DeROSE: I appreciate that based on the -- on your assessment of the physical and financial risks, you elected not to do it. I think my point is just simpler.

Had you -- had a decision been made that you would implement the L+A report, it could have been done?

 MS. CARMICHAEL: It may have -- if we did accept that, I believe it was 500,000 pounds, if we did accept that, our contracts in Q4 may have been different.

 MR. DeROSE: Okay. Thank you very much.

 One small question and then I am done. Board Staff Interrogatory No. 95 -- so that is the very next one -- in this response, Board Staff has asked you whether OPG's existing fuel contracts are consistent with certain L+A suggestions on how to contract, and one of the things that you respond in (a) is that OPG was unable to obtain termination for convenience provisions during negotiations for any of the contracts.

 Two related questions. First of all, can we assume from that that you did request or seek a termination for convenience provision, and it was rejected?

 MS. CARMICHAEL: I, again, wasn't the one negotiating the contracts. But when I asked that question, they basically said that they could not negotiate those termination clauses. So that there was an attempt, but they couldn't get that negotiated in the terms.

 MR. DeROSE: Okay. And do you know, either in your experience or in the experience of OPG that has negotiated these contracts sort of over a long period of time, is this something that, in terms of the industry-wide practice, termination for convenience clauses are not seen in contracts? Or is this something that OPG has just never managed to negotiate?

Do you know if any of your counterparts are able to do it?

 MS. CARMICHAEL: I don't know the answer to that.

 MR. DeROSE: Okay. Fair enough. Those are all my questions. Thank you very much, panel.

 MR. MILLAR: Thank you, Mr. DeRose.

I think we will take our afternoon break. When we return, Mr. Rubenstein, you had yourself down for about 30 minutes; is that -- I'm sorry, Mr. Garner.

 MR. GARNER: Yes. I think that probably will be correct. Maybe 45.

 MR. MILLAR: Let's return at 25 minutes to 4:00.

 --- Recess taken at 3:19 p.m.

 --- On resuming at 3:37 p.m.

MR. MILLAR: Welcome back, everyone. I think we will get started again.

So continuing now with the nuclear panel, Mr. Garner?

 MR. KEIZER: Sorry, Mr. Millar, before we proceed with Mr. Garner, there’s just one issue –- actually, it’s not really an issue, but just as a follow-on to the questions that Mr. DeRose had, I believe Ms. Carmichael had a comment she wanted to make with respect to the Longenecker recommendations.

 MR. MILLAR: Okay.

 MS. CARMICHAEL: So Exhibit F2, tab 5, schedule 1, page 12, bullet number 4, I would like to read into the record:

"Is OPG's target inventory policy for uranium concentrates consistent with other utilities' inventory policies?"

They recommended that OPG conduct an ongoing evaluation of its target inventory levels, based on an assessment of the potential risk of its reactors being shut down due to uranium concentrates supply shortfalls.

 MR. MILLAR: Thank you.

Mr. Garner?

 **QUESTIONS BY MR. GARNER:**

 MR. GARNER: Thank you, Mr. Millar.

My name is Mark Garner. I am a consultant with SEC on this case. I am going to try and be as quick as I can, and hopefully we will move through this in due course.

 The first interrogatory I would like you to bring up is School Energy Coalition Interrogatory 77, which is Exhibit L, tab 5.5. It is page 74 of 81 of the PDF document, and it is to do with nuclear production forecast.

 MR. KEIZER: Sorry, Mr. Garner, what was the interrogatory number again?

 MR. GARNER: It is Schools 77, and it’s under tab 5.5, Exhibit L.

 MR. KEIZER: Thank you.

 MR. GARNER: If you have that interrogatory -- first of all, thank you for the answer. It is quite detailed and quite good. It is unfortunately not quite the answer I was expecting. Let me tell you why, and perhaps you can help me.

 In the interrogatory, what we asked was to find the

relationship between temperature and the changes in output, lake temperature and the changes in output.

And what you have provided is a number of -- what you are calling HLWT production losses, which is high lake water temperature losses.

 And the interrogatory response doesn't quite go to what I was hoping we would see. What I was hoping to see is, first of all, it appears that there is an average lake temperature from which there is a variance that you are

calculating.

 The first thing we would like to have seen is what that average lake temperature is, because as I notice from your response, every year has a production loss for lake temperature changes, which means it is a variance from something. So there is an average lake temperature.

 The second thing we were looking for was actually what the lake temperature forecast was that you were using in order to figure out what the production changes would be due to lake temperature changes.

 And the third thing we were looking for -- and you have tried to address, but it doesn't quite help us, and you tried to address through the graph you gave us -- was the relationship between that delta, the variance between the average lake change and your forecast, or average lake temperature and your forecast, and what you in essence multiplied that by to get you a production-level forecast change.

 Am I making myself clear? Do you understand what I am

trying to get to and see in this interrogatory?

 MR. WOODCROFT: Yes.

 MR. GARNER: Is it is it possible for you to provide a

response? I am sure you can't do it right now, but in an

undertaking that would give us that information, so that in

essence what we could see is what your forecast is for the lake temperature and how you then derive those numbers.

 MS. SWAMI: In calculating the losses for lake water temperature, we don't forecast what the lake temperature will be. We look at the historical performance and judge it based on that.

So we don't actually do a forecasting of lake temperature.

 MR. GARNER: Okay. I am a little confused, then. How is the loss, then, for 2014 then -- how would that be calculated?

 MS. SWAMI: So I think Mr. Woodcroft is going to provide a little bit more detail here. But what we do is look at the historical information and we judge, based on an historical performance, what we would anticipate in future.

But we don't go out and calculate or estimate what the lake water temperature is going to be in 2014, as an example.

 MR. GARNER: Okay.

 MR. WOODCROFT: That's correct. So we predetermine based on historical performance.

If you look at the table in the response, the actual HLWT production losses, you can see a trend going up from 2010 of 0.28 terawatts to 0.32 in 2011, to 0.40 in

2012.

 MR. GARNER: Correct, yes.

 MR. WOODCROFT: So in 2014 and in 2015, our forecast has lake water temperatures of 0.40.

 MR. GARNER: You mean production losses of 0.40?

 MR. WOODCROFT: Correct.

 MR. GARNER: So can I say it back to you? You're

extrapolating from that first table -- which goes from 2009, 0.30, to 2013, 0.26 -- you are extrapolating from that table to derive the 0.40 in the table below?

 MR. WOODCROFT: That is how we did it.

 MR. GARNER: I see. Thank you. Can you help me -- that suffices. Thank you. I see how you're doing the calculation.

 Can I ask you to explain a little bit more the explanation that is given right above that table? Which starts with:

"However, following review of past production losses, OPG determined it overstated production forecast due in part to the impact of HLWT and began to separately account for it in the production forecast."

 I was a little lost at what you were trying to say here. What happened with --

 MR. WOODCROFT: Basically, before -- I believe it was 2000 and -- I can't remember the actual date, before the date, we just incorporated in our forced loss rate. So basically we weren't accounting for it and thus losing the production in the forecast.

 MR. GARNER: Is that for both Darlington and Pickering, or just Darlington?

MR. WOODCROFT: Both. For both.

 MR. GARNER: Both? Okay.

 MR. WOODCROFT: So now going forward, we're using 0.34 at Darlington and 0.06 at Pickering.

 MR. GARNER: All right. Okay. Thank you.

I am now going to change areas and go to Schools Interrogatory No. 48, which is Exhibit L, tab 4.7, SEC Interrogatory 048. I believe it is at page 801 of the PDF document.

 In this table, what we're seeing is an update. You have provided an update from the 2013 budgets to the 2013 actuals for capital expenditures for nuclear operations.

 I just want to confirm on the record. That update for 2013 did not cause you to update your 2014 or your 2015 capital expenditures for nuclear operations; that's correct, isn't it?

 MS. CARMICHAEL: On this table, table 2 in the response, the only update was the 2013 actuals.

 MR. GARNER: Right. Thank you. And their difference is around $30 million, as I see it, between 2013 budget and 2013 actual.

 And my question is really this: Are none of the projects that were done in 2013 related in any sense to projects that were going forward in 2014?

 MS. CARMICHAEL: They could be, but I don't have that actual information because there's over 200 projects that we're doing at once.

 Basically, we reprioritize all of the time in our AISC management process. So we could be moving ones forward, and we could be deferring other ones.

 MR. GARNER: Okay. Thank you.

So it was your view, however, that the $30 million of overspending in 2013 will not have any impact on 2014's capital budget?

 MS. CARMICHAEL: That is correct. It will not adjust that.

 MR. GARNER: Thank you.

 I wonder if you could pull up Exhibit L, tab 4.7, SEC Interrogatory No. 49, page 802. So it is the next interrogatory, 802.

 And I think this may be just my misunderstanding. This is a question about contingencies, and I may be and must be reading the evidence incorrectly, so I will just try and clarify it with you.

 This interrogatory, if I read it correctly, indicates that contingencies aren't included in the budget amounts. That is the way I read the interrogatory; is that correct?

So when you are budgeting, you are not -- in the tables we're seeing -- the one, for instance, we just looked at -- we're not seeing a contingency dollar amount in those budgets?

 MS. CARMICHAEL: So there's a difference between a ceiling amount, a BCS amount and a budgeted amount.

 So our ceiling for each year is as per table 2, but as we do the BCSs, we incorporate a certain amount of contingency, which is what basically gets approved as a funded project.

 But in terms of giving a project manager a, quote, "budget," we do not allocate contingency to that project. We hold all contingencies in sort of a bit of a pot and reallocate those as needed or not needed.

 MR. GARNER: Right. I think I understand the purpose for budgeting and the purpose you are using it for. I wouldn't want to put words in your mouth, but incenting people to fall within their budgets.

 What I am still left unclear at is, if we take the table we just talked about, the contingency amount that is hidden -- let's call it for a minute -- from the operating people in the budget, is that included, though, in those tables that I am looking at? Will that money be in those tables?

 MS. CARMICHAEL: Yes. There is a ceiling that is set, which is those numbers on table 2, and we have to fall within that ceiling amount. And so when we're reallocating or allocating out contingency to a project, we're always balancing against that amount. So that would include contingencies, if we had to -- if we were using contingencies on a project.

 MR. GARNER: Thank you.

 So the interrogatory was trying to get those contingencies that I think you have indicated are actually included in the original -- in the table that we're talking about. We're trying to get an estimate of those contingencies in the overall budgets, to be able to understand the amount of contingency that was budgeted for at the highest level in those forecasts.

I am wondering if those can be provided.

 MS. CARMICHAEL: That's going to be difficult just because of the way our process works. We set a ceiling, and then we have even unallocated projects still, so we don't know necessarily what the contingency amounts of those are going to be. And it is always sort of moving every month or two in terms of what projects we're doing and what we're not doing and deferring, and what contingencies we're allocating on a monthly basis out of this pot.

So it would be very difficult to say: There is this much contingency on this project that makes up the 196 million for 2014.

 MR. GARNER: Thank you.

 Are you telling me, then, that if I looked at table 2, which is in your interrogatory just above -- we just talked about capital expenditures summary -- you would not know

for 2010 -- I will just take line 1, which is Darlington NGS, $33.8 million of capital expenditures -- you would not know -- as I understand what you told me, when that budget -- that's the actuals. There would be a budget amount for that, which would have been different than $33.8 million, I presume, because that is the actual, unless by coincidence the budget and actual meet.

 There would have been a budget amount, and within that budget amount there would have also been at some level a contingency amount, so that when the executives of your organization looked at that, they would be able to say: This is the overall budget, and this is our contingency for that budget that we're holding.

 MS. CARMICHAEL: In a BCS, that would be the case, but only in the BCS.

 MR. GARNER: But not rolled up to the level of Darlington NGS, Pickering NGS? Is that what you're saying?

 MS. CARMICHAEL: I would have to check the actual breakdown of the Darlington and Pickering allocated projects and see what exactly is in there. But for all projects that there's a lot of unallocated, as you see, for '14 and '15, I wouldn't be able to say what that is right now, but I could take a look at that and determine how much contingency is in those -- that 47 million or 13 million.

 MR. GARNER: I wonder if you would. I mean, the purpose of asking you this, really, is what we're trying to understand is, when you are budgeting, how much of your budget is budgeted as contingency, and then in fact how much contingency is required on a high level. Not at the low -- each one of the projects, but on a high level, and what I would -- what we would have thought your executive would look at.

So at a high level: We budget this area, we budget contingency this area, and at the end of the year we used up X amount of our contingency and therefore have some high-level understanding of how contingency is working in the budgetary process.

 Is it possible for you to, in doing that, try and help us understand that?

 MS. CARMICHAEL: I could give you an explanation of how we flow the contingency through and what makes up these numbers.

 MR. GARNER: I would appreciate, I think, whatever you could do that would help us understand that. Thank you.

 MR. MILLAR: JT1.21.

**UNDERTAKING NO. JT1.21: TO PROVIDE AN EXPLANATION OF HOW THE CONTINGENCY IS FLOWED THROUGH AND WHAT MAKES UP THE NUMBERS.**

 MR. GARNER: I am going to jump around a little bit, and this is a much easier question. This is SEC Interrogatory No. 58, and it is Exhibit L, tab 4.10. And it is on page 1,926 of the PDF document.

 And while you are looking up -- you may know this anyway -- this is about the Holt Bridge, and we asked a question about the Holt Bridge and the $31 million related to it.

 And the real -- the simple question in here was really whether -- why the municipality was not building this bridge or contributing to this bridge, and maybe you have a simple answer for that question.

 MS. SWAMI: So this project is actually being managed by the Darlington refurbishment team, and they would be in a better position to be able to answer that question for you.

 MR. GARNER: Okay. Thank you.

 Again, the question of clarification. This is on -- oh, this may be Darlington refurbishment also, or Darlington panel, but I will ask it.

 It's Schools Interrogatory 64, Exhibit L, tab 4.11. It is page 1,933 of 1,960, and it was really about how target pricing works. For the Darlington -- thank you.

 And the next one I would go to is -- sorry, I am just having trouble bringing it up. I believe it is Board Staff Interrogatory 48, which is at Exhibit L, tab 4.9. It's page 818 of 1,960. I believe it is this one, yes.

 And it's again -- it's -- while you are pulling it up, the question is relatively straightforward. There is a reference in this response, in (b), to the response to Board Staff that talks about partial in-service amounts. It says:

"OPG has added a column to identify the years where there has been a partial in-service amount for greater clarity."

 And I was left wondering about what that meant, because I know what an in-service is -- item is. But I was unclear as to what it meant to be partially in-service and whether the amounts that are shown in the column that is titled "Amounts in 2014 rate base" include anything that is described as "partially in-service".

 MS. SWAMI: So again, I would -- if you could just lift this up a little bit so I could see the bottom.

 MR. GARNER: To the -- sorry, go ahead.

 MS. SWAMI: Yes. So this actually -- there's a separate panel to be able to answer these questions more specifically, and so if we could -- if I could leave that.

 MR. GARNER: Yeah, I'm happy -- I'm -- thank you. We will move on quickly. I am happy to give it to the Darlington panel, and I'm sure they'll be -- corporate, sorry.

 MS. SWAMI: Actually, it is the corporate panel.

 MR. GARNER: Oh, that one's the corporate panel? Thank you.

 MS. SWAMI: Yes, it is at the bottom of the interrogatory.

 MR. GARNER: Right. Thank you.

I am just now trying to make sure that, as I look through these, I don't have the ones that were corporate or DRP.

 I can't see it on this interrogatory, so I will try you. And if it is not you, by all means tell me.

 I am on the interrogatory Schools 47, and it is tab 4.7, and page 799 of 1,960.

 MR. KEIZER: Sorry, what was the number again, Mark?

 MR. GARNER: It was Schools Interrogatory No. 47, tab 4.7, and it starts at 799 of 1,960.

 MS. SWAMI: So we have that one.

 MR. GARNER: Thank you. The question really in this

interrogatory relates to the forecast, and the actual in-service amounts that are in the bottom of the table 1 that is attached to that interrogatory.

 If you go through that table, you will notice the 2010

forecast and the 2010 actuals; you have provided the two

numbers.

 And in each year, 2010 through 2013, there is a considerable difference between forecast and in-service amounts for each one of those years, and it varies from 20 percent, let's say, to even larger than 20 percent.

 I am wondering if you can help me understand what the

difficulty is in the forecasting that you are doing that causes so much error to continually occur in your forecast. That's the first part of the question.

And the next part would be: What, if anything, have you done to try and improve the forecasting that you are doing in the capital projects area of nuclear operations facilities?

 MS. CARMICHAEL: Okay. So referring to table 1, attachment 1, forecasting in-service additions is basically very complicated and difficult, because as projects get deferred and cancelled, that moves the in-service addition actual amounts.

 You will see that in 2011 versus -- the forecast versus the actual, the big difference there was the feeder repair by weld overlay, which is row 14.

 So we had forecasted a $40 million in-service addition

and ended up deferring the project -- actually cancelling the project.

And so things like that cause our in-service addition to be adjusted as actuals happen.

 In 2010, you will also see that we sometimes have additional cost expenditures on projects. So in 2010, actuals versus forecast, we had that issue on the ISTB project.

 And then in 2012, we also had a delayed maintenance facility, which changed those numbers.

 Now, the attachment we provided as part of the response had an error in the Excel file. The amounts in the 2012 forecast should total $49.7 versus $21.4 million.

 So we have basically deferred and cancelled projects. Projects that sometimes have to be deferred because of outage scheduling, they can only be done in an outage and in a certain window. Or if we're done and equipment is not available, it is out of service, we can't do that project.

 There's also unforeseen issues discovered during execution.

 We also have a process whereby we have to prove that an asset becomes available for service, and that criteria sometimes isn't met and the project is sent back to do some further analysis or further work.

 So all of those combined can create these differences. And the fact is we also have, like I said, a couple of hundred projects on the go.

 MR. GARNER: I guess what I'm looking for is: Is there anything that has changed recently that would give us comfort that the forecasts that are done for 2014 and 2015 would be improved from the forecasts that were done in the past?

Is there any business process, anything that has changed in the way you are approaching these in order to improve those forecasts?

 MS. CARMICHAEL: We are looking at in-service additions and putting together a process to vet them more closely.

 We also have a challenge of executing projects as well, in terms of the budgets, actually doing the projects, the doability. We have increased that in terms of with -- in certain IRs, we talk about it in terms of negotiating the ESMSA contract, where we can get more work done.

So those things should help us to forecast better, but again, like I said, it is very complicated and we have to make business decisions on projects based on business circumstances, what's going on, and they will impact in-service additions amounts.

 MR. GARNER: Okay. Thank you.

My last question isn't in the interrogatories. It is really in a reference to your -- in your filing. And that is Exhibit B-1, tab 1, schedule 1, table 2. And it's not necessary to bring it up.

It is actually called the "Prescribed facility rate base for nuclear," and you did a lot of updates in response to the Board Staff. I think it is Interrogatory No. 2, you did a number of table updates, but I didn't -- as part of the 2013 numbers that you provided, the actual 2013s.

But I didn't find this table, which is the rate base for nuclear updated. I may have missed it.

 If I did and you could point me to it, I would appreciate that. If I didn't miss it and you didn't update it, could you do that?

 MS. CARMICHAEL: Could you give us a moment, please?

 MR. KEIZER: Just if I could note on that, one, I think probably the question is better addressed to the corporate panel, which will deal with the rate base.

 But also, I think the decision is made by the company not to update the rate base for 2013 -- oh, sorry, 2014 and 2015.

I just want to clarify your question, Mr. Garner. Could you just repeat it again?

 MR. GARNER: I was looking for the update to table 2, which is the prescribed facility rate base. And if I hear your response, if that hasn't been done, it can be done for 2013, because that is the -- what's down there is the budget.

 I think the objection I have heard from OPG is to provide an update to 2014 and 2015's rate base.

 MR. KEIZER: That's correct. Just back to your question, you are looking for the update to 2013?

 MR. GARNER: Yes, which would be the closing rate base to 2013.

 MR. KEIZER: Yes, I believe we can provide that.

 MR. MILLAR: JT1.22.

 MR. GARNER: Thank you.

**UNDERTAKING NO. JT1.22: PROVIDE UPDATED CLOSING RATE BASE TO 2013.**

 DR. SCHWARTZ: Mr. Chairman [sic], I'm sorry, it's Larry Schwartz, Energy Probe. Could I ask a quick follow-on to this very exhibit?

 MR. MILLAR: Mr. Garner, are you finished in any event?

 MR. GARNER: I am, actually, and so I am fine.

 MR. MILLAR: Sure.

 DR. SCHWARTZ: I'm sorry, may I ask --

 MR. MILLAR: Did you put in an appearance, Dr. Schwartz?

 DR. SCHWARTZ: Yes, I did.

 MR. MILLAR: Thank you.

 **QUESTIONS BY DR. SCHWARTZ:**

 DR. SCHWARTZ: Because it came up in an Energy Probe interrogatory, could you take a moment, please, and explain the meaning of "cash working capital" as it is shown on line 4 of this -- of the rate base?

 MS. SWAMI: So --

 MR. KEIZER: I think that we should move that to the corporate panel. It is probably best to answer that as part of the finance.

 DR. SCHWARTZ: That's true, but it happened to be here, so...

 MR. MILLAR: If you would prefer that bumped, then that is what we will do, I guess.

 Thank you, Mr. Schwartz.

You've finished, Mr. Garner, so we are on to you, Mr. Crocker.

 **QUESTIONS BY MR. CROCKER:**

 MR. CROCKER: Thank you.

 Before I get started, can I ask you who created the -- or coined the expression "human performance event," and can I use that?

You're not going to answer that?

 MS. SWAMI: Yes. That was actually done by INPO, so that is something, if you choose to use it, that is where it came from.

 MR. CROCKER: This will be a bit scattered, because some of the areas that we were interested in have already been or partially have been canvassed.

 I want to start with Issue 4.7, capital projects, and I want to go to Exhibit 2-D [sic], tab 1, schedule 2, table 2. Yeah. It's 4.7, capital projects. It is Exhibit 2-D -- sorry, D2.

 MS. CARMICHAEL: D-2.

 MR. CROCKER: Did I say it the other way around both times? Dyslexic. Tab 1, schedule 2, table 2. And all we're trying to do here is to get a better picture of costs at Darlington and -- separate from costs at Pickering.

 And in line 3, can you please provide the part of the nuclear support division which is attributed or attributable to Darlington, and -- from 2010 to 2015? And the same thing for Pickering?

 MS. CARMICHAEL: Could you repeat the question, please?

MR. CROCKER: Yes. Could you -- what I am asking you to do is to break out the nuclear support division's costs and attribute them to Darlington and to Pickering.

 MS. CARMICHAEL: The nuclear support division costs are projects that are done centrally, that don't necessarily -- are work on a station. So they're projects done by engineering, maybe nuclear services, nuclear waste. So they're not -- they can't be attributed directly to a station.

 MR. CROCKER: Can any part of them be attributed?

 MS. CARMICHAEL: We don't -- we have not done an allocation methodology for these, but we can see if there is sufficient information to allocate and determine which projects are on -- which benefit Darlington or Pickering and then which ones don't.

 MR. CROCKER: Okay. Well, if you could do that, that would be better than nothing, sure.

 MR. MILLAR: JT1.23.

**UNDERTAKING NO. JT1.23: TO ADVISE WHETHER AN ALLOCATION CAN BE MADE BETWEEN NUCLEAR SUPPORT DIVISION PROJECTS THAT BENEFIT DARLINGTON AND PROJECTS THAT BENEFIT PICKERING, AND IF SO, PROVIDE DETAILS. AND TO PROVIDE THE SAME INFORMATION FOR MINOR FIXED ASSETS, TO THE EXTENT POSSIBLE.**

 MR. CROCKER: And I have the same question with respect to line 9, with respect to minor fixed assets.

 MS. CARMICHAEL: Okay. We will do that.

 MR. CROCKER: Thank you.

 MR. KEIZER: I think that we're going to have to just caveat that to some extent, because of -- depending upon the amount of work that is involved and the various aspects of that, you know, minor fixed assets or other things may be a significant number. So I think we will do what we can to provide the allocation, but we have to obviously look at it as to whether it is doable in an accurate or meaningful way.

MR. CROCKER: You will do what you can do, I guess. Thank you.

 I would like you to please turn to Exhibit L, tab 4.7, schedule 17. It is Schools Question 50. I am looking at table 4. And this is under the issue "In-service capital additions, nuclear."

And I am just looking at the total in-service -- well, maybe I will break it -- let's do total in-service capital additions.

 MR. KEIZER: Sorry, which table are you looking at?

 MR. CROCKER: 4.

 MR. KEIZER: Table 4?

 MR. CROCKER: Can you explain the reason for the difference between the budgeted and the actuals for Pickering in 2013? And I am going to ask you the same question, if you could explain the difference between the budget and the actuals with respect to minor fixed assets and why they dropped, or why it dropped.

 MS. CARMICHAEL: I am going to have to take an undertaking for that, or ask to be provided, because there's a lot of projects in those numbers, and I only have a certain amount of information with me.

 MR. CROCKER: Okay.

 MR. MILLAR: JT1.24.

**UNDERTAKING NO. JT1.24: TO PROVIDE THE DIFFERENCE BETWEEN BUDGETED AND ACTUALS AMOUNTS IN 2013 FOR PICKERING WITH RESPECT TO MINOR FIXED ASSETS AND EXPLAIN WHY IT DROPPED.**

 MS. CARMICHAEL: Could you also clarify for the record exactly what you want us to look at?

 MR. CROCKER: Yes. I just need an explanation of the

difference in the budgeted amounts and the actual amounts for 2013 for Pickering. It is just a large amount. There is a big difference, and I just wondered if you could explain it.

 MS. CARMICHAEL: So the difference between 53.6 and 94.9 million?

 MR. CROCKER: Yes, yes.

 MS. CARMICHAEL: Okay.

 MR. CROCKER: And similarly, the difference between 19.9 and 10.24 of minor fixed assets, also a big difference.

Okay. I am going to 5.0, "Production forecast," and the reference is Exhibit L, tab 5.5, schedule 1. It is Board Staff Interrogatory 65. And my question deals with planned outages, and you can see the interrogatory.

 And your response to (c) is that

"The practice was included in the 2013-2015 business plan, as there was one mid-cycle outage in 2013, another in 2014. The additional mid-cycle outage in 2014 and 2015 were added to address preventive maintenance concerns to reduce future forced outages to achieve OPG's 2016 target improvement in FLR to 5 percent."

 My question, the first question is: What was the targeted forced loss rate -- forced loss rate, I guess -- in 2016, according to the 2013-2015 business plan?

 MR. WOODCROFT: In the 2013-2015 business plan, we did

not have any forced loss rate for 2016. 2016 was not included in the plan.

 MR. CROCKER: Okay. Can you give us a table from 2010 -- from 2010 to 2013 for approved and actuals for that number, to give us a sense as to the significance of the answer to the interrogatories?

 MR. WOODCROFT: Just repeat the question. You are looking for the forced loss rate at the Pickering station?

 MR. CROCKER: Yes.

 MR. WOODCROFT: 2010 to 2013?

 MR. CROCKER: Yes.

 MR. WOODCROFT: Okay. Hold on, we’ll have to --

 MR. CROCKER: Board-approved and actuals, please.

 MR. KEIZER: What do you mean by "Board-approved"? Do you mean Energy Board-approved or --

 MR. CROCKER: I'm sorry, your forecasts.

 MR. KEIZER: Forecasts versus actual?

 MR. CROCKER: Mr. Millar --

 MS. CARMICHAEL: So what our actual forecast is versus

business plan for 2010 to 2013, a table?

 MR. CROCKER: Yes.

 MS. CARMICHAEL: We are just checking to see if it is in the evidence already.

 MR. CROCKER: I'm sorry. I thought you were going to say yes, and there was going to be an undertaking next.

 MR. WOODCROFT: Yes. If you would move to table 1 on

Exhibit E-2, tab 1, schedule 2, table 1, that takes us through the budget and actuals, 2010.

 MR. CROCKER: I'm sorry. Could you give me the reference again, please?

 MR. WOODCROFT: Sure. Exhibit "Echo" 2, tab 1, schedule 2, table 1.

 MR. CROCKER: Okay. Thank you.

 The reference is Exhibit L, to my next question, tab 5.5, it is AMPCO -- I'm sorry, schedule 2, AMPCO Question 26.

 And my question is: I don't mean to be pejorative in the way I am describing your business plans, but did the old business plan not take into account historical performance, when we're talking about allowances?

 MR. WOODCROFT: Yes, we've always considered historical performance.

 MR. CROCKER: Okay. Can you explain, then, the

increase in allowances in the new business plan?

 MS. SWAMI: So during the preparation for the 2014-2016 business plan, the senior management team looked at our performance over the last number of years and recognized that we had not met our production forecast for that period of time. We also recognized that we were again in that situation in 2013.

And so the senior team directed us to review the appropriateness of our production forecast, which we did undertake. And that, of course, the underage on our production forecast also resulted in a revenue deficiency, which we needed to recognize as well.

 And given that, we reassessed the production forecasts and developed our business plan going forward.

 MR. CROCKER: I would like to go to the next AMPCO question, please, which talks about Darlington.

It is 27, and you see at the bottom of the page where you have established that the old allowance is 0.50 terawatt-hours, and earlier on, in a couple of paragraphs above, above the graphs, you have 0.46 terawatt-hours.

 That doesn't make -- what's the total? I will ask another question afterwards, but what is the total terawatt-hours we're talking about here?

 MR. WOODCROFT: So just to repeat the question, you're

looking for the total terawatt adjustment for Darlington in which years?

 MR. CROCKER: For 2014 and 2015.

 MR. WOODCROFT: Just to clarify, for which business plan?

 MR. CROCKER: I could ask you for both.

 MR. WOODCROFT: Okay. So I can explain both, then.

 So on the 2013-2015 business plan, the fleet level

adjustment was 0.50 terawatts.

In the 2014-2016, we added an additional 0.46 terawatts to station-level contingency, not fleet-level contingency.

The total contingency would be 0.96 terawatts at Darlington in the 2014-2016 business plan.

 MR. CROCKER: So why then –- okay. Sorry. Could we go forward to AMPCO Interrogatory 33? And we're talking about the same issue.

 MR. WOODCROFT: Okay. I'm there.

 MR. CROCKER: Okay. The question we asked was:

"Please confirm the total allowance in the production forecast for 2014-2015."

And you said --

 MR. WOODCROFT: The nuclear fleet-level allowance for

Darlington in 2014 and 2015 is 0.5 terawatts, correct.

 MR. CROCKER: Right. And that is the right answer?

 MR. WOODCROFT: That is correct.

 MR. CROCKER: Okay. Can we go back to -- I'm sorry for, as I said, for jumping around a little bit. Can we go back to AMPCO Interrogatory 26, please?

In that interrogatory, we're talking about discrepancies, and my question of you is: Are the calculations that we see there update -- take it another way. Are you updating your calculations to take into account the discrepancies that are identified?

 MR. WOODCROFT: Sorry, you are going to have to further clarify that, because I don't understand the question.

 MR. CROCKER: Okay. In -- I am reading your response:

"During a review of the forced extension to planned outage days for Pickering, a discrepancy was found in the impact statement."

 And what I am asking you is: Is your revenue requirement work form taking into consideration that

discrepancy?

 MR. WOODCROFT: So the business plan and the tables provided here are correct.

 MR. KEIZER: Sorry, is your question, Mr. Crocker, that whether or not those differences in days somehow showed up in revenue requirement? Is that what you're saying?

 MR. CROCKER: Yes.

 MR. KEIZER: Probably what we should do is just take that to check.

 MR. CROCKER: Okay. And I am asking the same question with respect to the issues described in the next interrogatory, 27.

 MR. KEIZER: Why don't we just deal with that first undertaking, and then you can deal with the next question? Is that fair?

 MR. CROCKER: Well, it is the same question. One is -- 26 is Pickering and 27 is Darlington.

 MR. KEIZER: I see. Okay. I understand.

 MR. MILLAR: Yes. JT1.25.

 MR. WOODCROFT: So just to further clarify, on our IR only the days changed. The correct answer was 72.6 days, not 82.5 days. The terawatt-hours didn't change, so I don't believe there would have been an impact.

 MR. KEIZER: I guess that answers the undertaking.

 MR. CROCKER: Well, if I look at -- if we go to 27, you do, I think, suggest a change -- not a huge change, but a change -- in the terawatt-hours from 0.46 to -- I'm sorry, to 46, and not 49?

 MR. WOODCROFT: That's correct.

 MR. CROCKER: Do you still suggest there is no impact?

 MR. WOODCROFT: There would be on this one.

 MR. CROCKER: There would be?

 MR. WOODCROFT: Yes.

 MR. CROCKER: Okay. So do we go back -- do you need some time to let me know what the -- okay.

 MR. MILLAR: Is this part of JT -- this is a new JT1.25?

 MR. CROCKER: Yes.

 MR. MILLAR: Okay.

**UNDERTAKING NO. JT1.25: TO ADVISE WHETHER OR NOT THE ERROR IN PLANNED OUTAGE DAYS AND CHANGE IN TERAWATT-HOURS IMPACTED THE REVENUE REQUIREMENT FOR DARLINGTON AND PICKERING.**

MR. WOODCROFT: Sorry, just to further clarify, I think it was just in our breakdown. I don't think it has changed the totals, but we will check it.

 MR. CROCKER: Okay. Can you tell me, in light of the

answers to those questions, how you calculate terawatt-hours from days? Or vice versa?

 MR. WOODCROFT: We have a calculation out of our nuclear generation planning tool that we use. It is just a coefficient, just a straight number.

 MR. CROCKER: Okay. Can you -- I am told I don't need the number. That was good enough.

 I am at Issue 6.3, "OM&A nuclear," and the exhibit number is L, tab 1, schedule 1. It is Staff Interrogatory 2, and it is table 22.

 MR. KEIZER: Sorry, could you just give us back that again? It is tab which, sorry?

 MR. CROCKER: It is Staff Interrogatory 2, which is at Exhibit L, tab 1, attachment 1. And I am looking at table 22.

 And my question is: Can you add a column for budgeted to the columns -- for each of the columns?

 MR. KEIZER: I'm sorry, Mr. Crocker, I am just going to need the coordinates one more time, sorry. L-1-1?

 MR. CROCKER: Schedule 1. It is Staff Interrogatory 2, and it is table 22.

 MR. KEIZER: Okay.

 MR. CROCKER: And I'm sorry, though. I am going to ask a comparison question.

So you are also going to have to look at Exhibit F-2 -- well, let me ask the question in parts.

 What I would like you to do is to compare or explain to me the total outage OM&A 2013 actual of 277.5 million to the budgeted number of 311 million. And you can find that at F2, tab 4, schedule 1, tab 1.

 And the more I hear the references all day long, I wonder whether the same person created the references as the one who came up with "human performance event."

 MS. CARMICHAEL: Is there a specific question?

 MR. CROCKER: Yes. The question was: Can you explain the difference between the actual of 277.5 million and the budget of 311 million?

 [Witness panel confers]

 MS. SWAMI: The biggest change in 2013 was deferral of the unit 4 outage from the fall until earlier this year. So that's where the majority of that change comes from. That is a Pickering -- I'm sorry, Pickering unit 4.

 MR. CROCKER: Okay. Thank you.

 Same topic area. Board Staff Question 81, which is at Exhibit L, tab 6.3, schedule 1, once again, it is going to be a question about differences in price -- differences in cost, I mean.

 MR. KEIZER: Sorry, what was the interrogatory number, Mr. Crocker?

 MR. CROCKER: 81.

 MR. KEIZER: 81? Thank you.

 MR. CROCKER: I am reading your response. The question was concerning the execution of VBO, vacuum building outage, maybe outages.

And you say, at line 34, in the 2014-016 business plan the VBO execution is 84.2 million, with preparatory work of 11.8.

And then in (c) you say the most recently completed VBO at Pickering was in 2010 and the cost was 6.5 and 30.1.

 And the question is how –- and similarly, on the next page, you say the most recently completed VBO at Darlington was in 2009. And you give the prices for that, the costs for those.

 And I wonder if there is an explanation for the, in some cases, significant difference in these costs.

 MS. CARMICHAEL: So the VBO that was done in 2009 at

Darlington is significantly different than the VBO that is being done in 2015.

 In general, I will just talk about the different -- every outage has different scope in it. So in general, there's been scope additions for this VBO because it is actually a VBO/SCO outage in 2015, which is station containment outage.

 MR. CROCKER: I was going to say it took me forever to

remember what VBO is. And SCO is?

 MS. CARMICHAEL: Station containment outage. So the basic scope is that will be doing a pressure relief valve replacement, emergency service water piping replacement.

We are going to be doing odd and even electrical work,

whereas usually it is alternating. Station containment work -– sorry, station containment outage, which is going to add about 50 percent more work.

We also have first-time evolution work in this VBO, so we have never done certain work before.

 And also there is a 3 percent per year escalation

factored into the fact that it was six years ago that we did the last VBO.

 So those are generally the reasons why the VBO cost

structure for 2015 is different than the 2009.

 MR. CROCKER: Okay. Thank you.

 Can we go to Staff Interrogatory 77, please? And I am

looking at attachment 1, table 1, and I just have two silly little questions.

 MS. CARMICHAEL: Okay.

 MR. CROCKER: I am looking at lines 4 and 5, and I am

looking at 2013 actual in millions of dollars, and I wonder how you can have those two negative numbers.

 MS. CARMICHAEL: It is an accounting entry. It is basically a reversal of an accrual. And so there was a certain amount accrued at the end of the year that didn't come to bear.

 MR. CROCKER: Okay. If we could go to Staff Interrogatory 78, which is Exhibit L, tab 6.3, schedule 1, and I am at page 3 of 3.

 MS. CARMICHAEL: Would you go to the bottom of the slide, please?

MR. CROCKER: And toward the end of line 6, you say:

"Bruce Power's power pricing contract..."

I'm sorry. Are you with me?

 MS. SWAMI: I am just looking for which page.

 MR. CROCKER: Page 3 of 3.

 MS. SWAMI: Okay. Thank you.

 MR. CROCKER: Sorry.

"Bruce Power's power pricing contract with the OPA is not tied to the ONFA reference plan to reflect increased costs of nuclear waste liabilities. There are no provisions in the current lease term for OPG to recover directly from Bruce Power, increasing the nuclear waste liability costs."

 Are you familiar enough with the lease with Bruce Power to know whether any increases in nuclear liability costs are recoverable?

 MR. KEIZER: I think, Mr. Crocker, probably the appropriate panel is the corporate panel.

 MR. CROCKER: Okay. I have some other questions in the same area, so I will wait. You can let them know that I am going to ask the question, because they won't have the answer either.

 MR. BARRETT: They're going to refer it back to this panel.

 [Laughter]

 MR. CROCKER: I'm at Exhibit L, tab 6.3, Board Staff 82, schedule 1. Board Staff 82, page 1 of 2, and you can take a quick look at what is being discussed.

 My question is: Have you set a completion rate target for training? That is what the issue is here.

 MS. SWAMI: I'm not sure if we've actually set a targeted rate. What we have done is we have looked at what the industry completion rates are, and we used that to benchmark our performance.

 So in this particular case, it is somewhere in -- 60 to 65 percent is the normal completion rate in industry, and what we have seen over the last few years is we've been increasing from 45 percent to 59 percent in 2013, and we anticipate projection of 63 percent in 2014.

 So we're moving our performance to that benchmark level.

 MR. CROCKER: Do you incent completion?

 MS. SWAMI: I don't think I would call it "incent completion."

 This is a very difficult program. It requires a high degree of knowledge and understanding of plant operations. The people that become certified through the CNSC are charged with actually operating the nuclear reactor. So we expect them to have a high level of performance.

 The incentive, of course, is that on achieving that type of role in our business, that is a fairly significant role. And certainly the completion and successful certification itself is an incentive to most of the

individuals.

 MR. MILLAR: How are we doing for time, Mr. Crocker?

 MR. CROCKER: I have a bit left, but not a tonne. I am probably close to two-thirds through.

 MR. MILLAR: Okay.

 MR. CROCKER: For how long, Mr. Millar, would you like this to continue?

 MR. MILLAR: We had you for 15 minutes and it has been well past that, and there is still people to come following you. So I would ask you to move as quickly as you can.

 MR. CROCKER: See, as soon as you say that, the people

beside me say: Skip that, skip this one. Move on to this one. You don't realize the influence you have.

[Laughter]

 MR. CROCKER: Okay. I am at Exhibit F2-2-3, attachment 1.

 MR. WOODCROFT: Could you please repeat that one more time?

 MR. CROCKER: Yes. F2-2-3, attachment 1, and I am on page 9.

Before I ask a question, I want to confirm something because of past experience, Mr. Keizer. The top of this page says: "Business case Pickering 5.8 continued operations, OPG confidential."

I want to confirm that this is not confidential.

 MR. KEIZER: It is publicly available. If there is information that is confidential, I am assuming that this is the redacted version.

 MR. CROCKER: Okay. I am going to read a few bits and pieces of this, and then --I am going to move on, I'm sorry.

 You were very persuasive, Mr. Millar. We're done. Thank you.

[Laughter]

 MR. MILLAR: I had no idea I had such power as a

--

 MR. CROCKER: I didn't either.

 MR. MILLAR: -- bureaucratic functionary, but thank you, Mr. Crocker.

 I think we are on to Staff now. Mr. Chute?

 MR. KEIZER: Sorry, can I just get a sense from you, Mr. Millar, what kind of timing we have left? Our panel has been up there now for about two hours, so I just want to get a sense of how long you think you are going to be.

 MR. MILLAR: I think we're about 15 minutes or so. If it goes longer than that --

 MR. KEIZER: He held up five fingers.

 MR. MILLAR: Well, there is two of them.

 MR. KEIZER: I have one question of the panel. Are you good?

 MR. WOODCROFT: We're good.

 MR. MILLAR: If it goes -- we will check in in 15 minutes again if we're not close to done.

 Mr. Chute?

 **QUESTIONS BY BOARD STAFF:**

 MR. CHUTE: Thanks. I only have one question in one issue. It is Issue 5.5, the nuclear production forecast, and the question deals with the scheduling of the VBO -- or rescheduling of the VBO to 2015 from 2021. I'm referring to Exhibit N1-1-1, page 15, and further references are to Board Staff IR 67, AMPCO IR 032 and 030.

 In evidence, OPG states that, moving forward, the Darlington VBO from 2021 to 2015 --

 MR. KEIZER: Sorry, before you go into your question, can we just make sure -- you've got about three references there. I just want to make sure everybody has the three references.

 MR. CHUTE: Okay. There is evidence [sic] N1-1-1, page 15, lines 18 to 20.

 MR. WOODCROFT: Okay. I've got that.

 MR. CHUTE: And then the further references are IRs -- Board Staff No. 67, AMPCO Nos. 032 and 030.

 MR. ANDERSON: We need the issue numbers on those so that we can appropriately --

 MR. CHUTE: It's Issue 5.5.

 MR. ANDERSON: Thank you.

 MR. CHUTE: My first question is related to the evidence, line 18 to 20, and the response to Board Staff IR No. 67.

In the evidence, OPG states that:

"The 2015 VBO eliminates the need for the 2021 VBO, reducing the complexity and resource demands during the Darlington refurbishment project."

In the response to Board Staff IR 67, the response essentially repeats that statement.

 Now, this is a six-year moving forward of a complex project. Is that the only rationale for moving this project forward six years, is that it will reduce complexity and resource demands?

 MS. SWAMI: So that's not the only rationale for moving the vacuum building forward. That is one of the factors. We also looked at the change in the production. So going forward with this work that we're doing during this VBO/SCO will eliminate the need for any future SCOs, which essentially eliminates any -- so there was an SCO every six years and a VBO every 12 years. So we will be eliminating SCOs going forward for the remaining life of Darlington, so that we will only have a VBO every 12 years rather than this interim or mid-cycle, 12-year period. We won't have that SCO any more.

 So when we looked at that, there's a net present value of 48 million for that change.

 MR. CHUTE: That's subject to approval by the regulator, of course?

 MS. SWAMI: Yes. We anticipate approval. We have made a submission already for the approval. They have provided us the steps that we are required to take to demonstrate that this is an appropriate change, and once we get through the testing during this SCO/VBO combination, we anticipate approval.

 MR. CHUTE: Was the likelihood of near-term SBG conditions a factor in moving this forward?

 MS. SWAMI: It was not part of our calculation when we looked at the NPV.

 MR. CHUTE: Okay. So you have done some quantification in terms -- dollar terms of this reduced complexity in resource demands?

 MS. SWAMI: Yes.

 MR. CHUTE: And in answering AMPCO 030, OPG states that:

"The rescheduling of the VBO while Darlington unit 3 is under a planned outage will add 7.2 days to that unit's planned outage."

Is that correct?

 MR. WOODCROFT: It would have been an impact if there was an SCO.

 MR. MILLAR: Microphone.

 MR. WOODCROFT: Oh, sorry. That's the total impact for the VBO that is planned. There would have also been an impact if there was a station containment outage in 20 --

 MR. CHUTE: Okay. So -- but combined you have an extra 7.2 days from the planned outage?

 MR. WOODCROFT: Mm-hmm. Correct.

 MR. CHUTE: So is it safe to say that you can do a VBO with one station out of production on a planned outage and -- whereas the complexity of two stations -- two units out in 2021 added extra costs and complexity and therefore made it necessary to move that forward to 2015?

 MR. WOODCROFT: Just to clarify, to execute either a station containment outage or a vacuum building outage, you need all four operating units in a guaranteed shutdown state.

 MR. CHUTE: Okay. But then that would indicate that the impact on a production forecast, if you already had a planned outage, would be less then it would be if you were running at full operational capacity?

 MR. WOODCROFT: I don't follow the question.

 MR. CHUTE: Well, you have already got a planned outage in 2015.

 MR. WOODCROFT: Correct. Regular planned maintenance outage on unit 3.

 MR. CHUTE: On unit 3?

 MR. WOODCROFT: Correct.

 MR. CHUTE: So you are moving this forward to 2015 and --

 MR. WOODCROFT: No, we --

 MR. CHUTE: -- all the stations are out, but the impact on a production forecast where you already had a unit out is less --

 MR. WOODCROFT: The original --

 MR. CHUTE: -- than if you had all four units running.

 MR. WOODCROFT: Just to clarify, the original business plan for the last six years had a station containment outage planned in 2015. There would have been a station containment outage in 2015.

 MR. CHUTE: Okay. But if you are moving a VBO forward and that takes all of them out --

MR. WOODCROFT: The station containment outage also takes all of them out.

 MR. CHUTE: Okay. Did OPG consider rescheduling the VBO and the SCO to 2016, when unit 2 for Darlington is supposed to be out at the start of the DRP?

 MS. SWAMI: So consideration for whether we do this outage in 2016 -- I think that is the question that you are asking -- as a combination with moving into the refurbishment outage period, is that the question?

 MR. CHUTE: Yes. One unit is out in 2016; one unit is out in 2015. Is there any material difference between moving that to 2016 from 2015?

 MS. SWAMI: Yes. So we have, you know, looked at that as a potential scenario at a high level. And the issue there is that moving into the refurbishment outage, we need to be sure that we have all of the pieces in place, because a refurbishment outage is significantly different from a regular planned maintenance outage.

 So the planned maintenance outage would be based on the lifecycle management plan activities, inspections and the like, whereas the refurbishment outage will be the replacement of a large amount of equipment in the plant, plus all other activities. And that, in itself, will take a large complex organization.

 I believe that the Darlington refurbishment panel can provide a lot more detail on their outages.

And so on top of that, if you add in a very complex vacuum building SCO, plus an additional -- all of the units being out of service for that would add such complexity that we felt that the risk of doing that would be too great.

 We also need to complete the SCO every six years, so that would be a requirement, that we had a hard line on that SCO to make sure that that got done in this period of time, in the 2015.

So we would have had a further complication of approving an extension of that SCO to 2016.

 MR. CHUTE: Yet you were going to go ask the regulator to eliminate SCOs entirely afterwards?

 MS. SWAMI: Correct. But we would have had to complete the SCO in 2015, because that's the current regulatory requirement, to complete it every six years.

So we did it in 2009. In 2015, we were required to come back and do the SCO. We would have had to ask not only for elimination, but we would have had to ask for a delay in obtaining the information to seek approval for that elimination.

 MR. CHUTE: So any assessment of the probabilities of

achieving one or the other of those strategies higher -- higher to ask for elimination of the SCO or higher likelihood you would achieve that? Or a delay for six months to one year?

 MS. SWAMI: So I think the difference is with the elimination of the SCO, we are required to do certain testing during this SCO to demonstrate that it is acceptable to eliminate it going forward.

So this SCO is critical to obtain that information.

 If we, at the same time, asked for an extension to 2016, that would have been a more difficult discussion, I guess, or approval from the CNSC.

 MR. CHUTE: Okay. Thank you.

 MR. MILLAR: Thank you, Mr. Chute.

And last but not least, Mr. Ritchie.

 MR. RITCHIE: Thank you, Mr. Millar.

 I have a few questions. I will go in order, and I will start with 6.3, Board Staff 79.

MR. RITCHIE: Basically I am looking at table 1, which is on the second page of that interrogatory.

 And basically what you were doing there was you provided a table that showed the 2002 Board-approved, this Board-approved, versus the -- sorry, 2012 actuals.

 And you made the adjustments for the business transformation, and you showed a variance of $118.1 million, which is -- I calculate a variance of about 6.9

percent over the Board-approved amounts.

 I am just wondering if you can provide sort of some further explanation on the reasons for the drivers for this overage in the 2012 actuals versus the Board-approved.

 MS. CARMICHAEL: Firstly, the top part of the calculation shows that nuclear operations would have been about 160 million over.

 We -- due to the decision of the Board for the 90 million, we -- obviously there's a time delay between trying to exercise the 90 million cut to our budget. So, you know, we did take that into consideration and worked towards it, reduced our headcount. But there was still, you know, a challenge in meeting that disallowance.

 On the second part of it, through business transformation, you will also note that our corporate cost allocations went down. So we did some savings on that end, through also attrition of corporate-allocated folks. So you will see a reduction there, and that netted out to 118 million over.

 MR. RITCHIE: I will probably have to go back through other pieces of evidence.

 Moving on, I will move on to 6.3, AMPCO 43, and I am actually moving on to the second page of that interrogatory, and it is really the response to part (a).

I am just wondering if OPG could undertake to provide a similar table in response in part (a), basically comparing the 2013 actuals to the 2013 budget for these nuclear outage OM&A costs.

 MS. CARMICHAEL: I believe it is -- this would be in Board Staff 1, maybe -- 2. The tables that we were updating. We will just check that.

Yes. So that was the difference in actuals. It was

277.5 million versus a budget of 311 million.

 MR. RITCHIE: Sorry, maybe you could just say where you --

 MS. CARMICHAEL: Exhibit L, tab 1, schedule 1, Staff 002, attachment 1, table 22.

 And I believe we discussed that earlier around why there was a difference in those numbers, and we characterized it as being part of the deferral of the Pickering unit 4 outage.

 MR. RITCHIE: Okay. Yes. So I guess basically 22 gives the actuals; it doesn't give the budget. So you are not -- we don't have, like, the variance as we had here. But yes, I will take -- we will try to do the analysis and if there is further, it will be through the oral hearing, I guess.

 MS. CARMICHAEL: Okay.

 MR. RITCHIE: 6.3, LPMA 13.

 MR. KEIZER: What is the schedule number?

 MR. RITCHIE: Sorry?

 MR. KEIZER: What is the schedule number for LPMA?

 MR. RITCHIE: It is schedule 13.

 MR. KEIZER: Sorry. Thank you.

MR. RITCHIE: And I am looking at page 2 and the table 1 to that, and basically really looking at the last line of that table, where it is showing the percentage change in the labour cost per FTE, and showing, again, like, some, I guess, some downs and then ups and, you know, increases.

 And I am just sort of wanting to try and understand, really, what are the drivers for the forecasted increases in the labour cost per FTE.

Like, and I know basically you are going to have the contract agreements. You are probably going to have progression. But, like, I guess, business transformation. I don't know about your incentive plans.

 I am trying to get a better understanding of what really is driving what we're seeing, in terms of these year-over-year percentage changes in that table.

 MS. CARMICHAEL: Well, the plan is based on a certain assumption of labour escalation rates. I think there is an IR that explained what those amounts were.

 And so based on that, we would do a forecasted labour rate per FTE, so we calculate a standard labour rate and then apply it to the different FTEs, and that's how we come up with a forecasted, basically cost per labour -- per FTE.

 MR. RITCHIE: Okay. I think on this what we would like to have a better understanding, really, what is driving, what is contributing to what we're seeing in terms of these changes in the expected labour cost per FTE. You know, and again, it could be in terms of, like, percentage contribution to that change, and again, it can be on a best-efforts type of --

 MS. CARMICHAEL: Yeah, the real -- the drivers are listed there as overtime, incentive pays, fiscal years, adjustments, things like that. So it is based on a modelling of those costs.

 MR. RITCHIE: Well, but what I'm -- what I am trying to understand is really, what are each of those drivers contributing to that bottom line. So in other words, trying to disaggregate the amounts as to the contributors.

 MS. CARMICHAEL: I would have to get that information. I don't have that with me.

 MR. RITCHIE: Okay. Would you undertake to try and do that, even on a best-efforts --

 MS. CARMICHAEL: On a best-efforts basis, and within the time, I will try.

 MR. MILLAR: JT1.26.

**UNDERTAKING NO. JT1.26: TO ADVISE WHAT EACH OF THE DRIVERS ARE CONTRIBUTING TO THE BOTTOM LINE.**

 MR. RITCHIE: Okay. I am looking at 6.3, SEC 87, and that is schedule 17. And I guess really what I am just asking is, again: Could OPG provide the -- again, I was trying to look at this -- the 2013 actuals for the nuclear operations and the nuclear projects analogous to how it is shown against the second table, which is the 2014 to 2016 business plan in that response?

 MS. CARMICHAEL: I believe there is updated evidence on FTE amounts in one of the, I think, Board Staff 2 tables. Is there an FTE? I think it is table -- it could be... well, I will have to check.

 There may be a difference because of headcount in FTEs, so I would have to go and check that and reconcile those.

 MR. RITCHIE: Okay.

 MS. CARMICHAEL: We will provide you with the 2013 actuals according to this table.

 MR. RITCHIE: Sure. That should do.

 MR. MILLAR: JT1.27.

**UNDERTAKING NO. JT1.27: TO PROVIDE THE 2013 ACTUALS ACCORDING TO THE TABLE FOR NUCLEAR OPERATIONS AND NUCLEAR PROJECTS ANALOGOUS TO HOW IT IS SHOWN IN THE SECOND TABLE.**

 MR. RITCHIE: Okay. I will move on to 6.4, SEC 92. And this is basically where you provided the nuclear scorecards for 2010 and 2012.

 And I am just wondering, you know, whether the 2013 industry data is available, or when it will be available?

 MR. WOODCROFT: For some benchmarks we do have the 2013 results from the industry, but not for all of them yet. Our plan is to issue our benchmarking report in July of this year.

 MR. RITCHIE: Okay. Thank you.

 And my last question is on 6.6, Staff 97. So that, I guess, is Exhibit -- or schedule 1.

And going to the third paragraph of the response, it is basically saying that OPG expects to submit documentation to the CNSC at the end of March 2014.

 I am just wondering, did OPG make the submission to the CNSC?

 MS. SWAMI: Yes, we did.

 MR. RITCHIE: Okay. And is there any sort of any further update as to the timelines or the expectations from what is provided in this response?

 MS. SWAMI: So the schedule for that hearing is May 7th, and so it is proceeding through that process. There -- as we discussed earlier today, there's the CMD that the CNSC staff have filed, as well as our own filings for this, and we're proceeding through that process.

 MR. RITCHIE: Okay. Thank you. That is all my questions.

 MR. MILLAR: Thank you very much, Mr. Ritchie.

 Unless there is anything more, that concludes our technical conference for panel 2. And that concludes day 1.

Thank you, panel, very much for your patience today and your assistance.

 A reminder to all parties that we are starting at 9:00 a.m. tomorrow, and we are in the west hearing room.

 Mr. Keizer, are there any final matters?

 MR. KEIZER: Nothing from me, no.

 MR. MILLAR: Thank you. We are adjourned.

 --- Whereupon the conference adjourned at 5:16 p.m.

EB-2013-0321

Ontario Power Generation Technical Conference

Tuesday, April 22, 2014

ERRATA

Page 7, line 20 "Richard Ilsley" now reads "Roger Islely"

Page 25, line 20 "Eight to 80 percent" now reads "80 percent"

Page 46, line 18 "MS. IRVINE" now reads "MR. WILBUR"

Page 58, line 4 "Richard Ilsley" now reads "Roger Islely"

Page 71, line 25 "Spilling" now reads "Swelling"

Page 101, line 26 "Darling" now reads "Darlington"

Page 108, line 26 "excedence" now reads "exceedance"

Page 143, line 6 "ASIC" now reads "AISC"

Page 148, line 22 "comp" now reads "column"

Page 164, line 13 "246" now reads "to 46"