# ONTARIO ENERGY BOARD

| | | |
|---|---|---|
| **FILE NO.:** | **EB-2017-0049** | **Hydro One Networks Inc.** |
| **VOLUME:** | **Volume 2** | |
| **DATE:** | **June 12, 2018** | |
| **BEFORE:** | **Ken Quesnelle** | **Presiding Member and Vice-Chair** |
| | **Lynne Anderson** | **Member** |
| | **Emad Elsayed** | **Member** |

**EB-2017-0049**

**THE ONTARIO ENERGY BOARD**

**Hydro One Networks Inc.**

**Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022**

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Tuesday, June 12, 2018,
commencing at 9:35 a.m.

---

VOLUME 2

---

BEFORE:

| | |
|---|---|
| KEN QUESNELLE | Presiding Member and Vice-Chair |
| LYNNE ANDERSON | Member |
| EMAD ELSAYED | Member |

# A P P E A R A N C E S

| | |
|---|---|
| JAMES SIDLOFSKY | Board Counsel |
| MARTIN DAVIES<br>KEITH RITCHIE | Board Staff |
| GORDON NETTLETON<br>GEORGE VEGH | Hydro One Networks Inc. (HONI) |
| LISA (ELISABETH) DeMARCO<br>JONATHAN McGILLIVRAY | Anwaatin Inc., Energy Storage Canada (ESC) |
| SHELLEY GRICE | Association of Major Power Consumers in Ontario (AMPCO) |
| MICHAEL BUONAGURO | Balsam Lake Coalition (BLC)<br>Arbourbrook Estates |
| TOM BRETT | Building Owners and Managers Association, Toronto (BOMA) |
| EMMA BLANCHARD<br>ERIN DURANT<br>SCOTT POLLOCK | Canadian Manufacturers & Exporters (CME) |
| JULIE GIRVAN | Consumers' Council of Canada (CCC) |
| BRADY YAUCH<br>TOM LADANYI | Energy Probe Research Foundation |
| VICTORIA CHAI | Ontario Sustainable Energy Association (OSEA) |
| RICHARD STEPHENSON<br>BODHAN DUMKA | Society of United Professionals |
| MICHAEL McLEOD | Quinte Manufacturers' Association (QMA) |
| JAY SHEPHERD<br>MARK RUBENSTEIN | School Energy Coalition (SEC) |
| RICHARD STEPHENSON | Power Workers' Union (PWU) |

# A P P E A R A N C E S

| | |
|---|---|
| BOHDAN DUMKA | Society of United Professionals (SUP) |
| MARK GARNER<br>BEN SEGEL-BROWN | Vulnerable Energy Consumers' Coalition (VECC) |

ALSO PRESENT:

| | |
|---|---|
| JODY McEACHERN<br>STEVEN VETSIS | Hydro One Networks Inc. |

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

# E X H I B I T S

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

Tuesday, June 12, 2018

--- On commencing at 9:35 a.m.

MR. QUESNELLE: Good morning, everyone. Please be seated.

Mr. Vegh, I understand there is a few preliminary matters you would like to discuss.

**HYDRO ONE NETWORKS INC. - PANEL 1, RESUMED**

**Chris Lopez,**

**Frank D'Andrea,**

**Henry André,**

**Steven Fenrick; Previously Affirmed**

**PROCEDURAL MATTERS:**

MR. VEGH: Thank you, Mr. Chair. Just two. I am going to be addressing the pension and other benefits deferral account issue that we discussed at the end of the hearing yesterday, and as well, the witnesses will have a couple of corrections to the transcripts from yesterday.

MR. QUESNELLE: Okay.

MR. VEGH: With respect to the first issue, at the close of the proceedings yesterday, Mr. Chair, you referred to the treatment of these -- the post-employment benefits variance account. And as by -- for way of context, as you are aware, on June 7th Hydro One sent a letter to the Board requesting that this issue be addressed in this case, and as you are also aware, this is an issue in both the distribution case and the transmission proceedings, and at the close of the proceedings yesterday you indicated that the Board's preference would be to address this in the transmission case and asked if that would place any restrictions or constraints on the Board's ability to address this issue in that case, and you have asked me to consider that.

In our view I don't believe that it does -- that it would impose any restrictions. I think that mechanically the way to do that would be for this Panel to indicate that this issue is better addressed in the transmission case, and Hydro One would then coordinate withdrawing the issue from this case and ensuring that the issue is addressed in the transmission case by including that request for relief in the transmission case, that the decision apply to both transmission and to distribution, and that then the transmission panel would be as free to address whatever remedy it seeks to address, and just as this Panel has that discretion.

MR. QUESNELLE: Why don't we do that by way of response to the letter of June 7th, and then we will capture what we just discussed yesterday and today in a letter back to Hydro One, and that will put that in motion then.

MR. VEGH: Thank you, Chair.

And the other matter, as I indicated, is a couple of corrections to the transcript. So the witnesses have reviewed the transcript. There are some questions that are more in the form of typos, and we will just advise of those in writing instead of walking through them. But there are some where the panel might have misspoken or wants to correct a piece of the evidence. So I will ask them to do that now, and starting with Mr. D'Andrea.

**ERRATA:**

MR. D'ANDREA: Good morning. I have got three corrections I would like to point out. The first one is on page 15, line 17 of the transcript.

MR. QUESNELLE: You get to enjoy the photo artwork for a moment longer.

MR. D'ANDREA: Page 15, line 17. It's in respect of the figure of 63.5 million. The correct number should be 69.8 million, and I would refer to interrogatory I25.Staff.123, and then on the bottom of the page 2 you can add the numbers there to get to the 69.8, which is the correct figure.

The next one is on page 157, line 5. The sentence reads into that line "the amounts are not large and they are not consistent". The statement should read "the amounts are large and they are not consistent", so strike out the word "not" in line 5.

And the third one is on page 158, line 11. I will read the statement. It says "through our distribution system plan we will demonstrate that these are large recurring expenditures". Strike out the "non" in line 11. Thank you.

MR. VEGH: Thank you. And Mr. Lopez, I believe you have a correction as well?

MR. LOPEZ: I do. Page 103, line 28, the saving is 24.9 million. And then the second correction is on the next page, 104. Line 3 should read, instead of 118 million, should be 114.4. And that ties to our annual report that I was referring to yesterday.

MR. VEGH: Thank you. I believe that is all.

MR. QUESNELLE: Thank you, Mr. Vegh.

Ms. Girvan, I think you are up first this morning.

**CROSS-EXAMINATION BY MS. GIRVAN:**

MS. GIRVAN: Thank you. Good morning, panel. I'm representing the Consumers Council of Canada. So I'm going to be very brief this morning. I am just trying to get in my own mind trying to understand the sort of time line with respect to putting this application together and putting your plans together. So you filed in March 2017, correct?

MR. D'ANDREA: That is correct.

MS. GIRVAN: And that was based on your distribution business plan. Correct?

MR. D'ANDREA: That is right.

MS. GIRVAN: And the timing of that was undertaken throughout 2015 and 2016?

MR. D'ANDREA: It would have been the December 2016 business plan.

MS. GIRVAN: Okay. So it was developed through 2016.

MR. D'ANDREA: Correct.

MS. GIRVAN: Okay. And then you had a subsequent business plan that was approved by your board in December of 2017?

MR. D'ANDREA: That is correct.

MS. GIRVAN: And subsequent to that you updated your evidence on December 21st which included Exhibit Q.

MR. D'ANDREA: That is correct.

MS. GIRVAN: Okay. So I am just unclear, is the capital plan that you are seeking approval of now in this proceeding, is it a function of the previous business plan?

MR. D'ANDREA: It would be based on December 2016 business plan.

MS. GIRVAN: Okay. And that is the one that was prepared in 2016.

Can you explain to me what process you undertook in preparing Exhibit Q. In effect what I am looking -- I am looking for is how did you determine what specifically to update and what not to update?

MR. D'ANDREA: So I am just referring to Exhibit Q. I am just going through it. So we updated for the cost of capital parameters, which we indicated in our original application that we would do. And then there was some discrete items that we wanted an update for, so changes in our pension costs and post-retirement costs. Those would flow through.

And then what we want to do is give some -- the updated evidence -- or updated -- the actuals, but really wanted to focus on the veg management program, which is the one significant change in terms of the capital program.

MS. GIRVAN: Did you consider updating to reflect the new business plan that was approved by your board on December 8th, 2017?

MR. D'ANDREA: Just a moment.

I am advised by my colleague Chris that we did not change the business plan for distribution in 2017. So it was the same business plan, '16 and '17.

MS. GIRVAN: Oh, it is. Okay. Okay.

So you received a transmission decision on December 8th, 2017. Is that correct?

MR. D'ANDREA: Correct.

MS. GIRVAN: Can you let me know, in the context of that decision, does that impact at all your distribution operations?

MR. D'ANDREA: First of all, I think the decision was September, it wasn't December.

MS. GIRVAN: Sorry, yeah.

MR. D'ANDREA: -- the draft rate order was in December, is the latest.

MS. GIRVAN: December, yeah.

MR. D'ANDREA: And did it change our distribution plan?

MS. GIRVAN: Yes.

MR. D'ANDREA: No, it did not.

MS. GIRVAN: But it -- sorry?

[Witness panel confers]

MR. D'ANDREA: Sorry, could you just -- I want to make sure I got your question correctly.

MS. GIRVAN: I am looking to what extent -- you received the decision from the Board in September of 2017 with respect to transmission. How does that potentially impact your distribution operations, that decision?

[Witness panel confers]

MR. D'ANDREA: It doesn't affect the operations.

MS. GIRVAN: Okay. It is my understanding, though, that you also do a consolidated business plan, transmission and distribution, right?

MR. LOPEZ: Yes, we do.

MS. GIRVAN: Because essentially you are the same company, right? It's one company.

MR. LOPEZ: Yes.

MS. GIRVAN: I guess what I don't fully understand is if you get a decision on transmission, why that wouldn't impact what you're planning to do for distribution.

MR. LOPEZ: In terms of operating the company, it didn't affect the application. But we did make a couple of specific changes to our application that we had made concessions or agreed to certain outcomes in the transmission decision, things like executive salaries, which we have adjusted for here in distribution.

So we've done that. We present a distribution -- sorry, a depreciation study and we update for that.

So there are items that are very discrete and we can update our plan for that. Our consolidated plan reflects that. This distribution application reflects that also.

MS. GIRVAN: I am just trying to understand how you work. For example, if in transmission you had delays or there is some work that you didn't get done and you had more resources available, can you direct those resources to distribution? I mean, you're one company.

MR. LOPEZ: I think that is possibly a better question for the planning panel. They could tell you which resources will switch between the business units.

MS. GIRVAN: Okay. For transmission, you have a plan that is two years, a two-year cost of service?

MR. D'ANDREA: That is in effect for '17 and '18.

MS. GIRVAN: Okay. My next set of questions is regarding the capital factor, and I am not very good with numbers. So can you explain to me exactly how that is going to be calculated? I am having trouble getting my head around it.

MR. D'ANDREA: Do you want to go to the actual schedule? We can go back to -- it's Exhibit A, tab 3, schedule 2, page 6.

MS. GIRVAN: Just from a practical perspective, can you explain to me how this is supposed to work?

MR. D'ANDREA: Without the details of the numbers?

MS. GIRVAN: Yes.

MR. D'ANDREA: If you want to take the table 1, you can look at the table in half, for example. And let's keep the acquireds out of the discussion for a second.

MS. GIRVAN: Let's say you are preparing your application for 2019. Can you explain to me how you are going to arrive at that capital factor?

MR. D'ANDREA: What we do is -- so we are looking at the top part of the chart. We form the distribution system plan in this case, and it says what the specific requirements are for capital and supports our requirement for a revenue cap model, so five years' worth of forecasted costs.

Then what we do is we do simple math. We take the difference between the capital -- and I'll just call I broadly capital;, capital-related revenue requirement between 2018 and 2019, and there is a number there. That number in the particular chart I am looking at on line 12 is 42.6 million. So that is the additional capital we are asking for in that year.

That capital has a factor -- as a base of 2018 works out to, in terms of line 13, 2.84 percent. So 2.84 percent or 42.6 million additional capital in 2019 versus 2018.

Then what we say is because of the IRM formula in terms inflation minus stretch, that capital would have naturally progressed by that factor. So you have to reduce it so you don't double count. That is what line 14 is about. So as I say, take that double count out and you get to a net capital factor. It is really pure additional capital less what is already captured by the IRM formula.

MS. GIRVAN: So it is an increase to the revenue requirement, ultimately?

MR. D'ANDREA: Correct.

MS. GIRVAN: Based on that incremental capital that is not captured in the formula?

MR. D'ANDREA: Right.

MS. GIRVAN: Okay. Now...

MS. ANDERSON: Sorry, Ms. Girvan, before you go on, you said to leave aside the acquireds for a second. What then happens with the acquireds? Do they roll into that?

MR. D'ANDREA: Correct. So in 2021, the capital that is in the 2021, so the top part of the chart, the capital related to the acquireds is included in there, and then that forms the base for the next two years.

MS. GIRVAN: Can you explain that again, sorry, with the acquireds?

MR. D'ANDREA: What we do is we set up 2018 essentially as a cost of service. We use the formula for '19 and '20. Then in 2021, we layer on -- I will call it layer on.

MS. GIRVAN: You layer on the revenue requirement associated with the acquireds?

MR. D'ANDREA: Right. So there's a capital that's included in the top part, and there's the OM&A, which is more explicit there, 10.7 on line 10. So it is a layering on. And then the formula just continues for the next two years.

MS. GIRVAN: What is the 10.7?

MR. D'ANDREA: 10.7 is the incremental OM&A associated with the acquired utilities. That is line 10.

MS. GIRVAN: You are adding that to the revenue requirement of the company overall?

MR. D'ANDREA: Right, because the acquireds are coming into our entire distribution business.

MR. ANDRE: If I could just clarify? So line 1, rate base, so the number in 2021 that Mr. D'Andrea was referring to capital, it is that rate base amount that is shown in

2021 that includes the rate base associated with the acquireds.

So the rate base gets added to line 1 and then, as Mr. D'Andrea said, the OM&A costs associated with the acquireds get added as part of line 9.

MS. ANDERSON:  If I recall, that is in around 9 million in capital, ish?

MR. ANDRE:  That is why I wanted to clarify.  What you are adding in 2021 is the rate base that is associated with the acquireds.  I think it is in -- I don't have the exact figure, but the rate base associated with them is in the neighbourhood of 165 million, subject to check.  I know there is the rate base added.  What you referring to is the actual capital expenditures, which is different.

MS. GIRVAN:  But would all elements of the revenue requirement associated with the acquireds be included in that?

MR. ANDRE:  Certainly.  Once you add the rate base, the subsequent rows 2 to 5 calculate the return on debt associated with that rate base, the cost of return on equity, depreciation, income taxes.  So all of those lines would reflect the addition of the rate base.

MS. GIRVAN:  What about something like other revenue?

MR. ANDRE:  Yes, that would be reflected -- this table doesn't show external revenues, but that would be reflected in the external revenues.

MS. GIRVAN:  So that's the full -- all the elements of the revenue requirements?

MR. ANDRE: Correct.

MS. GIRVAN: Okay. So today we are in the middle of June, and I am guessing you probably won't get a decision in this case until sometime in the fall. A lot of complex issues. When do you plan on filing for 2019 rates?

MR. D'ANDREA: It would all depend on the decision, right? I guess if the decision comes out end of this year, it is capturing the foregone revenue for 2018. Then there's an effective date; we would look for the effective date. And then 2019 would have to be updated for the inflation factor, as well.

MS. GIRVAN: I think you discussed this yesterday. What is the formula on revenue associated with 2018?

MR. D'ANDREA: It is just the delay in the effective date.

MS. GIRVAN: What is that amount?

MR. ANDRE: I know we have an interrogatory response, Ms. Girvan, that asked for that calculation.

MS. GIRVAN: It is not so easy to find the interrogatories.

MR. ANDRE: I know. It has to do with...

MR. D'ANDREA: It is easy when you're...

MR. FENRICK: We collected the rider and I don't have that reference here. But certainly after the break, I can come back with that reference that specifically has the amount of the foregone revenue.

MS. GIRVAN: Has Hydro One considered at all not seeking recovery of that 2018 amount? Implementing rates in 2019 and leaving existing rates in place for '18? Have you considered that?

[Witness panel confers]

MR. D'ANDREA: We have discussed it. In reality there is a -- we have capital needs to meet our distribution system plan, and that is really driving 2018. The other element is the load factor. The load factor is significant in 2018. So if you look at the rate increase, about half of that is related to load as well.

MS. GIRVAN: Load forecast, you mean?

MR. D'ANDREA: Well, the change in load forecast.

MS. GIRVAN: Change in load forecast; okay.

MR. ANDRE: If I could just -- so the load forecast in '18 is significantly dropped from what was forecast in '17, so the resetting of load is a big contributor to the additional revenue that we require in 2018 because the load as currently approved for 2017 is significantly higher than as it turns out --

MS. GIRVAN: Do you know to date how your load is tracking, your load forecast, your actual load?

MR. ANDRE: To date in '18?

MS. GIRVAN: Yes.

MR. ANDRE: We have that information on a sort of month end --

MS. GIRVAN: Could you provide that, the most recent information?

MR. ANDRE: So I am going to be, as you know, Ms. Girvan, up here on panel 7 --

MS. GIRVAN:  Yup.
MR. ANDRE:  -- to talk about load forecasting and cost allocation and rate design.  So I think that is probably more appropriate to answer there, and I've taken your question, and as Mr. Quesnelle has pointed out, since I am aware that you are going to be seeking that information I will have that for you --
MS. GIRVAN:  I guess it would be -- it might be nice to have it ahead of time again, like...
MR. QUESNELLE:  Are you seeking an undertaking for that --
MS. GIRVAN:  Yes, please.
MR. D'ANDREA:  We will take the undertaking.
MR. SIDLOFSKY:  That will be J2.1.
**UNDERTAKING NO. J2.1:  TO ADVISE HOW THE ACTUAL LOAD FORECAST IS TRACKING TO DATE.**
MS. GIRVAN:  Just a clarification.  With respect to your Z factor, I know you are proposing $1 million.  Is your current Z factor 2 million?  I thought I saw that some --
MR. D'ANDREA:  Yeah, I am not sure, to be honest with you.  I mean, we've taken the 1 million to be compliant with the handbook.  That is what we're suggesting.  I don't have a reference for the 2 million.  If you do I can address your question.
MS. GIRVAN:  Okay.  I thought I saw it somewhere, but I'll probably never be able to find it again.  Could you undertake to find that, the current -- what is your current

Z factor materiality threshold?

MR. D'ANDREA: For distribution?

MS. GIRVAN: Yeah.

MR. VEGH: I believe the Z factors are in the filing requirements, and Hydro One has not developed a unique Z factor.

MS. GIRVAN: Okay. Are you aware that Union Gas currently has a materiality threshold of $4 million?

MR. D'ANDREA: No.

MS. GIRVAN: No? And OPG of around $10 million, I think, I believe.

MR. D'ANDREA: I know OPG does, yeah.

MS. GIRVAN: All right. Thank you.

And just quick -- briefly, if you acquire utilities in the term plan over the next five years, how is that dealt with in rates, if at all? Is it --

MR. ANDRE: In the next five years, it wouldn't be dealt with as part of rates. The only time that the rates for those new acquired utilities would come into play would be at the end of whatever rebasing period the Board approves for that particular application.

MS. GIRVAN: Okay.

MR. ANDRE: So it certainly within the next five years be a factor.

MS. GIRVAN: Okay. And so I guess what I am thinking about is what if you acquired utilities and you wanted to rebase those earlier? Could you do that?

MR. ANDRE: So now we are going into sort of MAADs policy --

MS. GIRVAN: Yeah.

MR. ANDRE: -- and I know that in the past we have a rebase for a period of five years, and the update to the policy actually allows a period of ten years before rebasing. So a utility needs a certain amount of time to be able to recover the cost associated with acquisition --

MS. GIRVAN: So there wouldn't be any circumstances in the context of this plan that you would bring new utilities in under a Z factor or anything like that?

MR. ANDRE: Not that I am aware.

MS. GIRVAN: Okay. And could you just briefly -- we asked -- I think we asked this in the technical conference, but I just wanted an update. What is the status of the elimination of seasonal rates?

MR. ANDRE: So again, we have a number of IRs with that. Right now the Board initiated a proceeding, a new proceeding, to look at the details of the elimination of the seasonal class. They have created a proceeding number, but we are still waiting on notice to communicate to customers and interested parties about that proceeding. We are waiting on the board in terms of the next steps with regard to that --

MS. GIRVAN: So since the interrogatories and everything else there haven't been any updates.

MR. ANDRE: No, there haven't been any updates from what we gave in the interrogatory responses.

MS. GIRVAN: All right. Thank you. Those are my questions.

MR. QUESNELLE: Thank you, Ms. Girvan.

Good morning, Mr. Brett.

**CROSS-EXAMINATION BY MR. BRETT:**

MR. BRETT: Mr. Chair, Panel.

Just a follow-up question to begin, panel. I guess to you, Mr. Lopez, from Ms. Girvan's questions. Are the -- do these numbers that you filed in this plan reflect the decision of the Board in the transmission case, Hydro One transmission case, with respect to taxes? You recall there there was a major decision by the Board where it directed -- and I am going to paraphrase, and I won't do this as well as my colleague Mr. Shepherd, but in any event.

The Board said to Hydro One, as I understand it, that some of the tax benefit that Hydro One transmission was claiming from the privatization should be allocated to ratepayers, and of course the context was the transmission case, but I believe, as I recall, the Board in the decision sort of divided up the amount applicable to ratepayers into a transmission ratepayer component and a distribution ratepayer component.

Now, does this proposal that you have put in reflect the Board's decision on that tax issue in the transmission case or not?

MR. LOPEZ: One second.

[Witness panel confers]

MR. LOPEZ: No, it doesn't. It reflects the position before that decision. That decision is currently in front of the OEB in a motion to review and vary, and that is following its course now. The first hearing of that has already occurred, and we are waiting on a decision. That decision would influence the outcome here as well. There is a separate motion to review and vary focused purely on tax. It is focused on transmission, but when they made the transmission decision they looked across both, so we would expect it to be applied to both at that time.

MR. BRETT: Okay. So it is not in your current application.

MR. LOPEZ: It hasn't been adjusted -- the application reflects the full recovery of taxes at this point.

MR. BRETT: Okay. In a sense that is a little odd, isn't it, in that the Board has already made its decision? It is under appeal, but why wouldn't you -- why wouldn't you have put in the Board's decision? Why wouldn't you have reflected the Board's decision, given they've already made a decision?

MR. LOPEZ: They also accepted the -- they accepted the motion to review and vary to look at it. So we thought it prudent to leave it consistent for the time being until that decision is reached.

MR. BRETT: Okay. Could you -- Mr. D'Andrea, could you -- would you accept subject to check that -- give me a second here -- would you accept subject to check, Mr. D'Andrea, that the handbook, the rate handbook on which you base your application, does not contain any reference to a revenue cap plan? It contains reference to a price cap, a system IR plan, or an annual IR plan, but it does not contain any reference to a revenue cap plan except with respect to transmission, where of course because of the uniform transmission rate in Ontario the Board has said that a revenue cap plan could be utilized.

Would you accept that subject to check?

MR. D'ANDREA: Can I just check the handbook for a moment?

I was looking for a particular reference. At the top of page 6, the first paragraph says:

> "This handbook applies specifically to rate applications..."

MR. BRETT: The top of page 6 of the 2016 handbook?

MR. D'ANDREA: Yes, the top of page 6. So there it is on the top of page 6, and then it says in the second:

> "...which are intended to set rates for a multiyear period custom IR for the first year of a multiyear period price cap IR or revenue cap IR."

MR. BRETT: Where are you reading from?

MR. D'ANDREA: It is on the screen. It is the top of page 6 under section 4, the first paragraph.

MR. BRETT: I see that. Is it not the case that that reference is in fact -- the revenue cap part of that sentence is in fact a reference to a transmission?

MR. D'ANDREA: There is no reference --

MR. BRETT: This handbook covers both electricity transmission and distribution.

MR. D'ANDREA: I agree it covers transmission and distribution. But the paragraph is broader saying these are the options in terms of rates and options, and it is broader. It is multiyear custom IR and talks about differences between cap and revenue. There's nothing to do with transmission there.

MR. BRETT: If you look at page 23 of that -- turn up page 23 of the rate setting options, electricity distributors. Would you agree with me that under those paragraphs in 23 and 24, electricity distributors are offered three option: a price cap, a custom IR, and an annual IR index? There is no mention in those three paragraphs of a revenue cap.

There is a mention under the title "electricity transmitters" just below, that says:

> "Electricity transmitters may choose either custom IR or a revenue cap."

Now, I don't want to argue with you in this case at this point, but it seems to me they are making -- it seems to me that the three paragraphs that I read you, or that I referred you to under electricity distributors on page 23, are pretty clear that revenue cap is not an option for -- is not an option for an application for a distributor.

MR. ANDRE: No, I would disagree with your statement. In fact, if you read the description -- so the first option that is available is specifically labelled a price cap IR. The words "price cap" are right in the description of the first option.

The third option available is the annual IR index and again, in the describing that, they say under this methodology, rates are subject to the same annual adjustment formula as those under a price cap. So both in the first one and the third one, the reference to price cap is included in the definition.

If you read the definition of a custom IR, there is no reference in that description of custom IR to either price cap or revenue cap.

My understanding is that custom IR is leaving it open in terms of how you do it, and the only requirement is that they say that under this methodology, you set rates considering a 5-year forecast of both costs and sales volumes.

So as long as it does that, I don't think the custom IR is prescriptive as to whether you have to use a price cap or revenue cap approach.

MR. BRETT: You stated that a couple of times yesterday, and you sound like a Thomistic philosopher. But I am going to leave that at this point and move on.

I want to move on to a couple of questions on everybody's favourite topic, the capital factor. These are more of -- I would ask you to turn up the same table you were discussing with Ms. Girvan a moment ago. That is exhibit A, tab 3, schedule 2, page 6.

I won't go through all of these numbers because you went through some of them with Ms. Girvan. But I just have a couple of questions around the edge of this. The first of them is that your OMA budgets are escalated under your plan by the I minus X formula, am I correct? But it is just the I minus X. In other words, the capital factor is not applied to the escalation of the OMA budget.

MR. D'ANDREA: The OM&A goes up by I minus X, yes.

MR. BRETT: I minus X. And you talked about, at line 12, being the incremental revenue requirement which is driven by capital-related factors. That 40 million, 41 million, 58.6 and 41.3.

So the capital factor, as you explained a moment ago, is driven by essentially the increase in revenue requirement that arises as a result of the increase in rate base, correct?

MR. D'ANDREA: Correct.

MR. BRETT: It is capital driven.

MR. D'ANDREA: It is capital-driven.

MR. BRETT: The capital-driven part of it comes from the -- it is driven in essence ultimately by your capital expenditure increase over the period and the increase -- the concomitant increase in rate base, right?

MR. D'ANDREA: It is capital-related, yes.

MR. BRETT: The percentages that you arrive at, you explained how you got the 2.67 and 2.64, and so on, in line 13. And then you also explained that you had to reduce that because the 1 minus X factor had already taken some -- effectively raised revenue requirement from the capital side, correct? That is the 0.79, .80, .81 reduction.

I am talking about it sort of in a practical manner here. I don't want to get into a great argument about the metaphysics of this. But is that approximately right?

Let me maybe, just so we all understand, turn to page 7 for a moment, because this explains it better than I just did. Look at that first paragraph on page 7. It talks about the 2.67 increase in total capital-related revenue requirement. That is the number from page 6, correct?

MR. D'ANDREA: If I could...

MR. BRETT: Sorry, just answer my question, please, before you start.

MR. ANDRE: I was hoping to clarify something because I see...

MR. BRETT: I'm going to ask the question...

MR. QUESNELLE: Mr. Brett, there is a clarification that may be of assistance. I think we can allow it.

MR. ANDRE: I want to clarify that the evidence you are looking at -- I think you may be looking the pre-update. What is on the screen for the Board Panel and for interveners is the updated information.

So some of the numbers you are quoting aren't exactly the same, and I think that might by potentially creating some confusion. I think your principle is fine, but the actual numbers quoted are different.

MR. BRETT: Thank you for that. I apologize. So in other words, what you are saying is the 2.67 that I am quoting you from exhibit A, tab 3, schedule 2, is a number that has been updated to 2.84. It is confusing because you have several changes to your plan, and it is sort of a day's work just to keep up with the changes.

In any event, let me start with the 2.84 then. However, a 2.84 increase must be offset -- and this is the key concept I just want to make sure I've got right -- must be offset by the increase in revenue requirement that results from the application of the inflation and productivity factors, 1 minus X, of the RCI.

Here is the key point:

"This is done by determining the percentage of the total capital-related revenue requirement in line 8," and that is on page 6, "that is already provided for by the inflation and productivity factors."

So you do a little multiplication and division there to get the reduction of -- going back to my numbers of the -- to get the capital factor, you have to take away 0.79 percent from the 2.67 percent to give you 1.88 percent, correct?

MR. D'ANDREA:  That is correct.

MR. BRETT:  Now, the custom capital factor, you have defined it in different places, but the definition I wanted to read you, because I think it is the most -- it is the one that struck me as most useful, is actually at -- I don't think you have to turn this up, but you can if you wish.  It is your executive summary, A1, tab 1, schedule 1 at page 6.  I am just going to read you a four-line quote from that.  It defines a custom capital factor.  There it is.  Just look at the part under C.  Hang on.  You're right there. Definition of C:

"C is Hydro One's custom capital factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed distribution system plan, beyond the amount of revenue recovered in rates."

When you say "recovered in rates" do you mean recovered in rates -- what would be recovered in rates without the capital factor? Is that the idea?

MR. D'ANDREA: That is correct, because part of the capital is recovered through the I minus X, and that is --

MR. BRETT: So in a sense -- I mean, I realize there is some distinctions, but in a sense the capital factor is performing the same function in your plan as the ICM -- ARM/ICM construct performs in a price cap plan, correct?

MR. D'ANDREA: The Well, ICM/ACM would be different because they would be related to discrete capital projects. This is based on the revenue cap model, which says I've got multi-year large variable capital, and therefore it is meant to be formula-based. So it is not distinctly ACM or ICM.

MR. BRETT: It is interesting that you raise that, because when you say it is formula-based, as you say -- let me go back half a step. In the ICM, would you agree with me that in an ICM construct, number one -- and if you look particularly at the Alectra decision in this regard, which -- have you examined the Alectra decision? Are you aware of the Alectra decision?

MR. D'ANDREA: Yes.

MR. BRETT: Okay. I am not going to ask you the details of it, but the ICM construct, as you said, is based on the consideration of individual products, correct, in the sense that each project, each claimed ICM project -- or put it a little better, each project for which the applicant is claiming ICM financing has to be looked at individually by the Board, and the Board has to determine as they did in Alectra whether that particular project qualifies in the sense that, number one, it is material, and number two, it is important -- it is significant to the operation of the utility, and number three, it is discrete and not part of an ongoing normal utility program. Are you with me so far?

MR. D'ANDREA: So far.

MR. BRETT: All right. Now, that is the ICM. And as you are aware, I think, you could take subject to check, that in the Alectra -- recent Alectra rate case the Board approved some of the ICM projects but did not approve others. And if memory serves me, and my memory isn't always exactly right, but it is pretty good, the Board had something like 58 million of ICM projects in front of it and it approved approximately half. Is that about right, ballpark?

MR. D'ANDREA: I can't quote those numbers, but subject to check.

MR. BRETT: All right. Now, you mentioned that in this case the capital factor is formulaic, in the sense that it is -- if you agree to that, if the Board were to approve that, then you would not be looking at -- then the increase in the projects would be approved and you would not be examining each individual project. Is that the idea?

MR. D'ANDREA: We've got a five-year distribution system plan supported with investments. This is the purpose of the revenue cap model, is to review those individual. And if you look the handbook, it specifically says that the revenue cap index is supposed to be supported with a forecast of costs and volumes. So this is what we're doing.

In terms of your reference to the ICM model is, in a situation where there is a limited number of discrete projects, we've got a large and variable work program that covers five years, and that is why we have gone with a revenue cap model.

MR. BRETT: But essentially would you agree with me that you -- that in this circumstance you are not going to have the same level of examination of each individual project that you would have with an ICM model if the projects were being -- if ICM funding were being sought for the projects?

MR. D'ANDREA: The purview of the capital program is the distribution system plan. There you can see the five years' worth of forecasted costs in the individual projects. So there is visibility to that. What you are suggesting -- or I am not putting words in your mouth, but following an ICM model the Board would have to review the one or two or five or however many projects make up those and individually approve those. We're asking about a capital envelope that is based on a five-year projection of costs that's supported by distribution system plan that's been vetted through our consultants, AESI. That is how we support our capital program.

MR. BRETT: You are asking that they be approved for five years -- over the five -- for the five-year period in this proceeding, correct?

MR. D'ANDREA: That is the purpose of the application, yes.

MR. BRETT: I will move on a little bit. The -- just one last thing on this topic we have been discussing. So in the five-year distribution plan you don't break out the capital projects that you will fund from -- you propose to have funded from, if I can call it notionally, your base rates, the rates that you would obtain by applying the I minus X and the projects that you would require funding from the capital factor. You don't break those out into two categories, I take it, right? You don't distinguish or differentiate the two projects -- the type of projects -- two baskets of projects.

MR. D'ANDREA: I can't say for sure, because it is involved in the distribution system plan, but there again you will have the visibility on the projects that we're asking for. So are you -- so to clarify your question, are you asking in terms of the rate base that is brought in in

2018?

MR. BRETT:  Well, in the -- I am talking with respect to each year, but in two-18 I would ask the same question, whether they would be -- in 2 -- I take it you have identified the -- my question's applicable really to the entire five-year period.  It is a question of principle.  In other words, in the price-cap situation I think the -- and in the Alectra situation I think the Board basically said, among other things, that, you know, we would like you to distinguish what projects you are asking -- you are funding in your base rate in your I minus X and which projects you are going to seek funding for in your ICM.  But you don't do that in this case.  You don't have two baskets of projects.

[Witness panel confers]

MR. D'ANDREA:  So just to clarify, you are talking about the funding, what the distribution system plan does is starts with 2018 on a cost-of-service basis, so this is the rate base that is going in, and every year thereafter it shows what the forecasted project costs are, and so you have visibility to what those projects are on an individual basis from now in 20 -- to the end of the rate period, the five years, and you have visibility there.  So it is totally transparent what we are asking for.

MR. BRETT:  But to add to my question originally you don't distinguish each year those projects that would be financed effectively with recourse to the capital factor as opposed to in the base rates, the I minus X amount.

MR. D'ANDREA: But that's not the purpose of it. The purpose of the distribution system plan is to show those incremental costs every single year. The capital factor is math based on those projected projects. The distribution system plan supports the capital factor.

MR. BRETT: The capital factor is defined as an amount of additional -- is defined, as I understand it, as a factor that will, when applied to your capital-driven determinants of the revenue requirement -- it's a factor that when applied to that will raise sufficient additional income for your to finance your program.

MR. D'ANDREA: To meet the DSP requirements, yes.

MR. BRETT: Moving on -- and this is my last question, or very close to it. Could you turn up 7 VECC 3, please? I want to just read a passage from that and ask you about it because there is -- would you scroll down a little bit?

I want to look at the last paragraph. I do this because we had a lot of discussion yesterday on this and some of it, I believe, was contradictory. I would like to just pursue this a bit. I want to look at -- read the last paragraph:

"Price cap IR and revenue cap IR are equally capable," and I emphasize equally capable, "of continuing the transition to a fully fixed residential rates, eliminating the seasonal class, and accommodating changes to the rate design of commercial and industrial electricity customers over the custom IR term."

Hydro One listed these additional items -- this Hydro

One listed refers to the question, which is effectively why is a revenue cap plan superior to a price cap plan with respect to these various considerations. This response is stepping back and saying, no, no, they are equally helpful, these other -- for all of these things. And if you go over to the next, there another -- okay. Let's just stop there for a minute.

What that leaves is as the main reason, I think, for your preference for the revenue cap is that it makes it easier for digest or display, I guess, the acquisition of -- the effects of the acquisition of the three LDCs.

Mr. Andre, you spoke at great length about this yesterday. I am not asking you to repeat that. But what I conclude from this is that that is the principle -- that seems to be the main reason. Do you agree with that, with what I have said based on the reply to the VECC interrogatory?

MR. ANDRE: You are right, Mr. Brett. I think there was quite a considerable amount of discussion about this yesterday. As I indicated yesterday, the integration of the acquired classes -- as Hydro One is proposing where we creates six new classes -- does present a problem in terms of a price cap being applied for the integration of the acquired utilities, because you don't have rates in 2020 to escalate via a price cap for 2021. I would agree with you on that part.

And I would just clarify that, you know, yesterday I talked about how this response talks about it being more easily and more transparent to integrate the acquireds, and I emphasized that it actually goes beyond that in terms of the issues there are applying a price cap to the integration of the acquireds.

With regard to the second paragraph, just to finish off, I think we also discussed yesterday that reference to equally capable, and I emphasized that the transition to fully fixed rates I agreed revenue cap IR -- sorry, price cap and revenue cap are both equally capable of dealing with the transition to fully fixed residential rates. But I did indicate to the extent that eliminating the seasonal class or changes to commercial and industrial rates, to the extent that those items will involve a shifting of cost between classes making the existing rates that exist in the prior year unsuitable for the coming year, so to the extent there is cost allocation and rate design, the price cap would also be problematic.

So I backed off on the words "equally capable." I agreed that equally capable with respect to transitioning to fully fixed residential rates, but I do think that price cap could be a problem in the elimination of the seasonal class, or integrating the decision from the commercial and industrial rate design depending on what that comes up with.

MR. BRETT: You basically changed your evidence on that point.

MR. ANDRE: I clarified that -- I think I've given my answer. Equally capable applies to the first item, not so much to other two items, depending on how they are implemented.

MR. BRETT: Just on the addition of the LDCs -- and this is my last area really, a last question -- I want to make sure I understood the evidence from yesterday.

For the years 2018, 2019, and 2020, the numbers from the acquired LDCs, if I can put it that way a little crudely, they are not integrated in any way into this plan for those three years, correct?

MR. ANDRE: Yes, that is correct.

MR. BRETT: Okay. So then we look at 2021 and 2022 -- and you just went over this with Ms. Girvan, so I will be very brief -- but essentially what happens then, in part at least, is that the rate base of those three utilities, the OMA budgets and everything that derives from that are essentially added in to the numbers that you now have in your proposal. We are in that table 6 that we looked at a while back.

Is that right? That is how that works?

MR. D'ANDREA: Right. They are added in '21 and then in '22, the formula would apply.

MR. BRETT: Sorry. I take your point. I noticed -- I ask you to take this subject to check, but if you need to look it up, I have references.

Looking at those three utilities that you are going to bring in in 2021, the 2021 capex seems to be about $10 million, and the 2021 OM&A seems to be about $10 million. Is that about right? That is from page 23 of the business plan, of your business plan. It is also, I guess, in some other spots, but -- that is page...

MR. D'ANDREA: Could we ask for the references?

MR. BRETT: I am just looking for sort of a rough order of magnitude there. I am sorry, it is actually 25, page 25 of A31, attachment 1, which is your 2017-2022 distribution business plan. Those are aggregate numbers for 2021 for the three of them together, 10.7 million for OMA and 9.4 million for capital. Agreed?

MR. D'ANDREA: That is correct.

MR. BRETT: Then I think one of you mentioned that the rate base, the approximate rate base of 168 or something in that order. The question I wanted to just raise with you is when I look at those numbers and then I look at the numbers of Hydro One rate base capital OM&A, what strikes me immediately is those numbers are very, very, very small compared to the Hydro One existing numbers. I mean they, seem to be between one and two percent of the OMA budget or the capital budget, and I assuming that would translate roughly into the revenue requirement. So you are looking at somewhere between a 1 and 2 percent variation -- not just a rounding error, but not a large impact, correct, just as a matter of fact?

[Witness panel confers]

MR. D'ANDREA: Mr. Brett, if we go back to the table in terms of the acquired utilities, we're including the --

MR. BRETT: This is the number 6 at page 6, or --

MR. D'ANDREA: Do you want to go back --

MR. BRETT: Sorry, this is the actual numbers I gave you --

MR. D'ANDREA: Oh, we can use the numbers we used before, but let's talk about -- we can use the round numbers if it is easier. We are talking about 10- or $11 million we are adding in OM&A --

MR. BRETT: Right.

MR. D'ANDREA: -- and then 168, let's call it, in terms of capital, and so we --

MR. BRETT: Of rate base.

MR. D'ANDREA: Rate base, right? And let's say that translates into about 10 percent on your revenue requirement. So we're talking about 25 million or so in revenue that --

MR. BRETT: Revenue requirement?

MR. D'ANDREA: Revenue requirement. So we would view that as being material. So I would disagree with you that it is not material.

MR. BRETT: All right. So you are at something like 11 percent or something like that. All right. One last --

MS. ANDERSON: Sorry, just before -- Mr. Brett, before you leave that, I guess -- I guess I would like to have -- I think it would be helpful to have that number on the record. That was a rough estimate of revenue requirement compared to the overall total revenue requirement of the consolidated utility. Do you have that number?

MR. ANDRE: Yes.

MS. ANDERSON: I think he was saying -- Mr. Brett was saying between 1 and 2 percent, and I just want to make sure we are clear.

MR. ANDRE: I think if it would be helpful to summarize the revenue requirement that gets added as a result of the integration of the acquireds, I believe -- so what we could do is, it may already be an interrogatory response, in which case we would just point you to that, and if not, I think we could summarize that for you --

MS. ANDERSON: Okay.

MR. ANDRE: -- in an undertaking.

MS. ANDERSON: Sure, and whether or not Mr. Brett's estimate of between 1 and 2 percent was accurate at all.

MR. BRETT: Yeah, my estimate -- just the 1 and 2 percent, I was looking at the capital and the O&M. So I didn't really get into the mechanics of rate base, but I think an undertaking would be helpful.

MS. ANDERSON: Yeah, I guess I would find it helpful to know the revenue requirement of the three acquireds compared to the total, something like that.

MR. ANDRE: In terms of the revenue requirement, their addition to Hydro One, what that does to Hydro One's revenue requirement. No, I agree, Ms. Anderson --

MS. ANDERSON: Thank you.

MR. ANDRE: -- I think we should do that to be helpful.

MR. SIDLOFSKY: That will be J2.2.

**UNDERTAKING NO. J2.2: TO PROVIDE THE IMPACT OF THE THREE ACQUIREDS ON REVENUE REQUIREMENT.**

MR. BRETT: One last question, thank you, Ms. Anderson, this just to pick up on something from yesterday, and I wasn't too clear. You were saying that in 2021 you were going to make -- I thought I heard you say that that's the year that you integrate these utilities, these three LDCs. But I thought I heard you say you were going to make a proposal to the Board to change the cost of capital, and my question is, are you talking about changing -- do you mean there you are changing the ROE, the proposed ROE, from what it has been for the last three -- what it will have been for the years two-18, two-19, '20, or are you talking about something else?

MR. D'ANDREA: That is what we are talking about. So we would update for the ROE and the load in 20 --

MR. BRETT: The ROE. So the ROE in the first three years is a fixed amount or is it -- you are using the Board's amount?

MR. D'ANDREA: We are using the Board and whatever the Board determines in 2021, we would use that number.

MR. BRETT: Okay. So it's not any kind of a grand scheme to revise your approach to ROE. You are still taking the Board's annual ROE.

MR. D'ANDREA: That is correct. We are agnostic to it.

MR. BRETT: And -- you are agnostic as to the ROE; all right. Now then, Is there more to this proposal? I mean, Are you essentially saying that you are going to -- leaving aside that -- you have the proposal that's -- you have the information that is required to advise the Board of how you have integrated the three LDCs. I understand that. But are you saying you are going to go beyond that and amend your, what I will call your base capital numbers, your capital budgets for Hydro One as a whole or your OM&A for Hydro One as a whole, quite apart from the integration of the three LDCs for 2021 and 2022? I mean, is this a wholesale upgrading or retake on the entire proposal?

MR. D'ANDREA: Simple answer is no. If you refer to Interrogatory 13.CCC.15, it describes the process that we will go through, and we are not updating capital OM&A. Those are based on the forecasts that we have today. So the forecasts --

MR. BRETT: You are really just -- so what you are really doing is just making the changes that are necessary to accommodate the three LDCs.

MR. D'ANDREA: That is correct. So the three -- as we have talked about, we bring in the OM&A and the capital requirement and then we update for the cost of capital or the ROE and the load and we change the billing determinants at that time.

MR. BRETT: You are just changing what you're applying the ROE to, effectively, to base...

MR. D'ANDREA: Right.

MR. BRETT: Thanks. Those are my questions.

MR. QUESNELLE: Thank you Mr. Brett. Mr. Sidlofsky?

**CROSS-EXAMINATION BY MR. SIDLOFSKY:**

MR. SIDLOFSKY: Thanks, Mr. Quesnelle.

Good morning, panel. I am going to be asking about three areas this morning: Productivity improvements, density and service area, and capital plan inflation and assumptions. And if in any of those areas you think that another panel of witnesses might be better suited to answer those questions, feel free to send me over to that other panel.

We have filed or we have provided a Staff compendium, and I would like to mark that as Exhibit K2.1.

**EXHIBIT NO. K2.1: BOARD STAFF CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1**

MR. SIDLOFSKY: I took the liberty of putting hard copies up on the dais this morning.

MR. QUESNELLE: Thank you.

MR. SIDLOFSKY: Just one -- actually two comments on that. At the last page of the compendium there is a spreadsheet. I will get to that in the third part of my questions, but you will see it is a little difficult to read. For the purpose of cross-examination I have asked the Hydro One staff to make sure they use the Excel version of that so it will be a little easier for everyone to read on their screens.

The other thing is that I will tell you now that that spreadsheet was based on the original version of the Hydro One evidence. It doesn't reflect the December update, but for the -- so it doesn't reflect the Exhibit Q update, but for the purposes of our questions it is not actually the exact numbers that are at issue for us in the questions.

So if you would like to update the table with more current information, we can talk about that when I ask you about it, but I think you will find that the questions don't really require that.

So I would like to start with a bit of an introduction in my first couple of questions, but if we could open up page 4 of the compendium on the screen, please, page 4 of the compendium, which is probably page 5 of the PDF document.  Thank you.

Going back to OEB Staff Interrogatory No. 123, which is Exhibit I, tab 25, schedule Staff.123, and I will note that we have provided a copy of that interrogatory response in the compendium as well at pages 1 to 3 for your reference.

That interrogatory refers to table 17.  The detailed productivity savings forecast from your originally filed evidence, that was Exhibit B1, tab 1, schedule 1, section 1.5, pages 1966 to 1967.  In part A of that interrogatory Staff requested detailed calculations used to derive the projected productivity savings identified in table 17, and your response to that interrogatory noted that the updated evidence filed on December 21st of 2017 had included an update to your productivity savings forecast and that had been embedded into your business plan, and it provided a more detailed view of the savings initiatives and the associated assumptions used but no detailed calculations.

In part A, you were asked for -- you were asked for the detailed calculations and first of all, I am just wondering why those weren't provided as requested in the interrogatory.

MR. LOPEZ: We had interpreted the question to provide an outline or detailed outline of what makes up the productivity numbers. That is what we provided here, is the initial -- the groupings of productivity initiatives that form the basis of the numbers that we'd originally provided.

MR. SIDLOFSKY: I assume that is reflected in your explanations in the middle column of that table?

MR. LOPEZ: Yes. We explain what the measure is and how it is derived.

MR. SIDLOFSKY: But do you have the underlying calculations?

MR. LOPEZ: We would have a system that sits below this that tracks it by month, and it would be -- there may be more than one initiative in each -- like move to mobile, for example, there may be five or six subsets of that and we would have detailed calculations around those specific areas.

MR. SIDLOFSKY: So those would be activities within each of those initiatives then? So move to mobile is a more general category of work and there are individual projects within it? Is that the way it works?

MR. LOPEZ: Well, there could be more than one calculation. So move to mobile may affect more than one work group, and the calculation for each work group would be different. You could end up in an extensive number of calculations to get to that number.

But sitting behind that, we have a governance process that oversees this, that we now report externally and which is then subject to review. So we report that all the way up to the board. Our internal audit function looks over it. So we set out the measures that we use, we report on those all the way from the initiative all the way through to the board.

So the board would see a summary much like you are seeing here, maybe even a little more summarized than that. But at the management level, we would see all the detail. The supervisor, for example, would see the detail at their level, so for their work group, exactly what their target was, what they have achieved, and so on.

MR. SIDLOFSKY: So if I wanted to know what's involved in the move to mobile initiative, and I look at your table here and I see a description of labour hours per unit, historical baseline verses actual. And in 2018, I am seeing a $10.3 million forecast for savings from that project?

MR. LOPEZ: Yes.

MR. SIDLOFSKY: I can't see here what initiatives go into the move to mobile project -- excuse me, I should have said that the other way around. What individual projects go into the move to mobile initiative; maybe that is a better way to describe it.

MR. LOPEZ: For the detailed outline of move to mobile, so to understand exactly how they capture these savings, we worked out that at a high level, previously an individual may have done something paper-based or would have to go back to the office to report on something. Today they don't have to do that. So we allocated a baseline to that work for hours and then, to the extent those hours reduced for that work crew, then we would record those as a productivity savings.

That is one example of that. There would be more than one of those. The panel that could explain that the best and give you a subset of that, which we would have in detail for history, but for future planning, as you would appreciate, it's done at a very summary level. So it's not done all the way down to each work group, to each allocation.

So here we are showing the plan going forward. In the past, all that detail is available. For the future, it's more based on past history and applying it to changes in activity. So it is not detailed, as you are suggesting.

MR. SIDLOFSKY: But you do have a set of calculations that result in a $10.3 million saving?

MR. LOPEZ: We do.

MR. SIDLOFSKY: And those calculations reflect the individual components of that initiative?

MR. LOPEZ: It does.

MR. SIDLOFSKY: Could we have those calculations?

MR. LOPEZ: Yes, or whatever -- let me just clarify there, or whatever is available per the planning process. As I was suggesting before, the detail for the past is all based on actual, so it is very prescriptive. For the future in the plan, it is going to be much more summary level. So whatever is available in the plan at the calculation level we can make available.

MR. SIDLOFSKY: Understood, and I appreciate that.

MR. VEGH: Just so I'm clear, the undertaking is to provide the detailed basis for the move to mobile calculation?

MR. SIDLOFSKY: Well, no. I want the calculations for each of the initiatives. Move to mobile was an example. I think the panel understood that. Is that right, Mr. Lopez?

MR. LOPEZ: The volume could be quite a large undertaking on that. For one -- or if we pick the two or three larges ones and get most of the value, that could be done. For the smaller ones, again we could be looking at a lot more information.

MR. QUESNELLE: Mr. Sidlofsky, perhaps -- I think what would be of assistance is gaining an understanding as to how these are calculated and a narrative as to whether or not this is comparable. What I am getting at is is the methodology to ascertain what the savings have been and what they are projected to be similar for all these programs. And if not, then we will need more granularity would be informative.

But to the extent that a sample of the types of tracking on an initiative is replicated over and over again, I don't know that that, Mr. Sidlofsky, would be useful or of any additional benefit to have the entire data set.

MR. SIDLOFSKY: Thank you, sir. Perhaps, Mr. Lopez, what we could do is if you could identify the three largest initiatives. I think one would be procurement -- just looking at this quickly -- procurement, telematics, and move to mobile.

MR. LOPEZ: Agreed.

MR. SIDLOFSKY: Okay. On move to mobile -- actually, with all of them, you've got -- they fall into different categories, OM&A and capital as well. You will provide the information for each of those broad categories of expenditures, correct?

MR. LOPEZ: Agreed, for those three initiatives.

MR. SIDLOFSKY: Yes.

MR. VEGH: The undertaking is to provide the detail behind these numbers for the three initiatives we've discussed, move to mobile, procurement, and telemetrics, as well as the methodology for determining these calculations.

MR. QUESNELLE: Yes, I believe that --

MR. SIDLOFSKY: I think, Mr. Quesnelle, you were also mentioning the idea of -- or the question of whether those -- that approach is representative of the other categories.

MR. QUESNELLE: A narrative as to whether or not what we are seeing is the same approach used in other initiatives. If we are not going to have a sampling of each one and we're just going for the top three, how is that replicated in the other initiatives as well, just a narrative description of that.

MR. LOPEZ:  Understood, thank you.  We'll provide the undertaking.

**UNDERTAKING NO. J2.3:  TO PROVIDE THE DETAIL BEHIND THE NUMBERS FOR THE THREE INITIATIVES MOVE TO MOBILE, PROCUREMENT, AND TELEMETRICS, AS WELL AS THE METHODOLOGY FOR DETERMINING THESE CALCULATIONS; AND TO PROVIDE A NARRATIVE AS TO WHETHER OR NOT WHAT WE ARE SEEING IS THE SAME APPROACH USED IN OTHER INITIATIVES**

MR. QUESNELLE:  I must say, Mr. Sidlofsky, this is quite a large undertaking.  I am not talking about the magnitude of it, but the type of information that I think would have been better to form cross-examination on, as opposed to receiving subsequent to our hearing.

So I think that if this was something that you felt fell short of a full reply, it might have been better to raise this earlier in the process.

MR. SIDLOFSKY:  Thank you, sir.  I am going to take the panel to page 4 of the compendium, back to page 4.

The table at page 4 of the Staff compendium was prepared by OEB Staff, and it compares the productivity savings in the application as originally filed and in the update as filed in the interrogatory.

Those numbers were taken from Hydro One's response to Board Staff Interrogatory 123.  As I have mentioned, a copy of your response to that interrogatory is at pages 1 to 3 of the compendium.  Have you had a chance to look at those numbers?

MR. LOPEZ:  The numbers on page 4?  Are you referring to the numbers on page 4 of your compendium?

MR. SIDLOFSKY:  Yes.

MR. LOPEZ:  I have not.  I have put them in front of me now.

MR. SIDLOFSKY:  What they represent is a comparison of your savings forecasts for OM&A, capital, corporate common, and total categories, both as filed and updated.  So there are dollar-value changes and percentage changes.

Would you accept that those calculations are correct subject to check?

MR. LOPEZ:  I do.

MR. SIDLOFSKY:  Now, in part B of Staff interrogatory 123, Hydro One was asked how it would track these savings. And in your response you explained how productivity initiatives are approved and criteria are used to determine approval.

Hydro One then stated that productivity achievement is reported to the executive leadership team on a monthly basis and it is included as a metric on Hydro One's team scorecard for management staff, correct?

MR. LOPEZ:  That is correct.

MR. SIDLOFSKY:  At the bottom of page 4 of the compendium, the productivity savings relative to total OM&A and capital appear to be in the 5 to 7 percent range for 2018 to '22.  Would you agree with that?

MR. LOPEZ:  I need to provide one clarification.  That productivity savings that you referring to -- so let's just take one -- yeah, let's take 2018 as an example.  So in

2018 we are showing productivity savings -- I will use your numbers here -- 29.4 million. You will notice in 2019 the number goes to 33. So there is an incremental saving year over year of about $4 million. So that's the incremental change in productivity we are bringing to bear here. So just showing a $29 million savings on a total spend of 576 is not representative. The growth from last year's productivity would be about $4 million, somewhere in that order. The productivity savings we're showing here is versus a base line to 2015 unit prices. A lot of hard work and heavy lifting has already been done in the prior year and each year we are expecting another 4 or so million dollars of benefit. And that's what we can see as we move across the page. So 29 becomes 33, 33 becomes 40, 40 becomes 42. So some years grow a little more than others depending on when the initiative matures or when it is put into production.

MR. SIDLOFSKY: So the dollar values are cumulative savings then.

MR. LOPEZ: Correct.

MR. SIDLOFSKY: The dollar-value row represents cumulative savings.

MR. LOPEZ: Correct.

MR. SIDLOFSKY: Could you comment on whether an overall percentage of this kind, just looking at the percentages now, would an overall percentage of this kind represent a target or just a fallout from the initiatives? So just to put my question a little differently, did you target a certain percentage in productivity savings each year or did you stack up all your initiatives, consider how much productivity they would result in, and whatever the percentage that flows out of that just happens to be that percentage?

MR. LOPEZ: A combination of the two. There is no specific target. We like to consider all opportunities, and then depending on when they can be implemented, depending on timing outages, what work we have in the plan already, we would look at which ones could be advanced and which ones would need to be deferred or placed in a different year.

Overall, the goal is to try to offset inflation. That is the goal, to try to hold costs back. Beyond that is fantastic upside. You will notice in our 2016 year we didn't quite get to that number. In 2017 we had a large -- or a faster rate of growth, I would say. That rate probably -- or that size of growth is not sustainable forever, but we will find certain projects that lend itself to productivity.

The other part I will point you to is the productivity numbers that you see we report externally. So here we are reporting specifically on distribution. The productivity numbers we report externally include transmission, and they are more lumpy. So it depends on what transmission projects are in play, how many projects you are doing in one year, and that really puts the productivity numbers up and down.

So our corporate numbers can go up and down by a large number depending on our activity. Distribution I would expect to stay fairly steady at the rates that you're seeing here. OM&A, 4 million per year. If I looked at that, that's just slightly under 1 percent on a total OM&A spend.

The other part I would point to is the success of last year was more on the OM&A side. There are things that we could action immediately. Capital -- you are going to see capital appear more over time. So you are going to see a swing from OM&A savings towards capital savings.

Over the long term, the savings should represent in equal weightings between capital and OM&A based on our spend. And in distribution you can see they are roughly equal. So I would expect them to equal out.

But if you looked at our externals, we did get a lot of productivity savings in OM&A last year that is not representative of how we spend. It is just representative of, it takes a while before those productivity initiatives get into capital projects. Once they're in there they will apply equally to capital and operating. Productivity doesn't discriminate between OM&A and capital.

MR. SIDLOFSKY: Did Hydro One consider any external comparators or studies when you determined your productivity savings targets, or was it strictly internally derived, that forecast?

MR. LOPEZ: Within each group they may look at -- so operations panel will speak more holistically to this. But

I do know that each area of the business will look at certain benchmarks and say where are we potentially more expensive than a comparator, and we know there is an opportunity there. So we try to dig deeper in those areas, not by target-setting, but more productivity, to say, look, there is a gap there, so let's identify more initiatives that could close that gap in some way.

So at a corporate level we are not overlaying and saying it has to be this number. We're really encouraging -- the idea is to come forward based on what each business unit sees that they can achieve.

MR. SIDLOFSKY: And in your response to part B of Staff IR 123, you advised the productivity initiatives must first be approved by your finance department, and you set out the criteria that department uses to review productivity initiatives. I will just point you to the four bulleted points on page 3. The criteria the finance -- sorry, are those four bulleted points the criteria that finance applies to the reporting of the results of the initiatives or are they the criteria for the approval of initiatives?

MR. D'ANDREA: So initiatives can start in the business. What we are suggesting is before we will count it as productivity, because we are reporting it externally and we are accountable, it does need to meet the four criteria seen here. So that is when we say it is a -- finance reviews it and approves it in that manner, it is approved to be reported on going forward. There are other initiatives that are going on within the business that don't form part of this productivity number. Because we can't validate it, we can't objectively measure it, it can't be audited. If those things can occur then we can't hold those numbers out externally on our financial reports. So in that instance we call them tier 2. They're still savings, but it is just -- it is not an objective measure, so we can't count them in this table. We refer to those as tier 2 savings. We still track them. It is just not reported on.

MR. SIDLOFSKY: Do you have a sense of what percentage of productivity initiatives might be rejected by finance?

MR. LOPEZ: I do not. What I can say is that my sense is that it is -- if they are brought forward and they have validity to it and are objective they will find their way through eventually. The faults usually where it doesn't go through is just simply that the productivity measure or the productivity unit can't be measured. So in those cases, there may be a small gain to the corporation or the rate base, but because they cannot be independently verified -- they will go ahead, but they will just not be reported here as part of productivity.

MR. SIDLOFSKY: So when you show the numbers for your forecasted productivity savings, those won't include the tier 2 projects?

MR. LOPEZ: It does not.

MR. SIDLOFSKY: Okay. In part B of your response, in your list of criteria applied to productivity reporting, the third bulleted item is -- says: "In line with Hydro One's definition of productivity", and then it goes on to say, in brackets, "(hard savings and not cost avoidance)."

Can you give one or two examples of how you would distinguish hard savings from cost avoidance?

MR. LOPEZ: Yeah. So in regard to hard savings what we were talking about is we a plan, so what we're seeing here is a distribution system plan, and they have costs identified in there. So when a productivity project comes up or initiative, we want to see exactly what part of the distribution system plan will benefit from that, so which specific OMA area is going to reduce cost. Wood poles, for example. Let's use to move to mobile. If the unit cost of woods poles comes down, then we would reduce the budget for wood poles that year -- not the units; it would be the budget, the dollars, still have to get the work done -- and we would track that. So that's a hard saving.

If they came to us and said, oh, we found a risk and we are now offsetting that risk, but they can't change their budget, then we would not count it as a productivity saving.

They still have the obligation to meet their budget, so have to find another way to -- and we have other methods to do that around reallocating resources to different initiatives that we need to. Not productivity initiatives, but that would be the difference between a hard saving and cost avoidance. And cost avoidance typically would fall into a tier 2 again, where they say, look, I did this, it was great, but I can't commit to a reduction in my costs.

Well, if you can't, then we cannot record it as a tier 1 productivity saving, and you have would not be rewarded on that either in a tier 2 sense.

MR. SIDLOFSKY: Sorry, just to go back to what you said initially, a reduction in pole costs represents a productivity saving?

MR. LOPEZ: Yes, so the -- when we say a reduction in pole costs, I want to be really clear here. It is the reduction in the unit price of the pole. So to put up one pole, if it cost us $100 and now we have taken certain steps to reduce the cost of establishing a pole to $95, then that five-dollar difference would be a productivity saving. You have done something different to yesterday, but I am getting the same outcome. I am getting the pole installed at a 5 percent lower cost.

MR. SIDLOFSKY: Is that why -- in the more detailed update that you gave in part A to that response, one of the productivity initiatives was described as telecom services contracts, and the measurement and expected benefit was described as lower cost per contract -- it's a third to a halfway down on the table -- in OM&A.

Does that mean that any negotiated reduction in a contract price would be considered a productivity improvement, or are there particular reasons why that renegotiation, the telecom services renegotiation, would qualify and others might not?

MR. LOPEZ: Yes. So just resulting in a lower price, if you also delivered a lower volume or a lower quality of service, that wouldn't be productivity. So sitting behind it, there would be other reasons why a lower price in some cases would get in here and a lower price on others wouldn't.

If I'm at a lower price, but the quality of the service failed or something was changed, then that again would not qualify as productivity.

MR. SIDLOFSKY: Okay. Just one other item from that tabling table, engineering work team migration, and the measurement and expected benefit in that case is described as FTE reduction, a reduction in support staff that was utilizing the legacy software. Would that reduction in support staff be reflected as an absolute reduction in your overall FTE levels, or would support staff no longer required in that area just be moved over to other responsibilities in Hydro One?

MR. LOPEZ: It would have to be reflected in this case as a permanent reduction in that activity.

MR. SIDLOFSKY: That is the only way it makes into the productivity calculation?

MR. LOPEZ: Yes, if what you do is you re-deploy it. There could be a situation where another area could accept the reduction, they had a vacancy and a the person moved across to that vacancy. We would have hired from outside anyway, so that one potentially would count.

But we've got to see an absolute reduction in heads for that activity. That has to occur.

MR. SIDLOFSKY: In your December update in Exhibit Q, among other items you described a strategic change to your vegetation management program and that was included as attachment 2.

The executive summary of that report noted that your current maintenance cycle exceeds eight years, but the three-year cycle strategy proposed in this report will generate similar investment outcomes in one-third the time.

I am wondering why that new approach to vegetation management wouldn't show up as a productivity initiative in this table.

MR. LOPEZ: Panel 5 would be best able to answer why. What I understand -- at a high level, to provide some help -- is that the first cycle through, we are not going to see a reduction in cost. We are doing it over eight years, we weren't getting to everything in a timely manner. It is now going down to three. But the first three-year cycle -- the fist cycle through every area, we are going to get everything fixed, but it is going to cost the same price.

Future cycles will then be a lower price because we will have reset to this new version. But there is an amount of work that needs to be done to accommodate the new three-year cycle.

MR. SIDLOFSKY: You may become more effective, but it is not going to save you any money?

MR. LOPEZ: It is transition. I think the future -- you know, once we are one cycle through, the future cost of cycles will be a lot lower. That initial cycle to get through is going to cost more than what we see a future cycle would cost.

So we do see it as productivity, but it is just not showing up as dollars just yet.

MR. SIDLOFSKY: I am going to move to a different area, the density and service area. Just a few questions about your service territory, as Hydro One documents it.

I will take you to page 8 of the compendium, which will be page 7 of the PDF version -- excuse me, page 9 of the PDF version. Thank you.

That is attachment 1 from Anwaatin 1, which is exhibit I6.Anwaatin.1. So that's attachment 1 to your response to Anwaatin interrogatory 1, and specifically that is page 4 of that -- sorry, page 34 of that response. I understand that is from a presentation that Mr. Hubert gave to First Nations representatives. Is that right?

MR. D'ANDREA: None of the panel members recognize that, but we'll take it as accepted.

MR. SIDLOFSKY: Looking at page 34 of that presentation, we see Hydro One defining itself service area as 960 -- rounded to 960,000 square kilometres for its rural area, and 677 square kilometres for urban areas.

We can see that on the charts. Do you agree with those numbers?

MR. ANDRE: They are similar to numbers that I've seen as part of the annual triple R reporting that the company does to the OEB on an annual basis. So yes, they look familiar.

MR. SIDLOFSKY: The next page in the compendium was taken by OEB Staff from the Ontario Ministry of Finance website. You will see that the total area of Ontario is listed as a million -- roughly a million and seventy-six thousand square kilometres. But the land area is listed as just under 918,000 square kilometres. Correct?

MR. ANDRE: Yes, I see that.

MR. SIDLOFSKY: I appreciate that Hydro One does have some submarine cables and aerial cables that cross over lakes. But it's not clear to me how you explain how Hydro One defines its service area as greater than the land area of the province of Ontario. Can you give some explanation of that?

MR. ANDRE: I can tell you that the numbers that are reported for triple-R purposes and, as I say, are consistent with the table that you had on your page 8 are generated using our GIS graphical information -- or geographic information system, and that calculation would simply look at a total area.

They have a polygon -- it defines a polygon for our service area. So it would include any water bodies that are within that GIS polygon.

MR. SIDLOFSKY: I assume essentially what it does is it carves out LDC service areas, the local distributors, and whatever is left, you call your own. Is that right?

MR. ANDRE: Yes, I believe that's the number that comes out of the GIS, yes.

MR. SIDLOFSKY: So that's going to include lakes, provincial parks, remote northern Ontario, all of that area?

MR. ANDRE: I believe it excludes area served by Hydro One remotes, but it would be treated the same as other LDCs. But yes, it would include all those other things.

MR. SIDLOFSKY: If we look at page 7 of the compendium, which is page 33 of Exhibit I6 Anwaatin 1, that is a map of Ontario's -- excuse me, that's a map of Hydro One's distribution territory. It appears from this that Hydro One shows all of Ontario as red, except for the service areas, municipally-owned, and investor-owned utilities.

So that's consistent with your comment a moment ago, isn't it, Mr. Andre?

MR. ANDRE: I agree that that is what it appears to show, yes.

MR. SIDLOFSKY: So I think we can agree that particularly in northern Ontario there are large areas of land that aren't serviced by Hydro One or by any community -- well, there is simply no communities there. Correct?

MR. ANDRE: The communities aren't there. If communities were to arise in those areas then I think the onus would be on Hydro One to serve them. But, yes, I agree there are large areas of northern Ontario in which there aren't any customers or communities.

MR. SIDLOFSKY: So currently you are not serving large areas of the province, northern Ontario at least.

MR. ANDRE: I don't have a specific familiarity with the extent of our distribution system. In generic terms I would agree with you that there are large areas of northern Ontario that don't have a lot of customers, but in terms of the specifics of the scope and extent of our distribution system I wouldn't have the details behind that.

MR. SIDLOFSKY: Any areas serviced by Hydro One remotes aren't part of this application. That's a separate entity.

MR. ANDRE: Yes, that is correct.

MR. SIDLOFSKY: There is also, I understand, a project underway by a consortium of Fortis and the Watay First Nations to build a transmission line into remote northern Ontario. Correct?

MR. ANDRE: I am vaguely -- somewhat familiar --

MR. SIDLOFSKY: I've included some material related to that on pages 10 to 12 of the compendium for your reference.

MR. ANDRE: Yeah, I'm -- as I say, I am somewhat familiar with this project, yes.

MR. SIDLOFSKY: And that will eventually connect many First Nations in the north that are currently reliant on diesel for electricity.

MR. ANDRE: Yes, that is my understanding.

MR. SIDLOFSKY: And Hydro One won't be the distributor -- it won't be the distributor for those communities, correct?

MR. ANDRE: That is correct. I believe Wataay, the company Wataay was the one that is taking on building this in this line.

MR. SIDLOFSKY: So given that, I am trying to get a better sense of Hydro One's real distribution service area. And the reason I am getting at that is because the issue of density did come up during the technical conference, and it came up in Dr. Lowry's evidence as well. So the issue -- and correct me if I am wrong, but my understanding of the issue is that despite serving around 1.4 million customers Hydro One's position is that its customer per square metre density is much lower than most U.S. rural electric cooperatives. I am not sure if that is a question for Mr. Andre or Mr. Fenrick.

MR. FENRICK: Right. Based on the GIS work that PSC undertook, that was the finding that on a square km per customer basis Hydro One was less dense than the average of the rural electric cooperatives. Now, there are certainly rural electrical cooperatives that are found to be less dense than Hydro One, and there's some that are more dense than Hydro One, and on average you are absolutely correct that Hydro One was found to be less dense than the average rural electric cooperative.

MR. SIDLOFSKY: Hydro One was found to be less dense than the average rural electric cooperative based on its service area, much of which is completely empty.

MR. FENRICK: Based on the service territory as it was defined from an external third-party source that we used -- we used Platts data to get the GIS coordinates of the service territories, and we used that consistent for the entire sample, and so we didn't modify that in any sort of way. We used that third-party vendor to define the service territories and use the data as it was presented to us.

MR. SIDLOFSKY: When you were looking at rural cooperatives in the U.S. did you find many with characteristics like this where significant portions -- I couldn't tell you what it is. I would ask you if you had a better sense of what it is. But significant portions of the service area are completely unserviced. Did you find many rural electric cooperatives that were similarly situated?

MR. FENRICK: Given that there are a number of rural electric cooperatives that were actually found to be less dense than Hydro One, they certainly would exhibit similar characteristics. Now, I don't know, and I haven't examined -- it would be pretty large to examine every rural electric cooperate, because remember, we are talking about over 300 utilities in the sample here. Whether there is large entire areas not being served or mostly not being served, but on a density basis there is certainly comparators within that data set.

MR. SIDLOFSKY: And I am not expecting you to go back and do that.

MR. FENRICK: Thank you.

MR. SIDLOFSKY: You are welcome. But I will ask a question in a different way. Do you have any way of more accurately calculating the area of the province that is actually served by Hydro One?

MR. FENRICK: Maybe if I could refer you to Exhibit I, tab 10, Staff 44, and I'll wait for that to come up. We go to our response. So the issue came up with, we did look at the kilometres of line variable, which is what PEG used in their research. And, you know, I think that variable is certainly -- should be considered as a variable. And we did consider that variable as well.

So the issue arises in my experience with working with the utilities is that data set that PEG is using, it is not consistent. Some utilities are reporting primary km of line. Others I believe are reporting primary plus secondary. And the differences can be quite large. And if you look at the annual change, I am just not comfortable using the km of line variable that comes from the data set that PEG has used.

If that was a consistent data source I would certainly be open to using that to measure customer density. But given the inconsistency in that data source, I just didn't -- I thought it would hurt the research integrity to include that measure, even though that could be a perfectly appropriate measure if the data was consistent. And I certainly did investigate it, and it is just -- it is not appropriate given the primary plus secondary issue, as well as PEG -- Dr. Lowry also mentioned in an IR it also is not consistent as far as reporting overhead line and underground line. And so given those two issues we went with a different source. And this is the only -- the Platts service territory source is the only source that I know of that provides the GIS folks with an overlay of the service territories in North America.

MR. SIDLOFSKY: I appreciate your answer. But just to be clear, I wasn't suggesting that you change your methodology for the purpose of answering my question, because I do understand that PSE and PEG have different approaches to this issue. What I am asking, though, is even based on the GPS approach that you used is there a more accurate way of determining the actual service area of Hydro One so that we are not dealing with huge swaths of empty land -- unserviced land?

MR. QUESNELLE: Can I interject? I am not -- because I am not clear, Mr. Sidlofsky. Is it on the record as to what the square kilometres that the Platts study landed on? Is it the same as or different -- substantially different than the rural service area that Hydro One is using that Mr. Sidlofsky brought us to earlier, the 960,000-odd square kilometres? Just, if they had an approach that wasn't just lifting the number, what did that approach determine, and is it different than the rural area that is claimed to be serviced by Hydro One?

MR. FENRICK: There was an interrogatory that addressed that issue. However, I am not exactly sure which one. It was in that ballpark of the 900 to 1 million km squared number. I would say in response I think you would be hard-pressed to individually carve out Hydro One and not make that same -- not take that same approach to the rest individually carve out Hydro One and not make that same --

not take that same approach to the rest of the sample. To the extent there are other distributors in the States that are serving areas that are mostly not being served, that maybe just have small pockets of customers or whatnot. There is no data set that could make a consistent variable to include in the model.

MR. SIDLOFSKY: Thank you for that.

Mr. Chair, I am aware of the time. I am over already. I have one more area which relates to the inflation assumptions underlying the capital plan.

Now, this may be the better panel to deal with it. If the panel tells me that it is better dealt with by the panel addressing the distribution system plan, I can wait for that, as well. Otherwise I would ask for the Board's indulgence for a few moments.

MR. QUESNELLE: Why don't you pose the question and then we will determine whether or not you're coming up after the break. We'll take the break either way, but let's determine that now as to whether this panel can address your questions or not.

MR. SIDLOFSKY: The line of questions here relate to the capital cost inflation that Hydro One factored into the capital expenditures and capital additions to rate base for the custom IR plan.

I will take you to page 24 of the compendium. In the middle of that page, which is from -- it is page 3 of Exhibit A, tab 3, schedule 1. At the middle of the page, there is a section 5.1.1, titled "budgeting assumptions."

And here Hydro One states that for 2018, Hydro One assumed a 2 percent annual inflation and cost escalators for construction, and OM&A expense growth of 2.5 percent and 2.2 percent, respectively.  Those assumptions are explained in further detail in section 2.1.2 of the DSP.

Now, this is about 2018, but it doesn't speak to the rest of the plan term, the four years from 2018 to 2022, correct?

MR. LOPEZ:  I think I can answer this one.  It is consistent across the planning horizon, so we hold it constant.

MR. SIDLOFSKY:  Okay.  Sorry, that is constant for both capital and OM&A?

MR. LOPEZ:  Yes, across all years in the planning horizon.

MR. SIDLOFSKY:  Okay.  If I can take you to the next page, the last page of the compendium -- and as I mentioned, if I could have the Excel version of that spreadsheet put up, please.  Thank you.

As I mentioned before, this spreadsheet was prepared by Board Staff.  It doesn't reflect the December update, but as I said, that is not really the point of the spreadsheet for the purpose of these questions.

So the spreadsheet was prepared based on tables on pages 6 to 8 of Exhibit A32, and that pertains to the custom IR plan.  It is also based on the table summarizing the customer and load forecasts at an aggregate level from E1, tab 2, schedule 1.

Staff did this because we weren't able to find the capital cost inflation that was assumed and factored into the capex and capital additions beyond 2018. Staff wanted to see what the growth in capex or capital additions relative to the growth in demand would be, and primarily the growth in customers.

Given that, Staff brought together data from the various tables and calculated the growth rates. Where Staff have done those calculations, they are highlighted in the spreadsheet here. Have you had an opportunity to look at these numbers at all?

MR. ANDRE: Yes, I did see this spreadsheet and look at the numbers when you sent them.

MR. SIDLOFSKY: The non-highlighted numbers are taken from your evidence. Can you confirm they are consistent with the values in your evidence?

MR. ANDRE: Yes, I can confirm that.

MR. SIDLOFSKY: Do you have any comments about the calculations shown in the highlighted rows, the Staff calculations?

MR. ANDRE: One thing that I did note is, for example, on the screen it is on row 16 and it is true whenever Staff calculated a percentage change. Our calculation of a percentage change looks at the increase in an amount over the prior year, and then divides that increase by the prior year's amount to come up with a percentage change. That is how the numbers that Hydro One produced were calculated.

I noticed that Board Staff appear to have calculated the percentage change using natural logarithms. I admit I am not a mathematician. I went online to see what the difference might be. It generates slightly different numbers when you calculate it on a natural logarithm basis. So that's what leads to some of the differences that you see.

But other than that, I was able to follow the calculations.

MR. SIDLOFSKY: I am told it was based on a standard logarithm approach. So you're right in the way you read those calculations.

MR. ANDRE: Right. And a percentage increase. I would just point out when Hydro One calculates the increase in capital over related revenue requirement for example, which is the row 7 if we are looking on the screen, and we say the increase in capital-related revenue requirement is 2.84 percent. That's simply the increase in capital divided by the absolute amount in the prior year. That is normally how I would calculate percent increase.

It ends up with a slightly different number if you use a natural logarithm.

MR. SIDLOFSKY: Okay. If I can point you to rows 20 -- excuse me, rows 16 and 13, row 16 shows annual percentage change in the revenue requirement. I won't read those across that row, but row 23 shows annual changes in customer account, so percentage growth in customers. The 2019 growth rate would be 0.67, 0.67 in 2020, 5.07 in 2021, and I assume that due to the integration of the acquired utilities' customers.

MR. ANDRE:  That is correct.

MR. SIDLOFSKY:  And then back to 0.65 percent in 2022.

MR. QUESNELLE:  Mr. Sidlofsky, is it possible to move the screen to the left-hand margin slightly.  It is coming up on the large screen, but on our monitors I can't follow the row numbers here.

MR. SIDLOFSKY:  Except for 2021, when the acquired utilities are being integrated, the annual percentage change in revenue requirement exceeds the growth in customers, correct?

MR. ANDRE:  Yes, that is what the numbers show.  The change in the amount shown on line 16 would be the change in revenue requirement including the capital expenditures, right, so including the capital factor.  And yes, those numbers are different than the percent change in customer account.

MR. SIDLOFSKY:  In fact, if we look at row 29 of that table, the annual percentage change in revenue requirement as adjusted for changes in customer growth are shown, correct?

MR. ANDRE:  That's correct.  That was the other thing that I did notice when I looked at this spreadsheet.  In row 29, you are translating the percent change in customer account to a revenue requirement impact.  Implicit in that assumption is that the impact on revenue requirement for us is completely driven by the change in the number of customers.

That assumption isn't correct, Mr. Sidlofsky. We have in our evidence -- in the rate design evidence, we actually have it. It is Exhibit H1, if we could bring that up, H1, tab 1, schedule 1, page 5.

This is the rate design exhibit and it shows how -- what happens to revenue requirement in 2019. The table that you are looking at there -- so column 1, that is our 2018 revenue requirement, 1551; it is the same number we have seen in other tables. And then in column 2, what you see there is the revenue that would be collected in 2019 if you use the 2019 forecast and 2018 rates.

So you can see that the 2018 revenue requirement under current rates collects $1,499,000, million dollars, and the revenue at those same rates but with the '19 forecast actually ends up collecting you only 1,498,000, so when you are looking at the impact on revenue requirement you can't just look at the change in number of customers. You have to look at -- because fixed revenue represents roughly 50 percent of the -- fixed rates, rather, represent about 50 percent of the revenue. We have a significant amount of revenue that comes from our general-service customers that is driven by the change in peak kilowatts, and then we have a significant component that is driven by the kilowatt-hour consumption.

So when you look at the impact on revenue from the 2019 load forecast, it is actually -- it represents a decrease in the revenue that we would be collecting at the 2019 forecast load.

So your assumption, going back to your other spreadsheet that, you know, .67 is the additional revenue that is being generated by the increase in customer count, when you translate that to line 29 and translate that number and sort of make a one-for-one correlation that this increase in customer count translates to an increase in revenue requirement, that is not correct.

MR. SIDLOFSKY:  Sorry, just if I could have a moment, sir.

So just moving on from there, in all cases, though, the customer growth adjusted revenue requirements, revenue requirement increases exceed 2 percent.

MR. ANDRE:  Yes.

MR. SIDLOFSKY:  And from your custom IR proposal OM&A is being adjusted by the I minus X formula, correct?

MR. ANDRE:  Yes, that is correct.

MR. SIDLOFSKY:  And in your summary model in Exhibit A-3-1, inflation is assumed at 1.90 percent and your X factor inclusive of the stretch factor is .45 percent.  So your assumed OM&A inflation is 1.45 percent, correct?

MR. ANDRE:  Yes, that is correct.

MR. SIDLOFSKY:  The revenue requirements, the sum of OM&A expenses, and the capital-related revenue requirement, that is depreciation, return on capital, associated taxes?

MR. ANDRE:  Yes, that is correct.

MR. SIDLOFSKY:  And from Table 1 of Exhibit A-3-2 it looks like capital-related revenue requirement might be about 60 percent of the total revenue requirement with OM&A

about 40 percent, roughly?

MR. ANDRE: I haven't done the math, but I will take your word for it.

MR. SIDLOFSKY: Okay. We will even let you check it if you want. You can take it subject to check.

And from Table 1 of Exhibit A-3-2 we have capital-related revenue requirement for 2018 of $915.1 million, with OM&A at 584.8 million. So the rough calculation is about a 60/40 split.

Capital-related revenue requirement increases over time as capital expenditures increase more than -- more so than OMA. Correct?

MR. D'ANDREA: That is correct.

MR. SIDLOFSKY: Okay. Now, if the revenue-requirement increase is above 2 percent and even above two-and-a-half percent year over year for most of the plan and your OM&A at about 40 percent of the revenue requirement is increasing at 1.45 percent, then my understanding is that your capital-relate revenue requirement must be growing at a higher rate. Is that right?

MR. D'ANDREA: On a year-to-year basis, yes, OM&A contributes less than capital does.

MR. SIDLOFSKY: Okay. So would you agree with me that the growth in the capital-related revenue requirement has to be much higher to give the increases in the aggregate revenue requirement, whether it is adjusted for the number of customers or not?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: Now, the increases in the capital-related revenue requirement or of the capex or capital additions in each year over the plan will reflect both the quantity of work as well as the inflation in capital prices. Correct? That is both for assets like poles and wires and for equipment and capital labour?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: Now, Staff haven't been able to determine what portion of the cap ex and capital additions are represented by changes in capital quantities or what is due to inflation in the capital prices over time.

Do you have the capital price inflation for each year of your custom IR plan beyond the 2 percent documented for 2018?

MR. D'ANDREA: Mr. Sidlofsky, we believe that information is in the distribution system plan, and I would refer you to panel 5.

MR. SIDLOFSKY: Okay. That probably covers my next question as well, which is whether the capital price inflation is different than the GDP IPI FDD. Would that be panel 5 as well?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: And, yeah, I think I will leave it at that. Thank you. I will direct the rest of my questions to panel 5. Thank you. And I apologize for the length of time, Mr. Chair.

MR. QUESNELLE: Thank you, Mr. Sidlofsky.

Why don't we take a break. And given that I think

Schools has about 90 minutes still booked, why don't we break until five after 12:00, those who need to grab a quick bite or snack or something, recognizing we'll probably be going 'til about 1:30. So why don't we take a little longer break now and then go right through and everybody will have a later lunch. Thank you.

--- Recess taken at 11:42 a.m.

--- On resuming at 12:10 p.m.

MR. QUESNELLE: Thank you. Please be seated. I have Mr. Rubenstein down, but is it Mr. Shepherd or Mr. Rubenstein? Mr. Rubenstein; thank you.

MR. RUBENSTEIN: Thank you very much, Mr. Chair. I will be splitting my cross with Mr. Shepherd. There are two compendiums that you should be provided with.

MR. QUESNELLE: I think we have them both.

MR. RUBENSTEIN: One says compendium of the School Energy Coalition, Panel 1 general, if we can get that marked.

MR. SIDLOFSKY: That will be K2.2.

**EXHIBIT NO. K2.2: SEC CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1, ENTITLED "COMPENDIUM OF THE SCHOOL ENERGY COALITION, PANEL 1 GENERAL"**

MR. RUBENSTEIN: While we're at it, the second is the compendium of the School Energy Coalition, Panel 1 PSC, if woe can get that marked.

MR. SIDLOFSKY: K2.3.

**EXHIBIT NO. K2.3: SEC CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1, ENTITLED "COMPENDIUM OF THE SCHOOL**

**ENERGY COALITION, PANEL 1, PSC"**

**CROSS-EXAMINATION BY MR. RUBENSTEIN:**

MR. RUBENSTEIN: Thank you very much. We will start with K2.1. I want to follow up on one thing that was asked yesterday -- and a bit this morning, actually. There was a discussion with Mr. D'Andrea yesterday, and I think he referenced the response to 4 Energy Probe 3, and this was a chart showing the bill impacts of the foregone revenue requirement if the January 21, 2018, effective date was approved, what that would look like. I think there was some agreement that it was high because you would be recovering that over the one year, or at least that is what the illustrated example was.

And what I took from the discussion that was had was essentially Hydro One -- that wasn't their proposal and they were -- I guess what I took from you, Mr. D'Andrea, and your response in those questioning is I guess we will see what happens about the best way to recover that. Do you are call those discussions?

MR. D'ANDREA: I do.

MR. RUBENSTEIN: Maybe I could just ask you a more specific question. What is the -- if we assume, based on where we are in the year until the time to get an argument and decision and rate order, the effect date is -- sorry, the implementation date for rates would be January 1, 2019.

What is the Hydro One proposal with respect to what to do with foregone revenue?

MR. D'ANDREA: Mr. Rubenstein, we currently don't have a proposal on that. We were on the assumption that we would get January 1st. We are late in this stage of the process, so we would wait for the decision and assess what would be the appropriate approach to that forgone revenue.

MR. RUBENSTEIN: Well, I want to ask you to -- the problem is that once we get to that point, we're done the discovery process. I am just trying to understand what the bill impacts would look like under different scenarios.

So maybe the best way to do this then is you can consider your views on this issue and for the last panel that deals with rate design and cost allocation, you could think about this issue and I will ask the same question to you.

MR. ANDRE: Sure. I can do that.

MR. RUBENSTEIN: Thank you. I want to begin by asking about the structure of the custom IR application and some of its features. I know there's been a lot of questions, and I am not going to retread on that ground.

How I understand the revenue cap index to work is you are building in -- you are rebasing the OM&A in 2018, and the OM&A will increase by the I minus X, correct?

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: What about the revenue offsets? Is that escalating every year in a similar way?

MR. D'ANDREA: Sorry, could you clarify what you mean by revenue offsets?

MR. RUBENSTEIN: You have external revenue that you deduct from the revenue requirement. I know we have been showing, I think it's Q1, there is the table that everyone has sort of been pointing to. I notice that other revenue is not on that, so essentially, revenue you bring in from specific service charges or other sources. I am trying to understand how that fits in.

MR. ANDRE: Other revenues, external revenues, are specifically forecast. We forecast quantities for the specific services that generate other revenues and the unregulated -- you know, joint use and other unregulated services that provide revenues. Those are specifically forecast for each year of the application and that is what is included in other tables that show the total -- that show the revenue requirement as well as had offsets to that revenue requirement.

MR. RUBENSTEIN: Why would that approach be appropriate and not like you've done with OM&A, where you take the 2018 amount and then escalate it by an I minus X?

MR. ANDRE: External revenues are revenues. They are not costs. Those are specific to the anticipated volumes for those items. So they are revenues, not costs.

MR. RUBENSTEIN: That would be -- your approach then would be different than my understanding of how Toronto Hydro did theirs, essentially since it was built into their price cap at their adjustment, my recollection is they did it -- essentially they had a -- whatever they base test year was, and then it was I minus X, or maybe it was just I for the following years.

MR. ANDRE: I am not familiar with the details of how

Toronto Hydro did it. I can confirm for Hydro One, there is an explicit forecast of external revenues for each year of the application.

MR. RUBENSTEIN: Okay. Let me ask you -- there was some discussion about the adjustments that you're going to be making and I think brought -- you discuss CCC.15 and I have provided that on page 2 of our compendium, that response. And at the bottom of that, it lists those adjustments.

So my understanding of what those adjustments will be is that for the year 20 -- going into 2021, what you will do first is you will adjust the 2021 and 2022. When you are bringing in the acquireds, you will also update the load forecast for those two years. Do I understand that correctly?

MR. ANDRE: Yes, that is correct. The proposal is to update the load forecast for all of Hydro One's customer base for 2021 and 2022.

MR. RUBENSTEIN: Then there is a discussion about a adjusting the cost of capital parameters as well for those two years, and I understand that is limited to the return on equity portion of the cost of capital. Correct?

MR. D'ANDREA: It is the ROE in 2021, and that stays fixed for 2022.

MR. RUBENSTEIN: So we're not updating the -- your long term debt?

MR. D'ANDREA: No.

MR. RUBENSTEIN: If I can ask you to turn to page 9 --

well, we start, I guess, at page 8 of the compendium. This the OEB rate handbook, and if we can turn to -- do you see that, I guess, on your paper copy?

So this is the rate handbook, and if we turn to page 9, you will see about in the third heading therein, it says "Specific considerations for custom incentive rate setting." Do you see that?

MR. D'ANDREA: I see that.

MR. RUBENSTEIN: If we can turn over, flip the page, page 26 of the handbook under updates -- do you see that further down? This is, I think, the last pullet point.

MR. D'ANDREA: I see that.

MR. RUBENSTEIN: It says:

"After the rates are set as part of a custom IR application, the OEB expects that there are to be no further rate applications for annual updates within the five-year term unless there are exceptional circumstances, with the exception of clearance and establishment of deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance, or sales volume."

Do you see that?

MR. D'ANDREA: I see that.

MR. RUBENSTEIN: You are seeking an update of the cost of capital and the sales volume for 2021 and 2022. Do I have that correct?

MR. D'ANDREA: In 2021, yes, a one-time update, not an annual update.

MR. RUBENSTEIN: Is there an exceptional circumstance that warrants that?

MR. D'ANDREA: Our view is that the integration of the acquired utilities, we have not seen anyone -- no other utilities have integrated utilities in the middle of a five-year rate setting mechanism, and we view that as the exceptional circumstance. And so to be fair to our customers, and going back to the IR that you referred to, we treat it from a fairness perspective that we would update the cost of capital and the load at that time.

MR. RUBENSTEIN: Can you help me understand what the -- bringing in the acquired utilities has anything to do with updating the cost of capital? What is that -- what's the linkage there?

MR. ANDRE: So Mr. Rubenstein, in response at Exhibit I, tab 7, schedule CME 1, we specifically dealt with the update to the cost of capital, the proposed update to the cost of capital. In part B of the response you can see there that we point out that some of these utilities haven't been rebased in quite a long time. Woodstock, their last time they were rebased was 2011.

And so this being -- 2021 being the first time that they are being rebased, we wanted to ensure that we are accurately capturing the cost associated with serving those utilities so that both the cost of serving those utilities plus the cost of serving all of the other Hydro One customers in order to ensure that when we go through the cost allocation step and assign the costs to the new acquired classes versus existing Hydro One classes that that is done as fairly as possible and accurately.

MR. RUBENSTEIN: Am I correct that for 2021 and 2022 in this application today you forecasted and you're seeking approval of the OM&A for the acquired utilities in 2021, the capital for the acquired utilities for '21 and '22, today in this application? And those won't be adjusted at a later date in this custom IR term?

MR. ANDRE: Yes, you are correct.

MR. RUBENSTEIN: So what does it -- what is the -- what's specific about the cost of capital that you have to change that part?

MR. D'ANDREA: So we are not updating the OM&A and the capital factor. It gets to the point of fairly allocating the common costs when the acquired utilities come in. So we are sticking with our five-year forecast in keeping with the five-year custom IR, but the special circumstance or the unique circumstance of integrating the acquired utilities is why we are updating the cost of capital and the load.

MR. RUBENSTEIN: I still don't understand what makes the cost of capital -- you're forecasting today the acquireds, what they are going to need for capital and OM&A today in 2021 and 2022.

What is it that the cost of capital requires a change in? You are not updating those aspects for 2021 and 2022 at a later date.

MR. ANDRE: Certainly one factor would be that the -- our forecast of the OM&A and capital spend is -- reflects what we know now. So we are looking out four years, three years, to when that spend level will happen, whereas the cost of capital on which -- the last time they were rebased is going back to 2011. So it is going back ten years in the case of Woodstock. So we are taking that opportunity to ensure that the costs related to cost of capital that are built into the cost allocation model and built into the revenue requirements reflect as accurately as possible their true cost of capital.

MR. RUBENSTEIN: But why don't you just use the cost-of-capital parameters today? I mean, you have -- I am correct in the application you have set out a 2021 cost allocation model where you are utilizing the cost-of-capital parameters that you are seeking for 2019 and you're -- it comes out of that model with the costs that you're seeking approval for rates. Correct? I have that correct?

MR. ANDRE: Yes, the cost of capital that we are forecasting now is what we would be using in 2021 if we didn't update it.

MR. RUBENSTEIN: So I am still unclear why that's not appropriate. Why can't we just say, that's it, we have -- we're doing all this in this application today with respect to those costs. What is the exceptional circumstance -- using the Board's own language in the handbook that requires that one aspect to be updated in 20 -- or one of two aspects to be updated in 20 -- for 2021 and 2022?

MR. D'ANDREA: Mr. Rubenstein, we will again refer you to the same interrogatory. I don't think there is anything more that we can add to your question.

MR. RUBENSTEIN: Okay. Let me ask about the load forecast part. Am I correct that you have a forecast in this current application for what the customer account increases will be for the acquireds in '21, '22, what the demand and the energy increases will be for those acquired utilities in '21 and '22, you have forecast for that now?

MR. ANDRE: Yes, that is correct. We do.

MR. RUBENSTEIN: And again, why would you require to update the load forecast in '21, 2022? We can't we just set the rates now?

MR. ANDRE: So the --

MR. RUBENSTEIN: Set the revenue requirement now --

MR. ANDRE: Right.

MR. RUBENSTEIN: -- and the billing determinants now like you are doing for everything else for '18, '19, and '20?

MR. ANDRE: So load forecast is, if you understand the workings of the cost allocation model and in terms of what drives the allocation of costs across the rate classes, load forecast, the peak demands, the coincident/non-coincident peak demands are key factors. They are essential to the allocation of costs.

So this, you know, given that this is -- we are creating new classes, we are establishing initial rates for these new classes, we believe it's -- we want to get as accurate information as possible on the allocation of costs to those new classes and ensuring that we have a good forecast that fairly reflects their contribution to the load forecast, the contribution of these new classes to the load forecast versus what other classes are contributing to the load forecast, will ensure the most accurate allocation of costs.

MR. RUBENSTEIN: I take it you have less confidence in your load forecast abilities today than you do for, say, capital or OM&A?

MR. ANDRE: Oh, no, that is not what I am saying. I am saying that three years from now in 2021 when we are looking at 2021 the forecast that we make for 2021 in 2020 will be more accurate. You will be one year out at that point in time. So it will be more accurate than the forecast we have now.

We have confidence in the forecast that we have now. But as I say, would it be more accurate if you have the opportunity to update it? Yes, it would.

MR. RUBENSTEIN: Yeah, but you are not seeking to update the OM&A numbers or the capital numbers, and they are based on a five-year forecast.

MR. ANDRE: As I indicated, the absolute quantum of the revenue requirement I think as we talked this morning, you know, it is probably 25-, 26 million in terms of the overall revenue requirement, whereas the relative peak demands of the classes are a key element of allocating the cost across the classes.

So if we are going to deliver on what the Board decision was, in the MAAD applications, to try to develop classes that -- or develop rates for the new acquired customers that accurately reflect their cost to serve, the best way to do that to accurately reflect their cost to serve is to have the best information available at the time that you establish those rates.

MR. RUBENSTEIN: All right. Now, there's a lot of discussion about the merits of price cap versus revenue cap, and I understand why you're utilizing the revenue cap. I understand your position on that. And -- but I just want to make -- ask you this question: For the first three years of the plan, the 2018, 2019, 2020, that is not the issue of why you are utilizing the revenue cap. It is really because of the '21 and '22 and how you actually bring in those acquired utilities. That is what I took away from the discussion yesterday. That is the big issue.

MR. ANDRE: Yes, I would agree with that statement.

MR. RUBENSTEIN: So let me ask you about those first three years. If you had used the approved Toronto Hydro approach to setting rates, where you would use their model -- using your numbers, but essentially determining your capital factor that would be utilized under their model, their -- using your numbers and using your growth rate, at the end of the third year would Hydro One have collected from customers as a whole any more or any less revenue compared to your model?

MR. ANDRE: So the -- it would come down to the calculation of the growth rate, so the growth rate as calculated by Toronto Hydro was intended to reflect the impact of the changing sales volumes on their revenue. So if the growth rate, the average growth rate over those first three years, '19 and '20 was calculated correctly, it should arrive at the same point.

MR. RUBENSTEIN: In my understanding, the difference between the two approaches then, while the aggregate amounts would be collected from ratepayers may not change, the individual ratepayers may pay a different amount and that is because -- you can correct me if I am wrong -- in the Toronto Hydro price cap approach, every year each component of the base rates or the fixed and variable are multiplied by the same -- what I will call an escalation factor, the I minus X minus the capital -- the more complicated formula, but the formula.

Whereas in your approach, you take the revenue requirement that is allocated in 2018 to each class. You multiply it by your escalator, but then you are dividing it by the billing determinants and insofar as different classes have -- the billing determinants are escalating or at different rates than each other, you will have different customers their year over year rate increases will be -- as a percentage, will be different, where in the Toronto Hydro model, everybody is going up the same amount.

Understanding that the fixed variable residential shift complicates things, do I have that correct? That is the big difference?

MR. ANDRE: I think to a large extent, yes. The increase, though, in revenue that would be collected from each class would be reflective of the overall revenue deficiency. So all classes would share in whatever revenue deficiency exists.

But then you are correct that in calculating the rates for that year, it would depend on the load forecast for each individual class.

I would point out that in terms of the overall impact on loads, there is -- sorry, in terms of the impact of load on revenue requirement in 2019 and 2020, they are generally small and offsetting. I believe in '19, we have a slight revenue deficiency; the forecast load doesn't collect enough revenue. In 2020, we have a revenue sufficiency of roughly the same magnitude.

So I don't think in '19 and '20 that load would have a material impact on rates.

MR. RUBENSTEIN: May I ask you to turn to page 7 of the compendium? Mr. Fenrick, this is from your report, correct?

MR. FENRICK: Correct.

MR. RUBENSTEIN: If we look at these numbers, this is the sort of results of your total cost benchmarking findings, this is how you derived the 0.45 stretch factor, correct, the basis of it?

MR. FENRICK: Right. This formulated the basis of the stretch factor recommendation.

MR. RUBENSTEIN: It shows either using the average of 2014 to 2016, an average of -- or an average of 2017 to 2020, they are in the plus-10 to plus-25 cohort, which equals the 0.45?

MR. FENRICK: That's right.

MR. RUBENSTEIN: What the numbers show, as I understand it, if we take a look going year by year, compared to the benchmark, what the model would predict their cost should be, in 2014 Hydro One was 29.3 above that benchmark, correct?

MR. FENRICK: Right. Hydro One's total costs, their actual total costs in 2014 as measured by our models was 29.3 percent above the benchmark expectation, or the model expectation.

MR. RUBENSTEIN: Then we see it going down in 2015 to 23.2, and then in 2016 to 21.6. Do you see that?

MR. FENRICK: Yes.

MR. RUBENSTEIN: Now, if we look at sort of the forecast, we see that 2017 is at 21.3. Do you see that?

MR. FENRICK: I do.

MR. RUBENSTEIN: Then we see 2018, so the first year of the plan, it is going now up by 0.1, and then it's at 21.4, and in 2019 it's at 22 percent. Then in 2020 it's at 22.4. In '21, it's at 22.4 again, and then at 2022, it's expected to be using at 22.7 percent. Do I have that correct?

MR. FENRICK: Yes, those are the numbers.

MR. RUBENSTEIN: My question is for Hydro One. As I take it then, throughout the term of the plan, your benchmarking performance is going to get worse. Why should ratepayers accept that? I would like Hydro One to -- this is a question for Hydro One.

MR. D'ANDREA: Mr. Rubenstein, this is the first time I have seen these numbers, so I can't comment on their derivation.

I will say that we are committed to productivity savings, and we've baked in our productivity savings in our application. We are committed to that and we applied the stretch factor on top of that. That is all I can add right now.

MR. RUBENSTEIN: You would agree with me --

MR. FENRICK: Could I add to that, given it's my study?

I would say in this context for Hydro One, any utility that is coming forth with a C factor, which is basically they're saying they have capital needs above and beyond what the I minus X formula might dictate, given that, that they're putting forth a C factor, it would likely be expected that their benchmarking performance would worsen because of their C factor that is being requested. Their costs are going up higher than the I minus X would imply, which is why the benchmarking would be getting worse.

MR. RUBENSTEIN: Mr. Fenrick, between 2015 and 2017, my understanding is the abbreviated custom IR plan that the Board approved was a straight cost of service that had significant capital. There was no formula, so there was no need for the C factor. We see the costs -- we see the performance getting better. Do you see that? Do I have that correct for 2015, '16, and '17?

MR. FENRICK: That is correct.

MR. RUBENSTEIN: Then my question to you -- my understanding is your -- there is no more Hydro One against the benchmark. It is not getting any better anymore. As they're seeking a C factor, we can only expect it's going to increase. Do I understand your response, Mr. Fenrick?

MR. FENRICK: My response is from a data perspective. Looking at what they have proposed in the application, it's the numbers that flow out of that is what I am evaluating. What we can expect out of Hydro One, that is beyond my expertise.

MR. RUBENSTEIN: That is my question was for Hydro One's witnesses. Why can't customers expect, at the very least, you will keep your performance compared to the benchmark flat? How is it continuous improvement if you are getting worse every year?

MR. D'ANDREA: Again, Mr. Rubenstein, I can't comment because of the numbers. You can take Mr. Fenrick's word on how those numbers are derived. In this application, we are committed to savings that we're guaranteeing in the millions. So that's how we are driving our efficiencies.

MR. RUBENSTEIN: Let me ask you about the test year OM&A. I understand you are seeking the test year OM&A. I think there was a discussion before that and the basis for the OM&A for the future years will be the I minus X

formula, correct?
     MR. LOPEZ:  That is correct.
     MR. RUBENSTEIN:  My understanding is the test year proposals in OM&A are 576.7 million.  Do I have that correct?  I am on page 20 of my compendium.  You can see that.  This is the most updated.  I recognize there was an update to this yesterday that changed the categories, but the totals were the same.  Do I understand that correctly?
     MR. D'ANDREA:  Yes.
     MR. RUBENSTEIN:  And the history of the numbers, as I understand it, is in June 2017, the forecast, I believe, was $584.8 million.  Do I have that correct?  We can see that on page 17.
     And then there was a reduction to 579.6 on page 18 as part of the Q update to deal with the removal of the transformation costs to mirror what the Hydro One TX decision was, and then there was an OPEB re-evaluation?  Do I have that correct?
     MR. D'ANDREA:  Correct.
     MR. RUBENSTEIN:  And then additionally there was a -- I think it was discussed yesterday there was a further $2.9 million reduction to reflect due to the Fair Hydro Plan the changes in bad debt?
     MR. LOPEZ:  Correct.
     MR. RUBENSTEIN:  Now, with respect to your 2017 OM&A costs, if we go back -- am I correct that -- and I am on page 19 for this.  This is from the June update.  My understanding is your forecast in June 2017 was

$572.8 million?

MR. LOPEZ:  That is correct.

MR. RUBENSTEIN:  That was your forecast?  And if we go now -- flip back to page 20, you ended the year at $558.7 million, correct?

MR. LOPEZ:  That is correct.

MR. RUBENSTEIN:  So you were able to beat your forecast.  Correct?

MR. LOPEZ:  The June forecast, correct.

MR. RUBENSTEIN:  And can ratepayers expect something like that in 2018?

MR. LOPEZ:  The difference from June to the end of the year was an improvement in productivity that will carry forward, but there was also a number of initiatives that we had slowed down for the balance of the year.  But given the strategic change -- we're already talking about vegetation management being moved to a different cycle.  So for the back half of last year the spend on that program was slowed down in anticipation of that new initiative being rolled out late last year into this year.  So that had reduced -- that was not included in the June forecast, so it resulted in a reduction that is not repeatable in the back half of the year.

PCB replacement is another.  Grid modernization is something we're moving towards.  These were outlined, I believe, in Exhibit Q.  But the panel 5 again would be able to take you through exactly what they changed and why in the back half of the year.

The other part that I would say is that our productivity was definitely back-end-loaded. Our expectations of productivity in the first half were high, but we weren't meeting them. So the acceleration of productivity happened all in the back half of the year. So that's why it dropped off fairly quickly versus our expectations with those two main factors.

MR. RUBENSTEIN: If we can turn to page 21 of the compendium. This is an edited transcript from your Hydro One's limited earning call for Q1; do I have that right? That's what I'm looking at?

MR. LOPEZ: Yes.

MR. SHEPHERD: If we can turn to page 25 of the compendium. This is -- you can just -- you can see on 24...

MR. LOPEZ: Excuse me. We have got an updated version of what you've sent out. Sorry, which page was it again?

MR. RUBENSTEIN: Well, if you -- on page 25. Just for reference, on page 24 this is Paul Dobson, the Hydro One CFO, just talking.

MR. LOPEZ: Yes.

MR. RUBENSTEIN: And I will read you the first paragraph here on page 25:

"OM&A costs were down slightly quarter over quarter. However, distribution OM&A includes one-time costs related to the restoration effort during the storms in Baltimore, Boston, and Nova Scotia which were fully recoverable with the offsets recorded in revenue.  Net of these costs distribution OM&A was down 4.1 percent, reflecting lower corporate support costs."

Do you see that?

MR. LOPEZ:  I do.

MR. RUBENSTEIN:  And so just to be clear, when we are talking about quarter over quarter we are talking Q1 2018 over Q1 2017?

MR. LOPEZ:  Correct.

MR. RUBENSTEIN:  And am I correct for the purposes of your financial statements the transformation costs would be included in your distribution costs, so for regulatory purposes you've taken them out, but for financial purposes they would be allocated to the distribution costs?

MR. LOPEZ:  Transformation costs?  Can you explain?

MR. RUBENSTEIN:  Well, my understanding is you removed certain transformation costs from your request for 2018 OM&A.  This is the language from the Board's decision in the TX case, the CEO and CFO costs over a certain amount?

MR. LOPEZ:  Correct.

MR. RUBENSTEIN:  But I am correct for the purposes of your financials those are still in, because those are real. You're still paying the salaries.

MR. LOPEZ:  I think the question you are getting to is we have reduced -- we have taken the costs associated with senior management, which really is Mayo, and the CEO, the CFO, chief legal officer, so on.  Those costs would continue to be allocated into the segments but not included in the application.

MR. RUBENSTEIN: All right. So I am a bit confused. If you expect -- and I am looking at from the distribution side -- 2018 over 2017 a 2.1 increase in OM&A cost, and we can see that number -- I am looking at that number from page 20. We see it is a 2.1 percent year over year between actuals and forecast. Do you see that?

MR. LOPEZ: Give me one second. I just want to orient myself. So please repeat that.

MR. RUBENSTEIN: So it's a -- you were forecasting for a 2018 year-over-year increase --

MR. LOPEZ: Yes.

MR. RUBENSTEIN: -- of 2.1 percent in OM&A, correct?

MR. LOPEZ: Correct.

MR. RUBENSTEIN: But already in the first quarter you are 4.1 percent less in distribution OM&A, and included in that amount is costs that you are not even seeking recovery. So in fact the real cost reduction would be higher. Can you help square that?

MR. LOPEZ: Yes, so the difference in Q1 is entirely timing. Our forecast for the year has not changed. So it is timing. A good example would be that we had planned to spend the majority of the regulatory filing costs in Q1. They have not occurred. The substantive cost of that will now be in Q2. That is one example.

But the annual forecast for distribution is exactly on plan. The way that we would need to offset the costs associated with Mayo or the CEO and others not being recovered, I would need to look into that deeper. But it is a small fraction. It is one quarter of the number you see here. But the large determinant is purely timing.

MR. RUBENSTEIN: So then today with the best information that Hydro One has, you are going to be at 576.7 at the end of the year.

MR. LOPEZ: Yes, and panel 5 could explain more of the difference between the 558 and the 576 in terms of work that was slowed down in the back half of the year and why that is not repeatable in 2018.

The other part that I point out on this is you can see 2017 was a little bit of an aberration for the points I just raised. If I look back from 2015, approved 543, til today, the increase is basically in line with the actual number 572, is basically in line with inflation. So what we are really seeing here is that as costs increase we are fairly successful in offsetting the inflation component of that. That's what we're seeing as I look across there. So I am looking at specifically 2015 was 572, the actual, and the amount we are asking for in 2018 is 576.

So across one, two, three, four years, there is effectively no increase in cost.

MR. RUBENSTEIN: So that is why I brought you to what the comments were in the transcript, because it seems even being an abberation at 558.7 you are tracking already below that.

MR. LOPEZ: Just timing, Mr. Rubenstein. I have answered that question.

MR. RUBENSTEIN: All right. Let me ask you about productivity. There has been some discussion, and I don't want to take too much -- spend too much time on this. But we had asked you at page 36 to go back to the last custom IR proceeding and to essentially fill out a table that shows what you did versus what you had proposed to the Board in that proceeding, because you in that proceeding -- and I'll take you to that in a minute -- had -- sort of had another very detailed table of all the productivity savings that you are going to achieve. That is on page 35, and I apologize, there is some sort of printing snafu, so it's on page 35 on the screen but not -- and so this was what you provided showing the productivity savings you were going in the last case. And that is the reference in that IR. Do you see that?

MR. LOPEZ: I see the table.

MR. RUBENSTEIN: Going back to page 36, this is your response. Essentially the response is it's a new system, out with the old and in with the new. We have a better system now tracking, but we can't track those old productivity initiatives. Is that a fair understanding of what your response to SEC 33 is?

MR. LOPEZ: Can give me one second, please? I want to familiarize myself with the question and the background.

Earlier today, I think I answered a similar question where we talked about -- I think it was yesterday, as well -- about the governance around productivity. And the governance really only came into practice, in the level we spoke about this morning and yesterday, in late 2016, early 2017.

Before that, the tracking, the performance, the measurement was difficult and perhaps not complete. So providing a look book beyond that period is challenging. What I am very confident in is the numbers in 2014 -- sorry, in 2016 and 2017 -- so confident in fact we can now put it on our annual report, subject to scrutiny for all stakeholders. That was definitely not the case the last time we did the rate case.

But I am very confident now going forward because we are going into this rate case with that governance in place.

MR. RUBENSTEIN: If we go to page 38, and this is your response to Staff 123 that we talked about where you have -- it looks to me essentially this application's version of that previous table. When we're back here in 2022 for the next five years, are we going to have the same problem where you can't track, don't know, new systems in place? Are we going to be in the same situation we are now, where you can't verify?

MR. LOPEZ: We will not be for the same answer I gave a minute ago, which is we now have governance in place. We have a system that goes from the project level all the way through to the board and through to external reporting.

Again, that was not in place at the time of the last hearing. It is now. It is in place before we start this proceeding. So we are very confident we'll be able to track against these measures and give clear and transparent progress.

MR. RUBENSTEIN: If I could ask you to now turn to page 41? This is your response to JT1.18, and this is your 2018 corporate scorecard. Do you see that? Do you recognize that?

MR. LOPEZ: I do.

MR. RUBENSTEIN: I want to ask you about the productivity column. Here you have performance levels 103.1, 114.5 and 140, do you see that, for the threshold budget and maximum?

MR. LOPEZ: I do.

MR. RUBENSTEIN: I assume that's on a corporate-wide basis. That's not a distribution number.

MR. LOPEZ: It is corporate-wide.

MR. RUBENSTEIN: Can you help me relate the numbers on -- on page 38, you have totals for 2018. I think this is the 69.8 that was corrected this morning. What does that relate to? If we had the distribution component of those numbers, what would that number relate to? Is that the threshold number, the budgeted number or the maximum number?

MR. LOPEZ: Sorry, can you just repeat that? You're looking at two numbers, and I just got a little bit -- I wasn't able to follow along.

MR. RUBENSTEIN: That's fine. I am try to relate the productivity forecast you provided in Staff 123, that is 69.8 million for distribution for 2018. I have that number correct?

MR. LOPEZ: Yes.

MR. RUBENSTEIN: I am trying to understand how that relates. I understand these numbers are on a corporate-wide basis. But I assume underlies that there is a breakout into the various components, correct?

MR. LOPEZ: Correct.

MR. RUBENSTEIN: So what does the 69.8 -- how does that relate to it? Is that the distribution portion of the threshold amount, the budgeted amount, the maximum amount, or some other number?

MR. LOPEZ: It is in between the budget and maximum. So it would be a stretch.

MR. RUBENSTEIN: Are you able to provide the distribution version of the 103.1, the 114.5, and the 140 by way of undertaking?

MR. LOPEZ: We would back calculate that, because it's not set out for the distribution business that way. It is set out corporately. So it would be a back calculation.

MR. RUBENSTEIN: There is no actual number --

MR. LOPEZ: There is no scorecard for productivity in distribution. It is a corporate score card.

MR. RUBENSTEIN: All right. Then when you were deriving the productivity benefits at Staff 123, and for things that are in both -- things that are transmission and distribution components of it, are you using the way that -- how you separate it out into those two distribution amounts the same way you are allocating other sets of costs throughout the application?

MR. LOPEZ: I don't get the question.

MR. RUBENSTEIN: I want to understand. If we go to Staff 123, there's a bunch of different initiatives. I assume many of these initiatives are not specific to distribution. They will have an impact on transmission, correct?

MR. LOPEZ: Some might, yes.

MR. RUBENSTEIN: When you split those two distribution, or transmission, or corporate, or unregulated, or whatever category you have, did you do that the same way you've split out many other costs using the corporate cost allocation model?

MR. LOPEZ: The only time we do that sits under the last part, CCC, corporate common costs. They're the only ones that are using that allocation. The rest of them would have specific drivers to distribution and distribution teams.

MR. RUBENSTEIN: Okay. It's more of a bottom up --

MR. LOPEZ: Yes, absolutely.

MR. RUBENSTEIN: I want to ask you about the planning process. There was some discussion yesterday and I just want to walk through that with you and make sure I understand how this application came together.

We can start at page 42 of the compendium. In my understanding, this is the October 11, 2016, submission to the board of directors, which set out your recommendations about -- at the time about how the application -- what your distribution application should look like. Is that Correct?

MR. D'ANDREA: Yes.

MR. RUBENSTEIN: On page 43 and page 44, you are summarizing for the board of directors -- you can see this fully on page 44 -- what you got from your customer engagement. Do I have that correct?

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: I see the big points were keeping costs as low as possible as customers' top priority. Maintaining reliable electricity service is consistently a second priority to cost. Large customers are more concerned with reliability of service they currently receive than residential and small business customers. However, although this group of customers is more inclined to value better reliability, they are not willing to entertain the corresponding rate impact. We have all large customer segments prioritize a renewal program that focused on replacing equipment that affects reliability. And lastly, willingness to accept rate increase to maintain and improve service level is limited.

I have that correct? Those are the key messages that you took from the customer consultation?

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: In that proposal, you at the time recommended the plan A over the plan B.

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: I understand the plan A, at the time at least -- if you take it subject to check, I believe it was about a 7.3 percent rate increase in 2018. I don't think I excerpted that.

Ultimately, the board disagreed with you and essentially sent you back to do better, I guess.

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: If we turn to page 47, you come back in November 2016 and you provide them with this new modified plan B, correct? You had plan A and plan B to show them and now you actually had modified Plan B and Plan C. You actually added two. Do I have that correct?

MR. D'ANDREA: Correct.

MR. RUBENSTEIN: And if we turn to page 50, the Plan B, as I understand it at the time, was proposing a 2018 rate increase of 6.2 percent, average annual increase of 3.5 percent. The reliability would have SAIDI improves by 3 percent and SAIFI by 2 percent by 2020. That was the Plan B, correct?

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: But the board -- your board chose the Plan B modified, correct?

MR. D'ANDREA: That is right.

MR. RUBENSTEIN: And if we can turn to page 54, this is from your application. This is on line 6. It says:

"As a result, an adjusted investment portfolio with a forecast 2018 rate impact of 5.4 percent Plan B modified was developed that would maintain overall forecast system reliability at current levels while continuing to offer discrete power quality and reliability improvements for certain segments of the network."

Do you see that?

MR. D'ANDREA: I do.

MR. RUBENSTEIN: So do I take it from this that ultimately what the board of directors said to you was, we want a rate impact that would allow us to keep overall system reliability at current levels while continuing to offer the discrete power quality and reliability improvements for certain segments?

MR. D'ANDREA: That is how we posed it to the board. So again, going back to our customer feedback, we were very limited towards getting rate increases, so we had to balance it. That is why we went back. And then we looked at the operating metrics and said, well, we can keep the operating metrics sufficiently so that we can maintain the system. Not a lot of improvements in the system, but at least maintain the system for that period.

MR. RUBENSTEIN: And that was the balance that the board wanted in improving the application, the message you got from them, and then ultimately this application is, keep reliability constant, there are areas where we need to make improvements, and we will do that, and then the impacts that flow from that will flow from that.

MR. D'ANDREA: Right. That is what we refer to as striking the balance.

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

And just to be clear in you have determined the rate impacts are zero is essentially the tables on page 54 and 55. Correct? And spreadsheets that Ms. Grice asked for to do the back math on that. Correct?

MR. D'ANDREA: I'm sorry, I couldn't hear you.

MR. RUBENSTEIN: Sorry, the way you got the zero percent reliability impact is the tables on page 54 and 55, that's table 4 and table 5.

MR. D'ANDREA: Correct. That is where we looked at the reliability statistics.

MR. RUBENSTEIN: All right. We can turn back to page 15 of the compendium. So this is a version of the electricity distribution scorecard that you have set out targets through the plan. Do I have that correct?

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: All right. And if we can go to the system reliability section here. Do you see it says "average number of hours that power to a customer is interrupted"? Do you see that line?

MR. D'ANDREA: I see it.

MR. RUBENSTEIN: So that is SAIDI, correct?

MR. D'ANDREA: Yes, that is my understanding.

MR. RUBENSTEIN: And if I look through that and I look at any of the years that we are talking about here, then I look the 2022 forecast, I am obviously seeing not a zero percent reliability impact, I am seeing significant reduction.

MR. D'ANDREA: Sorry, could we see the other part of the chart at the end? I think there is a piece missing. So we see SAIDI going down to 5.8 by 2022.

MR. RUBENSTEIN: Regardless of what base year, what averages historically, that is a reduction. Correct?

MR. D'ANDREA: Correct.

MR. RUBENSTEIN: So going back to what your board of directors said, which was essentially keep the system, keep reliability at zero, what is the rate impact that flow from this, at least based on what I see on your scorecard you are not actually forecasting. You are forecasting some -- it is a positive thing, don't get me wrong -- reliability increases. Can you help me square those two things?

MR. LOPEZ: Yeah, I will have a go at it. I think the big benefit that is coming here is the impact of our new vegetation management program. So the main driver of SAIDI, given our network and its being out in the rural areas, is impacts by trees. So by changing that program, which I already said doesn't have a lot of cost to it in this cycle -- it will in the future -- we do start to see some improvements in SAIDI.

So we see an effectiveness uptick from that program. Panel 5 will be able to give you a discrete and full view of what that program does and why. That is my understanding of what is driving that metric to improve.

MR. RUBENSTEIN: If the message you got from your board of directors was our customers care about rate impacts. It is definitely number one. Number two, and some distance is reliability. Keep reliability flat. But based on what you are doing you are actually making significant improvements in reliability.

MR. LOPEZ: As I said, this is a great story for ratepayers, because they are not paying any more for it. The actual cost of the program is down, and we're minimizing as much as we can. But this is one of those benefits that we are just doing things more intelligently. We couldn't reduce the cost in this cycle. It will get reduced in future cycles. But as a by-product of that they get the benefit of the improvement in reliability today.

MR. RUBENSTEIN: So why aren't then in certain other areas did -- this information was going to the Board today -- make adjustments to your capital plan to lower the cost, because we're getting the -- we have now -- it seems to me Hydro One has now found a way to improve reliability in one area. In the risk/reward OM&A capital all offsetting each other and what are the different interrelationships between these two things, why wouldn't we expect a change then in your capital forecast?

MR. LOPEZ: Yeah, I think panel 5 can go into more detail there, because I think this was a discrete initiative that didn't impact others. And so taking out other capital projects and looking to say, can I take this one and improve -- or impact SAIDI by .1 or .2, I think they are best able to speak to why that is not in the best interest of ratepayers.

MR. RUBENSTEIN: All right. And just one last thing as we are looking through this, the same thing happens with the average number of times the power to a customer is interrupted. This is a SAIFI measure, correct?

MR. D'ANDREA: That is correct.

MR. SHEPHERD: And just, it is the same thing. We are seeing a reduction in 2022 in SAIFI.

MR. D'ANDREA: That is correct.

MR. RUBENSTEIN: And is the response the ration --

MR. D'ANDREA: I would direct you again to panel 5 to answer that question.

MR. LOPEZ: I think, Mr. Rubenstein, what he's seeing is some of the productivity initiatives that we put in play and some of the improvements we're making at Hydro One are starting to come out. They may not have been there in 2016 when we looked at this plan initially, but we are starting to see some of these benefits. Panel 5 will be able to articulate that far better than we can.

MR. RUBENSTEIN: Just a couple of small things. There was a discussion yesterday with Ms. Grice about the AESI. They had done some work for you. Do you recall your discussion? I think she's asking --

MR. D'ANDREA: Correct. We took an undertaking on that.

MR. RUBENSTEIN: But I just wanted to ask about what you actually asked AESI at a general level. And am I correct AESI -- there was a discussion at the technical conference about that -- was tasked with essentially reviewing your application to determine if it met the filing requirements of Chapter 5?

MR. D'ANDREA: My understanding is they specifically reviewed the distribution system plan.

MR. RUBENSTEIN: So the distribution system plan evidence to determine if it met the Chapter 5 filing requirements.

MR. D'ANDREA: Correct.

MR. RUBENSTEIN: Is that what they were tasked with, essentially?

MR. D'ANDREA: That is my understanding.

MR. RUBENSTEIN: So they weren't tasked with doing an independent assessment of your asset management plan or your planning processes, correct?

MR. D'ANDREA: Not that I am aware of, no.

MR. RUBENSTEIN: All right. The last thing I personally want to ask you about -- Mr. Shepherd will ask you something -- is I want to ask you to turn to page 56. And I know this wasn't for you, but I want to ask for an undertaking before we get to another panel that I -- something that I -- only came to my radar as I was reviewing for a future panel. And this is from the report of the Clear Path Utilities Solutions Hydro and Forestry assessment. Do you see that. It is on page 56?

MR. D'ANDREA: Yes, I see it.

MR. RUBENSTEIN: And if we flip over to page 56, oddly also titled 56, but then last page of -- this is an excerpt from it. And it talks about on page -- on the second paragraph it talks about three recent assessments: Boston Consulting Group, CNUC study, and the Ontario Energy Board.

Do you see that?

MR. D'ANDREA: I see it.

MR. RUBENSTEIN: Now, I'm aware of the OEB, I believe it is referring to the Board's past decision. I am aware of the CNUC study. But I can find no reference anywhere in the material to work that was conducted by the Boston Consulting Group.

Is there a report that they published, or what exactly were they tasked with doing? Was it specific to vegetation management, or did you have theme come in to look at the whole operation?

MR. D'ANDREA: My understanding is they came in to look at the entire operations.

MR. RUBENSTEIN: Was there a final report provided? What work? There is no reference of it anywhere in the evidence.

MR. D'ANDREA: I would have to check that.

MR. RUBENSTEIN: Could you file that? Would you undertake to provide that report?

MR. D'ANDREA: If there is a report and it is subject to confidentiality, then we will provide it in the proper form.

MR. RUBENSTEIN: I would ask you to do that, and I would ask you to do that before panel 5. Can you do that?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: J2.4.

**UNDERTAKING NO. J2.4: TO PROVIDE IN ADVANCE OF THE APPEARANCE OF PANEL 5 MATERIAL CREATED BY BOSTON**

**CONSULTING GROUP**

MR. RUBENSTEIN:  Thank you, those are my questions. Mr. Shepherd will have questions.

MR. QUESNELLE:  Thank you, Mr. Rubenstein.  Mr. Shepherd?

**CROSS-EXAMINATION BY MR. SHEPHERD:**

MR. SHEPHERD:  Thank you, Mr. Chairman.  I have the last 30 minutes, and as my grandfather used to say, it's a fat 30 minutes.

After long negotiations with Rubenstein, we agreed he would not ask any questions of Mr. Fenrick and I would not ask any questions of any of the other witnesses.  So he is obviously in breach of that agreement, for which you are all witnesses.

But my point is that my questions are only for Mr. Fenrick.  I am not really looking for answers from the Hydro One witnesses.  I am only asking questions about the expert reports.

MR. QUESNELLE:  We will leave the rest of that for your internal cost allocation negotiations.

MR. SHEPHERD:  Oh, no, the consequences will not be cost worthy.

Mr. Fenrick, we have talked before.  We have a compendium on this and you have seen this, I think.  If you can turn to page 2 of our compendium, it is Exhibit K2.3. This is a response to an interrogatory that we gave.

We with were asking about the interactions between Hydro One personnel and you when you were doing your report in the context of how -- during the process of doing your report. You will agree that there was lots of interaction between you and Hydro One during the development of your two reports that you've filed in this proceeding, right?

MR. FENRICK: There was certainly interaction between my and the company. I don't know how you characterize lots, but there was certainly interaction back and forth.

MR. SHEPHERD: The company has said in this response -- you didn't write this response, right?

MR. FENRICK: That is correct.

MR. SHEPHERD: So although it was a question on your report, it is not -- it was actually responded to by Mr. D'Andrea. Did the company have an influence over what you --

MR. VEGH: Sorry, just to be clear, the question is in response to question C, and the request is to have information provided by Hydro One. It is all information provided by Hydro One, so it's a question for Hydro One. I think that provides more accurate context to the answer.

MR. SHEPHERD: The company has refused to answer this. But it is true that they did provide you with -- they did have some influence over what you did, right? They were your client.

MR. FENRICK: They certainly had influence over the scope of what I did. They had no influence and no direct control over any research results, or anything pertaining to that scope that that they laid out.

MR. SHEPHERD: They did provide you with instructions from time to time on how to carry out your report, right?

MR. FENRICK: As far as certainly timelines and scope and what they wanted -- what type of research they wanted me to conduct. They laid that out certainly. They didn't have any influence over how to carry on the research, or carry out the research. That was certainly in my domain to decide upon.

MR. SHEPHERD: I am going to come back to some of the specifics of this, but I guess -- the reason I am asking this is because this interrogatory response is a refusal to provide the information we requested.

You will recall that during the technical conference, we also asked you for a number of pieces of information relating to your work. We also had refusals on those, right, several of them. And you'll find that at pages 6 through 10 of our materials. You recall that discussion?

MR. FENRICK: I do.

MR. SHEPHERD: For example, we asked for draft reports and were told no, and we asked for e-mails that you got from the company providing substantive input and we were told no, and all of the various inputs the company gave you.

I am now asking you to provide those things again.

MR. VEGH: Mr. Chair, I have to object to this line of questioning. As Mr. Shepherd points out, this was addressed in the technical conference and Mr. Shepherd said the grounds for this is that his client was going to take the position that Mr. Fenrick is not qualified as an expert in this proceeding.

Now, this issue was before the panel yesterday and the panel determined that Mr. Fenrick was qualified as an expert in this proceeding.  There were no objections by any of the parties.  So the Board has made this determination of the qualification of Mr. Fenrick.

Mr. Shepherd has had this application, including Mr. Fenrick's evidence, for over a year now.  If they wanted to bring a motion to strike the evidence, they could have done that.

So this issue is legally irrelevant.  I do wonder why this is being addressed now.  And since there is no legal consequence of this and the Board has already determined that Mr. Fenrick is qualified to give evidence, one can't help but think that the point of this cross-examination is just frankly to throw some mud.

Mr. Shepherd had the opportunity to address this issue when it was really relevant.  The Board has made a determination.  Hydro One has not objected to providing any answers to any questions on the merits in the last two days.  We sat by and even if anything was tenuously connected to the merits, there were no objections.

So what I would asked, Mr. Chair, is you direct Mr. Shepherd to ask questions about the merits of the report, the merits of the application, and not re-argue or relitigate the issue of Mr. Fenrick's qualifications to provide evidence in this proceeding.

MR. QUESNELLE:  Mr. Shepherd?

MR. SHEPHERD: Mr. Chair, we didn't challenge Mr. Fenrick's expertise. We believe he is an expert in this area. But independence goes to both -- this is a question of independence, and independence goes to both whether you qualify as an expert in the first place and the weight that the Board Panel gives to the evidence if you are qualified.

In fact, it is very common, as the Board will well know, for challenges to experts to be -- to conclude that we will let the expert in, but the issues related to their independence will go to weight.

That is why I didn't even show up yesterday because there was no reason. The Board doesn't need another procedural fight. The Board didn't need a notion after the technical conference on this stuff.

The Board needs to get this show on the road as it were, and frankly, a bunch of procedural wrangling wouldn't have helped anybody.

So I am going to ask about some specific things later in which I believe the conclusions of Mr. Fenrick were directly driven by Hydro One. In the meantime, I am asking him to give the instructions, the influence that came from Hydro One in the process of him doing his report. I am asking him to file that information.

There will be e-mails. There will be markups of his documents and things like that, and that will tell us how Hydro One influenced his results, and that goes to his independence. It is not appropriate for Mr. Vegh to say, sorry, too late. If there is a question about his independence, he can still be an expert, but you will give his views less weight if you feel that he was overly influenced by Hydro One.

MR. QUESNELLE: Thank you, Mr. Shepherd. Mr. Vegh, I will make the observation that in the response provided to the IR, your client does suggest to Schools, if SEC wishes to test the objectivity and the independence of the Power System Engineering and the conclusions that were reached, this could occur through questions asked of Power System Engineering witnesses and the test of whether or not Power System Engineering's independence and objectivity was at any time impaired by the process which Power Systems Engineering used to prepare its reports.

How is what Mr. Shepherd is attempting to do now outside of that?

MR. VEGH: Again, Mr. Shepherd made clear at the beginning at the technical conference that he said Mr. Fenrick is not qualified as an expert because he is not independent. I am just saying these issues could have been addressed on their merits at the time of the determination of Mr. Fenrick's qualifications, and I would say what is fair game is to look the merits of his opinions, the merits of his conclusions, which by the way PEG has also found to be reasonable, and drill them as hard as you can.

But to turn this into a sideshow where it is just attacking Mr. Fenrick and trying to colour his evidence is, I think, totally inappropriate.

MR. QUESNELLE: Well, Mr. Shepherd's response is the separation of the qualification as an expert versus the independence, and he sees that the independence challenge can happen even though your witness has been accepted as an expert by the Board. What is your response to that directly?

MR. VEGH: Well, independence is a component of expertise, and that is what Mr. Shepherd indicated in the technical conference as well when he perhaps wasn't as guarded about parsing out these arguments. Again, he said Mr. Fenrick is not qualified as an expert because he is not independent.

MR. QUESNELLE: Mr. Shepherd?

MR. SHEPHERD: Independence is not binary. And we reflected on whether we should challenge Mr. Fenrick on the basis that he was not independent at all, and I think my personal conclusion was that would be unfair to him, because he is independent. He is just not as independent as some other people might be.

MR. QUESNELLE: Why don't we carry on with the line of questions, Mr. Vegh, and we will see where we go as far as challenges as to what has to be produced.

MR. SHEPHERD: So I take it that providing the direct input that was given to you by Hydro One on the contents -- the substance of your report -- I don't care about timelines and all that sort of stuff. I am talking about, maybe you should include this, maybe you shouldn't include that, that sort of thing. I am asking you to provide all of that. Will you do that?

MR. VEGH: We object for the same reason, that this is irrelevant. And I just make one more point, Mr. Chair, not to reargue the point about independence. But the reason this is a concern is that, you know, quite frankly, the Board is continually saying that what it is concerned about in setting rates is outcomes, results. And the other points about the legalistic wrangling and playing games around trying to produce more and more evidence and raise gratuitous issues is not at all consistent with what the Board is saying that it is trying to do in rates cases.

So again, if we are going to focus on results, go at it. If we are going to be focusing on -- gratuitously focusing on just communications between the witness and the party, Hydro One objects to that.

MR. QUESNELLE: Understood. Mr. Vegh, we do in our attempts to get to more of an outcomes-based approach, we are still relying on evidence. Obviously, this is why we are here. And the Board relies on fact-based evidence and opinion-based evidence. And I think Mr. Shepherd is rightfully pointing out to something that would go to weight, and we have done that in the past, is looked at the nature of the engagement. I think it's pretty typical to have the engagement letter with experts on record. I think what Mr. Shepherd is looking for is a step beyond that, was there anything that influenced Mr. Fenrick's conclusions, and I think that is something that I think the Panel will hold off on ruling on that particular element, Mr. Shepherd, but if you carry on with your questions and on the ruling of whether or not we require that production we will hold and provide that ruling later.

MR. SHEPHERD: Thank you. I don't need a decision on that right away.

I wonder if you could turn to page 12 of our materials, Mr. Fenrick. This is your proposal to Hydro One on the TFP RFP, and this is an excerpt from that. Right?

MR. FENRICK: Yes.

MR. SHEPHERD: All right. So I would like you to go to the second-last paragraph, and there is a sentence that begins:

> "PSE will create a far more comprehensive TFP calculation by including other 'outputs' " -- outputs in quotes -- "such as regulatory, service quality, and environmental to provide the OEB with a comprehensive outlook at Hydro One's TFP."

You see that?

MR. FENRICK: I do.

MR. SHEPHERD: Why was outputs put in quotes?

MR. FENRICK: It doesn't match the traditional definition of outputs that has been put forth before this Board. In third-generation IR and fourth-generation IR where it was number of customers, kilowatt-hours, maximum peak demand, those types of outputs in a traditional TFP type study, so that is why I put it in quotes is there are other performance aspects of a distribution utility such as some of these listed here that the utility is also performing and doing and can be seen as outputs, outputs

that serve the public good or customers.
MR. SHEPHERD:  So this is outputs in a broader sense, which is why you put it in quotes.
MR. FENRICK:  Yeah, that is fair.
MR. SHEPHERD:  All right.  And so you suggested regulatory, service quality, and environmental.  Did you include any of those in your final report?
MR. FENRICK:  Yes, the service quality.  And by that I meant reliability, that those -- we had two indexes, the SAIFI and the CAIDI was --
MR. SHEPHERD:  Sorry, can I just stop you, because I didn't -- service quality to me means do you answer the phone on time and things like that.  It is a common definition throughout North America.  You're saying that you meant service quality as reliability?
MR. FENRICK:  Yeah, absolutely.  The quality that the company is providing to customers.  That is the service. Ultimately delivering electrons to customers, that is the service, and to the extent they can do that with fewer outages or duration of outages, that is an improvement in service.  So that's how I was using it.  Perhaps we have a different definition of service quality, but that is how I was using that term --
MR. SHEPHERD:  You have been in this industry a long time.  I am surprised that if you meant reliability you wouldn't just say reliability.
MR. VEGH:  Mr. Chair, I hate to keep interjecting, but, you know, Mr. Shepherd has been criticizing or raising

concerns about Mr. Fenrick's ability to give this evidence, yet Mr. Shepherd is now giving evidence on what service quality commonly means throughout North America. I think that is a quotation from him.

MR. SHEPHERD: I think it is fair for Mr. Shepherd to put his observations to the witness and ask for a comment.

MR. SHEPHERD: It is also, Mr. Chairman, the way that the Board uses the term "service quality." But I guess why didn't you use reliability if you really meant reliability?

MR. FENRICK: Mr. Shepherd, in my head reliability and service quality -- yes, there is a customer-service component, you're answering the phones, but -- and I apologize. I am an economist. In my head service quality, reliability also encompasses that. And so I certainly meant to include that. That was -- I mean, I have written papers on the importance of reliability. You know, you have costs and cost performance. And the next big one is reliability. I certainly would not have left out intentionally mentioning reliability, and I certainly meant it to be encompassing in that word or those two words. So, you know, if I have a different definition --

MR. SHEPHERD: That is fine. So you did include reliability in your final report. Right?

MR. FENRICK: Yes.

MR. SHEPHERD: And the other thing you included was safety. That wasn't on your list. Whose idea was that?

MR. FENRICK: That was my idea.

MR. SHEPHERD: Why isn't it in here? I didn't see it anywhere in any of the materials that you provided to Hydro One. I didn't see you suggesting safety.

MR. FENRICK: In this sentence, I was just giving examples. It was a much more comprehensive look at what type of data can we actually get to include these additional outputs to provide the board and stakeholders with a more comprehensive TFP trend. And so I have the word "such as". To me that is not mutually exclusive to all other potential outputs. So we looked at the data available, and for instance, regulatory, we looked at that, and it is really hard to construct a variable on regulatory outputs. We, you know, we couldn't figure out how to construct that variable. Environmental is the same way.

But the two metrics that do lend themselves to creating an empirical-based objective study was the reliability of the SAIFI and CAIDI and then the safety. Those components did allow themselves, given that there is actual data and tracking and data going back in time to actually insert those into the TFP study.

And I would say in our report we say it is more comprehensive than the traditional TFP analysis that has been done. In fairness to the past work that was to calibrate X factors and those types of things. So it was perfectly appropriate for that type of research. Here we are trying to make it more comprehensive, but we never made a claim it was fully comprehensive.

We have taken a step forward with this research where we have now incorporated reliability and safety, but it is by no means fully comprehensive of the performance trend of a distributor.

MR. SHEPHERD:  I wonder if you could turn to page 13 of our materials -- and Mr. Rubenstein and I think alike of course, so you've talked about this already.

But it is true, isn't it, that Dr. Lowry has also done these calculations you have in table 3.3, and his calculations are very similar.  His productivity or his benchmark conclusions are slightly worse than yours, but only slightly and they have the same trend, right?

MR. FENRICK:  Yes, that is correct.  Dr. Lowry, in the 2014 to 2016 time period, came up with a plus 24.8 percent and we came up with 24.7 percent.  So I would characterize that as extremely close and consistent results.

MR. SHEPHERD:  I was referring to table 3.3.

MR. FENRICK:  For the projected?  Sorry.  Same story. What are they -- they are at 23.0 percent.  We are at 22.0 percent, so very close.

MR. SHEPHERD:  We can take it that the conclusions related to forecast benchmark results are pretty robust. You have slightly different ways of doing it, you and Dr. Lowry, and you came to roughly the same conclusions.

MR. FENRICK:  Yes, that is fair.

MR. SHEPHERD:  It is true, isn't it, that when you do a benchmark using the econometric methodology that is used in Ontario, you have a predicted cost and you have an actual cost or, in this case, a forecast cost, right?

MR. FENRICK:  Right.

MR. SHEPHERD: Those costs are in turn disaggregated into operating costs, OM&A costs, and capital components on both sides, right?

MR. FENRICK: The sum of those two formulates the total cost. They are not ever disaggregated within the study. The study itself is a total cost study, but they are comprised of the OM&A and the capital.

MR. SHEPHERD: Well, I have seen the tables that PEG uses, and I think you have the same thing. They have a list of cost components that have operating type costs and have capital type costs, right?

MR. FENRICK: Could you take me to those tables?

MR. SHEPHERD: You designed part of this model, didn't you?

MR. FENRICK: Yes. Could you show me where those are because I am not familiar with the table you are referring to, if you could take me to it.

MR. SHEPHERD: You are not familiar with the output tables for the benchmarking model?

MR. FENRICK: Not ones that disaggregate the OM&A and the capital.

MR. SHEPHERD: Okay. Can you tell me whether this increase in the -- this deterioration in benchmarking results over the next 5 years or so, whether that is driven more by operating costs or more by capital costs? Is that something you can determine?

MR. FENRICK: Not directly through the benchmarking because we only did a total cost benchmarking study. I could get at it indirectly and make a very educated guess based on the PFPs, which is the productivity -- there is a total factor productivity. I believe in interrogatories, we were asked to separate out the OM&A partial factor productivity and the capital partial factor productivity for the company. In those, we could surmise what was driving it. I believe it is on the capital side of things.

MR. SHEPHERD: All right. If you go to page 14 then, this is the -- it is actually an undertaking, a technical conference undertaking in which you split out the partial factor productivities and it includes the forecast at the bottom, right? Do you see that?

MR. FENRICK: Mr. Shepherd, this might help on the prior questioning. This is for the TPF analysis. Before, I believed you were referring to the total cost econometric benchmarking when I said there was no breakout.

So if this is what you were referring to, which is what our confusion was -- no? Okay.

MR. SHEPHERD: But you would typically assume that if you have this sort of results in the PFP, that that would also translate into the benchmarking results from the same period, right? That is the decline in benchmarking performance is likely driven by capital, not by operating, because operating looks like it is going to be doing well, right?

MR. FENRICK: In the projected time period?

MR. SHEPHERD: Yes.

MR. FENRICK: Yes, that's true.

MR. SHEPHERD:  The benchmarking is a comparison to peers, right?

MR. FENRICK:  Ultimately, yes, it is a comparison using the full data set of distribution peers and constructing a model to formulate a prediction, or a model expectation of what total costs would be.

MR. SHEPHERD:  Can you tell me whether your conclusions on page 13 relating to future benchmark total costs and how they relate to predicted costs -- can you tell me whether the operating costs forecast by Hydro One are better than peers or worse than peers, and similarly the capital costs?  Is that something that is possible to get out of the data?

MR. FENRICK:  Are you asking for what a separate benchmarking result would be for OM&A and capital?

MR. SHEPHERD:  That's a little more complicated.  I am asking, from the data you have, could you identify how is Hydro One trending relative to its peers on the operating cost side and how is it trending -- according to its forecast on the capital side.  Is that something you can do with the data you have?

MR. FENRICK:  Through the econometric model?

MR. SHEPHERD:  Through the data you have.

MR. FENRICK:  It would be a separate analysis comparing -- you could some sort of PFP trend of the industry and then compare Hydro One's PFPs on the OM&A and capital side.  That would be a separate study, if you will, but the data would be there.

Through the benchmarking procedures, no, it is a total cost model and the variables were all calibrated with how they influenced total cost and not OM&A or capital separately.

MR. SHEPHERD: Okay. If you can turn to page 15 of our materials, this is what you have said here is -- this is your report, right? And you've said, under the heading 2.14, that the TFP results that you have for Hydro One shouldn't be used as the basis for productivity parameters in an incentive regulation plan. And the reason is because the productivity factor should be external to the utility, right?

MR. FENRICK: Correct.

MR. SHEPHERD: You can, however, compare the TFP results for Hydro One to the TFP results for the whole industry to see how they do, right? In fact, we have the tables on pages 16 and 28. We have the charts, right? And this is what you got, right? These are the past and future TFP for the industry and for Hydro One, right? Pages 16 and 28.

MR. FENRICK: One second, please.

MR. SHEPHERD: These are your calculations, right? These are your charts?

MR. FENRICK: These are, yes. On page 8 of our TFP report -- I don't have the reference offhand, but we state: "PSA provides a word of caution about the incongruities between the Hydro One unadjusted TFP results and the updated

Ontario industry results."

We did not endeavour to make the calculations consistent in any way. We did the Hydro One TFP analysis in the best manner that we saw fit. And that was from a directive from the Board. And then subsequent as the projects moved along Hydro One requested an update on the Ontario TFP. And there we used the fourth-generation IR methodology consistent all the way through 2012 and '13 we made a couple of adjustments as far as the capital expenditures, we used the data that was available there, and the EUCPI was discontinued, and so we made an adjustment with an index only for 2015. Otherwise we tried to endeavour to make as consistent as possible the fourth-generation IR update. So it was never meant to be compared to the Hydro One finding.

MR. SHEPHERD: Ah. All right. So this Board can't reach a conclusion, for example, that the industry until 2011 was still relatively productive relative to its history, but then started to decline, whereas Hydro One started to decline -- its productivity started to decline in 2005. It can't reach that conclusion?

MR. FENRICK: Certainly looking at the indexes can reach those conclusions based on those indexes alone. You can look at the Ontario industry index and see if that statement is true based on that index. You can look at the Hydro One index and see if that statement is true or not based on that index.

MR. SHEPHERD: But you can't compare the two.

MR. FENRICK: They are not meant to be directly comparable, no.

MR. SHEPHERD: And the Hydro One TFP index that we've given you here, the one that is your final conclusion here at page 28, that has adjustments for reliability and safety. Right?

MR. FENRICK: Yes.

MR. SHEPHERD: And the one that we have here for the Ontario industry doesn't have those adjustments, does it?

MR. FENRICK: Which one for the industry? Is that on --

MR. SHEPHERD: Page 16.

MR. FENRICK: -- page 16? That is correct. The adjustments were not made. It is purely traditional outputs driven as far as number of customers, kilowatt-hour sales, and peak demand.

MR. SHEPHERD: And would it be reasonable to conclude -- and I know you haven't done the detailed work, so I am not asking for your expert opinion on this. I am asking sort of at a more general level would it be reasonable to conclude that if you adjusted the Ontario industry TFP for safety and for reliability that it would similarly flatten out in the last few years? Is that likely true?

MR. FENRICK: I would hate to speculate. I haven't investigated what reliability trends and how that would influence. I have no knowledge on the safety trends of other distributors in the province, so I would hate to speculate what would happen there.

MR. SHEPHERD: All right. I want to go to reliability. You have included reliability as one of your outputs. By the way, how many -- how often have you seen reliability as an output in a productivity study in North America -- a TFP study?

MR. FENRICK: To my knowledge this is the first research making the TFP trends more comprehensive, as far as performance. This is the first study of its kind.

MR. SHEPHERD: And similarly, no TFP study in North America has used safety as an output, has it?

MR. FENRICK: Again, the same answer. Incorporating this is, if you will, cutting edge as far as incorporating and creating that extra service quality dimension to the total factor productivity.

MR. SHEPHERD: Mr. Chairman, I have about another 20 minutes. So I know I am over my time, and I know everybody is hungry. But on the other hand, I think I have some good stuff to do, so...

MR. QUESNELLE: Well, I think the intention of our extended break earlier was to give some comfort to people that may have to go, so 20 minutes or -- perhaps -- anyone need a break, or can we go ahead for 20 minutes, and -- we are fine? Not seeing any --

MR. SHEPHERD: Thank you.

MR. QUESNELLE: -- please continue. 20 minutes? We're fine with the witnesses? Thank you.

MR. SHEPHERD: So I want you to turn to page 18 of our materials, Mr. Fenrick. And you have agreed in this interrogatory response that you have put a weight of 38.5 percent on reliability in your study. Right?

MR. FENRICK: Yes.

MR. SHEPHERD: Okay. And what that means is that you are assuming that the cost inputs -- of the cost inputs 38.5 percent of them are driving reliability outputs. Right? That is what the question says, and you confirmed it.

MR. FENRICK: I don't think that is exactly right. I think -- the 38.5 percent is -- the value of reliability is essentially 38.5 percent of the cost value. And this gets into abstract concepts, but if you look at the Lawrence Berkeley lab study -- I think you have it later in your compendium -- looking at those costs of how customers value reliability and looking at the reliability performance of Hydro One, I believe in 2008, those -- that value of service came out to 38.5 percent of the total costs of Hydro One. And so that is how we came about to that weight.

MR. SHEPHERD: So it is basically saying of -- and this is what the question asked, and this is why I am being very specific. The question asked, is it true that 38.5 percent of the inputs of the adjusted TFP model are assumed to be used to deliver reliability outputs, and you said yes. So are you saying something different today or is that still correct?

MR. FENRICK: Now that I reread that, I think I did miss -- I think that is wrong. It actually is what I said before as far as relating to the value of service of reliability relative to the total costs of the company. And so, yeah, if I could redact (sic) that, confirmed, and make a more -- a better answer, if you will. It's not actually the inputs of the TFP model. It is, that weight is constructed based on the relative value of service of reliability to the total costs of the company. And that would have been a much -- a better answer, if you will.

MR. SHEPHERD: Would it be fair to say then that from a customer's point of view 38.5 percent of their distribution bill is -- they are paying that for reliability, in an econometric sense? I'm not saying in a --

MR. FENRICK: No. I think -- I think -- I don't think that would be the correct way to look at it. The proper way to look at it would be they are getting -- they value, if you will -- 38.5 percent of their value of the service comes from improving reliability versus getting a lower bill. So that finding essentially says, yes, customers would probably value a lower bill more than improved reliability up to a certain point, and that that weight is 38.5 percent relative to the total costs of the company.

MR. SHEPHERD: Well, that is interesting, because on page 22 and 23 of our materials, we have an excerpt from your report in which you show us how you calculated the weight for reliability. And basically, if I can cut to the chase, Tables 13 and 14 say the value of reliability to the customers is $500 million, and therefore that ends up being

38.5 percent of distribution costs. So you're saying --

MR. FENRICK: Where do I say that?

MR. SHEPHERD: 128 million plus 370 -- or 71 million is 500 million, and then you see in Table 15 that is what gets you your reliability weights, right?

MR. FENRICK: Right, dividing -- taking that 128 million and divide it by the total cost gets you the 9.9 percent, and the 370 million divided by total cost gets you the 28.6 percent.

MR. SHEPHERD: So by implication you are saying for the customers the reliability is worth $500 million a year. Right?

MR. FENRICK: What I am saying based on the Lawrence Berkeley paper that we referenced, that data says that this is the value that customers would place on the reliability of -- yes.

MR. SHEPHERD: The reason why I was very specific on that is because you have also broken it down by classes. Small C&I is about 475 million of that. The reason why I thought that was sort of weird was because small C&I customers don't spend $475 million on distribution every year.

So you're saying that the value of reliability to them is worth more than their distribution bill. Is that right?

MR. FENRICK: Those are the findings from the U.S. Department of Energy, the Lawrence Berkeley National Laboratory. Those would be the findings they found that electricity is an extremely important commodity to C&I

customers, and even small C&I customers. The value of it is enormous within our economy.

MR. SHEPHERD: So then this Board should be able to conclude that if Hydro One was able to get to perfect reliability for those small C&I customers, they'd pay another $475 million a year for that result, right?

MR. FENRICK: If they were able to get to perfect reliability?

MR. SHEPHERD: Perfect reliability.

MR. FENRICK: Yes, I believe that would be -- the conclusion would be that based on the study cited, if Hydro One could get to perfect reliability, that's what the small C&I would be willing to pay to get that. That's what flows out of there.

MR. SHEPHERD: You are familiar with the difference between customer cost studies and willingness to pay studies?

MR. FENRICK: Vaguely, yes. I am not an expert in that area.

MR. SHEPHERD: The Lawrence Berkeley study wasn't a willingness to pay study, was it? It was actually a cost study, a cost impact study.

MR. FENRICK: I don't know that offhand.

MR. SHEPHERD: But you used it.

MR. FENRICK: I used it, yes. It was also used by PEG in a separate proceeding independent of -- we thought -- I should also mention, Mr. Shepherd, this was meant to provide more information to the board and stakeholders. It was not meant to be a definitive conclusion, or certainly not used for X factor calibration. We even say that in our report. On your page 23:

"Given these and other certainties demonstrating the value of service (VOS), POC views these weights as a first approximation proposal. We are certainly open to suggestions on how to best formulate the weights when making these reliability adjustments."

We feel getting these adjustments and creating a more comprehensive performance trend is important for stakeholders and the board to see. We never presented this as this is the exact only way to do this. We are certainly open to improving this methodology.

MR. SHEPHERD: In fact, even though reliability had a 38.5 percent weight, if you take a look at page 26 -- this is also from your report -- it didn't really have much -- any significant impact on your TFP, did it?

MR. FENRICK: For the Hydro One TFP, no. Including the reliability really did not have -- didn't move the needle. The whole 2002 to 2015 period, it is stayed the same. It was only in the later period -- the 2002 to 2010 that made things slightly improve for the company, and then the 2010 through 2015 slightly worse.

But overall, it had no real impact on the TFP trend by including the reliability.

MR. SHEPHERD: If you go back to page 25, this is safety. What you did with safety is basically said -- by the way, it has a 6.8 weight, right? A 6.8 percent weight? Do I have that right, safety?

MR. FENRICK: One second. I can check.

MR. SHEPHERD: I don't think I included that because I didn't want to include your whole report, but I think it was 6.8 percent. Will you accept that, subject to check, because we have limited time?

MR. FENRICK: I know -- I believe those weights actually changed throughout time.

MR. SHEPHERD: They did.

MR. FENRICK: I know it is not one number. Here they are, on page 30 of our report. It was 6.1 percent in 2015 was the final safety weight.

MR. SHEPHERD: However, safety had a big impact on your productivity, right? You see that on page 25. It is not much different in the first two -- in the first segment, 2002 to 2010. But then in 2010 to 2015, Hydro One has had a lot of success in improving their safety record, right?

MR. FENRICK: Right, yes, according to the three-year rolling average we used, there was a downward trend in safety.

MR. SHEPHERD: The result is that flipped your TFP result from negative to positive, right?

MR. FENRICK: For the 2010 through 2015 period, no, it went from minus 1.4 percent to minus 1.0 percent.

MR. SHEPHERD: I'm sorry. For 2010 to 2015, it flipped it from negative 0.4 to plus .6, right?

MR. FENRICK: Yes, that is true.

MR. SHEPHERD: In fact, if you see on page 27, the result of that -- it also overwhelms the reliability impact because it was basically zero, and it gives your final TFP, which you have in your figure 6 on page 28, your final TFP which is 0.5 in the 2010 to 2015 period, which is what you were looking for, right? You are looking for their improving. That was the whole point of your study, right?

MR. FENRICK: The whole point of my study was to find the truth and to look at the data and -- look at the data and do the best analysis we could possibly do, and provide truth to the board and stakeholders. It was not to come up with any specific result by any stretch of the imagination.

MR. SHEPHERD: I am sorry, I didn't mean to imply that you were going after a particular answer. My point was that the reason why Hydro One had to go out and do a study like this on their productivity was because they had been criticized for not improving enough, and they came to you and said will you check and see whether we are improving our productivity. Isn't that right? I thought that is what it was.

MR. FENRICK: I don't want to speak for the company, their rationale for why they engaged PSE in the study. But in the March 12, 2015, decision of the Ontario Energy Board -- and this is on page one of the report -- it says:

"The OEB sees value in Hydro One measuring its own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB. The OEB leaves it to Hydro One to determine its preferred total factor productivity study method. However, the period of the study should include years at least going back to 2002, and the results of the study must be files as part of Hydro One's next rates application."

So I would certainly say that was likely the motivation for engaging and hiring, and looking at their own total factor productivity.

MR. SHEPHERD: Indeed, that is offer the case, right? When you do linear productivity studies for a individual company, the point is to see whether you are improving or not, right, typically?

MR. FENRICK: Possibly. The point can be just how is this trend changing. It might not be improvement. It might be are we getting worse and why, and trying to accommodate and address that.

MR. SHEPHERD: in fact, you will see on page 27 that even without your adjustments for safety and reliability, Hydro One was still improving. They had a negative 2.1 TFP from 2002 to 2010 on your study. And it is improved to negative 0.4, even on the conventional method, right?

MR. FENRICK: The numbers are less negative.

MR. SHEPHERD: The only thing that adding safety did was it flipped it from negative to positive in that final year, that final period?

MR. FENRICK: I would say what safety did is it made the index more comprehensive and of more value to decision-makers and people evaluating the trend. Whether it went negative or positive was of no consequence to me.

MR. SHEPHERD: I just have one small area to deal with, and that is on page 31 of our materials.

You made an error in your study. It is your TFP study, I think, yes, your productivity study for Ontario in that you missed the IFRS change. Right? It is discussed in Dr. Lowry's response to your interrogatory 61, and he shows the calculation in your interrogatory 24. Do you see those?

MR. FENRICK: I certainly would not characterize it as an error. PEG has done additional research in response to our report and quantified the OM&A adjustment to IFRS. If we could turn to PEG's response -- let me get the -- we can turn to PEG's response, Exhibit L1, tab 8, HONI 25.

MR. SHEPHERD: I don't have that in here, but go ahead.

MR. FENRICK: While she is pulling that up, the point is PEG only adjusted for the OM&A impacts of IFRS, and they did not look at the capital impacts. And so -- and I think looking at their research they are absolutely correct that the move to IFRS increased -- was a one-time increase on OM&A, and so they made that correction in their report.

What they left out was capital would also -- would decline. You know, if things are being -- if the accounting procedures are being changed and OM&A increases because of those accounting procedures changing, capital is also -- is going down. And they made no adjustment for the TFP impact on the capital declining. And so it was a one-sided adjustment when they made that. 25. And so we asked PEG, would this -- what about the capitalization? Did you leave that out?

MR. SHEPHERD: And they agreed that it would lower the industry TFP trend, yes?

MR. FENRICK: Right. Essentially, if you look at part B(ii), with lower capitalization of costs, move capital costs in the opposite direction of the OM&A, I have an IFRS adjustment suggested by PEG, and they agreed it would. So, you know, the truth is somewhere in between the experts in this case with this IFRS. They have done additional research, but they have left out a piece. And so the truth is somewhere between our number of negative .9 percent and their number of negative .25 percent, which is a fairly narrow difference. We are both saying X factor of 0.0 percent. They have done the IFRS adjustment on OM&A, but they have left out a capital piece which would bump up their number closer to ours. And our number would likely go down a little bit if this was all -- if we had time and we could sit in a room and figure this out, we would likely come somewhere in the middle of negative .9 percent and negative .25 percent.

MR. SHEPHERD: Well, in fact the capital impact is so small they didn't bother to include it, right? And the reason it is so small is because it trickles out over 40 years of the life of assets as opposed to OM&A, which is an immediate hit. Isn't that true?

MR. FENRICK: I don't think that is actually true. The capital, say it is $100 million of OM&A going up, that is going to be $100 million of capital spending going down. And that is going to be -- in that year that is going to show up in the TFP calculation. So it is not going to flow over 40 years. It is going to be a much shorter time period than --

MR. SHEPHERD: They're going to match. They're going to offset each other.

MR. FENRICK: I don't think they will offset each other. I think the truth is somewhere in the middle. And we haven't done that analysis and PEG hasn't done it either, because, frankly, there is no way of knowing exactly what the IFRS adjustment is. And when we did our research, that is why I certainly would not characterize it as an error. We didn't have that data, and we hadn't done that research, but the truth is somewhere in between what the experts are saying.

MR. SHEPHERD: If you take a look at page 33 of our materials, you had an OM&A productivity for Ontario for 2011 to 2015 of minus 3.58, of which 2.13 of that, about 60 percent -- no, 55 percent of it -- 60 percent of it was that error. Right? You --

MR. FENRICK: Are you looking at TFP or OM&A?

MR. SHEPHERD: I am looking at OM&A productivity. You had 3.58. By the time all the adjustments were made, PEG had 0.55, with your methodology, just correcting for the errors, right, of which the biggest error by a long way was IFRS.

MR. FENRICK: Mr. Shepherd, that is not an error. That is IFRS and PEG making -- looking at data and doing research and estimating what they think that impact is on a total factor productivity basis, which is what we presented in our report. We didn't look at the IFRS issue. In fact, in the fourth-generation IR the IFRS was also -- there was no adjustment made. And we were simply following through on the fourth-generation IR methodology. If we had introduced some IFRS adjustment and done those types of things then we would not be following the methodology of fourth-generation IR. So it is certainly not an error. It is subsequent research that PEG has done, and they have -- focus only on the OM&A, and they have ignored the capital impact which would move to offset that on the total factor productivity.

MR. SHEPHERD: And at the time of fourth-generation IR, isn't it true that only one utility had gone to IFRS? That's Toronto. And they were excluded from the study. Isn't that true? And that is the reason why it is not in there. But now everybody is gone.

The point is it had no significant impact in fourth-generation IR and it has a significant impact today. Isn't that right?

MR. FENRICK: Well, I would say it as an unknown impact today. We don't actually know what the IFRS adjustment should be to TFP. And it's -- frankly, it's probably handled in some sort of generic proceeding to go through what that adjustment should be -- at the end of the day the fourth-generation IR X factor was 0.0 percent.  Our findings are 0.0 percent, and PEG's findings are 0.0 percent for the X factor.  What the actual IFRS adjustment -- and it is fairly -- it is very complicated to figure out what the OM&A impact is and the capital and how that all flows through.  That is certainly better served in a generic proceeding than this for one distributor.

MR. SHEPHERD:  Thank you.  Those are all my questions.  Thank you for your indulgence.

MR. QUESNELLE:  Thank you, Mr. Shepherd.

The Panel has some questions.  Ms. Anderson?

**QUESTIONS BY THE BOARD:**

MS. ANDERSON:  My first --

MR. QUESNELLE:  Sorry.  I thought you were saying something, Mr. Sidlofsky.  No?  Okay.  Okay.

MS. ANDERSON:  My first question, can you refer to the -- yesterday's transcript, page 18, top of page 18.  Do you have it there?  Do you have it there, Mr. D'Andrea, I think, because the question is probably for you.  There we go.

So the reference is that Hydro One will keep Norfolk rates frozen for an additional six years.  Can you explain what you mean by an additional six years?

MR. D'ANDREA:  Sorry, that is a typo.  It should read that we've kept it frozen for six years, not an additional -- so it's one year additional.

MS. ANDERSON: The Board approved five years of deferred rebasing. Are you seek an additional year specifically of deferred rebasing in this application then? Is that part of your relief sought?

MR. D'ANDREA: No. What we've done is we integrated all the utilities in the same year. If you follow the Board's, you would have brought in Norfolk in year 5, adjusted the rates. And then in your sixth year, you would have done Halderman and Woodstock.

So in our application, we originally said let's all do this is one year for simplification purposes rather than disrupting rates. What we've been open about this is because we did the extra year, there are additional savings that we achieved because of the extra year that goes beyond the Board-approved five years. So we are willing to put that amount into a deferral account and give it back to ratepayers.

MS. ANDERSON: So it's an additional year of deferred rebasing that you are basically proposing in this proceeding, is that correct?

MR. D'ANDREA: Yes.

MS. ANDERSON: Thank you. The next question -- I just want to be absolutely clear about the productivity improvement for capital, just so -- I think I understand it. There are a number of initiatives that I've seen in the DSP, but the actual stretch factor of 0.45, does it apply to anything for capital, or is it the initiatives that are part of your DSP?

MR. LOPEZ:  That is a good question.  In the actual capital spend envelope that we are applying for, it has the capital productivity that we have listed in the -- we can bring it up, if you like.  But it has the productivity in each year that if it wasn't there, our capital ask would have been higher.  So that's baked in.

Then you get to the revenue requirement, and the revenue requirement, it applies to the whole revenue.  So revenue is made up of OM&A that is recovered and an amount that applies to the rate base plus new capital.

That revenue requirement is being stretched by a further .45 of one percent.  So Hydro One, as does any other utility, has to find a way to make that up.  And the way we will do that is by stretching ourselves even further in the OM&A.  That's why I think the OEB has set a test year for OM&A in the first year and that is held flat, plus productivity.  To the extent we can get more productivity, we can use that to offset that gap in revenue.

MS. ANDERSON:  When Ms. Girvan was asking about the capital factor, I understand there is something that gets subtracted out in determining the capital factor when that be IPI minus X.

Doesn't that essentially add back the .5 percent?

MR. LOPEZ:  No, it is reducing the revenue requirement.  When you reduce that 0.88, it is actually reducing the revenue that the corporation gets.

MS. ANDERSON:  Correct, by inflation minus X.  If you are subtracting I minus X, doesn't that mean you --

MR. LOPEZ: Only on the growth piece. That is only -- The capital factor is only for that additional capital. So rate base is $7 million. That's the largest single line item. So that additional rate base, every year you are only spending $500 million on capital, 5 to 700.

MS. ANDERSON: But then for the capital factor for that incremental capital piece ...

MR. LOPEZ: That is being adjusted.

MS. ANDERSON: Then there is no .5 percent in that one. That's basically the initiatives you have in your DSP, is that correct?

MR. LOPEZ: No, because what's happening here is your capital factor is being reduced by productivity. We would have asked for your increase in capital-related revenue requirements on the screen, line 13. So we would have said you would have asked for 3.84 as the capital factor, but now you are reducing that capital factor by 0.88. We are asking for 1.96; that's actually being reduced.

MS. ANDERSON: It is being reduced by inflation less --

MR. LOPEZ: Productivity.

MS. ANDERSON: -- 0.45.

MR. LOPEZ: Yes.

MS. ANDERSON: Because the factor is already reduced by 0.5, by subtracting it out, aren't you adding it back? I just want to make sure I understand this. I could see if you were subtracting out the inflation part, but you are reducing it by less than inflation.

MR. LOPEZ: Yes. But again, I think it is only on that growth piece.

MS. ANDERSON: Understood.

MR. LOPEZ: Okay, yes. Then I would say yes. It was taken out before, and we're adding it back now.

MS. ANDERSON: Mr. Fenrick, can you provide us your view of the purpose of a stretch factor?

MR. FENRICK: There's a couple of theoretical bases for a stretch factor. The first would be a utilities that is moving from cost service to incentive regulation. If you have increased incentives to contain costs, there should be an expectation, if you will, that the utility should exceed the historical productivity of the industry.

It is also been known as, you know, a consumer dividend in those types of things. To me, I think that was the best use, or my view of it is to create incentives to perform well relative to peers and create that -- in a way, mimic that competitive marketplace where if you are doing well versus your peers and you are doing well on the total cost benchmarking, your costs are allowed to escalate faster than relative to peers that are doing poorly.

In this case, a 0.45 percent, our finding is Hydro One is in that group 4, costs are above what we would expect. So it is a fairly large stretch factor of 0.45 percent that kind of mimics, if you will, that competitive market.

MS. ANDERSON: Thank you. Those are my questions.

MR. QUESNELLE: Thank you.

DR. ELSAYED: I just have a small question. Mr.

Fenrick, how long did it take from the time you were engaged by Hydro One until you completed your final report, roughly?

MR. FENRICK:  You said roughly, right?

DR. ELSAYED:  Yes.

MR. FENRICK:  I believe it was at some point later in 2015 when we were engaged.  Let me find the dates of our benchmarking report.  I believe that was the -- then it was May of 2017 is when we actually finalized the report.

DR. ELSAYED:  You were engaged in 2015?

MR. FENRICK:  I believe it was towards the end of 2015, if my memory serves me.

MR. QUESNELLE:  I just have one question actually. Mr. Lopez, you had a conversation this morning talking about productivity -- I think it was with Mr. Sidlovsky -- referring to the productivity and Hydro One's view of productivity, and focusing the incentive programs on the cost savings as opposed to cost avoidance.

Can you elaborate a bit further on that?  What I am looking for is -- in the business of hydro distribution, I think you recognize that it is very capital intensive so the cost avoidance not including that, where does cost avoidance come in if not in the incentives to save the consumer money?

Where are we with the -- where in the whole planning spectrum does that occur to, as referred to earlier, sweat the assets to avoid the cost of replacement, to provide the same service with less cost to begin with as opposed to just a cheaper way to deliver the same cost items.

MR. LOPEZ: I understand the question. When we are using cost avoidance, we are really tying that to a committed plan and a budget. So from time to time, you will get a part of the business that comes in and says I've got a great idea and this is the benefit to the consumer, but there was no cost to begin with. There was no cost associated with that activity.

So they've found something that they believe they are making a saving on, but we don't have any tangible hard benefit that we can capture. In that case, we would still be pursuing it if it is reducing our risk in the long term, if it's a stitch in time saves nine kind of understanding.

But because we can't measure that benefit specifically, we can't say that the cost of service has reduced by $100,000 next year. We don't record it as a tier 1 productivity saving.

MR. QUESNELLE: Where is the opportunity -- how do you incent the thinking that would avoid the cost in the first place, rather than bake it into a budget and then see what I can do about removing it from the budget? How do you incent the thinking that would avoid the cost ever being -- surfacing in a budget to begin with?

MR. LOPEZ: So that would be the -- at the system plan level, so in five years when we say, here is the envelope of funds that we have to produce the best outcome for consumers, that would be at that level. We make decisions amongst, this project is more valuable than that project.

What I am speaking to is, once the budget is -- we said, here is the plan and we are moving forward, then we really do stick to that plan.  We do make some changes along the way if new information comes to light, but productivity is only measured by a lower cost -- in our mind a lower cost to consumers or, for the same price, a better service, so better reliability, for example.

So we do have that black and white when we are incenting for productivity.  When we are talking about the overall system plan over years, that is when we would consider the broader spectrum to say, what is -- is a dollar spent today better than $10 five years from now.

MR. QUESNELLE:  So there is a reference plan notion that would suggest, okay, to provide the service that we are expected to provide is a million dollars.  No one is incented to build that system for $800,000.

MR. LOPEZ:  So it is hard to say the whole system, but --

MR. QUESNELLE:  Just --

MR. LOPEZ:  -- yeah, whenever a part of the system comes up to look at it we are absolutely incented to look at the best solution for that decision or for that ask. How that comes into play -- and this is how it actually comes into play -- is that we are incented to reach our scorecards on reliability and so on.  So we are trying to spend the most efficient -- in the most efficient manner to get the best outcomes.  So that is where it is incented, is that if I can spend a dollar that can improve reliability by .1 or I have another choice to spend that dollar and it improves it by .5, that is how we look at it.  So it is at that level.

MR. QUESNELLE:  And once you have decided the best way to approach that, until you go through that cycle again there is no incentive to rethink the planned budget.  It is all about -- you are incented to spend the budget or find a cost savings against that budget and work that out from a business plan perspective.

MR. LOPEZ:  Find a cost savings.  Absolutely.  Then number two is -- we look at capital and operating the same way.  So if we can get that capital outcome for a lower cost, so say in the long-term plan we are going to build a transmission line for $100,000, and we could come up with a way to build that same transmission line for 80,000, we would capture that.  We would show that we did a better outcome.

MR. QUESNELLE:  Okay.  Thank you.  That is all I have.

DR. ELSAYED:  Can I clarify part of your answer, Mr. Lopez, to Mr. Quesnelle's question?  You talk about an envelope.

MR. LOPEZ:  Yes.

DR. ELSAYED:  I just want to understand the process, your planning process.

MR. LOPEZ:  Yes.

DR. ELSAYED:  Do you establish the envelope and then see which projects you could fit under that envelope or do you start from the bottom up and determine what are the key projects that need to be performed based on the risk -- the risk level that you want to take, or you do both?

MR. LOPEZ: So -- both. Panel 5 will give you a much better answer than I can, but I do oversee some of the planning -- and from a financial perspective, so I do know the processes. They know what each project will do to reliability.

Now, not any one project kills reliability and not any one project fixes it. So they have a risk factor associated with it. And then we look at what is the impact through customer preferences and needs, we look at what is the impact to bills, is reliability really important to that segment of our customer base, and we start to make some choices there. It does end up becoming a redlining process, because if you don't want the -- you know, we can provide, I think it was said earlier today, 100 percent reliability, but the cost would be very, very high. So it is always that balance, and we have a red line there that just says that next project, we can't do it because we don't -- the impact to the bills is too high. So we are doing a bottom-up. We have all that data, and then we look at it on a portfolio basis and say, okay, it has got to cut off here, and that is an acceptable level of risk on a total system basis.

As we go through the year we do get more efficient in capital, and it creates an amount that we can have another look at that risk profile and say is there another project that comes in, and if we have overruns due to storms, the first effort is always to try and absorb that in our envelope. If we have two or three exceptional storms, then that is when we would have to look -- we wouldn't be able to absorb that completely. But we're all -- that is when that envelope thinking comes in, is there are always things that are unplanned, and we will then reprioritize which projects gets done, and their impacts on reliability and cost.

DR. ELSAYED: And the envelope gets approved -- or -- by your board, I guess, based on --

MR. LOPEZ: When we do a long-term plan, once the OEB has approved our plan, if you looked at our last two years for distribution, if you looked at the last three years, the first year was a previous management team, and there was a -- they went through the capital ceiling. This current management team has not gone through that ceiling, and we have done everything required to ensure we do not go over those numbers. And that is what I am talking about there.

Sending this next set is coming through in this process, and the board did have their input to say, you know, we would like, you know, how we consider customer needs and preferences, we would like to ensure that we are managing our impact on the bill as best we can. So that is where their input would come into it. And that is what you have got here in front of you today. Once the OEB approves this plan we will hit those -- we will ensure we deliver or exceed the reliability numbers and we will not exceed the capital.

DR. ELSAYED:  Thank you.

MR. QUESNELLE:  Mr. Vegh, any redirect?

MR. VEGH:  I have no re-examination.  Thank you.

MR. QUESNELLE:  Thank you.

Thank you very much.  That concludes this panel.  And I apologize for not managing the timing better.  Hindsight is always 20/20, and we could have split this up and had an actual lunch, given where we are today.

And thank you to this panel.  You are excused.

So we will be starting with the next panel on Thursday morning, and from the schedule I guess we will be going to panel 3, anticipating that for Friday, and I believe that -- and just looking at the pure hours we will probably be mid-day Friday to start with Panel 3, just so that people are on notice for that, okay?  And so we are adjourned until Thursday morning.  Thank you.

--- Whereupon the hearing adjourned at 2:29 p.m.