Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**
VOLUME:	**Volume 1**	
DATE:	**June 11, 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 Monday, June 11, 2018,
commencing at 9:35 a.m.

VOLUME 1

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

ALSO PRESENT:

JODY McEACHERN 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>U N D E R T A K I N G S</u>

Monday, June 11, 2018

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

MR. QUESNELLE: Good morning, everyone. Please be seated. Good morning. My name is Ken Quesnelle. I will be presiding over the proceeding over the next few weeks. With me are Board members Lynn Anderson and Mr. Emad Elsayed.

The Board sits today on the matter of a five-year custom incentive regulation application filed by Hydro One Networks Inc. on March 31st, 2017 under section 78 of the Ontario Energy Board Act. They are seeking approval for changes to the distribution rates to be effective January 1, 2018 to December 31st, 2022.

The notice of hearing was issued on May 24th, 2017, and the first six procedural orders were issued -- or the first procedural order issued on August 30th, 2017.

The OEB has made determinations on several procedural matters, including the granting of intervenor status, the filing of intervenor and OEB Staff evidence, the manner and scheduling of discovery processes, and the scheduling of this oral hearing.

The OEB most recently informed all parties to the proceeding that it will be providing further information on how it intends to proceed with Hydro One's proposals with respect to pole attachments, charges, and that it will not be dealing with that issue within the currently scheduled oral hearing processes.

I will take appearances, please.

APPEARANCES:

MR. NETTLETON: Good morning, Mr. Chairman, Panel members. My name is Gordon Nettleton. I am appearing with Mr. George Vegh. We are counsel to Hydro One in this application.

MR. QUESNELLE: Mr. Nettleton, Mr. Vegh.

MR. BRETT: Good morning, Mr. Chairman, Panel. My name is Tom Brett. I am appearing for the Building Owners and Managers Association in this application.

MR. QUESNELLE: Good morning, Mr. Brett.

MR. YAUCH: Brady Yauch. I'm here on behalf of Energy Probe Research Foundation.

MR. LADANYI: My name is Tom Ladanyi. I am consultant to Energy Probe.

MR. QUESNELLE: Good morning.

MS. BLANCHARD: Good morning, Emma Blanchard on behalf of Canadian Manufacturers and Exporters, and my colleagues Erin Durant and Scott Pollock will be appearing to cross-examine other panels in this hearing. Thank you.

MR. QUESNELLE: Thank you.

MR. RUBENSTEIN: Good morning, Mr. Chair. Mark Rubenstein, counsel for the School Energy Coalition. I'd like to put in an appearance for my colleague, Mr. Jay Shepherd, who will be appearing from time to time. I've also been asked to put in an appearance for Ms. Julie Girvan on behalf of Consumers Council of Canada, as well as Michael Buonaguro, on behalf of the Balsam Lake Coalition and the Arbourbrook Estates.

MR. QUESNELLE: Thank you very much, Mr. Rubenstein.

MR. SEGEL-BROWN: My name is Ben Segel-Brown, and I am appearing on behalf of the Vulnerable Energy Consumers' Coalition. Appearing with me is Mark Garner.

MS. GRICE: Good morning. Shelly Grice, representing the Association of Major Power Consumers in Ontario.

MR. QUESNELLE: Ms. Grice.

MS. DeMARCO: Good morning, Mr. Chair. Lisa DeMarco, and with me is Jonathan McGillivray, appearing on behalf of Anwaatin and the ten First Nation members it represents.

MR. QUESNELLE: Good morning.

MR. DUMKA: Good morning, Panel. I am Bohdan Dumka. I am representing the Society of United Professionals. Just as an aside, that was the Society of Energy Professionals, and they renamed themselves in March.

MR. QUESNELLE: Thank you.

MR. STEPHENSON: Good morning, Mr. Chair. My name is Richard Stephenson. I am counsel for the Power Workers' Union.

MR. QUESNELLE: Mr. Stephenson.

MR. McLEOD: Good morning, Mr. Chair. My name is Michael McLeod. I am with the Quinte Manufacturers' Association.

MR. QUESNELLE: Good morning, Mr. McLeod.

MS. CHAI: Good morning. My name is Victoria Chai, counsel for the Ontario Sustainable Energy Association.

MR. QUESNELLE: Good morning.

MR. SIDLOFSKY: And good morning, Mr. Chair. My name is James Sidlofsky, here as counsel to Board Staff. I am here this morning with Martin Davies, the case manager on this file, and Keith Ritchie, another member of Board Staff working on this matter.

MR. QUESNELLE: Good morning, Mr. Sidlofsky.

[Technical interruption]

MR. QUESNELLE: Okay. Thank you. Mr. Nettleton.

MR. NETTLETON: Thank you, Mr. Chairman. We do have a few preliminary matters that we would like to address if we could.

MR. QUESNELLE: Certainly.

PRELIMINARY MATTERS:

MR. NETTLETON: There were several documents that have been placed on the record that do not have exhibit numbers, and we're hoping that we could have exhibit numbers assigned, and I'll just go through the list, if I could.

On April 20th Hydro One filed an updated Willis Towers Watson and Mercer study, and also in that filing we responded to the Board's direction of having certain of the Hydro One transmission rate case exhibits related to compensation also filed as part of the record of this proceeding.

It's an 82-page filing, and I'm in your hands in terms of how you might want to have that document marked as an exhibit. One way that I thought was, there seems to be three buckets of documents. There is the Willis Towers Watson report, there is a Mercer report, and then there is all of the 2016-0160 exhibits, and it may be best to have it marked as K1.1-1 or something to that effect, just to delineate between those documents.

MR. QUESNELLE: So we will just be relying on the transcript of what the listing that you just provided to identify that, Mr. Nettleton?

MR. NETTLETON: Yes, correct.

MR. QUESNELLE: Okay. I think that will be fine. Yes, let's do that.

EXHIBIT NO. K1.1: APPLICANT'S UPDATED WILLIS TOWERS WATSON AND MERCER STUDY WITH TRANSMISSION RATE CASE EXHIBITS

MR. NETTLETON: And secondly, sir, on May 28th Hydro One, through our offices, filed a draft hearing plan and that draft hearing plan contained a breakdown of all of the evidence and the witness panels that will be appearing in this proceeding.

Sir, what we intend to do with that plan is -- it will help the witnesses adopt their evidence. And so if we might have that filing marked also as an exhibit in this proceeding as it relates to the hearing.

MR. QUESNELLE: So that will be K1.2.

EXHIBIT NO. K1.2: DRAFT HEARING PLAN

MR. NETTLETON: Just for the benefit, sir, of how we are intending to present our case, the first two panels that will be appearing, sir, this week will be the custom incentive ratemaking panel and the financing compensation panels. Those two panels will be assisted by Mr. Vegh. Mr. Vegh is addressing the matters of finance and the IRM methodology, and also the load forecast and rate design. Those are the panels that Mr. Vegh will be here for.

I drew the short stick, and I am dealing with the customer engagement and the asset management, the expert panels and the shared services panels. So those are going to be inter-mixed after the first two panels happen.

With that, I just wanted to give you that context. I will be coming out -- or leaving today and Mr. Vegh and his team will be kicking in and they will carry on in that fashion, sir.

MR. QUESNELLE: Okay, thank you. I understand we also have a bit of a scheduling issue with potentially one member of panel 2; they may not be available until Thursday. So we've had some discussion as to how we might manage that, and it may be best to just see where we're at tomorrow afternoon and determine if we have to do anything to rearrange our scheduling, or whatever.

But why don't we just let the day unfold, and then we will know at the end of today or tomorrow whether or not we have to make any determinations on that. Does that sound fair?

MR. VEGH: Thank you, Mr. Chair, that's fair.

MR. QUESNELLE: If there is nothing else, Mr. Nettleton, I was just going to raise a letter. This is a on a letter that copy to the Board on June 7th, and this is with respect to the regulatory treatment of pensions and other post-employment benefits.

It was a filing which was subsequent to the report that went out last September, and there is laying out some options. We just wanted it better understand the context, I suppose, as to how the matter is, in the context of the relief sought in this application before we determine which is the better route to take, those being IRs -- well, the proposals are whether or not IRs be asked on the subject-matter through this proceeding and then perhaps bring a witness at the end of the oral proceeding, or set it is up so it's deferred to a later date.

We also want to understand -- I understand there is also some related matters that are being determined on the transmission side that the Board sees as being perhaps one in the same, but if we could understand that better, it would be helpful.

MR. VEGH: Thank you, Mr. Chair. Yes, so the letter that was filed and the information that was filed on June 7th with respect to the treatment of pensions and Hydro One's request for a departure from the default approach, Hydro One has proposed its -- its approach to the treatment of the pensions and we're in your hands, sir, as to what is the best way to deal with it in this proceeding.

We thought the simplest way would be just to address it at the end of the proceeding, and that would give the parties an opportunity the opportunity to review the evidence and ask questions, and that's our proposed approach.

MR. QUESNELLE: Is there a relationship with the request here and matters which have been recently determined in the transmission, under the transmission heading for the same subject matter of OPED?

MR. VEGH: It is intertwined with some of the issues in the transmission decision, but this has been raised -- the Board's direction did arise in the context of distribution rates application.

But if where you're going is there is something that can be addressed in the transmission rates application that's coming up, Hydro One believes it can be addressed there as well.

MR. QUESNELLE: Okay, thank you, we'll consider it then. Thank you. If there are no other preliminary matters?

MR. SIDLOFSKY: Sir, if I could just interrupt? Just before we started, MR. Nettleton handed me copies of a couple of amended interrogatory responses.

I'm not sure if Hydro One's plan is to introduce them now just to get them on the record, or later?

MR. VEGH: We will have panel 1 speak to those exhibits. We wanted to provide hard copies around, but we will be -- the panel will be referring to those updated exhibits.

MR. QUESNELLE: Okay, we will recognize them at that point then. Okay. Thank you.

MR. VEGH: Thank you. If there is nothing else, then, I'd like to commence with panel one and I'd ask that they be affirmed.

HYDRO ONE NETWORKS INC. - PANEL 1

Chris Lopez

Frank D'Andrea

Henry Andre

Steven Fenrick, Affirmed

MR. VEGH: Thank you. Panel, just for a bit of a roadmap to this introduction, what I planned to do -- what the panel plans to do is first provide a brief introduction of all the panel members.

Mr. Fenrick of PSE is offering expert evidence, so I'd like to have him qualified as an expert -- or at least proposed to be qualified as an expert.

Mr. D'Andrea will provide a short opening statement for the Panel, and then, as we indicated, there is a correction to the evidence that Mr. Lopez will be speaking to.

So, with your leave, I'd like to proceed on that basis.

EXAMINATION-IN-CHIEF BY MR. VEGH:

Good morning, witnesses. You've been affirmed. I just wanted to introduce you to the Board Panel, and I'll be referring to a couple of documents to do that and I'd ask that Ms. McKinnon have them available.

I'll be referring to your CVs, which are in the June 7th filing by Hydro One. As well, I'll be referring to the hearing plan that was marked Exhibit K1.2 this morning. It is a letter to the OEB from McCarthy Tetrault dated May 28, 2018.

If we could start with you, Mr. Lopez, and we won't go through your entire CV, just enough to give the Panel an understanding of your current position and your responsibilities in that position.

So starting with you, Mr. Lopez, I see that you are currently senior vice president of finance at Hydro One.

MR. LOPEZ: That's correct.

MR. VEGH: Can you just provide the Panel with a brief explanation of your responsibilities in that position?

MR. LOPEZ: I oversee most financial matters day-to-day, treasury, finance, external reporting.

MR. VEGH: Thank you. And the other document I'd like to refer to is the hearing plan, which identifies your areas of responsibility in this file. It is marked draft still, but this is the hearing plan.

Under the first panel, custom IR, you're identified and then there is a number of application exhibits and interrogatories set out that the -- set out the first two pages of that exhibit.

Mr. Lopez, can you confirm that you will be -- that you are adopting this evidence on behalf of Hydro One?

MR. LOPEZ: I can confirm.

MR. VEGH: Thank you, Mr. Lopez.

Turning to you, Mr. D'Andrea, your CV is also at Exhibit A, tab 9, schedule 2. And if we can scroll down just a little bit, you are currently vice-president, regulatory affairs and chief risk officer at Hydro One?

MR. D'ANDREA: That's correct.

MR. VEGH: Could you please provide the Panel with a bit of a background on your responsibilities in that position?

MR. D'ANDREA: I have a dual responsibility. I manage all regulatory affairs as they relate to the Ontario Energy Board. As well, I am the chief risk officer looking at enterprise-wide risks for the company.

MR. VEGH: Thank you, sir. And if you could turn to K1.2, the hearing plan, your areas are, I believe, addressed at pages 5 to 8 of that plan. So Mr. D'Andrea, there is pre-filed evidence, interrogatories, and undertakings provided at the technical conference. Do you adopt that evidence on behalf of Hydro One?

MR. D'ANDREA: I do.

MR. VEGH: Mr. Andre, I will turn to you next. So Mr. Andre, you are currently director of pricing and compliance, regulatory affairs, corporate finance, at Hydro One?

MR. ANDRE: Yes, that's correct.

MR. VEGH: Could you please provide the Panel with a brief statement of your responsibilities in that position?

MR. ANDRE: So I so I oversee the preparation of load forecast for Ontario Hydro -- for Hydro One.

MR. QUESNELLE: You've been doing it for a while, I take it.

[Laughter]

MR. ANDRE: And I also develop -- do the cost allocation and rate design for both the transmission and distribution businesses of Hydro One.

MR. VEGH: Thank you. And the hearing plan at pages 8 to 9 identifies pre-filed evidence, interrogatories, and undertaking responses that were provided at the technical conference.

Do you adopt that evidence -- do you adopt that as part of your evidence?

MR. ANDRE: Yes, I do.

MR. VEGH: Thank you.

So those are the company witnesses, but I'll turn now to Mr. Fenrick, and as I indicated, Hydro One is offering up Mr. Fenrick as an expert in the area of econometric and performance benchmarking and productivity analysis on behalf of Hydro One, so I'll be asking Mr. Fenrick some questions that go to his qualifications to provide that evidence.

MR. QUESNELLE: Thank you.

MR. VEGH: So Mr. Fenrick, I see we have your CV in front of you. So you are currently the leader of PSE's economics and market research group?

MR. FENRICK: Correct, although that title has been modified to director of economics.

MR. VEGH: Okay, and I see that, going down your CV, you've provided -- how long have you been with PSE?

MR. FENRICK: Since 2009.

MR. VEGH: Right. And prior to that you were employed by the Pacific Economics Group. That's from 2001 to 2009?

MR. FENRICK: That's correct.

MR. VEGH: And at page 2 of your CV you outline your education: Bachelor of Science, Master of Science, at University of Wisconsin. I'll also ask: I also understand that you have authored various publications and papers in the area of utility performance and benchmarking?

MR. FENRICK: That's correct.

MR. VEGH: And those are identified in your CV, and if we can go down to page 3 of your CV. I understand that -- so I'm looking under "expert witness experience". We have given expert evidence in a number of regulatory proceedings, including, I believe, three proceedings before this Board where you were qualified as an expert?

MR. FENRICK: Yes, that's true.

MR. VEGH: And two of them were custom incentive regulation applications? That's for Hydro Ottawa and Toronto Hydro?

MR. FENRICK: Correct.

MR. VEGH: And finally going down to pages 4 to 8, you list a number of major research projects on utility performance and benchmarking; is that right?

MR. FENRICK: That's right.

MR. VEGH: Panel I would ask that Mr. Fenrick be qualified as an expert in the area of utility econometric and performance benchmarking and productivity analysis.

MR. QUESNELLE: Okay, thank you, Mr. Vegh.

Any submissions on that point?

The Panel will accept the witness as an expert, Mr. Vegh.

MR. VEGH: Okay. And thank you, Mr. Chair, and just to refer to the evidence that Mr. Fenrick has filed, and I'm sure he will be taken to it in his cross-examination, but for the benefit of the Panel it's at Exhibit A, tab 3, schedule 2, as well as an update to that evidence at Exhibit A, tab 3, schedule 2, attachment 2.

MR. QUESNELLE: Thank you.

MR. VEGH: Thank you. I have no further -- oh, and so as I say, the next steps will be Mr. D'Andrea will provide a brief opening statement for the Panel and then Mr. Lopez will provide the correction to the evidence that we discussed in the preliminary matters.

Mr. D'Andrea, I would ask you to proceed.

OPENING STATEMENT BY MR. D'ANDREA:

MR. D'ANDREA: Good morning. My name is Frank D'Andrea, and I am vice-president of regulatory affairs and the chief risk officer for Hydro One. I am pleased to provide a brief overview of our distribution rates application for the period 2018 to 2022. We have put forth a proposal that we believe balances the needs of our customers in regard to rate levels, provides adequate resources to support the investments required to maintain a safe and reliable system, and incents productivity.

My colleagues on the asset management planning and work execution panel will be pleased to answer any questions on the distribution system plan that supports these investments.

We have put together a plan that meets the principles of forming the OEB's expectations in the renewed regulatory framework for electricity and its handbook for utility rate applications.

Specifically, our application is aligned with the principles in the handbook's option for a custom incentive regulation framework and includes a five-year term, an index for the annual adjustment, benchmarking, performance metrics, productivity enhancements, and mechanisms to protect consumers.

The index for the annual adjustment which we have proposed is a revenue cap index that is based on incentive regulation plan approved in Toronto Hydro's most recent custom incentive regulation application, specifically EB-2014-0016.

The first year of the five-year custom IR is determined using a cost-of-service approach. However, even here the costs included in the 2018 rebasing have incorporated productivity savings of 63.5 million when compared to business as usual. The productivity savings will be addressed by my colleague Chris Lopez, to my right.

The revenue requirement in each year in the following four years, that is, 2019 to 2022 inclusive, is determined using the revenue cap index. The revenue cap index includes a industry-specific inflation factor which is set out by the OEB and two custom productivity factors; namely, zero percent custom industry total factor productivity measure and 0.5 percent custom productivity stretch factor.

These productivity factors are supported by the work of Power Systems Engineering, who are engaged by Hydro One to conduct a study of total factor productivity for the Hydro One distribution in the Ontario industry as well as a custom econometric benchmarking study of Hydro One's total distribution costs in order to recommend a custom productivity stretch factor.

These productivity factors are supported by the report of the OEB's consultant, Pacific Economics Group, who agree that the proposed custom industry total factor productivity measure and the proposed Hydro One stretch factor and therefore the resulting proposed productivity X factor is reasonable.

The revenue cap index also includes a custom capital factor, which is designed to ensure that the total revenue resulting from the custom IR is able to meet Hydro One's specific circumstances as set out in Hydro One's distribution system plan.

The custom capital factor includes a 0.5 percent stretch factor and is similar to that approved by the OEB in Toronto Hydro's EB-2014-0016 application. Moreover, we propose a capital in-service variance account to ensure that ratepayers only pay for capital additions that are brought into service.

We also propose an earnings sharing mechanism which will share with customers 50 percent of the earnings that exceed the OEB allowed regulatory ROE by more than 100 basis points in any year of the application term.

As noted, Hydro One proposes a revenue cap index rather than a price cap index. One of the reasons for the selection is that it better allows us to proceed with the rate integration of the three local distribution companies that Hydro One has recently acquired -- namely, Norfolk Hydro, Haldimand County Hydro, and Woodstock Hydro -- and the OEB's requirement these rates be based on the costs of servicing those utilities in 2021.

For the same year, we also proposed to update the load forecast and the cost-of-capital parameters in order to ensure that the cost allocated to the required utilities accurately reflect the cost to serve them, and to ensure fairness in cost allocation between those rate classes at that time the newly-acquired customer base is integrated from a rates perspective.

My colleague, Henry Andre to my left, will address questions required in the acquired utilities and their integration. I would note that Mr. Andre, who is director of pricing and load forecasting in Hydro One, will also be on the load forecasting and rate design panel and on that panel, he will address rate matter setting for the acquired utilities.

So on this panel in particular, Mr. Andre will address integration of the acquired utilities and the associated updates to set rates in 2021. And on an the on the later panel in which Mr. Andre will also participate, he will address cost allocation and rate design for Hydro One overall, including the cost allocation and rate design for the acquired utilities.

In regard to Hydro One's acquisition of Norfolk, the

OEB approved a five-year rebasing deferred period in order to proceed with the rate integration of all three acquired utilities at the same time for this application. Hydro One will keep Norfolk rates frozen for an additional six years since the acquisition, and I can confirm that Hydro One will be recording the amounts associated with these efficiency savings that are forecasted to accrue in the sixth year in a deferral and variance account for reimbursement to ratepayers.

Calculations in this regard will be set out in the draft rate order.

Finally, Hydro One advises that it will be lowering its proposed revenue requirement to reflect the impact of the Fair Hydro Plan on cash working capital and a reduction to OM&A by 2.9 million, as a result of lower bad debt expense as set out in the interrogatory response at exhibit I, tab 33, Staff 179.

We are also not asking for a cost recovery of $25,000 in customer service guarantee costs referred to in Exhibit I, tab 2, schedule Staff-2. Thank you.

MR. QUESNELLE: Thank you.

MR. VEGH: Thank you, Mr. D'Andrea. As I've mentioned, I would ask Mr. Lopez to address the updated and corrected evidence that was discussed this morning. So Mr. Lopez?

MR. QUESNELLE: They are linked together, so...

MR. LOPEZ: Thank you. I have two corrections. The first one is I-38-SEC70, and here 2018 OM&A figures have been corrected to reflect Exhibit Q OM&A numbers.

The second correction, exhibit I-24 SEC 38; system capacity reinforcement projects are divided between OEB categories of general plant and system service.

We discovered that a handful of systems capacity reinforcement projects were incorrectly met between these categories. We have corrected the mapping in tables 54 to 57 of the DSP provided in exhibit I-24 SEC 38.

We also took the opportunity to reflect changes described in Exhibit Q, and updated the OA forecast reflected in I.38 SEC 70.

Thank you.

MR. VEGH: Thank you, Mr. Lopez. And just for the benefit of the Panel and the parties, the actual evidence on the details of these corrections will be addressed in subsequent panels, the panels dealing with asset management planning and work execution, as well as the shared services panel. But we wanted to provide this correction at the update -- at the outset of the hearing, so that there is an opportunity for the parties to read it, to understand it and prepare for any questions that they might have of subsequent panels on that.

MR. QUESNELLE: So can we mark the package of corrections as one exhibit, Mr. Vegh? Would that work?

MR. VEGH: Thank you, yes.

MR. SIDLOFSKY: That will be K1.3.

EXHIBIT NO. K1.3: EVIDENCE CORRECTIONS PRESENTED BY MR. LOPEZ

MR. VEGH: Thank you, Mr. Chair. I have no more questions for the panel.

MR. QUESNELLE: Thank you. Mr. Ladanyi?

CROSS-EXAMINATION BY MR. LADANYI:

MR. LADANYI: Good morning, panel. My name is Tom Ladanyi; I am consultant to Energy Probe. I think we met each other at the technical conference a couple of months ago.

So the areas that I would like to cover are basically the differences between price cap and revenue cap, and exploring the reasons why you chose the revenue cap over price cap, or any other methodology. If we can -- we filed a fairly large compendium last week, and it's on the OEB's website, and Board Panel members have a paper copy. Do you have a copy of our compendium, by the way?

MR. ANDRE: Yes, we do.

MR. LADANYI: And you have had a chance to look through it?

MR. ANDRE: Yes, over the weekend I did.

MR. LADANYI: Okay, thank you. If you can turn to page 2...

MR. QUESNELLE: Mark it first.

MR. SIDLOFSKY: If we could just mark that as an exhibit. That will be Exhibit K1.4.

EXHIBIT NO. K1.4: CROSS-EXAMINATION COMPENDIUM OF ENERGY PROBE FOR PANEL 1

MR. LADANYI: Yes, K1.4, thank you. Could you turn to page 2? That's your evidence, and I hope I have the right evidence, but I don't have the -- because you've updated since then, so I am not sure if I've got every page right, but I believe this page has remained unchanged in the update.

So specifically, you are asking for a revenue cap and in past proceedings before this Board, there was a fair amount of confusion about what is a price cap and what is a revenue cap. And really, I think it would be very useful for everybody to understand what a revenue cap is. And a really good place to start would be Staff 21, which is on page 38 of our compendium. If you could turn to that, please.

So on page 38, there is actually a reference that Staff provides and they are providing, sort of three-quarters down the page, the standard revenue cap formula.

The revenue cap formula -- do you have it there? Very good. The revenue cap formula takes revenue requirement from year T minus 1, and multiplies it by a revenue cap index that includes 1 plus inflation, minus productivity, plus growth to arrive at revenue requirement in year T. You agree with that, don't you?

MS. ANDERSON: Yes, we do.

MR. LADANYI: In your proposal, you are more or less doing the same, except you do not have the item or the factor G, which is growth in that formula. What do you have instead?

MR. ANDRE: Our capital requirements as identified in the application include those requirements associated with the growth in our customer base and in our load. So our capital requirements already include growth. And then on OMA, the customer company has rebased in 2018 and then we are applying the index, the I minus X index, for beyond the '18 period. So we are not allowing for any growth in OMA as associated with growth in customer base and load.

MR. LADANYI: To arrive at the rate that the customers would be paying, one would then divide the revenue requirement by the billing determinants; is that right?

MR. ANDRE: Yes. So under a revenue cap, that index defines the revenue to be collected and then, you're correct, for the purpose of setting rates we would then divide that revenue in a given year by the billing determinants that fall out of the load forecast that we've provided in the evidence.

MR. LADANYI: And the billing determinants would then change every year, is that right?

MR. ANDRE: Yes. So we filed a five-year forecast in the application, and we're committing to that forecast now. So it will change every year per the forecast as provided in the application.

MR. LADANYI: And that forecast will remain fixed until 2021, when you are going to update the billing determinants? Is that correct? I just heard Mr. D'Andrea say that.

MR. D'ANDREA: Yes, that is correct, at the time that we integrate the acquired utilities.

MR. LADANYI: So again coming back to the standard formula for the revenue cap, in actual fact the growth that's in that formula is actually provided by two factors. Your capital factor plus the billing determinants is actually what is standing-in for the G in that formula?

MR. ANDRE: Right. So I think that's important because growth is used -- that word is used in a number of IR responses, and I think it is really important to understand there are two aspects to growth.

So there is the extent to which growth impacts the revenue that you need, the revenue requirement that you need to run your business. So as you have more output, more customers, presumably you need additional costs to serve those customers, so that's one aspect of growth, but then there is also the extent to which your customer base and your consumption is increasing, and that growth will impact the calculation of rates that you set for a given year.

So there is two components to growth, and I would argue that in this formula that you see in this IR response it is dealing with the first one. It is dealing with the extent to which growth could impact the revenue requirement that you need to run your business.

MR. LADANYI: Thank you very much.

So let's go back to page 2 of our compendium, please. So halfway down the page you are referring to the Toronto Hydro decision, or case, EB-2014-0016, as you say it. Could you for a moment also -- I checked that reference, by the way. I was puzzled by it. So could you check -- go to page 31 of our compendium.

Can you see what case that is, actually? That case seems to be a Direct Energy application for a gas marketer licence. So that's an error, actually, isn't it? And a mistake, a typo, in your evidence?

MR. ANDRE: The intent was to refer to the Toronto Hydro decision.

MR. LADANYI: Which is on the next page, page 32. Could you turn that over? Which is actually EB-2014-0116?

MR. ANDRE: So you are correct, the reference is incorrect in the IR response. It should refer to 0116 and not 0016.

MR. LADANYI: I'm sorry to say that is actually -- that reference -- the wrong reference is given in a number of interrogatory responses, so I expect you are going to correct that at some point.

MR. ANDRE: I think we are correcting it here, so any reference to the Toronto Hydro decision should refer to EB-2014-0116.

MR. LADANYI: Thank you. So on that same page too you are listing a number of advantages of the price cap, of revenue cap over price cap, and specifically referring to the need for flexibility. And by the way, if you want, you can also refer to your response to VECC number 3, which is on page 37 of our compendium. So could you explain to me what does the word "flexibility" in that context mean?

MR. ANDRE: So the Toronto Hydro decision was a price cap, so the index that they developed is intended to apply to the prices established in the prior year, the rates that have been established in the prior year.

In Hydro One's case, as Mr. D'Andrea said, in 2021 we'll be integrating three -- those three acquired utilities. We are proposing to create six new rate classes to accommodate those utilities and ensure that the cost to serve those utilities are reflected in the rates established for those six new classes, and so you don't have -- a price cap would require that you have rates in 2021 which could then be adjusted for -- sorry, in 2020 which could be then adjusted for 2021, and so a price cap isn't well-suited for dealing with the situation where you're rebasing, creating new classes, because you do not have prices in the prior year to which to apply the price cap index.

MR. LADANYI: So if I understand you correctly, the word "flexibility" really means ease of arithmetic? Is that what it is?

MR. ANDRE: The -- yeah, and I appreciate that the response -- and you have taken me to -- you pointed out to VECC 3, and I think that is probably the most comprehensive response in terms of the rationale for the resetting of rates in 2021 and the price cap versus revenue cap arguments, and so in that response to VECC 3 it does refer to more easily and more transparently, but I would suggest, and I'm saying to the Board now, that from a cost allocation and rates perspective it almost goes beyond easily and transparently. There is a need to have rates in the prior year to apply a price cap, and that simply doesn't exist in 2021 when we create these new rate classes. Just give me a second.

Yes, Mr. D'Andrea has pointed out that in the response to interrogatory CME 1 we actually use the words that it's difficult to update the billing determinants to accommodate those new rate classes in 2021.

Again, we are establishing new rate classes, we are rerunning the cost allocation and determining how much of the revenue requirement should go to Hydro One's existing legacy classes, how much of the revenue requirement should be collected from the new rate classes, and therefore you need -- you can't -- your starting point is the revenue that needs to be collected from all of these classes.

The starting point is not the rates that exist for those new classes, because they didn't exist in 2020, so there is nothing to escalate per the index, per price cap index --

MR. LADANYI: Again, I'm trying to understand what you're saying. You're saying that by doing what you're doing you're avoiding perhaps two or three calculations, because you could have done those calculations from a price cap. You are not really prevented by price cap in any way from integrating these utilities?

MR. ANDRE: No, I disagree. I haven't -- I thought about it when I saw this response. I don't see how a price cap could be implemented in the context of creating new classes, rebasing your costs for those classes, and establishing new rates in 2021.

There are no rates in 2020 to which a price cap index could be applied for those six new rate classes that are being created. And in fact, not only for those six new rate classes, the rates for the other classes that were established in 2021 are being reset in 2020 -- sorry. Let me slow down. The rates that were established for Hydro One's other classes in 2020, in 2021 they also get reset per the cost allocation, you know, to reflect the fact that a certain amount of the cost will now be collected from those six new rate classes to serve the acquired classes.

So in 2020 there are no rates for the new acquired classes, and the rates that exist for the legacy classes are not well-suited and, in fact, I'm not even sure how you would do that in terms of re-establishing those rates in 2021 under a price cap index.

MR. LADANYI: We might follow up this when you would be up here on the rate design panel.

MR. ANDRE: Absolutely.

MR. LADANYI: So let's go to another bullet on that page. It says "permits the continued transition to fully fix rates for residential customers", so there are other utilities in Ontario that are moving to fully fix rates. And they must be facing the same difficulties. They are not asking for a revenue cap; can you explain how -- so this is going to be easier for you than for the other distributors in Ontario; is that right?

MR. ANDRE: Yeah, so again, I think if we could go to the interrogatory response I7 VECC 3.

MR. LADANYI: Yes.

MR. ANDRE: Which you have in your compendium. I just want to bring that up, because I do want to clarify that. In the response to part A, the last paragraph, we say there that both the price cap and revenue cap are equally capable of continuing the transition to fully fixed residential rates. So in the evidence we just wanted to indicate that the revenue cap can accommodate it, but we are not suggesting that when it comes to the transition to fully fixed residential rates, we agree that both a price cap and a revenue cap can accommodate that change.

MR. LADANYI: Very good.

Okay, let's go down to another one. So: "Provides adequate flexibility to reset customer rates should the OEB proceed with elimination of seasonal rate class."

So adequate flexibility there, what does that mean? Again, it's an IESO calculation. Is that what you're talking about?

MR. ANDRE: Yes, so again, with respect to the elimination of the seasonal class, we are back to that same issue where you would have to -- if the seasonal class is eliminated, you then have to rebalance or redo the cost allocation to determine the rates that would need to be collected from the other classes, the seasonal class disappears, so you are resetting the rates, and when you are resetting the rates and redoing the cost allocation, a price cap, which would simply have taken the rates that existed and escalated them per the index, a price cap doesn't accommodate as well.

So again, we use the word "flexibility". I think when it comes to new classes or changed cost allocation it's prob -- "flexibility" is probably too weak a word. It probably should have said that it -- it actually can't accommodate, or at least I can't see how you could accommodate a price cap index to rates that didn't exist in the prior year.

MR. QUESNELLE: Mr. Vegh, just through Mr. Andre, Mr. Andre, perhaps it was just a bit of a -- you misspoke, but you suggested that should the OEB proceed with the elimination of the seasonal class. I just want to make it clear that that's not an issue that is being determined. It has been determined. The OEB has eliminated the seasonal class. So I didn't want it to be left in the air that that was a yet-to-be-determined matter.

MR. ANDRE: Yes, Mr. Quesnelle, I apologize. I meant to say how that is done, because I think the how part is still to be determined.

MR. QUESNELLE: Understood. Thank you very much.

MR. LADANYI: To the last bullet on that page:

> "Provide adequate flexibility to reset customer rates as OEB advances its initiative to determine rate design for commercial and industrial customers."

So my question to you is: Isn't that the problem that all of the distributors will be facing, not just you?

MR. ANDRE: The Board has a consultation underway to determine potential changes to commercial and industrial rates. We're waiting to see what the outcome of that consultation is.

I agree with you; it depends on what the outcome is. If it involves creating new classes, if it involves potentially rerunning cost allocation across new classes, that one -- it's uncertain what the outcome of that consultation will be. But if it did involve, as I said, rerunning the cost allocation and creating new rates for new classes, then you have the same issue.

MR. LADANYI: Thank you. So could you turn to page 3 of our compendium, please?

In the middle of the page, you talk about -- you say:

"Although specifically created for use for incentive rate-setting using the price cap IR and annual index plans, Hydro One proposes to use the same inflation factor in its customer revenue cap."

So I don't know if this is a question for Dr. Fenrick or is it a question for you, but perhaps you can explain why you can use the same inflation factor.

By the way, we also on the next page, page 4, we ask more or less the same question in our Interrogatory No. 5.

MR. D'ANDREA: I'll let Mr. Fenrick speak to the specifics of it, but what we are saying in our response is that we're agnostic, because the inflation factor is not set by us and it is independent of whether it is a price cap or revenue cap model.

MR. FENRICK: If I could just add to that? When designing a price cap index or a revenue cap index, that inflation factor is really meant to capture the industry input price inflation, and that should be identical between the revenue cap or a price cap index.

MR. LADANYI: Could you turn for a moment, Dr. Fenrick, to page 20 of our compendium? Do you have that?

Again, you could -- I could be wrong here, but my impression here is that what the Board says here that for fourth-generation IRM, the utilities are to use the composite index, which you are proposing to use. But however, you have a custom IR, and here they talk about a distributor-specific calculation, and again the composite index for the annual IR index column.

So can you again explain how you interpret this page, and do you feel it's appropriate not to have calculated your stand-alone distributor-specific inflation index?

MR. FENRICK: I think in the fourth-generation IR, and I was a part of that proceeding, the inflation factor was meant to be an industry input price inflation measure, and that was an appropriate measure in this case as well for the revenue cap index.

MR. LADANYI: Thank you. So further down on that page, on page 3, so the inflation factor will be updated annually by the Board being able to just use that number, is that right? Is that what it says?

MS. McKinnon: Sorry, on which page?

MR. LADANYI: We are on page 3 of the compendium.

MR. D'ANDREA: Yes, that's correct.

MR. LADANYI: Okay. So let's turn to page 5 of the compendium. Here you discuss -- and this is again your evidence and you are discussing the capital factor.

My only question on that page is, in the last paragraph, and that's with the exception of the applied-for cost-of-capital update in 2021. So the only update of cost of capital would all be for 2021, is that right, and the rest will remain fixed?

MR. D'ANDREA: That's correct, when we integrate the acquired utilities.

MR. LADANYI: Okay. Can you turn next to page 6 of the compendium?

So in this spreadsheet, what is -- by the way, can you explain to me what you are trying to show us with the spreadsheet or this table, table 1?

MR. D'ANDREA: So this is basically how the revenue cap model will work. So 2018 is your cost of service and in 2019, you have two elements going on.

One is the I minus X being applied to the OMA and then there is the capital factor, which is embedded in that formula. And if you take the capital factor that is embedded in that formula -- and if you scroll down, there should be a table there that shows you how it works when you take those factors. So that's your total, the index in total. So 3.41 for 2019, and if you scroll down to the bottom of that page -- the next page, sorry -- you can see how the formula works.

So you would take the 2018 revenue requirement and multiply it by the factor that's computed, and 2019 is the exact same thing. So the capital factor is part of that annual index.

MR. LADANYI: Thank you. If you go back to page 6, table 1, explain to me -- so about the methodology used for integrating the productivity factor into your calculation of the capital factor, particularly, as I understand it, there is no existing OEB-approved methodology for calculating a capital factor.

So this is your proposal, isn't it? You are not following anything that the Board has approved in the calculation of capital factors?

MR. D'ANDREA: The capital factor is similar to what Toronto Hydro did in it their application.

MR. LADANYI: Yes, but Toronto Hydro was a price cap. You will have to agree with me. We will get to that in a little while.

MR. D'ANDREA: That's correct.

MR. LADANYI: This is a revenue cap and as I see it here, you have applied a productivity factor of 0.45 percent, which is again your proposed proper factor, isn't it? That's not what you would have got otherwise? You would have otherwise had 0.6, isn't that right?

MR. D'ANDREA: The 0.45 is what our proposal is, and it's supported by our studies.

MR. LADANYI: Right, okay. So I was wondering why would you apply this productivity factor, for example, on line 7. Why not apply it to the entire capital factor at the bottom?

It seems like -- at line 7, it seems to have a very, very small effect on the capital factor.

MR. D'ANDREA: So the -- I mean, the application of the productivity factor is similar to what happened in Toronto Hydro's case, where you applied on the capital.

There is natural increase in capital-related revenue requirements just because of the IRM formula. So the -- we see on line 14 that is to reduce that amount of capital requirement, so you are not double counting it. And then 0.45 is the stretch factor applied to capital just as it is applied to OM&A.

MR. FENRICK: If I could, could I just jump in for a second? I believe he have in the fourth-generation IR benchmarking update, the last update that came out, the 0.45 percent was the finding in that latest report. It wasn't the 0.6 percent, but the 0.45 percent, I believe.

MR. LADANYI: Could you turn to for a second, just for a little while, to page 21 -- sorry, 29 of our compendium, which is your response to BOMA number 144?

In here, you are basically referring to Toronto Hydro and saying that the Board said that the stretch factor should apply to both capital and OM&A.

So, your proposal on page 6 of our compendium, on table 1 shows how you would apply it to capital; is that right? And you are going to apply to OM&A elsewhere?

MR. D'ANDREA: That's correct.

MR. LADANYI: So since Dr. Fenrick just mentioned the factors .6 and .45, could you turn to page 52 of my compendium, please? Okay. And there you are -- in the middle of the page you are explaining what you are doing. This is an updated forecast, is that right, that you have prepared, that justifies, you believe, changing the stretch factor from 0.6 to 0.45?

MR. D'ANDREA: That's correct.

MR. FENRICK: That's right.

MR. LADANYI: And if you turn to the next page, page 53, and -- which is your response to Board Staff 22, as I read that interrogatory, Board Staff is more or less challenging what you're doing because really you would have had to do a calculation of our benchmark all of the utilities to actually find where Hydro One's ranking would be, in which group it would be. You just moved it as if all of the other distributors had remained static and Hydro One changed, but perhaps in the intervening period the other distributors have become more productive, so it might not justify moving the cohorts, moving, let's say, Hydro One to a different cohort. And by the way, if you want to review where they are, it is on page 56 of the compendium.

So Hydro One is in group 5, and you are saying your new information justifies moving Hydro One to group 4; is that right?

MR. FENRICK: I believe this is from the 2014 stretch factor assignments. I believe the latest assignments that came out from Pacific Economics Group moved Hydro One to group 4 to be the 0.45 percent, which also aligns with our most recent research, as well as PEG's research in this case.

MR. LADANYI: So when did these new assignments come out?

MR. FENRICK: At some point in 2017, I believe it was.

MR. LADANYI: Okay, could you actually file that, please, as an undertaking?

MR. VEGH: Just so I'm clear, so what's the request for the undertaking?

MR. LADANYI: Well, we would like to see this document. I'm sorry. Obviously I have the wrong reference here. I am on page 56. I'd like to see what the correct one is.

MR. VEGH: So it is the 2017 stretch factor assignments?

MR. LADANYI: That's right.

MR. D'ANDREA: We can do that.

MR. VEGH: Yes, we can do that. It is on the OEB's website.

MR. SIDLOFSKY: That will be Undertaking J1.1.

UNDERTAKING NO. J1.1: TO PROVIDE THE 2017 STRETCH FACTOR ASSIGNMENTS.

MR. LADANYI: Okay. And specifically, did you make the change before the Board issued the new stretch factor assignments or after?

MR. FENRICK: I believe -- it's been a while, but I believe our report came out before, prior to the 2017 stretch factor update, so at the time when we filed our report I believe it was 0.6 percent, and then subsequently to that was the 0.45 percent that the Ontario Energy Board fourth-generation update came out and said that group 4 would be the appropriate group.

MR. LADANYI: Okay, thank you.

Let's go to page 7 of our compendium, please. So here on table 2 you are showing what the total customer revenue cap index is by the amount by which you are increasing your revenue requirement in each one of the years, and the numbers as I see are 3.41 for 2019, 3.28 for 2020, and so on.

So these numbers are fairly large increases, and they appear to be significantly higher than the inflation for those years. And it's largely driven by your capital factor, as I can see there; would that be right?

MR. D'ANDREA: Just to contextualize, you have got the inflation factor there. I think the inflation factor has now been updated. But it is inflation less the productivity.

What you referred to as large, I wouldn't call it large, is what is driving in the capital factor, and capital factor again includes the growth component, and this is necessary for us to go with a revenue cap model because it meets our needs -- our investment needs of our system.

MR. LADANYI: And just to come back to something that we talked about a few minutes ago, it is partially driven, also, isn't it, by load, essentially the load growth? Load growth is not increasing as quickly, and what you are dividing is large revenue requirement by essentially not as quickly increasing load.

MR. ANDRE: So the capital factor reflects the capital investments that are detailed in our distribution system plan and, you know, it's those investments are driven by the need to provide safe and reliable distribution system, so -- and they're fully detailed in the distribution system plan, and panel 4 will be here to defend that.

So what you're seeing there is the need for the capital spend, and that capital spend, you are correct, would include -- so to the extent that we anticipate needing to expand the system to accommodate growth, then that would be included in the capital forecast that we've submitted as part of our distribution system plan for the five years.

So you're right, it does include growth, but more importantly, it includes a careful assessment of the capital that we need to spend in order to deliver the outcomes of the R -- renewed regulatory framework.

MR. LADANYI: Very good. So on page 8 of our compendium are the revenue requirements that result from your calculation.

MR. ANDRE: Yes, and just a small note. There is a typo in 2019. It says that the 2019 revenue requirement would be 2018 times 1.0336. It should have said 1.0341, consistent with the table 2 on the previous page. So a small typo, but the revenue requirement amount is correct, five --

MR. LADANYI: The number is correct, 1-billion-551.0 is correct?

MR. ANDRE: That's correct.

MR. LADANYI: So if you could turn to page 9 next. So I thought it would be worthwhile to go back to basic differences between the revenue cap and price cap, and 20 years ago when Ontario Energy Board first started regulating or was preparing to regulate distributors in Ontario, I think at that time there were about 300 distributors in Ontario, and it was looking at the ways that it could efficiently and practically regulate those distributors. It convened a number of task forces or committees, and one of them was the cap mechanism task force. Somebody who had been around this industry for a while will remember that. Do you remember that, Mr. Andre?

MR. ANDRE: No, I wasn't involved in this business or this part of the business at that time.

MR. LADANYI: Very good. So if you turn to page 3 of the -- sorry, page 10 of the compendium. And here it just shows the rate regulation methodology that cap mechanisms, you can either have a price cap or a revenue cap, and they're also looking at other ways of regulation, benchmarking and so on, but that doesn't -- shouldn't concern us right now.

So then could you go also next to page 11 of the compendium. And there the committee or the task force described the price cap mechanism, and it says:

"The price cap mechanism provides an upper limit or cap to the price, or basket of prices."

So that appears to be an advantage of price cap, and would you agree with me that the revenue cap does not actually provide an upper limit or a cap to the rates that the customers are changed, whereas the price cap does.

MR. ANDRE: No, I would disagree with that. The revenue cap defines the revenue to be collected, and then the prices are capped at that revenue -- are capped to deliver on that revenue, taking into account the change in load that the utility is going to see in the subsequent year.

So, you know, and I would -- you know, you correctly pointed out that this was a 1999 report probably input into the first generation IRM models that the Board developed.

Since then, they've gone to second, third and now fourth-generation IRM. They've introduced a custom IR option. So, you know, this is likely a more theoretical discussion and I would note that in that same sentence you pointed me to, it says: "The price cap mechanism provides an upper limit or cap to the price, or basket of prices, charged by an LDC," and then it says, "and allows flexibility below the cap," seeming to suggest that you have some flexibility in setting prices below that cap, and the prices that we establish follow the Board's rules with respect to cost allocation and rate design.

And there is no flexibility in setting the prices. The prices are set in order to deliver the revenue cap that's established by the formula -- or sorry, the revenue that's established by the formula. So I don't think there is that flexibility.

MR. LADANYI: The way I read this flexibility, by the way, is really that it allows the distributor flexibility on how to run its business so that it can operate and provide service under a fixed price, or a limited price. And this is where incentive comes in to be more productive. The utility is not able to pass on its cost to ratepayers to run its business. It is actually limited from passing its cost, and therefore is forced to finding savings.

Would you agree with that?

MR. ANDRE: Yes, we agree and I think the Boards' rules around the custom IR and the process that is established for a custom IR achieves those same goals. There is a productivity factor built into the OM&A and the capital spend.

Hydro One has already included productivity in its initial 2018 costs; that was referred to in our opening statement. So there's productivity built in there. And I would expect we have -- I don't know if we have other mechanisms in terms of protecting customers around a custom IR.

So I would agree that the custom IR delivers those same incentives as the formula that you've set up here, or that you've referred to.

MR. LADANYI: Could you turn to page 12 of the Compendium? In the first paragraph, I think it's the third sentence:

> "The price cap approach has the distinct advantage that it comes the closest of the three to replicating the process of competitive markets."

So you can see what the Board was looking at in regulation, and I think the Board is always looking to do that in regulation, to replicate the process of competitive markets.

But the price cap, it says -- if you read further down towards the end of that paragraph:

> "It leaves the LDC exposed to changes in energy throughput. Some have argued that the incentive for the utility to maximize throughput under the price cap mechanism is a drawback. On the other hand, this may be seen as an effective use of an available capacity."

So this is what the committee or the task force thought in that time about the price cap.

Do you still agree with that, or do you feel that things have changed so much that it's not -- it is no longer true?

MR. ANDRE: I don't know if it is no longer true. I mean, this was a 1999 report, and I think the Board has considered incentive regulation many times since then. And

I think the Board's current thinking on what is required in terms of delivering outcomes for customers is best reflected in their handbook for rate applications, and is best reflected by the three options that they now make available to utilities in terms of price cap index, a custom IR, or an annual index.

So I think the Board's thinking has evolved over time and we're -- we've put together our application with reference to the Board's current directions on how to prepare an application.

MR. LADANYI: So the next paragraph says: "The revenue cap mechanism attempts to resolve the throughput problem associated with a price cap PBR," performance-based regulation, which is what they called incentive regulation at that time.

> "Instead of setting a price cap, it sets a revenue cap. However, in resolving this problem, it create others."

And specifically:

> "Once the revenue cap has been set, the LDC has an incentive to set prices at levels that would under utilize the capacity of the system. This discretionary control over prices could also lead to greater price volatility. Moreover, the revenue cap mechanism requires throughput growth projections and the use of true-ups in the event of errors in any of the projections that make up the revenue cap. Perhaps most importantly, it

does not focus on the setting of relative prices and providing a set of incentives within the framework that encourages optimal efficiency."

So the way I read this paragraph, it suggests to me that the revenue cap does solve problems, certainly as they say. But it create new ones and it also does not provide as much of an incentive to increase efficiency or productivity as a price cap.

MR. ANDRE: Again, I think this paragraph points to the fact that thinking has evolved over time, and that this is probably a theoretical-based discussion because in the middle of that paragraph, as you read, it says this discretionary control over prices could also lead to greater price volatility.

And as I think I indicated in my earlier response, there is no discretionary control over prices. The custom index as proposed will define the revenue that's to be collected, and then that revenue to be collected together with the load forecast that's been established for that year will determine exactly the prices to be set; there is no discretionary control.

So that suggests to me that this was a more of a theoretical discussion back in 1999 and as I've indicated, we're going with the direction that's currently identified by the Board's renewed regulatory framework.

MR. LADANYI: But the revenue cap could result, even under your method which is, let's say, the current method of revenue cap in greater fluctuation of rates. They could be up more or down more, depending on the load because they would be very dependent on the load and also on your capital factor.

MR. ANDRE: If it wasn't for the integration of the acquireds in 2021, the revenue cap as we've proposed is essentially identical to the price cap. All that would be required to translate that revenue cap into a price cap would be a reflection of what's happening to load, which is essentially what Toronto Hydro did.

If you look at Toronto Hydro's index formula, the first part of the formula calculates what changes are required to the revenue requirement. And then they add a growth factor to the end of their formula to reflect that they aren't updating for load forecast. They are using the load forecast that they established for their five-year period and came up with one growth factor.

In our case, we don't have one growth factor over the four years because the integration of the acquired utilities in 2021 doesn't lend itself to that.

Hydro One's revenue cap as proposed for 2019 and 2020, the years before the integration of the acquired utilities, that could easily be a price cap just simply by addressing the growth or change in customer -- number of customers and volume of customer load. So the addition of a growth factor for those years would make those two formulas identical.

I don't think there is as much difference between revenue cap and price cap as you are suggesting. It is really how you deal with the changing load in the subsequent years. And Hydro One has chosen to deal with that changing load by taking the actual determinants as we currently forecast for those years, and dividing the revenue requirement by those determinants to come up with a specific rate.

Could it be smoothed via a growth factor? Potentially. But again, we couldn't do that for 2021 because the integration of the acquired utilities drives both the discontinuity in the cost to be collected and a discontinuity in the load forecast over which those costs are collected.

MR. LADANYI: What you're saying -- my impression is that the revenue cap actually transfers the load risk to the ratepayers. Under price cap, the shareholders bear the load risk; under revenue cap, the ratepayers bear it.

MR. ANDRE: No, sorry. If that's what you took from my discussion, I wasn't clear. The price cap takes -- instead of having an annual adjustment to take into account for the load, it would come up with an averaged growth factor. So a price factor also takes load into account, but it does it via a G factor that applies to all years. Hydro One's proposal does that for each year of its application.

So, no, price cap will absolutely -- takes growth into account and puts that risk in the same place as a revenue cap, and that is with -- you know, the utility is agnostic as far as load is concerned, whether load is going up or down, and to the extent that that drives rates we're agnostic to that, but both the price cap via the growth factor and a revenue cap via the calculation of rates to take into account the subsequent years' billing determinants, those arrive at the same place.

MR. LADANYI: Thank you for that answer. If you could turn to page 16 -- page 15, perhaps, and tell us what we are looking at. During that same time period that the task force on cap methodology prepared a report, Board Staff also prepared its own report and discussed again the differences between price cap and revenue cap, and we'll go quickly through this, because I think we have probably covered in a fair amount of detail, but there are some good sentences in here that we should look at. So on page 11, if you look at the last paragraph, it says:

> "Price caps are a form of utility regulation that focuses initially on controlling prices directly, rather than indirectly as to cost-of-service rate-of-return regulation."

So price cap focuses directly on the rates that the ratepayers pay. And essentially, my read of this, that price cap is trying to keep those rates from increasing faster than the rate of inflation; that's the intent of price cap.

In the revenue cap it isn't really the same, and we'll turn to revenue cap in a minute.

MR. ANDRE: Yeah, so, I'm sorry, what was the question?

MR. LADANYI: The question is whether you agreed with what I said, and I'm not sure I will be ready to repeat it, but in essence if price cap is a simpler form of regulation that focuses directly on the rates that the customers or ratepayers are paying, by trying to keep them increasing at a lower rate than the rate of inflation increase in society at large, if you like?

MR. ANDRE: So again I would point to the recent rulings that the Board has made with respect to a number of utilities that have come under custom IR, and in terms of how it's being applied new with respect to price cap, Toronto Hydro is a good example. So the price cap index that Toronto Hydro has increases the revenue requirement to reflect product -- inflation minus productivity, adjusts that revenue requirement to reflect the change in capital via its capital growth factor, and then -- sorry, via its capital factor, and then it has a growth component to reflect its changing load in the subsequent years and what that has -- what impact that has on rates.

So, no, I mean, based on recent experience, the regulation now would adjust for the utilities' needs, OM&A and capital needs, and even under the price cap regulation, remember, that first option has the ability for an ACM or ICM in subsequent years to, again, address the capital need, so I think the capital requirements have been recognized by the Board. They've adjusted their IRM formulas to take that into account, and they've further provided a custom IR option where they recognize that some utilities' capital needs go beyond what could be provided via an ACM or ICM, and so they allow that option for utilities to file, and that's what Hydro One is doing, it's filing an option that recognizes its capital investment needs.

MR. LADANYI: Thank you. So if you could turn to page 17 of our compendium, there -- Board Staff report discusses revenue-cap regulation, and I've probably taken too much time on these basics, but I want to draw to your attention on page 18 a concluding statement which is in paragraph 1, and you can -- and we can read the rest if you like as well:

> "However, revenue caps differ from price caps in reducing both incentive risk and the risk associated with sales."

MR. ANDRE: So again, I would -- in terms of how it's been implemented since this report was written in 1998, in terms of how it's being implemented now, the change in sales is absolutely a consideration in the setting of the price cap index. In the Toronto Hydro proceeding PEG highlighted that as an issue, that the formula, as proposed by Toronto Hydro, wasn't taking into account the growth in customers, and the Board in that proceeding agreed with PEG and had required Toronto Hydro to include a growth component that takes into account sales in subsequent years.

So again, I think the sentence or the paragraph that you've pointed to is older thinking that doesn't reflect the latest directions from the Board.

MR. LADANYI: I included in the compendium also the Board decision that after receiving all of these reports the Board, on page 14 of the compendium, you can see that, it decided to adopt a price cap mechanism for the PBR for the first-generation IRM, if you like. It says:

> "Further, the Board is of the opinion that price cap regulation for all the electricity distribution utilities represents a simple approach that will provide incentives for efficiency improvements and will at the same time provide the ability to maintain service quality over the course of the first-generation PBR."

So at that time the Board believed that a price cap was providing greater incentives than other alternatives, including a revenue cap.

MR. ANDRE: Yeah, again, that sentence points to the fact that that was the thinking going into the first-generation PBR, and I think it's by the time they got to the third-generation PBR it was recognized that capital spend needs were an issue, and I think at that time they introduced the ICM module as an adjustment to price cap in order to deal with those needs. Since then they've developed a ACM approach and they've developed a custom IR approach to deal with those utilities that really have special circumstances that take them outside of what is suitable under a price cap.

MR. LADANYI: Since you do mention ICM, so if you see on page 20 of my compendium, you can see that ICM is not applicable to custom IR. You can see that, and we will agree with that.

MR. ANDRE: Absolutely.

MR. LADANYI: However, have you, prior to filing this application or even deciding on the revenue cap with a capital factor, have you done some calculations to see whether your needs could have been met by ICM or ACM?

[Witness panel confers]

MR. D'ANDREA: We did not do the calculations. We had to holistically look at the options that were available to us, and because of our large and variable work program, which is one of the requirements for custom IR, we thought that the custom IR, based on Toronto Hydro precedent, that would more suit our needs in terms of meeting our distribution system plan requirements. The ICM, ACM model is really meant for discrete projects that are non-reoccurring.

MR. ANDRE: And I just, I would add to that, so in addition to those considerations, again, integration of the acquired utilities in 2021 was another key factor in saying that a price cap approach wouldn't be suitable.

MR. LADANYI: So if I understand what you are saying is that your capital investments are large and lumpy, are large and not lumpy? What you are saying, because ICM is designed for large and lumpy, so yours are large but not lumpy; is that right?

MR. D'ANDREA: I would say they are large and lumpy.

MR. LADANYI: Yeah, but ICM specifically is designed for large and lumpy, so it's got to be large and not lumpy, but, I mean, we can get into that when we discuss the capital numbers. I don't want to get into a capital numbers discussion.

MR. ANDRE: I mean, I would point you to the Board's report on the funding of capital investments and the details of the advanced capital module, and that was under proceeding EB-2014-0219, and on page 14 of that report they point to the fact that the use of an ACM is most appropriate for a distributor that does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding. Hydro One does have multiple discrete projects, and ACM is most appropriate for a distributor that is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishment. Again, some of the capital that we are seeking is a recurring capital program, so not discrete projects for replacements or refurbishments, so again, Hydro One is in that situation and therefore an ACM is appropriate.

And then the last one is, an ACM is most appropriate for a distributor that is not proposing to use the entire eligible incremental capital envelope available for a particular year. And our capital needs make full use of the incremental capital envelope.

So, you know, based on the ACM report itself, Hydro One's circumstances are such that it wouldn't be suitable to make use of an ACM.

MR. LADANYI: Okay. I think we can probably argue that in argument, so I don't want to go any further with this.

Could you turn to page 25 of the compendium? This is from the handbook of utility rate applications, the Board's own handbook, and if you look at the last paragraph or last bullet point on that page, basically it says:

"Custom IR is not a multi-year cost of service. Explicit financial incentives for continuous improvement and cost control must be included in the application."

Do you believe that you have explicit financial incentives for continuous improvement and cost control in your application?

MR. D'ANDREA: Yes, I believe that. Let me elaborate.

We have productivity savings already baked into our custom IR. We've got it in capital and we've got it in OM&A, and those will even help us meet our DSP, and we've got the reductions for the productivity factor.

Our cost of capital is not updated annually, so it is meant to be a pure IRM formula and we're incented to define those savings. You've got to remember, too, when we put forth our capital programs, we have plans A, B and C. The recommendation was originally Plan A. We were challenged by our board, and so we're trying to find the right balance, we call it striking the right balance between customer rates, between the system reliability and the rate impacts.

So what we've done is develop a plan that meets our needs. There is not a lot of system reliability improvements, but it does meet our needs for the next five years.

So we are driven to find those efficiencies, because we are always gearing towards Plan A even though we have got a Plan B modified in terms of this rate application.

MR. LADANYI: Thank you. So could you turn to page 26 of the compendium, which, by chance, is exactly page 26 of the handbook. Amazing coincidence.

At the first paragraph, it says:

> "The index must be informed by analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes."

And so on. I don't have to read you the whole paragraph.

Have you performed this analysis of trade-offs between capital and operating costs?

MR. D'ANDREA: The analysis of operating or capital is really a question of the planning group, and in derivation distribution system plan, they make their informed investment decisions on whether to approach a particular investment that is operating or replacement through a capital addition.

MR. LADANYI: So we will, I guess, have to follow-Up about this trade-off analysis with the capital group?

MR. D'ANDREA: I can't speak to the analysis they've done, but I know they are the ones that make those investment decisions. So it would be best to leave it to that panel.

MR. LADANYI: But there is no clear evidence that would point me to a finding or assessing this trade-off? There is no specific piece of evidence. It is buried somewhere in the capital evidence, is that correct?

MR. ANDRE: Well, again let's -- if we read the that sentence, they say that the index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and cost capital costs. In other words, that analysis of your five years of OM&A and capital spending, as Mr. D'Andrea just said, which is part of our distribution system plan, that goes towards identifying the trade-offs that have been made.

I'm not as familiar as to whether there is a specific table or assessment that looks at that. It is the whole distribution system plan in total that gets to which investments are better handled through OM&A and which investments are better handled through capital.

MR. LADANYI: Okay. In the second paragraph, it says:

"It is insufficient to simply adopt a stretch factor that the OEB has established for electricity distribution IRM applications. Given

"...the utility's ability to customize the approach to rate-setting to meets its specific circumstances, the OEB would expense generally expect the custom index to be higher, and certainly no lower than the OEB-approved X factor for price cap IR that is used for electricity distributors."

So is your custom index higher or lower?

MR. FENRICK: I can answer that. So the X-factor would be the same that the company is proposing versus the IRM option, the 0.45 percent.

MR. D'ANDREA: If I could add to Mr. Fenrick's response, the capital already includes -- productivity savings are already baked in. So if you couple that together, it's actually higher because we have already baked in savings that we are committed to.

MR. LADANYI: I'll have to think about that. So if you go to page -- by the way, I am mindful of the time and I think a break is coming at 11:15. So let me finish this section; it will take us probably about five minutes and that will be a good time to break.

So page 27, the last bullet point says:

"Protecting customers: A key objective of incentive regulation is to drive productivity improvements within the utilities."

And it says in the paragraph below:

"However, the OEB expects utilities filing a custom IR application to propose one or more

mechanisms to protect customers from utility
earnings that become excessive."

So how are you doing that?

MR. D'ANDREA: In our application, we are proposing an earnings-sharing mechanism, as I said in my opening statement.

MR. LADANYI: So that is your main methodology for protecting ratepayers from excessive earnings?

MR. D'ANDREA: That's correct.

MR. LADANYI: Okay. If you go to page 28, in the very last paragraph on that page is a warning to custom IR applicants:

"If a custom IR application does not meet all of
these requirements" -- and there's many; I did
not obviously refer to all of them -- "the OEB
may impose a reduced term, reject the
application, or determine that an application is
incomplete and will not be processed until the
requirement are met."

So the last time Hydro One was before the Board, it actually got a reduced term. Is that right?

MR. D'ANDREA: That's correct.

MR. LADANYI: So at this time, you feel that you have met all the requirements and that you will not get a reduced term?

MR. D'ANDREA: As I said in my opening statement, we've gone through the handbook and we believe we strongly met the requirements. This is minimum of five years.

We've got an annual rate adjustment that is supported by empirical evidence, our 0.45 stretch factor. We've got benchmarking, which is also a requirement by PRC.

We've got performance metrics that are clear, visible and transparent, not only our OEB scorecard, but we have a supplementary scorecard and a team scorecard.

We have very little in the way of updates, and we are protecting customers through our earnings-share mechanism and our capital and service variance accounts.

On that basis, we believe, and actually following Toronto Hydro, that we've met the requirements.

MR. LADANYI: Thank you, this is a good time to break.

MR. QUESNELLE: Thank you. Let's do that then. Let's return at 11:30.

MR. VEGH: Thank you, Mr. Chair, just before we do break, I think we had indicated on the record...

As you are aware, and has been the practice in the past, even though on a break and on subsequent breaks, I'll continue to work with the panel with respect to answering interrogatories and things of that sort on an ongoing basis throughout the course of the hearing.

MR. QUESNELLE: That's understood, Mr. Vegh, thank you very much.

--- Recess taken at 11:15 a.m.

--- On resuming at 11:38 a.m.

MR. QUESNELLE: Thank you. Please be seated. Continue, Mr. Ladanyi.

MR. LADANYI: Thank you, Mr. Chairman.

If you could turn to page 29 of the compendium. Now, here we have covered most of what's in this response. One thing I want to just get a confirmation on, during examination in-chief I had the impression that Mr. D'Andrea said that the stretch factor was 0.5 percent. Perhaps it's the sound in the room. Were you saying 0.5 percent or 0.45 percent?

MR. D'ANDREA: My colleague Mr. Andre said I misspoke. It is .45.

MR. LADANYI: Thank you.

So could you turn to page 30 then of the compendium. Here you mention in your response in the third line that custom IR method was required to meet Hydro One's operational requirements. Could you explain to me what is operational requirements and how are your operational requirements significantly different from other distributors in Ontario?

MR. D'ANDREA: Our operational requirements as those spelled out in our distribution system plan. Again, we pick the revenue cap model because of the large and variable capital expenditures. I can't speak to how other utilities are doing in terms of their capital; all I can tell you is we picked the option that was considered for us, in terms of the options under the rate handbook. Again, there is no eligibility requirements. We picked the one that was most suited to our business needs.

MR. LADANYI: So it wasn't specific, let's say to your customer needs. It was really basically to Hydro One's or

Hydro One's shareholders' needs?

MR. D'ANDREA: No, I would disagree with that. As I stated at the beginning several times in my response, it is a balance. And we strike the balance with our Board. It's striking a balance between operational needs, our customer preferences, and the rate impacts.

MR. LADANYI: Now, further on in that response on page 30 you mention that you looked at Toronto Hydro and you are adopting the same kind of methodology. And Toronto Hydro, of course, is a price cap, and you can turn to page 32 and the following pages, 33 of the compendium, and there is the Board decision or portions of the Board decision in the Toronto Hydro case, EB-2014-0116, and we know that it is a price cap.

So rather than going through every page maybe you can simply tell me what are the similarities and differences between your application, in very simple terms, and Toronto Hydro's application, so first, what are the similarities, and then you can tell me what are the differences, or you can do it the other way around.

MR. D'ANDREA: Maybe what I'll do is I'll go through the different components, so our application is based on a five-year custom IR, as is theirs, the difference being they are under a price cap and we are under a revenue cap.

They have a capital factor as well, although in their case their capital factor was reduced by 10 percent. That reduction was based on lack of productivity improvements and a focus by Toronto Hydro as a replacement, as opposed to customer needs, whereas we've gone through an extensive customer consultation process.

The OEB-approved capital and service variance account, we have proposed a capital service variance account as well. We will add back verifiable productivity savings in our capital and service variance account. No such concept was there in Toronto Hydro.

Toronto Hydro applied for updates to the cost of capital and load forecast, both of which were denied. We are asking for a one-time opener, if you want to call that word, in 2021 when we integrate the acquired utilities, and we both have an earnings sharing mechanism with 100 basis points split 50-50.

MR. LADANYI: So would that be all?

MR. D'ANDREA: Those are the main highlights.

MR. LADANYI: Okay, thank you.

So if you could turn to page 28 -- sorry, 35 of the compendium, page 28 of the Toronto Hydro decision. And there is a -- there is a suggestion at the bottom that is discussing that. It says:

> "PEG's evidence suggested that C factor should include an adjustment for the growth in Toronto Hydro's billing determinants in order to prevent the C factor from over-recovering capital costs."

So are you sure that your C factor will not over-recover your capital costs? And how are you sure of that?

MR. ANDRE: So the -- PEG made that statement, and the Board in its decision agreed with that assessment because, as we've said, the Toronto Hydro is price cap, and so if they apply escalated prices to a growing customer base, right, same prices, but you have more customers and more load, that's going to generate additional revenues for you that you can use to offset your capital needs, so under a price cap -- and we absolutely agree with this statement -- under a price cap you need to take into account what's happening to your load and how that new load times the price-cap adjusted prices, what kind of revenues that will generate.

Under Hydro One's proposal we're increasing the revenue requirement that we need per our capital plans that we identified per our capital growth factor and then we're taking that revenue requirement, as an example, in '19, so the higher revenue requirement in '19, and then dividing it by the actual billing determinants in that year, so that given the forecast load that we anticipate we will exactly recover the revenue requirement as approved by the Board under the revenue cap index.

MR. LADANYI: And these billing determinants are forecasted for the entire five-year period, or tell me again how they work.

MR. ANDRE: Yes, our application includes a forecast of the billing determinants for the full five years of the application, and other than the update in 2021 for the reasons laid out in a number of IRs we are committing to stick to that forecast.

MR. LADANYI: So the update would be only for the merged utilities; i.e., the Hydro One's portion of the billing determinants would remain unchanged, but the only billing determinants will be essentially to that you'll add billing determinants for the merged utilities.

MR. ANDRE: No, our proposal is to update the load forecast, Hydro One's total load forecast, in that year.

MR. LADANYI: In its entirety.

Okay. So can you turn to page 40, please. This might be a question for Dr. Fenrick, because I think he provided the answer. This is a response to OEB Staff Interrogatory No. 25. And here they are questioning how the X-factor was calculated and whether the billing determinants are important in calculation of the X-factor. And your response was that billing determinants are not pertinent to design of an X-factor in the context of a revenue cap index.

And then you provide, Dr. Fenrick, some calculations, and I'm not expecting you to go through these, but if you can tell us in simple terms why billing determinants are not pertinent for a revenue cap?

MR. FENRICK: Absolutely. So a revenue cap index, if you to go a high level, is supposed to track cost, in total costs, and what the Hydro One needs as far as recovering those costs, and so the -- if there was some sort of growth index or the output index in the TFP calculation should be cost-elasticity-weighted rather than revenue-weighted or billing-determinant-weighted, and so that's the point I was getting at there, and the question was essentially for a price cap index, the revenue weights and billing determinants are the pertinent thing to be tracking in those output indexes, but in a revenue cap index context where we're trying to track costs and have revenues match cost, then cost elasticity-weighted output indexes are the appropriate index that will track cost the best.

MR. LADANYI: And the cost of a utility's actual costs, whereas in price cap they are not the utility's actual cost; is that what you're saying?

MR. FENRICK: Well, incentive regulation we are not tracking actual costs. We are tracking a projection of the escalation of that cost based on industry norms.

MR. LADANYI: So essentially what you are saying in price cap you are not escalating costs, but in revenue cap you are escalating costs, forecast costs?

MR. FENRICK: In a price cap, you are trying to come up with an escalation mechanism that will track unit costs, or what prices will need to be -- that the utility would need to be charging in order to recover revenue and that's driven by unit costs, which is inflation minus X.

In a revenue cap index context, you are trying to determine, rather than unit cost, what total costs and how that cost will be escalated, and that should be based on cost elasticity weights in the output index for the TFP calculation -- which is what we have here, by the way.

MR. LADANYI: I'll have to think about that.

In part (b), Board Staff says:

"The Ontario utilities' positioning to rate designs with high fixed charges for residential, and possibly also for other commercial industrial classes, that this reduced the weights that are appropriate for volume and peak demand variables in the output index for productivity research intended to establish a price cap index productivity factor."

And your answer is part (b), and you can see that. Can you elaborate on your answer, part (b) on page 42?

MR. FENRICK: I can. It is essentially the same answer as I just gave, as far as a price cap index should have the billing determinant revenue weights, as I say in that first sentence.

But when move to a revenue cap index, now we are trying to track costs rather than unit costs. So rather than billing determinant revenue weights, a cost elasticity weighting should be conducted.

In the TFP analysis that we provided, that's what we did was a cost elasticity-weighted index, which is the appropriate method. PEG also did the appropriate method as far as a cost elasticity-weighted output index for the revenue cap index, and so this is all -- if you go through the mathematics of it, it is exactly as it should be. It is best practice that we are putting forth here.

MR. LADANYI: Since I've got you answering questions now, could you just turn to page 48, which is your response to VECC Interrogatory No.8?

If I can ask you just a simple question. Dr. Fenrick, you have actually no methodological or philosophical differences with PEG or Dr. Lowry. Is that right? The only differences in the collection of data, is that correct?

MR. FENRICK: I would characterize it as there is certainly minor differences of opinions between experts. I think -- I believe that PEG's methodology overall is a sound one. We, in many ways, employ the same methodology. I believe it is best practice.

If you look at the total factor productivity research, we use similar methods as far as geometric decay assumptions that I believe are the most appropriate for distribution and transmission utilities. On the benchmarking front, we do a similar kind of metric approach.

Yes, we differ on sometimes the datasets. For instance, we have 380 different utilities in the PSE dataset, which is an extremely large dataset that we've conducted our econometric testing on.

PEG limited that to more around a 70 number. We came out with nearly identical results on benchmarking. Both independent consultants came up with a 0.45 percent stretch factor. Our findings are extremely close in those differences.

So I would characterize -- yes, we have minor differences, for instance on the input price assumptions and things like that. But overall, I believe PEG does employ best practice methods, as well as PSE does.

MR. LADANYI: In your answer to part C on page 49, you discuss the dataset. So PEG used an Ontario-only dataset, which you disagree with, and you used a dataset that included U.S. utilities. Is that right?

MR. FENRICK: When you say PEG, you mean PEG's fourth-generation IR benchmarking research as opposed to their report in this proceeding? They did use a U.S. -- they had utilities in the U.S. and came out with very similar results.

So you mean the fourth-generation IR?

MR. LADANYI: I think the answer in part C refers to the fourth -- I am looking at the answer, and I thought they were the same. But you are telling me there is a difference, so can you explain that?

MR. FENRICK: Right. For the fourth-generation incentive regulation, PEG uses an Ontario-only dataset that is meant to estimate stretch factors for all the distributors in the province.

In this specific case, PEG modified that dataset and included U.S. distributors which much more closely matched PSEs or our dataset, in which we also use U.S. distributors, essentially because evaluating Hydro One's total cost benchmarking performance, you really do need to employ a larger and more diverse dataset than the Ontario-only dataset.

Hydro One is an extreme outlier within Ontario and so, while PEG's 4G IR methods are perfectly sound for the best majority of distributors in the province, they are not appropriate for extreme outliers, such as Hydro One.

MR. LADANYI: So there are some U.S. comparators that are similar to Hydro One? Which ones would they be?

MR. FENRICK: I would say there is no exact similar comparators to Hydro One, which is why we did not use a peer-grouping approach. We used econometrics, which essentially looks at the variables that drive cost, you know, density, number of customers, peak demands, input prices, forestation, a whole host of variables that we put into the models and said okay, given these variables, how does each one influence cost of its distributor.

So using the econometric approach, we don't necessarily need exact comparators to Hydro One. We just need to determine those factors that drive cost, how those factors drive cost, and then fashion a benchmark using that analysis and that econometric approach, which is why we have 380 distributors in our dataset over 4,000-some observations when you look at all the annual observations to really drive down and determine, okay, given each of these variables, how does that influence distributor costs, and then we fashion that benchmark accordingly.

So it is a much more sophisticated analysis than doing a simple peer group approach, because you are exactly right, there is no exact comparators to Hydro One within North America.

And so using this approach is the most sophisticated, most accurate result that we can come up with, and both PSE and PEG have come to very similar conclusions on what that shows.

MR. LADANYI: Did PEG do the same kind of analysis or not?

MR. FENRICK: I would characterize it is a very similar. The datasets were different, so we used -- PSE used rural electric cooperatives in the U.S. to basically inform our models with utilities that have more rural service territories.

PEG decided to not include that dataset, but focused on the investor-owned utilities. There's also a few variable differences. But at the end of the day, they employed very similar econometric methods. Their cost definitions were very similar and their whole approach, I would characterize it is a very similar as well as the results came out nearly identical, even given those differences.

MR. LADANYI: Mr. Chairman, I'm mindful of the time. Do I have enough time, lets say, for another roughly another half hour? How constrained are we?

MR. QUESNELLE: Well, that is considerably beyond your estimate, Mr. Ladanyi. But carry on. As far as the lunch break goes, yes, you have enough time. But I'm hoping we get someone else started before lunch.

MR. LADANYI: Thank you, sir. There are a number of areas that I'd like to cover, but I'd like to go to something that's not in the compendium, which is a spreadsheet.

So Energy Probe tried to do a calculation comparison of price cap and revenue cap, and we exchanged draft spreadsheets with Hydro One last week. I don't know that we reached an agreement, but I would like to discuss some of the numbers on the spreadsheet with Hydro One and to -- they can point out, if there are some problems with it and what the difficulties are.

So it is up on the screen now. Can we have an exhibit number for that, please?

MR. SIDLOFSKY: Yes, that will be K1.5.

EXHIBIT NO. K1.5: ENERGY PROBE PANEL 1 SPREADSHEET

MR. LADANYI: So here in the first line we have the revenue requirements from the evidence, and there is a reference in the right-hand column. And then we increase the revenue requirements by the index and we arrive at -- we also have below that line -- in the line below that we have total load per year in gigawatt hours, and then we convert that to kilowatt hours, and then we calculate an average rate per unit delivered. Just a very simple calculation. And then we calculate an average annual -- average percent change in cost per unit delivered, and below that we try to duplicate what the price cap would do under the same circumstances, so we take the revenue requirement from in 2018, the base year, and we calculate just the very simple annual rate. I know that Hydro One has a complex rate structure, of course. And then we escalate that by 1.45, and you can see the annual revenue on -- using price cap, what it is, which is in the second-to-last line on the page. And then we have in the very last line the differences between the two.

And based on our calculation, which may or may not be right, and you will -- I will ask you to tell me where we're wrong -- it shows that your revenue cap proposal is recovering substantially greater amounts of money than a similar price cap would do.

So, for example, in 2019, you will be recovering from ratepayers $43 million more than you would have if you had a fourth-generation IRM price cap. And we are leaving out, by the way, any potential ICMs here or anything else like that.

So if I can ask you -- have you had a chance to look at this last week and possibly more over the weekend -- could you tell me if we're correct here in our assumption?

MR. ANDRE: So I did have a chance to look at this spreadsheet, and really my observations are two. One is, so in what you've done in the third row from the bottom -- and you didn't make that very clear -- what you've taken is the previous year's price, so in 2018, the third row from the bottom, the previous year's price was 4.16, 4.16, and then you escalate that by the -- what you are calling the price cap index, which is just inflation minus productivity, or 1.45 percent, so the 4.16 goes to 4.22.

And then you take the 4.22 and you multiply that by the forecast load in 2019, which is a decrease, so the load did drop, so you take this adjusted price that only takes into account the 1.45 percent, multiply that by the lower load, and that's how you come up with what you're saying is the revenue -- annual revenue under price cap, and then you calculate the difference.

So my observations are two. One is obviously if you only take into account the 1.45 percent you are ignoring the fact that Hydro One has significant capital needs and Hydro One's revenue cap includes the revenue associated with funding its capital requirements as identified in its distribution system plan. So that's one.

If you only take into account productivity -- inflation minus productivity, you are ignoring the capital needs that Hydro One has identified.

And then the second issue is, under your approach, you are ignoring the change in load. So as the fourth row shows -- and you are only looking at kilowatt hours, and I think you did point out that other, you know, number of customers and peak demand would also drive revenue, so this is a simplification of what would drive revenues. But taking that as a simplification, you see that the load drops from 2018 to 2019, right, and so -- and there has been no adjustment in your price cap to recognize that load is dropping, you know, the -- as I mentioned before, certainly Toronto Hydro's formula would take into account the change in load.

Now, in their case load is going up, so their growth factor was, we're generating more load -- more revenue as a result of load going up. In this case it illustrates that Hydro One's load is going down in '19, so really the rates should be adjusted upwards to reflect that the load, which is beyond Hydro One's control and which we're forecasting to drop, that that load should be -- or, sorry, that the rates should be adjusted to reflect that dropping load.

So those are the two things that really we completely disagree with. Your price cap, as formulated here, doesn't take into account the capital requirements, revenue associated with capital, and it doesn't appropriately account for the changing load from '18 to '19 and for the other years as well.

MR. LADANYI: So doesn't specifically what you just said prove that your revenue cap proposal, in fact, transfers the load risk to the ratepayers? So if you had a price cap, more of that risk would have been borne by the shareholders and would have actually restrained Hydro One from its spending in order to meet its, let's say earnings requirements, so with a revenue cap there is actually a built-in adjustment in your proposal whereby Hydro One is protected from essentially load risk; isn't that right?

MR. ANDRE: No, I disagree. I think a properly constituted price cap as it was in the case of Toronto Hydro takes into account the impact of changing load on the index that gets applied to prices.

So in Toronto Hydro's case, load was increasing, so they adopted a growth factor that drops the prices to recognize that load is increasing in subsequent year and therefore you don't want to over-recover costs, and they use an average growth factor over the years of -- over the four years of their plan.

In Hydro One's case, we also need to take into account load, so price cap takes into account load, a properly constituted price cap takes into account, and our revenue cap also takes into account load. They both do.

MR. LADANYI: But don't the fourth-generation IRM, the other distributors, apart from Toronto Hydro, have the kind of protection that you're seeking?

MR. ANDRE: You're right, under fourth-generation IRM there is no recognition of what's happening to load, but, you know, I would point you back to the Board's handbook for rate applications, you know, and they specifically say -- just bear with me.

So on page 24 of the Board's handbook they -- you know, at the very top of the page -- it's been up on the screen before, but I can read it for you. So custom IR, under this methodology rates are set for five years, considering a five-year forecast of the utilities' costs and sales volumes, so that's what we're -- you know, under a custom IR it is contemplated that both the costs and sales volumes would be taken into consideration in developing the index. That's what Hydro One -- that's what Toronto Hydro did in theirs, and the Board -- they didn't initially, but PEG pointed out that growth was an issue, the Board agreed with that, so in the end what got approved for their price cap took into account sales volumes, and this is what Hydro One is doing in what we believe is a simpler, more direct and transparent way, by adopting a revenue cap and then adjusting for the sales volume in the calculation of rates in the subsequent year.

MR. LADANYI: Thank you.

Just one more question. I'm mindful of the time, Mr. Chairman. So could you turn to page 66 of our compendium. This will be my closing question.

So this is in response to our interrogatory Energy Probe number 3, and this table shows the 2019 bill impacts. So on that table, the column around the middle of the table that says "change in Dx bill", so it says "change in", I think that's distribution bill; is that correct?

MR. ANDRE: Yes, that's correct.

MR. LADANYI: So the percent changes, when I look at these changes, they are pretty scary. These are very large numbers. Are you concerned about these large increases?

MR. ANDRE: Sorry, could I see page -- I don't happen to have that one in my witness binder. Could I see page 1 of that?

MR. LADANYI: The question, actually?

MR. ANDRE: Yeah. Ah, okay. So the question asked: If rates were made effective January 1st, 2019 -- sorry, the application was approved as-is but an effective date of January 1st, 2019. So what that table is shows is showing is the revenue-requirement that would have been required in 2018 is approved, but it's collected in '19. So what you're seeing is the impact of one full year as a foregone revenue being collected in '19, in addition to the increase that's required in both '18 and '19. So you are seeing a compounding effect by effectively taking all of the '18 increase and '19 increase and lumping it into one year.

MR. LADANYI: So -- and I take your answer and I agree with it. But what it really also shows is that the customers will be seeing very large percent increase and they're going to be very concerned about this, and some of them will have difficulty in dealing with those increases.

Are you concerned about that? Do you have any proposals of how to deal with that?

MR. ANDRE: Well, I mean -- I agree those are significant increases, you know, if you attempt to collect the 2018 foregone revenue all in one year. So in essence, I think that's what this is, is disposition of the foregone revenue, the 2018 foregone revenue over the 2019 year period.

It may point to the need to dispose of any foregone revenue over a longer period perhaps, or it may point to the need for some form of bill impact mitigation.

I would note that in terms of the impact on total bill, other than the R2 class, the impact -- and the sentinel light class and the DGen class, but DGen, we're already proposing bill mitigation for that.

So for the bulk of the classes, let's say, the impacts are less than 10 percent total bill, which again the Board's filing requirements would suggest that at total bill impacts above 10 percent, you would need some form of mitigation. And therefore, this clearly shows that if the foregone revenue is to be disposed of in a single year in 2019, some form of bill impact mitigation would be required for the R2 and the sentinel light classes.

And as I've said, we have already made similar proposals on the DGen in terms of bill impacts.

So as I've said, what you're seeing here is the combined impact of that 2018 foregone impact all being collected in '19. When look at the average impact across the five years, the bill impact is around --

MR. D'ANDREA: 3.4 percent.

MR. ANDRE: -- 3.4 percent. So yes, I agree that foregone revenue and how to deal with foregone revenue is an issue that the Board is going to have to consider in this application.

MR. LADANYI: These are all my questions, Mr. Chairman, and thank you for indulging me and allowing me to go a few minutes longer than expected.

MR. QUESNELLE: Thank you for responding to our concerns.

MR. SIDLOFSKY: Sorry, Mr. Quesnelle, if I could just interrupt for a moment?

Mr. Ladanyi, I'm not sure. Did you file a table electronically, Exhibit K1.5?

MR. YAUCH: We just sent it around this morning.

MR. SIDLOFSKY: Okay.

MR. YAUCH: I can file it.

MR. SIDLOFSKY: If you could, I think that would help, just so it's in the web drawer. Thank you.

MR. QUESNELLE: Thank you. Mr. Stephenson?

CROSS-EXAMINATION BY MR. STEPHENSON:

MR. STEPHENSON: Good afternoon panel. My name is Richard Stephenson, and I am counsel for the Power Workers' Union. I don't have a compendium. There are very few documents that I am going to take you to. I am going to deal with this, I think, at a fairly high level.

Mr. D'Andrea, I think most of this is for you. I'm going to be focusing on the question the selection -- the ultimate selection of the Plan B modified investment proposal, okay? And I take it you are the right person to talk about that. Is that correct, Mr. D'Andrea?

MR. D'ANDREA: If you are looking for the plan details themselves and what's behind the Plan B modified, it is panel 5.

MR. STEPHENSON: No, I'm talking about the decision that this was the correct approach, the rejection of the other alternatives, that question. I take you are right person for that?

MR. D'ANDREA: Let's try that.

MR. STEPHENSON: Okay. If I could get you first to take a look at -- it's Exhibit I, tab 3. It's SEC 4.

This is the documents that went to the Ontario -- sorry, the Hydro One board of directors. And if I could just take you to the -- it is the third page of that document, which is the October 11, 2016 submission to the board of directors.

I gather that at the time, your predecessor, Mr. Hubert, was in charge ever this document; is that right?

MR. D'ANDREA: That's correct.

MR. STEPHENSON: Were you involved at all at that time, or just subsequently?

MR. D'ANDREA: Subsequently.

MR. STEPHENSON: Okay. You are familiar with both the process and the document generally, however, correct?

Okay. If you scroll through that document and starting really at page 7, there is a discussion starting at that page and following about Plan A and Plan B.

And just to be clear, the Plan A and Plan B that are referenced here are the same Plan A and Plan B that are discussed subsequently that are part of the four options, correct?

MR. D'ANDREA: That's correct.

MR. STEPHENSON: And at the time of this document, Plan A was recommended and Plan B was not recommended, correct?

MR. D'ANDREA: That's correct.

MR. STEPHENSON: And obviously we know that the board of directors had concerns about that, and there was a revisit, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. But starting at page -- it's page 7 at the very bottom of the document, in the middle, there is a chart there that outlines the basis of the fact that Plan A was recommended and that Plan B was not Recommended, okay. Do you see that?

MR. D'ANDREA: Okay.

MR. STEPHENSON: Okay. The concerns -- well, let's put it this way. The merits of Plan A and the concerns regarding Plan B, I take it that those merits and those concerns were valid then and are valid now. It's -- there were other factors that led to the change in thinking, correct?

MR. D'ANDREA: Well, it was the factors that we tried to balance; again, customer needs, system requirements and rate impacts.

MR. STEPHENSON: Fair enough. But what's written down in this document is accurate? Those were the validly stated merits of Plan A and the validly-stated concerns of Plan B. Leaving aside the issues that were ultimately decided, but as far as this document goes, Hydro One is still of the view that it is a fair and accurate description of those -- of the matters set out therein?

MR. D'ANDREA: That's correct.

MR. STEPHENSON: Okay. And just to be clear as to where these options sit on the spectrum, the difference between Plan B and Plan B modified was that Plan B had slightly more spending embedded in it.

There was more activity embedded in it than in Plan B modified, correct?

MR. D'ANDREA: That's correct, there was more capital.

MR. STEPHENSON: And so directionally, the concerns that are in this document with respect to Plan B are all present in Plan B modified as well, except to a slightly greater degree; fair?

MR. D'ANDREA: Fair -- as compared to Plan A?

MR. STEPHENSON: Well, no, Plan B modified relative to Plan B. Plan B modified has got -- all of the concerns expressed in this document about Plan B exist with respect to Plan B modified, correct?

MR. D'ANDREA: No, the concerns were with Plan A, Right? Plan A was -- we'll call it too much for example, and I'm trying to figure out what you are comparing it to.

MR. STEPHENSON: Let's take a step back. In this document, the one we're looking at right now, Plan A was the recommendation, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: There wasn't concerns about Plan A in this document. Plan A was the recommendation, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. Plan B was not recommended, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: And there were concerns expressed in this document which justified the fact that it was not recommended?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. And you've said already Hydro One stands by this document as far as it goes, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. All I want now to deal with is that the ultimately approved proposal was Plan B modified.

MR. D'ANDREA: Correct.

MR. STEPHENSON: Which has less activity and less spending.

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. So the concern expressed in this document about Plan B was that it didn't have enough activity and it did didn't have enough spending, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. And so all of those concerns would also be true of Plan B modified, fair?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. Now, we know, fast-forward, the Board has got concerns about Plan A and they have concerns about Plan B, which leads to Plan B modified, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. And the Board's concern is fundamentally a rate impact concern and a bill impact concern, fair?

MR. D'ANDREA: Well, they looked at reliability as well.

MR. STEPHENSON: I understand that, but they -- and they struck a balance, fair?

MR. D'ANDREA: Correct.

MR. STEPHENSON: But just to be clear, Plan B modified results in less reliability than either Plan B or Plan A, right?

MR. D'ANDREA: Correct.

MR. STEPHENSON: But the Board considered it to be an acceptable trade-off, fair?

MR. D'ANDREA: Fair.

MR. STEPHENSON: Now, at this Board there has been a lot of discussion over many, many hearings about the deferral of capital spend and OM&A on system maintenance, and from time to time Hydro One has come in looking for specifically spending to make up for essentially concerns regarding the system -- the robustness of the system and prevent system degradation; you are familiar with that history, correct?

MR. D'ANDREA: Yes.

MR. STEPHENSON: And whenever you had -- the consequence of going for Plan B modified is that certain spending that was proposed and recommended under Plan A is deferred; correct?

MR. D'ANDREA: That's correct.

MR. STEPHENSON: And in fact, that was one of the risks identified in Plan B; correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. So the bottom line is that all of that deferred spending is going to be -- let's put it this way: The deferred work, the deferred work is going to be done sooner or later; it's just going to be done, relatively speaking, later, correct?

MR. D'ANDREA: Well, we were asked to look at pacing of our investment, so, yes, that's what we were doing.

MR. STEPHENSON: It's going to happen later, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. So the first point is:

Doesn't that create an intergenerational equity problem that future ratepayers are going to be faced with the cost of that work that really should be done now?

MR. D'ANDREA: I can't say what will happen in the future, because we are trying to continuously be productive and find efficiencies, so it is our goal to manage those investments, manage the pacing, and find better ways to do the work.

MR. STEPHENSON: Okay. Mr. D'Andrea, let's get real here. Are you telling me that future ratepayers are going to get this work for free because you are going to be that much more efficient? Let's get real.

MR. D'ANDREA: I didn't say it was for free.

MR. STEPHENSON: Okay. So they are going to pay for it. So doesn't that create an intergenerational equity problem? You are asking later people to pay for work that should be done now.

MR. D'ANDREA: Well, we have been asked to look at -- we have to strike the right balance, and we would have to do the same decision in the future, so we would have to look at the rate impact and the investment and the reliability. Are we deferring -- are we --

MR. STEPHENSON: Well, I understand that --

MR. D'ANDREA: -- deferring the work? Yes, we are deferring --

MR. STEPHENSON: Right. Okay.

MR. D'ANDREA: -- work --

MR. STEPHENSON: But for the rate impact you'd be doing it now, right? There is no doubt about it.

MR. D'ANDREA: Well, most of the rate increase that is we are seeking for are capital-related. They are already capital-related. If you look at what we've done in terms of what's driving our rates, our OM&A is generally flat, less than inflation --

MR. STEPHENSON: I -- I --

MR. D'ANDREA: -- so it is a capital issue.

MR. STEPHENSON: -- agree with you --

MR. D'ANDREA: It is a capital issue.

MR. STEPHENSON: It is this incremental amount, and the question is: Who pays for it? Is it paid for by current ratepayers or is it paid for by future ratepayers? And you've made a choice. It's future, yes?

MR. D'ANDREA: To the extent we've deferred it, yes.

MR. STEPHENSON: Okay. So part of the Board's concern about rate impact, I take it, arose by virtue of the feedback that Hydro One received when it did its customer consultation about its proposed planning; is that fair?

MR. D'ANDREA: That's fair. Our customers were concerned about price.

MR. STEPHENSON: Okay. Now, all of that customer consultation, and I believe the Board decision, occurred before the implementation of the Fair Hydro Plan; is that correct?

MR. ANDRE: Yes, the Fair Hydro Plan was implemented July 2017, and would have been discussions about what that might look like and some initial information on what that might look like came out in early '17, so --

MR. STEPHENSON: The Board might have been aware of that, but that certainly wasn't part of the customer consultation, fair?

MR. LOPEZ: You are correct. At the time of the consultation, the Fair Hydro Plan was not at a point where it could have been disclosed, so they would not have been aware.

MR. STEPHENSON: Right. Just before I move on to that, just, there was something I needed just to tidy up.

This business about Plan B modified, we're now almost halfway through 2018. Am I correct that Plan B modified is what you are, in fact, ruling out in terms of your work program already in 2018?

MR. D'ANDREA: That is my understanding.

MR. STEPHENSON: And that's how you are going to proceed until you are told otherwise?

MR. D'ANDREA: That's correct.

MR. STEPHENSON: Okay. So we asked a question, an interrogatory about the effect of the Fair Hydro Plan, and I don't think you need to turn this up, but for the record, it's tab -- Exhibit I, tab 3, PW number 1. And in response to that, you told us that your R1 and R2 rate classes are -- get distribution rate protection at the Fair Hydro Plan; correct?

MR. ANDRE: All customers -- yes, distribution rate protection, yes, that applies to Hydro One's R1 and R2 customers, as well as other rural customers and other utilities.

MR. STEPHENSON: Right. You are one of the utilities that's specifically prescribed by the regulation, correct?

MR. ANDRE: Yes, that's correct.

MR. STEPHENSON: Okay. And the effect of that is that the bills that those customers receive -- any changes in those bills for the duration of the Fair Hydro Plan will be what is prescribed in that regulation, correct? That is how their bills will look.

MR. ANDRE: That is how the distribution -- the base distribution rates component of their bill will be, yes. Those changes will be as prescribed per the regulation.

MR. STEPHENSON: And the outcome of this proceeding will not determine what their bills look like on that base distribution rate, correct?

MR. ANDRE: Yes, that's correct, so the bill impacts that we show in the application per the Board's filing requirement show the change in distribution rates as a result of what we proposed, but as Mr. Stephenson said, in terms of what customers will actually see on their bill, any increase in base distribution rates that we show in this application wouldn't actually appear on customers' bills as a result of the distribution rate protection for Hydro One's R1 and R2 customers.

MR. STEPHENSON: And technically speaking, those rates aren't frozen or those bills aren't frozen under the regulation, but directionally that's what's going on, fair?

MR. ANDRE: Yes, the bills aren't frozen. We were taking about the distribution rate protection?

MR. STEPHENSON: Yes.

MR. ANDRE: Is limited per the regulation, and there is some mechanism to potentially increase that, so, yes, so there is nothing frozen, but they should go up very slowly.

MR. STEPHENSON: And in addition to that, those same customers, the R1 and R2, may have -- may get other -- let me back it up.

There are a variety of other savings that are passed on to current consumers under the Fair Hydro Plan, and those are outlined in this interrogatory response, correct?

MR. ANDRE: Yes, there's distribution -- or electricity prices have come down, which is a benefit to all customers under regulated price plans, and some of the regulatory charges have come down, yes.

This interrogatory lays out all of the different impacts from the Fair Hydro Plan on customers.

MR. STEPHENSON: But there is one that is not indicated in there that I understand that these customers will have the benefit of. I want you to confirm that I'm right about this.

As I understand it, again depending upon what happens to the rate of inflation and, in particular, depending upon what happens to Toronto Hydro distribution rates because they are the prescribed proxy customer under the act, all customers in Ontario may get reductions in their commodity costs in the future to offset increases in distribution rates, correct?

MR. ANDRE: I'm not sure about your statement about to "to offset increases in distribution rates." Yes, the electricity prices changed per the Fair Hydro Plan regulation. So any changes to electricity prices that come out of that would apply to all customers in Ontario.

But I'm not sure I see your link between that and distribution prices. When it comes to distribution prices, there is a specific regulation that deals was that.

MR. STEPHENSON: Absolutely. All I'm saying is that -- let me back it up.

Under the Fair Hydro Plan, commodity costs no longer move around; they are prescribed by statute, correct, for people on standard service?

MR. ANDRE: Yes, if they are linked to that proxy, to the proxy customer's bill, yes.

MR. STEPHENSON: So if Toronto Hydro's distribution rates go up more than the rate of inflation, as I understand it, the commodity cost for all Ontario customers under that prescribed commodity cost will decrease by the difference between the Toronto Hydro distribution increase and inflation, correct?

MR. ANDRE: Yes, I see what you're saying now. Yes, that's my understanding of how it would work. I think -- I don't know if we've had an occasion to see that being implemented. In fact, I do -- it has, the first change...

MR. STEPHENSON: Coming up?

MR. ANDRE: No, the first change came up in May where there was reference to it. So yes, I think in principle I would agree with you, Mr. Stephenson.

MR. STEPHENSON: So again, that exerts a downward influence on R1 and R2 customer bills, correct?

MR. ANDRE: Certainly, yes. They pay electricity, so to the extent that electricity prices are reduced for all customers in Ontario, then R1 and R2 customers would also see that benefit.

MR. STEPHENSON: Okay. We also asked you in terms of the significance of R1 and R2 classes to your total customer base and revenue base, and you told us that in terms of number of customers, R1 and R2 amount to, combined, 60 percent of your total customers, correct?

MR. ANDRE: Yes, that's correct.

MR. STEPHENSON: And 57 percent of your distribution revenue, correct?

MR. ANDRE: Yes, that's correct.

MR. STEPHENSON: And that's for 2016. Is there any reason to expect any material change in those proportions for 2017-'18 going forward?

MR. ANDRE: No, I mean, to the extent of -- you know, depending how the elimination of the seasonal class is implemented, that might result in significant numbers of customers moving into the R1 and R2 classes, but -- so other than that that proviso, I would say yes, those numbers aren't going to change materially.

MR. STEPHENSON: If anywhere, the numbers are if going to get higher, is that fair?

MR. ANDRE: Yes, that would be fair.

MR. STEPHENSON: Okay. So here's where I'm going Here. You know, 57 percent of your distribution revenue, that's a lot. It is the majority of your distribution revenue.

If you had chosen to go to Plan A relative to Plan B modified, those 60 percent of your customers, that 57 would not -- they would not experience that on their bills during the period of the Fair Hydro Plan, correct?

MR. ANDRE: Yes, that's correct.

MR. STEPHENSON: You would get that revenue, but those customers wouldn't see it. They would see it however Fair Hydro Plan is going to be recovered downstream, right?

MR. ANDRE: Yes, that additional revenue would be recovered through the Fair Hydro Plan mechanisms, which would mean it would come from -- would be funded through the government.

MR. STEPHENSON: Didn't you think that that was something that you ought to take into consideration?

Objectively, Plan A was the preferred plan but for the rate impact consideration. You had -- you know, 60 percent of your customers aren't going to be paying it. Wasn't that a relevant consideration?

[Witness panel confers]

MR. D'ANDREA: I think, as was pointed out, we didn't know at the time. So it wasn't a consideration; that came out after.

MR. STEPHENSON: I get that, but you now -- you filed your application, and I appreciate that at the time you filed your application, you didn't have it.

But applications get amended all the time. This is a pretty material change in the substrata of this application. Your primary concern -- the Board's primary concern is rate impact.

You've got 60 percent of your customers that are facing no rate impact. You didn't take a re-look?

MR. ANDRE: I mean, as you've mentioned 60 percent -- 40 percent of our customers would see the impact of any increases in revenue requirement, and the Board's filing requirements require us to demonstrate what the impact would be of -- separate the Fair Hydro Plan, what the impact would be on rates.

So I think those are also valid considerations.

MR. STEPHENSON: I understand that. I'm not prejudging the outcome of your analysis. I'm just asking you the question: Did you ask yourself the question? And you say, you know what? We decided to do X. The world has changed. Maybe X isn't the right answer any more. Maybe we should do something different.

Did you ask that question?

[Witness panel confers]

MR. ANDRE: Mr. Stephenson, my answer would remain as I've said. I agree that the impact on R1 and R2 customers are mitigated.

The impacts on distribution rates are mitigated by the Fair Hydro Plan. But we have 60 percent of our other customers that would see the impact of increased revenue requirement, and as Mr. D'Andrea has said, I mean, there's three things that we are considering: the needs of our system, the needs of our customers, the preferences of our customers and the impact that those two things have on rates.

MR. STEPHENSON: I think you meant 40 percent of your customers there?

MR. ANDRE: Sorry, 40 percent.

MR. STEPHENSON: Yes. But wouldn't you agree with me that at least for R1, R2, the 60 percent of your customers, 57 percent of your revenue, they get the system they need and deserve, right? That's what Plan A says, and they are not facing the rate impact.

Like, who puts the hand up for those guys and says they're better off. You know what, maybe we should do the right thing for those people. I understand that our other customers are going to face some costs, but why do the other customers -- why does the tail wag the dog? Why is the 40 percent governing for the 60 percent?

MR. ANDRE: It's -- Mr. Stephenson, my answer isn't going to change. As I said, they represent 60, but the other 40 percent of the customers see the impact.

It's the answer that I've given. I'm not sure that I can give you anything new.

MR. STEPHENSON: Okay, so the 60 percent are the losers here.

Okay. One other -- a couple other little things just to deal with. You -- the application indicates the differential rate impact between Plan B modified and Plan B and Plan A, but I didn't see in the application -- and maybe I missed it. There is a lot in there -- the revenue-requirement differential between Plan B modified and Plan B and Plan A.

There must -- there must be a number there, because you couldn't have done the rate impact differential without it. And I guess maybe if you can just give me an undertaking, like, it may be in the application already, but if it's not you can tell us what the revenue-requirement differential was?

MR. D'ANDREA: We'll take an undertaking to get it.

MR. STEPHENSON: Thank you.

MR. SIDLOFSKY: J1.2.

UNDERTAKING NO. J1.2: TO PROVIDE THE REVENUE-REQUIREMENT DIFFERENTIAL.

MR. STEPHENSON: Let me finish with this. One of the criticisms of the Fair Hydro Plan -- it's just from the public media, and it strikes me a fair criticism of it -- is that, you know, sooner or later you've got to pay the piper, that insofar as people are paying -- or aren't seeing bill increases now, sooner or later somebody is going to have to pay for them downstream; you've heard that criticism, fair, correct?

MR. ANDRE: Yes.

MR. STEPHENSON: So -- and we don't know exactly when that's going to happen, we don't exactly know how it's going to happen, we don't exactly know from whom it's going to happen, but here's the concern I have for you: You've deferred some spending. We all agree it's going to have to be done sooner or later, and when it's done later it is going to have to get paid for. So aren't we -- isn't there a very serious risk that future ratepayers are going to face a double-whammy downstream? Number one, they're going to have to pay for the cost of your deferred work, and just as they're doing that, they're going to have to pay the cost of the deferred Fair Hydro Plan costs. Like, isn't that a real possibility?

[Witness panel confers]

MR. D'ANDREA: You talk about risk, Mr. Stephenson. Yeah, there's a risk, but we don't know, again, in terms of how we fund work and how we plan work and what types of investment we would need to make, so there is some uncertainty around that, and we don't know how ultimately the Fair Hydro Plan will be dispositioned, so is there a risk? Yes, but we can't know what that risk is today, can't quantify that risk.

MR. STEPHENSON: Okay, so here's the problem that I'm -- I think it's -- it is as obvious as the nose on my face, anyway -- is Hydro One backs off and mitigates its current spending plans because of rate impact concerns. Exactly when in the future does Hydro One think that paying for this stuff is going to be more tolerable in the eyes of its customers? Like, aren't they going to be -- aren't customers going to be even more reluctant to pay for it in the future? Like, when are they going to say, Okay, now is the right time? When is the right time?

MR. D'ANDREA: We don't know what the right time is, and when we get to that point we may be faced with different options like rate-smoothing options. We just don't know.

MR. STEPHENSON: No, but, sir, you can do rate smoothing now.

MR. D'ANDREA: We wouldn't qualify for rate smoothing now.

MR. STEPHENSON: What makes you think you would qualify then?

MR. D'ANDREA: Well, I would have to see what the size of the rate increase is.

MR. STEPHENSON: So you are just kicking this problem down the road with absolutely no plan on how to deal with it and no expectation that life is going to be any more tolerable; isn't that right?

MR. D'ANDREA: Well, no, again, we are trying to balance the needs today and in the future so we can manage to run the system with a Plan B modified, and so when we file our next application, in combination with transmission, we will look at this all over again and look at what the plan investment is.

MR. STEPHENSON: Okay, those are my questions. Thank you very much, panel.

MR. QUESNELLE: Thank you, Mr. Stephenson.

Mr. McLeod, I take it you will be able to join us after lunch?

MR. McLEOD: Absolutely.

MR. QUESNELLE: All right. Thank you. We'll reconvene at 1:45. Thank you.

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

--- On resuming at 1:48 p.m.

MR. QUESNELLE: Mr. McLeod?

MR. McLEOD: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MCLEOD:

Good afternoon, panel. My name is Michael McLeod and I'm with the Quinte Manufacturers Association.

I only have a few interrogatories that actually I need some clarification on to clear the record for us. And if I could have -- Erin, if you could pull up BOMA number 32. Thank you.

I just want to take you through a couple of things here just so I'm clear, because I got a little confused on what I think I was reading, and it would be helpful if you could just clarify these things for me.

It is interesting in the first question there, that says:

> "Please provide the strategic direction from HONI's board of directors and executive leadership team, and any written responses, reports, and guidelines."

And the response to the reference there was to Exhibit I3, SEC 101. But the last sentence says:

> "There was no written strategic directive provided."

The question was to provide strategic direction from, so I got the sense that that was a bit more generic about strategic direction from Hydro One's board of directors. But the response was there was no written strategic directive.

So I just wanted to get clarification. Strategic direction, so the direction that the corporation is supposed to be going versus the directive that's referred to here. Can you help me with that?

MR. LOPEZ: Can you point me to exactly where on the interrogatory it is?

MR. McLEOD: So the interrogatory in A, it says "Please provide the strategic direction," and then the response is on the last sentence: "There was no written strategic directive."

So when we looked at that, we said one's a direction, the direction the corporation is going, and the response was to a directive.

I'm just trying to reconcile the difference there because I'm wondering if there was the focus towards the changes we talked about a little bit this morning from Plan A to modified Plan B. It just got a little confusing.

MR. LOPEZ: I'm trying to get the context here.

The response appears to be more towards do they make a specific decision or a set of guidelines that the budget was -- or the filing was based on, and the answer is no to that.

The company comes up with that. They bring up recommendations to the board. The board look at it and reviews it, and then provides some feedback. We heard that earlier this morning about customer rates, and that's when that occurs. There is no directive at the outset to say customer rates cannot be impacted by, or anything like that.

MR. McLEOD: Right. So when you look at the business plan where it says what the values of the corporation, for example, were, some of those things are very clear, obviously from a higher level. The directive is not pointed to any of those specifically. In other words, it wasn't a directives I guess is what I'm getting at.

MR. LOPEZ: No, there was no directive.

MR. McLEOD: Okay, that clarifies that for me, that's helpful.

And then in B, there is a reference to non-investment alternatives. And I got a little bit confused in here. This is what I think, and please correct me if I'm wrong, that when we're talking about non-investment alternatives, we're saying -- or you're saying in your response that Hydro One doesn't look at any of these things, and these are really IESO responsibilities.

[Witness panel confers]

MR. ANDRE: So, Mr. MacLeod, perhaps you could just repeat your question one more time, and I'll try to give the best answer that I can.

MR. McLEOD: Sure, and I'll put it in a little bit of context.

So our members, no surprise, are very, very, very concerned because they are always operating on sort of the edge of being in business and out of business. And we have significant players, as you probably know, in the Belleville and Trenton area.

One of the major concerns is when they are looking at non-investment alternatives -- and where I'm going at with this, could lead to DERs for example, because that comes up in conversations we have.

So when we're looking at non-investment alternatives -- and I'm thinking for this, as I say, as non-wires stuff -- from our perspective, you can't look at that just plainly and say it's non-wires. It is all connected one way or the other, and we talked about that this morning.

So we need some clarification around what this was actually trying to say so that we're clear.

MR. ANDRE: Right, and so I do know that as part of investment plan considerations, we will look, if it's appropriate, at non-wire solutions. For example, are there things that we can do to increase CDM so that it reduces the load on a particular station and perhaps defers the investment needs for that station.

So I do know that some of our investment plans, where appropriate, would have included non-wires considerations.

MR. McLEOD: So we know then because the Bellville TS is the big TS in our neighbourhood, and I can say this and I think it's appropriate to say it here, is for the most part, our association members are appreciative of the service they get from Hydro One from that area. There is no question about being appreciative of the service and they like it.

But these kind of things become a bit of a concern when they're starting to look at, as I say, what other alternatives if they can avoid energy costs, either distribution costs or transmission costs or electronic costs, they're looking at that.

So when we're looking at this, we're kind of saying is this kind of held back and it's out of the picture for now, we can't talk about it, or is it part of it. Because if you go through the DSP, you can see references where it talks about these things and it comes back in and says okay. But there was just this sort of vagueness around it that we wanted that clarification on.

So when we saw this, especially from BOMA, we said, oh, maybe this is actually something else.

MR. ANDRE: No, I think it is referring to non-wires alternatives. I know that the IESO when they are looking at bigger regions will look at non-wires type of investments. But I read this response to say that even within our own distribution plan, where it's appropriate for a particular investment, we will look at if there is non-wires options that will help meet the need.

MR. McLEOD: I'm going to jump ahead just a little bit because...

MR. ANDRE: And really, just to be clear, that's probably as far as I can go. I think for a detailed response around this, you'll need to speak to panel 5 where they'd be able to give you more detail.

MR. McLEOD: Fair enough then. That's -- if I could have Staff interrogatory 123, please?

MR. QUESNELLE: Mr. Vegh, I note that on that IR response, it was Mr. Lopez that was the author of that interrogatory response, was he not?

MR. VEGH: I think that's right and the interrogatory response did refer to the DSP process. So there was a panel that Mr. Andre referred to on the DSP, so for specific investments, that's more a more effective panel for these questions.

MR. QUESNELLE: I understood. Just that Mr. Andre also suggested that that's as far as he could go in interpreting his response, and I think the author should be able to go further perhaps.

MR. LOPEZ: Yes, sorry. At a high-level I understood what it was getting at. But the difference between a non-wire investment and specifics around what the -- what was being asked there, I don't know how they could pair one against the other and how it would be included.

That's why I was suggesting it should go to panel 5, where they can say here's how we do that trade-off.

MR. QUESNELLE: I understand. That's helpful. Thank you.

MR. McLEOD: Thank you, Mr. Chair.

Staff's interrogatory 123 is -- we found it very helpful and focus on productivity and continuous improvement, productivity savings is very important to us and useful.

What's interesting, though, in interrogatory item C or clause C, it says:

"What assurances..."

And it is the word "assurances" I'm looking at:

"...do ratepayers have..."

And I'm thinking about our members in this case:

"...have that Hydro One will achieve a forecasted savings or forecast savings?"

And we see in the plan that you responded to that the savings are embedded in that, that's great, and then we go to the response in C at the back end. There's a number of things here I just want to clarify and make sure we're clear.

So the response is "ratepayers are assured through Hydro One's commitment", so this is in our view Hydro One's guarantee that the forecasted savings and targets are going to be met, and the commitment it says in here is demonstrated, and this is where we need some clarification, the enhanced governance and visibility.

Mr. Lopez, what does it mean, "enhanced governance", and I'm going to ask, is that governance oversight by the Board, by the executive leadership team, or something else?

MR. LOPEZ: All of the above. It's all of the above, so if I take a step back, Hydro One started their productivity push in late 2015, and we had made some strides forward in 2016, saving around $24 million in 2016, but it was still in its early infancy. In 2017 it is significantly larger, so we grew that $24 million to $118 million in that period of time. How we did that was by improving the governance, the transparency around productivity, how it's recorded, how it's tracked, how we hold people accountable, all the way from when we identified the initiative through to incentives, so it is linked to our team's scorecard, so people's pay is at risk if these targets are not met.

Their budgets are adjusted. As soon as the productivity initiative is approved, their forecasts are reduced by those numbers, so now they're on the hook to deliver those outcomes.

MR. McLEOD: Okay. So that's what I wanted to get to, then, in my next question when we were talking about visibility. So in terms of visibility, is that reporting? Is that what that means?

MR. LOPEZ: Yes, it does.

MR. McLEOD: Okay. So it is reporting internally?

MR. LOPEZ: And externally. You will notice in our fourth-quarter report or the annual report for the first time we disclosed productivity outcomes to all stakeholders, and that's in an externally published report.

MR. McLEOD: And then as we just go down the items here, embedded forecast savings in its business plan, okay, we get that. What's the achievement risk on Hydro One's net income and not on ratepayers? So we understand that. So the risk -- and Mr. D'Andrea, maybe you are the risk guy here -- is that risk that it's referring to here a risk that would be considered at the Board level?

MR. D'ANDREA: Simple answer is yes.

MR. McLEOD: Okay. So they would be aware of any of these changes, if it's falling off and not going to meet the productivity targets and starting to drift, that Board through the leadership team or whatever would get to see these things and they would know, because risk is a big -- obviously a big --

MR. D'ANDREA: They would know where we are on our productivity targets.

MR. McLEOD: Okay.

MR. LOPEZ: Yes, the HRC, the human resources committee of the board, reviews the team scorecard, and that productivity number is right there, and we report where we are, the date, and towards the end of the year and so on.

MR. McLEOD: You said, Mr. Lopez, the penalty can be a financial penalty to the team members --

MR. LOPEZ: Yes, to --

MR. McLEOD: -- group?

MR. LOPEZ: -- their income.

MR. McLEOD: Okay. And I think I've answered that.

So who -- just one other -- just clarification matter here, then. How often is the scorecard then reviewed and moved up the ladder to where it's actually going to -- somebody is going to say, start flagging things. Like, is there a lag -- I guess what we are looking for: Is there a lag in there before it actually gets reported?

MR. LOPEZ: So to get reported to the Board. So all the way to the Board level is one --

MR. McLEOD: Well, I think it's -- I think there's incremental steps here. Like, is it a minor thing or major thing? This is where we're having some trouble trying to figure out, how is it moving through so the message gets to the top, whatever the top is in this case, that things have to change; it is going offside because our members don't want to receive the impacts ultimately at the end of the day. I mean, that's the thinking.

MR. LOPEZ: Absolutely. Yeah, so it is reported on monthly at the senior executive level within Hydro One, and it will go to the Board once a quarter as part of our quarterly review of financial results.

MR. McLEOD: Okay. Good. Thank you.

And if we could turn to VECC number 23, please. And this talks about -- you've attached the consolidated, modified -- or updated consolidated business plan. I just want to look at a couple of things in here that came up that I want to have a look at. And all of this is kind of tied together.

If we look under a strategy section. So right there. That's perfect. We just wanted to have a couple look at a couple things here that are of interest.

In the second paragraph it says:

"Hydro One's strategic vision and business goals are consistent with and included in business

"...plans..."

Okay. I understand that, and it makes sense:

"...and the strategy will involve a number of strategic initiatives."

And it has the four there, and that's fine.

I need some clarification -- and it is all redacted below -- about diversification of entering commercial business, and we understand that, but what kind of commercial businesses are we entering into? And I'm going to bring this up, because it did come up in a conversation years ago in Ontario Hydro. Old Ontario Hydro got involved in purchasing a utility in South America and buying some forest, and all fine and good for back there -- back then, but it obviously raises a concern when somebody is thinking back on that and says, Well, what did this mean? So we just want to get a sense around, obviously the redacted part is not an issue. I just want to know what you're -- how can we put this in a context that says, Okay, this makes some sense?

MR. LOPEZ: So the first response would be that if there is any commercial business that Hydro One enters into, that would be Hydro One Limited, it would not be Hydro One Networks Inc., which is the regulated company. That's why it's redacted here. But to put everyone else's mind at risk (sic) is Hydro One Limited is effectively a regulated company, and it would be looking at similar type investments with very low risk along the lines that we have today. So it wouldn't be stepping out, I heard you say, I think it was South America or somewhere. We absolutely would not be doing that. Nothing along those lines.

MR. McLEOD: Okay. Now, Hydro One's commercial orientation -- of course, our members are all commercial enterprises -- means a company is going to be focused on customers, demonstrate corporate accountability, performance outcomes, all good stuff. That's where it all fits.

And it talks about managing relationships with key stakeholders, including customers, so the members obviously are customers of Hydro One, and how -- and you might not know this, and only because you weren't sure which area it would go into, but because, Mr. Lopez, your name was on here, how do we be more engaged with Hydro One on this type of issue? And the reason why I say that where I mentioned earlier that service to the plants is great from Hydro One employees, it's terrific, it is a great relationship, but when we're talking about these kinds of things where there might be some concern raised about Hydro One doing something that didn't involve -- I'm trying to couch this in a manner that says our members weren't consulted, and I'm kind of -- it is a broad statement that way, so I'm trying to get a handle on that, because it says "key stakeholders, including customers, would be managing", so it is beyond just the wires customers and actually goes to what other cost drivers beyond just normal service to the plants might come back where, say, our members weren't consulted? Not the question.

MR. LOPEZ: Yes, I'm not sure I understand the question. So when you say "members", I mean, this is a general statement to say that Hydro One is not going to do something that -- where we haven't consulted in an appropriate manner, so I'm just trying to understand --

MR. McLEOD: Fair enough. And I think the concern from our end was we haven't felt that there's been good consultation, and maybe that's partly on our side and maybe not on the other side, so when it states in here, quite clearly, because it is a business plan, the question comes in how they do this -- how does Hydro One do this if they haven't done it before? It is as simple as that, I guess.

MR. LOPEZ: I think perhaps I'm more financially based. I think the person on the panel that is most appropriate to speak to that would be the customer panel, and Ferio Pugliese I think is appearing, and he would absolutely love to take that question.

MR. McLEOD: I actually thought that's where this should go, but that's okay. Thank you, Mr. Chair. Those are my questions.

MR. QUESNELLE: Thank you, Mr. MacLeod. I understand, Ms. Blanchard, you will be going up next.

CROSS-EXAMINATION BY MS. BLANCHARD:

MS. BLANCHARD: Thank you very much. Good afternoon, Panel.

So I have prepared a compendium, and I apologize, I only emailed it around this morning, but I've brought some paper copies. I've left four of them with your counsel and

I have three for the panel. I would ask that this be marked as an exhibit.

MR. SIDLOFSKY: That will be K1.6.

EXHIBIT NO. K1.6: CME CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1

MS. BLANCHARD: Because I'll be flipping around a little bit, I think maybe the paper will be easier to use, frankly. All of the material in the compendium, though, is included in the record already.

I'm just going to start at a high level and ask you to confirm that in your last rate hearing, so in March of 2015, will you agree that the Board, the OEB, approved increases, significant increases in sustainment capital over 2015 to 2017?

[Witness panel confers]

MR. QUESNELLE: Mr. Vegh, just while the witnesses are considering that, I just want -- this compendium includes, Ms. Blanchard, documents that are still marked internal and confidential. I just wanted to know the origin of these, and if they are obviously clear for publication.

MS. BLANCHARD: They were all included in the IR response.

MR. QUESNELLE: So these are on the public record?

MS. BLANCHARD: I believe they are.

MR. QUESNELLE: I'm just being cautious here.

MS. BLANCHARD: I don't think they are confidential. They were included in IR response I.03.SEC.4, attachment 2.

And I think I got them all from the public -- I'm quite confident that they were included in that publicly filed IR response.

MR. QUESNELLE: Okay. I'm just making sure it wasn't --

MR. VEGH: Thank you, Mr. Chair, for considering that. All the confidential information has been redacted, so this is all in the public record.

MR. QUESNELLE: Thank you.

MS. BLANCHARD: Thank you. Well, if it would be helpful, I can direct the witnesses to a reference. But I think the question is fairly straightforward, which was that will you agree that in the last rate hearing for Hydro One DX, the Board approved substantial increases in sustainment capital for the 2015 to 2017 period?

[Witness panel confers]

MR. D'ANDREA: Sorry, we are taking some time because neither of the parties here were involved. So I am looking at a reference here, and maybe this will be helpful. It is Exhibit A, tab 2, page 26.

MS. BLANCHARD: I actually thought the question was going to be fairly straightforward, but if you'd like to pull up a summary...

MR. D'ANDREA: I want to make sure we have the right context because we're looking at -- let's say in the 2004 plan, 647.5 million, and that goes to the 2015 plan, 648.

MS. BLANCHARD: I'm going to take you to a different reference, if that's all right with you, and I'm going to take you to the IR responses.

And I apologize, I thought it was a straightforward question, or I would have put in another page. But I'm in the IR responses and it's in issue 1 to 6.

It is the balance of the SEC IR response, SEC.4. So the reference is Exhibit I, issue 3, SEC.4, attachment 2, and it's page 142 of that PDF.

MS. McKinnon: I need to know [microphone not activated]

MS. BLANCHARD: It's SEC.4, attachment 2, and it's at page -- I have other pages from this, so page 5 of that report to the Board.

MS. McKinnon: Thank you.

MS. BLANCHARD: So as a starting point, the third paragraph down, in March of 2015, Hydro One received OEB approval for a three-year 2015 to 2017 custom cost-of-service application which included increased sustainment capital investment.

So as a starting point, will you agree with me that there was an increase approved for that three years for sustainment capital?

MR. D'ANDREA: Yes.

MS. BLANCHARD: Okay. So I'm going to take you now to page 13 of my compendium and I've got -- on the screen, you will see a little bit that's highlighted. I don't think it would have carried through on to the paper copy, but I see that this is a report to the Board, correct? We've looked at this document already once today in the hearing.

MR. D'ANDREA: Yes, that's to the Board, yes.

MS. BLANCHARD: And the purpose of this document is to inform Hydro One's Board as to the proposed direction for the upcoming rate application. Is that fair?

MR. D'ANDREA: That's fair.

MS. BLANCHARD: And in particular, the mix of investments that are being proposed for that application and as you described it earlier, the balance between those investments and the increase in rates, correct?

MR. D'ANDREA: Correct.

MS. BLANCHARD: So when this report was brought to the Board -- and I think the date we've got there is November 11th, 2016 -- the Board was advised in that third paragraph that the 2018 bill impact already has non actionable rate increases of 5.1 percent included, correct?

MR. D'ANDREA: Correct.

MS. BLANCHARD: And those are over and above the increases that were approved for the 2015 to the 2017 period?

MR. D'ANDREA: Just a moment, please. Sorry, could you repeat your question?

MS. BLANCHARD: The question was: When the Board was informed that the first year 2018 bill impact has non-actionable rate increases of 5.1 percent included, that would be over and above the increases in the -- the increases already approved for the 2015 to 2017 rate period.

MR. D'ANDREA: Yes, that's true. And these are described as non-actionable, and I want to get into that word non actionable a little bit more.

So first of all, I'd like to ask you whether that means that the Board was advised that a 5.1 percent increase was a form of baseline and they weren't to look below that as a rate increase.

MR. D'ANDREA: That would be fair.

MS. BLANCHARD: And so is it accurate that the Board never considered a scenario where the rate increases would be less than that baseline?

[Witness panel confers]

MR. D'ANDREA: Yeah, I'm looking at your own exhibit. Just three pages down from there there is a figure where it talks about -- there on the bottom half of that, so it talks about the rate impacts of the Plan B modified, so at the same it would be modified that we talked about, and there's the things that we consider non-actionable, are the items to the left of the dotted line.

MS. BLANCHARD: And so the question was: Did the Board consider or was -- did the Board consider a scenario where the rate increase would be less than 5.1 percent?

MR. D'ANDREA: Well, no, because that's a Plan B modified, so that would have been our base. We did Plan C, and the rate increase would have been lower, but it wasn't really a plan, because we couldn't satisfy our operating system requirements with a Plan C, so we put it in front of the Board, but what we debated between the Board was Plan A to Plan B, and then ultimately it landed on Plan B modified.

MS. BLANCHARD: Was Plan C less than 1.5 percent, or did it just strip out the items in the controllable category?

[Witness panel confers]

MR. D'ANDREA: Yes, so if you look at the difference between Plan A and Plan B there the real difference is the controllable piece, and that's where we made the reduction.

MS. BLANCHARD: Right, and so my question was: Did the Board consider any scenario where the increase would be less than 5.1 percent? And I think your answer is no. But subject to --

MR. D'ANDREA: No. No.

MS. BLANCHARD: Okay, so I want to just get in a little bit to this 5.1 percent, which was established as the baseline, and you've got it broken out here in this table, and I think in the preceding page of my exhibit, at page 15, which is an extract from the same memorandum, you provide some -- so page 15 at the top. I guess it would be page 16 of the -- yeah, there we go -- down at the bottom there is a bulleted list, and I understand this narrative to be informing what's later represented graphically in the table; is that accurate?

MR. D'ANDREA: That's correct.

MS. BLANCHARD: And so you indicate a number of components to this 5.1 percent baseline, and I'm not going to dwell on all of them, but I do want to speak to the third item on the list, which is described as a "legacy rate base", and in that item the memo to the Board indicates that:

"Hydro One has approximately $105 million worth of additional work completed in 2015 above the prior revenue allowance."

Do you see that?

MR. D'ANDREA: I see that.

MS. BLANCHARD: Of that 105 million, was any of that sustainment capital work?

MR. D'ANDREA: I would need to verify. I don't know the answer immediately.

MS. BLANCHARD: Is there somewhere in the evidence a breakdown of this $105 million of legacy rate base?

MR. D'ANDREA: Again, I don't have the answer to that. I would have to check.

MS. BLANCHARD: Could you take an undertaking to --

MR. D'ANDREA: Yes.

MS. BLANCHARD: -- provide a breakdown of the $105 million?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: That will be Undertaking J1.3.

UNDERTAKING NO. J1.3: TO PROVIDE A BREAKDOWN OF THE $105 MILLION OF LEGACY RATE BASE.

MS. BLANCHARD: And so I see if you read on in the same line that's described as adding up to 0.5 percent; do you see that?

MR. D'ANDREA: Yes.

MS. BLANCHARD: And if I turn the page over in the exhibit, and I'm just trying to correlate now this narrative to your table where you're looking at these items here, I take it that that lines up with the purple box, where it reads "legacy rate base".

MR. D'ANDREA: That's correct.

MS. BLANCHARD: So beside that item there is another item that is titled "other revenue impacts" at 0.7 percent; do you see that?

MR. D'ANDREA: I see that.

MS. BLANCHARD: Can I assume that that 0.7 percent then adds up to something that is more than $105 million?

MR. D'ANDREA: I'd have to examine what that other revenue impacts is. I don't know if that's capital per se.

MS. BLANCHARD: Okay, what is that category generally? Because I don't see that .7 percent reflected anywhere in the bulleted list, although possibly I'm missing it. I just -- I've got a bulleted list with four bullet points and I don't see .7 percent on it, so I'm just interested in what makes up that 0.7 percent of other revenue impacts?

MR. D'ANDREA: I'm sorry, I can't answer that question right now. I'm happy to take an undertaking on that.

MS. BLANCHARD: Could I have an undertaking number for that?

MR. SIDLOFSKY: J1.4.

UNDERTAKING NO. J1.4: TO PROVIDE WHAT MAKES UP THE 0.7 PERCENT OF OTHER REVENUE IMPACTS.

MS. BLANCHARD: And did we get an undertaking number, sorry, for the previous one? We did. Okay. Thank you.

Okay. So we have that 1.2 percent, which is part of this baseline that the Board was advised. That's a must-have in terms of expenditures.

So I think I'm going to turn now to the business planning exercise, and again, I'm going to try to stay up at 10,000 feet. I appreciate that there will be other panels where we will be drilling down, but I'm going to go up at the 10,000-foot level, talk to you a little bit about the business plan, and I hope you'll agree with me that the business plan is part of what this panel is here to talk to us about.

MR. D'ANDREA: Fair.

MS. BLANCHARD: So when the application was filed last June, the business plan that was filed with it was the business plan that was completed at the end of 2016; correct?

MR. D'ANDREA: Yes.

MS. BLANCHARD: And when the evidence was updated in Exhibit Q this winter, another investment planning cycle had occurred, correct?

MR. D'ANDREA: Yes.

MS. BLANCHARD: And Exhibit Q is intended to provide a picture as to what has changed in terms of your planning and going into the application; is that correct?

MR. D'ANDREA: Correct.

MS. BLANCHARD: Okay, so I would like to spend a little bit of time just understanding what may have changed over that last year, and that's why, in part, I've given you the paper versions, because I want to flip back and forth a little bit and understand that evolution, so I'm going to start on page 2 of my compendium, which is an extract from the December 2016 business plan.

MR. LOPEZ: Just so we can keep up, there are two of us here that don't have a paper copy.

MS. BLANCHARD: Oh, I handed four paper copies to your counsel this morning so that you would have all have one. They are in a red folder. I apologize.

MR. LOPEZ: I've got one now.

MS. BLANCHARD: Now, I'd appreciate it if you would -- you have got page 2 there, but if you could also keep page 7 handy. Okay? Okay. So this is a portion of your business plan called are called "Circumstances and challenges", and I understand it's intended to provide a snapshot of the fleet and the business. Would that be a fair characterization?

MR. D'ANDREA: That would be fair.

MS. BLANCHARD: And it is a standard component of your business plan; is that fair?

MR. D'ANDREA: It is.

MS. BLANCHARD: Okay. So in 2016, I'm looking first at just geography, in 2016 Hydro One is maintaining 100,000 approximately kilometres of right of way; do you see that?

MR. D'ANDREA: Yes.

MS. BLANCHARD: And if you flip over to page 7, the following year, you are now maintaining 104,000 kilometres of right of way. And so could you provide some insight into why you've got the extra 4,000 kilometres worth of right of way?

MR. D'ANDREA: I wouldn't be able to answer that question. I would direct that to panel 5.

MS. BLANCHARD: Okay. Are you able, just generally, to comment on whether there was any change that you're aware of to the makeup of your system's big picture in that one year period?

MR. D'ANDREA: Sorry. Again, I wouldn't be able to answer that question.

MS. BLANCHARD: Okay. So this document, though, is the 10,000-foot view of Hydro One as a business and is intended to provide, at a very high-level, a picture of the fleet; is that fair?

MR. D'ANDREA: That's fair.

MS. BLANCHARD: So if there is a material change in this section, it means there is a material change in something that's happening with Hydro One? Is that a fair assumption?

MR. D'ANDREA: That's fair.

MS. BLANCHARD: So I'm going to observe that in the geography section, the document also indicates in 2016 that one-third of the lines are off-road, but in 2017, it's one quarter?

I'm happy to put those questions to panel 5. But again, you don't have any reason to believe that there was a major change in the makeup of your right of way configuration in that year?

MR. D'ANDREA: Not that I'm aware of.

MR. ANDRE: If I could add? I do know that the GIS system is becoming more prevalent and use of the information and output from our GIS system is becoming more prevalent.

So I think Mr. D'Andrea has pointed you to the correct panel. But it could be simply a matter of accuracy in terms of the information that is now available through our updated systems, our improved data issue.

MS. BLANCHARD: So it could be a data issue between 2016 and 2017?

MR. ANDRE: I wouldn't necessarily call it a data issue, just better data, more accurate data.

MS. BLANCHARD: Okay. Well, I'm just going to take you down the page, because as I understand one of the themes of this application and one that has appeared in past applications is about aging and deteriorating infrastructure is about aging and deteriorating infrastructure, and that's right there in your business plan. Would you agree that that's one of the themes?

MR. D'ANDREA: It is.

MS. BLANCHARD: So that would be a critical factor that would inform your business planning exercise; is that fair?

MR. D'ANDREA: Yes, it would drive our investment plan.

MS. BLANCHARD: And again, I don't want to get into the specifics. But in 2016, you have 240,000 wood poles beyond their expected life, and if you turn over the page to 2017, that number has gone up to 280,000 poles and I think -- are you going to point me to panel 5, again?

MR. D'ANDREA: I am.

MS. BLANCHARD: I'm going to do this one last time and I don't expect the answer. But I think it is important that we have this discussion at a high-level. I am seeing 144 station transformers that are beyond their expected life in 2016. So I've got 144 station transformers that are more than 50 years old in 2016 and if you turn the page, in 2017, I now have 279 station transformers that are beyond their expected life.

So the number of station transformers that are beyond their expected life are doubling in that one planning cycle. Now, I understand that this is not the panel that we are going to talk about project over project, but that order of magnitude suggests to me that something material is changing or there's a significant issue with data.

So are you able to speak to those -- that kind of delta in terms of station transformers?

MR. D'ANDREA: I would ask panel 5 that question.

MS. BLANCHARD: So you are not aware of any material change?

MR. D'ANDREA: I'm not aware of it, no.

MS. BLANCHARD: So I'll leave the demographics and the fleet piece for now, and I'll ask you now to go to the investment summaries.

So the first one, the 2016 investment summary, is at page 5 of my compendium and that's 2016, and that's the investment summary that was available when the application was first filed by Hydro One, correct?

MR. D'ANDREA: That's correct.

MS. BLANCHARD: And so I guess as a starting point, I understand that we are to refer to Exhibit Q to understand the delta between this capital expenditure plan that was presented in the June 2017 application and the one that is before the Board today --

MR. D'ANDREA: That's correct.

MS. BLANCHARD: -- referring you to schedule Q.

MR. D'ANDREA: Correct.

MS. BLANCHARD: Will you agree with me that schedule Q does not provide any detailed information about any change to the proposed capital expenditures in the sustaining category?

I can give you the reference, or you can take my word for it. Your choice.

MR. D'ANDREA: No, give me the reference, please.

MS. BLANCHARD: Okay. It's Exhibit Q, tab 1, schedule 1, page 8.

And I think this is the list of the substantial changes in terms of your capital expenditures that's provided in schedule Q.

Primarily, will you agree with me that this list looks at what, in effect, amounts to reduced investment in general -- in the general plant category overall?

MR. D'ANDREA: Yes, that's fair.

MS. BLANCHARD: So you can take it, subject to check, but I'll put to you that schedule -- or that Exhibit Q does not speak in any material way about the delta between the sustainment capital plan from the 2016 business plan and the sustainment capital plan from 2017 business plan.

MR. D'ANDREA: Right, so Exhibit Q is updating the 2016 plan, not doing a 2016 to 2017 plan.

MS. BLANCHARD: Right, but Exhibit Q doesn't tell me about what's going on with sustainment capital. Would you agree with that, or subject to check?

MR. D'ANDREA: Subject to check.

MS. BLANCHARD: All right, so I'd like to look at that a little bit with you today. So if you just have page 5 of my compendium open, and we'll just take you across the sustainment capital line now.

At page 9 of my compendium, I have the capital plan for the updated capital plan in 2017. So that's why I've given it to you on paper, but if we kind of go back and forth there, we can see the difference between what was proposed in 2016 for sustainment capital and what was proposed in 2017 for sustainment capital.

Now, I think it might get a little bit boring if I go line over line, but I'm going to give you just my basic math, which is subtracting one from the other, and if you'll take it subject to check, I think we can do it that way.

MR. D'ANDREA: Yes.

MS. BLANCHARD: Okay. You're good? So by my math, 2018, you've got $18 million more for sustainment capital, 2019, 23 million, 2020, 17 million, 2021, 17 million, 2022, 14 million, and it adds up to $89 million of additional sustainment capital. Will you take that subject to check?

MR. D'ANDREA: Subject to check.

MS. BLANCHARD: So that -- this capital number, this is informing your capital factor, correct? To some extent? It is part of the input to your capital.

MR. D'ANDREA: Part of the input.

MS. BLANCHARD: Yeah. And it will be part of what produces the increase in the rate.

MR. D'ANDREA: As part of the capital factor, yes.

MS. BLANCHARD: And, now, on page 5, just scanning down there, a little bit down the page, system renewal. Now, is -- I know you've been working on changing the nomenclature. I'm assuming that "sustainment capital" is largely within the system renewal heading; is that accurate?

MR. D'ANDREA: Based on the chart on page 9, 249 of that would be system renewal.

MS. BLANCHARD: So in 2016, system renewal investment costs were projected to increase by 3.7 percent annually? Can I assume that that percentage is going up in the amended plan?

MR. D'ANDREA: I am just looking at the math that would say yes.

MS. BLANCHARD: And, let's see -- I think I may actually leave that area for now.

So I'm actually going to shift gears and ask you some different questions now. Just keeping track of my time, I think I may have gone over my estimate, Panel, and I'll try to make the next couple of questions as short as possible.

MR. QUESNELLE: Thank you.

MS. BLANCHARD: Okay. So I'd like to ask you just a few questions about the scorecard. As I understand, this is the panel for scorecard questions.

MR. D'ANDREA: Yes.

MS. BLANCHARD: Okay. So I've got a copy of the scorecard in my compendium, page 17. This is a scorecard that was updated with targets and actuals in response to an SEC interrogatory.

So my first question relates to the cost -- total cost per customer metric, and the numbers are quite small, so it might be good to zoom in here.

So just scanning across the line, and I -- it was by zooming in we've lost the year, but if you read across, that 983 million is the cost per customer for 2015; correct?

[Witness panel confers]

MR. LOPEZ: That's just dollars per customer.

MS. BLANCHARD: Sorry, yes, 900 -- I'm used to adding the millions, sorry, so the $983 per customer, that's the 2015 number, correct?

MR. LOPEZ: Yes.

MS. BLANCHARD: And it's gone down from 2014. The cost per customer in 2015 is lower than the cost per customer was in 2014?

MR. LOPEZ: Yes.
MS. BLANCHARD: What is the explanation -- well, let me ask it this way: In 2015 there is an additional $105 million that is not accounted for in this cost per customer number; is that correct? Because we looked at that 105 million before that wasn't added into rate base. This number, does it include the legacy costs or not?
MR. LOPEZ: I don't know, I'd have to check.
MS. BLANCHARD: Could you check?
MR. LOPEZ: Yes.
MS. BLANCHARD: Would you take that as an undertaking, please.
MR. VEGH: Sorry, could you please clarify the undertaking. I'm not sure where some of these numbers are coming from.
MS. BLANCHARD: Well, I took the -- we understood when we looked at the report to the Board that there was $105 million of legacy rate base that had not been recovered through rates, and so my question is: Is the $983 per customer lower because it doesn't include that number or is there another reason why it's lower?
MR. LOPEZ: I think perhaps just a quick answer as to why it's lower, I think that's what the undertaking would be, I don't think it's included. 105 million wouldn't get included until the next rate case, so...
MS. BLANCHARD: Okay. Why it's lower would be fine.
MR. LOPEZ: So what caused the change from 2014 to 2015?

MS. BLANCHARD: Yes, yeah, that would be fine. Yes. Okay. And --

MR. SIDLOFSKY: That will be -- sorry. That will be Undertaking J1.5.

MS. BLANCHARD: Thank you.

UNDERTAKING NO. J1.5: TO ADVISE WHAT CAUSED THE CHANGE IN COST PER CUSTOMER FROM 2014 TO 2015.

MS. BLANCHARD: Now, a few questions about customer satisfaction, and I know we're not talking about the customer consultation in this particular panel, but you've got a metric that is called customer satisfaction survey results.

And would you agree with me that your current metric is showing customer satisfaction as 85 percent in 2014?

MR. LOPEZ: Yes.

MS. BLANCHARD: And then 85 percent again in 2015?

MR. LOPEZ: Yes.

MS. BLANCHARD: And then 84 percent in 2016?

MR. LOPEZ: Yes.

MS. BLANCHARD: Okay. And then I want to take you to page 22 of my compendium. Are you familiar with this report? I've included the title page, actually, the page previous, if you want to just look at that. It is a customer satisfaction study.

So if I go to page 22, overall satisfaction is falling. Would you agree?

MR. LOPEZ: Per this graph, yes.

MS. BLANCHARD: And in any event, it is substantially lower than 84 percent?

MR. LOPEZ: It is lower.

MS. BLANCHARD: So would you agree with me that the metric that you are showing in your scorecard is not capturing -- is it not up-to-date or it's not capturing your most recent survey results?

MR. LOPEZ: They may be showing two different things. I think the best person to answer this would be the customer panel, and they could explain the link between the distributor's scorecard and this particular item that you are pointing to, because they may be showing two subsets of customers or -- I don't know the answer, so I'm directing it to the customer panel.

MS. BLANCHARD: So are you able to explain how the customer satisfaction metric was generated for the purposes of the scorecard, or is that also for the other panel? Just what makes up that...

MR. LOPEZ: So it is generated externally. But you are showing me a report here that may be a subset of that; it may be something slightly different. So I think the best person to explain why this is different to the scorecard would be the customer panel.

MS. BLANCHARD: Okay. So jumping around a little bit, but I am still on scorecards and page 20 of my compendium. I understand that this is the updated productivity and outcome measures scorecard that formed part of the more recent business plan; is that correct?

MR. LOPEZ: Yes.

MS. BLANCHARD: So I'm looking at your measure called "number of vegetation-caused interruptions."

MR. LOPEZ: Yes.

MS. BLANCHARD: And will you agree with me that your targets are actually worse than your most recent historical result?

MR. LOPEZ: Sorry, could you point me to...

MS. BLANCHARD: I'm in the row -- number of vegetation-caused interruptions. So I think your last historical result is from 2016 and it's 67,674, and your target for 2017...

MR. LOPEZ: No, sorry, I think it's misaligned. So the number of vegetation-caused interruptions is the --it's starting with 6113 and then moving across.

MS. BLANCHARD: Okay. So this is actually the number of line equipment-caused interruptions?

MR. LOPEZ: Yes.

MS. BLANCHARD: So line equipment, you are targeting something worse than your last historical result?

MR. LOPEZ: So for the 18 to '23, the historical result?

MS. BLANCHARD: I've got 2016, 2,774 and for 2017, you are targeting 8200?

MR. LOPEZ: Yes.

MS. BLANCHARD: So you are targeting something worse than your last historical result?

MR. LOPEZ: Yes. And again, the panel on planning will be able to give more insight to that. But it could be something along the lines of weather impacting 2016 a lot less than 2017, an abnormal year, because if we look back, it is fairly consistent.

So again, I'd leave it to that panel to explain exactly why 2016 is a different -- an outlier.

MS. BLANCHARD: Will you agree with me that your target is worse than every year that is reported on this chart, other than 2014?

MR. LOPEZ: Yes, marginally lower -- marginally higher than 2015.

MS. BLANCHARD: I think those are my questions for this panel.

MR. QUESNELLE: Thank you. Miss Grice?

MS. GRICE: Good afternoon, panel. I'm Shelly Grice representing AMPCO and I too have a compendium that I left over with Board Staff.

MR. SIDLOFSKY: That will be Exhibit K1.7.

EXHIBIT NO. K1.7: AMPCO CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1

MS. GRICE: Do the panel members have a copy?

[Off-record discussion]

MS. GRICE: Okay, I've sent it now.

CROSS-EXAMINATION BY MS. GRICE:

So if we can please start with page 27 of the compendium, what this shows is the corporate governance structure for Hydro One Limited, and it shows the board of directors and then the committees that report to the board of directors.

And I wanted to ask if there are any other committees, or any different corporate governance structure that applies to Hydro One Networks Inc.?

[Witness panel confers]

MR. LOPEZ: No, there's no separate governance structure that applies to Hydro One Networks Inc.

MS. GRICE: Thank you. So it's the same committees; there are no additional committees?

MR. LOPEZ: Yes, it's the same committees.

MS. GRICE: Okay, great, thank you. If we could please turn to page 19, and I have some questions as well on the corporate scorecard.

So under the response here, 18 SEC 29, the first bullet says that:

> "The OEB revised the reporting methodology for SAIDI and SAIFI to exclude loss of supply and force majeure. SAIDI and SAIFI results prior to 2015 were not estimated (sic)."

So if we can then please turn to page 22.

MR. QUESNELLE: It actually says were not restated, I believe.

MS. GRICE: I'm sorry about that.

MR. QUESNELLE: Just for the transcript.

MS. GRICE: Thank you. And this is similar to the scorecard that Ms. Blanchard took you to, and there are a number of metrics under system reliability and the first three are related to number of interruptions and there are three categories: line equipment, vegetation and substations. Could you tell me if those three metrics, if they also include loss of supply and force majeure?

MR. LOPEZ: I can't answer that question.

MS. GRICE: Could you undertake to get that answer?

MR. VEGH: I believe another panel -- I would expect panel 5 would be able to answer these questions in greater detail.

MS. GRICE: Okay. And then similarly with respect to the SAIDI and SAIFI rural and urban categories that are under system reliability, again I want to ask if loss of supply and force majeure are excluded from those numbers as they are excluded from SAIDI and SAIFI as per the OEB direction? Can you tell me if those numbers are also loss of supply and force majeure?

MR. LOPEZ: I think -- similar to the previous suggestion. I think panel 5 is probably best able to answer the definition of each of those.

MS. GRICE: Thank you. I'll re-direct my question there.

My next question is not in the compendium, and I apologize, but I have provided it. If we can please turn to 24.SEC.46.

MR. QUESNELLE: Mr. Vegh, this probably goes without saying, but as we are moving questions along to future panels, if they're made aware of it so that they have the information and we're not taking undertakings next week.

MR. VEGH: Thank you, sir, I'm keeping a note of these.

MR. QUESNELLE: Yes. Thank you.

MS. GRICE: And that's -- I'm looking at attachment 1, and under "scope of work", which is section 3, under part B -- and this -- what we're looking at is the terms of reference for AESI which was hired by Hydro One to do a third-party review of the DSP, and it just covers off what their scope of work is, and under that bullet, under part B it says that:

> "AESI to is to participate fully, in cooperation with Hydro One, in the filing, discovery, hearing, and argument phases of the OEB review of the distribution unit cost benchmarking studies."

So does that mean that this is referring to the benchmarking studies that were done by Navigant in first quartile for the full replacement and station refurbishment and then the vegetation management study that was undertaken by CN Utility? Is that what that bullet is referring to?

[Witness panel confers]

MR. D'ANDREA: Sorry, we're unable to answer your question. We can take an undertaking if you'd like.

MS. GRICE: Okay, if we could get an undertaking, please, because that panel is coming up where I believe the contents of that report will be discussed, and so I wanted to ask questions regarding any assessment that was made by AESI regarding those unit cost benchmarking studies.

MR. VEGH: Mr. D'Andrea said he would provide an undertaking.

MS. GRICE: Thank you.

MR. SIDLOFSKY: J1.6.

UNDERTAKING NO. J1.6: TO EXPLAIN 24.SEC.46, ATTACHMENT 1, SECTION 3, "SCOPE OF WORK", PART B, TERMS OF REFERENCE FOR AESI

MS. GRICE: Okay. My next questions are regarding the Auditor General report. And I have some follow-up questions on a couple of outstanding recommendations that impact Hydro One's capital investment plan in this application and Hydro One's request for a custom capital factor. We know that the Auditor General filed the report in December of 2015. The report had 17 recommendations, and Hydro One has responded and completed most of the recommendations, but there are two recommendations that I wanted to discuss with you that were outstanding when this application was filed on March 31st, 2017, and I'm specifically referring to recommendations number 5 and 11.

So if we go to page 7 of the compendium, and this information was filed in Hydro One's application, and what this is is it's an internal audit by Hydro One and it is a follow-up, as of 2016, to the recommendations that were in the Auditor General's report, so I just wanted to ask some questions on this recommendation. Is that something this panel can answer?

MR. D'ANDREA: As I think as that relates to the distribution assets, this is better suited for panel 5.

MS. GRICE: If I want to ask about how this information was incorporated into the creation of the capital -- or the custom capital factor and the investment levels for modified Plan B. Could I ask them?

MR. D'ANDREA: In terms of Plan B, yes.

MS. GRICE: Okay. Okay. So this recommendation number 5 as stated here is information systems on asset condition including asset analytics, and my understanding is that the Auditor General created this recommendation because they wanted to ensure that Hydro One is replacing assets that are at the highest risk of failure as determined through accurate asset condition ratings, and that comes right out of the Auditor General report.

So if we look at what the recommendations are, and I'll just state them very quickly: Number one, Hydro One should enhance its asset analytic system. Number two, review and adjust current weighting assigned to risk factors in asset analytics. The third one is to make changes to its asset analytic system and procedures so that updates to its data are complete, timely, and accurate. Number four, conduct a comprehensive review of the data quality and asset analytics to update any incomplete or erroneous information on its assets and to ensure the information can support its asset replacement decision-making process, and number five, investigate why known deficiencies in the reliability of the asset analytic system such as those found two years earlier by internal Hydro One audits have not been corrected by management in a timely manner. So that's recommendation number five.

And will you agree with me that those items were outstanding at the time that you filed your application in this proceeding?

MR. D'ANDREA: At the time, yes, they were outstanding.

MS. GRICE: Thank you, and then if we just turn the page to follow up with recommendation number 11, and these two go hand in hand, recommendation number 11 is regarding quality of data for distribution assets, and the recommendation put forward by the auditor general was to ensure that management decisions on replacing assets are made using reliable and complete information, and that Hydro One should take the actions needed to ensure its asset analytics system provides timely, reliable, accurate, and complete information on the conditions of assets.

And if you look down at the second bullet under there, halfway through the update as of -- the update in 2016 on following up on these recommendations states that:

> "To date the focus had been on transmission data to support the more immediate needs of the transmission rate filing. This effort had not yet addressed the data quality of distribution data at the time of our follow-up."

And the date on this report is March 31st, 2017, which coincides with the filing of this application, so again, you will agree with me that any of the recommendations or the action items under recommendation 11 had not been undertaken at the time this application was filed.

[Witness panel confers]

MR. D'ANDREA: In terms of this application, I would agree specifically.

MS. GRICE: Thank you.

So here's my question now, and I'm trying to keep it at a high level related to Plan B modified and your custom capital factor.

So just to summarize, given the specific and unique circumstances of Hydro One, that both the Auditor General and Hydro One have identified significant data quality issues, and Hydro One had identified them two years earlier, that at the time of preparing the five-year capital plan had not been addressed because transmission asset quality data was addressed first.

Can you explain how this Board Panel can have confidence that Hydro One's proposed sustainment capital levels are optimal and that a custom capital factor is appropriate?

MR. D'ANDREA: The basis for our capital factor and what we're asking for in terms of investment levels is really driven by our distribution system plan, and I would direct you to panel 5, who are willing to defend that plan, and you can speak to them about the progress they've made in terms of data analytics.

So we while we found the application that was an incorporated part of it, we hadn't made progress on there, and they are willing to stand by and defend the investment plan that supports the distribution system plan.

MS. GRICE: But the investment plan that's part of

Plan B modified, and the five-year forecast, that does not reflect any progress made on data analytics; is that -- is that --

MR. D'ANDREA: At the time we filed, I agree, but there's been progress made, and we have a better sense of our investment needs, and the investment planners can defend the distribution system as filed.

MS. GRICE: So did Hydro One, as part of the business planning process and the business plan that was submitted to the board of directors in December 2017, did that involve a rerunning of the optimization of the investment plans to reflect that progress that was made in the data?

[Witness panel confers]

MR. LOPEZ: The -- like Frank said, panel 5 will take you through it in a more detailed process and what they went through. It's through the transmission process, went through it earlier, and got the benefit of a lot of the changes that were made.

But they did have a look at the 2016 data and run it through at a high level to see if it would be substantially different, and the answer was no. So I think that's what panel 5 will be able to take you through, in terms of looking at that.

So did it get the benefit of that process from the bottom up? It didn't, but it got it from the top down after the plan was formed.

MS. GRICE: If we could just please next turn to page 17 of the compendium.

This is now -- this was filed in response to an interrogatory and it was the follow-up to the Auditor General's recommendations, and the report is dated November of 2017, and it shows again the five recommendations that are under recommendation number 5. And aside from one, four of them are not complete. And then if you look under the observations, the third bullet down says:

"The data remediation effort has not adequately addressed distribution data completeness."

And the next bullet says:

"There is a lack of sustainable approach over the long-term to manage data completeness and data quality."

And then if we can please turn the page over to page 18, it is the same report and it is just providing Hydro One's response to recommendation number 11, and under the observations it says:

"Based on the evidence gathered on the distribution data remediation efforts, this project is completely running on an ad hoc basis with the lack of an implementation schedule, nor the establishment of the data completeness and accuracy targets."

So that report is dated November 27th. My assessment is that most of the action items under these recommendations are not complete, so I'm just trying to square that up with the investment plan that's part of this proceeding and the accuracy of that, in terms of achieving the most optimal investment capital -- capital investment plan, particularly under the sustaining category.

MR. LOPEZ: I think my previous answer will cover the same ground here, in that we believe that from a top-down approach, it is accurate and we're comfortable with it.

But the panel that's best able to demonstrate that to the OEB and to everybody here is panel 5.

MS. GRICE: Okay. If I wanted to -- so panel 5, I wanted to get an update on the status of recommendations 5 and 11, I should direct those to panel 5?

MR. LOPEZ: Yes.

MS. GRICE: Are you able to tell me who is overseeing implementation of the recommendations?

MR. LOPEZ: I can't answer that question. I don't know the response.

MS. GRICE: Okay. I wanted to understand, in terms of future internal audits that are being undertaken with respect to this data quality issue, a list of audits over the next three years was provided as part of 40.AMPCO.50 and that's been identified as an interrogatory for this panel.

Is that something you would be able to tell me is to flag which internal audits that are identified in the tables are related to this specific issue?

MR. LOPEZ: Can we scroll down? Is that in here?

MR. LOPEZ: I think, because it's such a long list, we'll be here for a while to read all of that. So I think we'll need to take an undertaking and have our current internal audit plan reconciled and tell you which ones apply to this.

MS. GRICE: To those two specific recommendations, 5 and 11?

MR. LOPEZ: Yes, recommendations 5 and 11.

MR. SIDLOFSKY: That will be undertaking J5.7.

UNDERTAKING NO. J1.7: TO RECONCILE THE INTERNAL AUDIT PLAN AND ADVISE WHICH APPLY TO RECOMMENDATIONS 5 AND 11

MR. QUESNELLE: Mr. Vegh, to the extent possible, if the undertaking could be responded to in advance of panel 5 being up, that would be very helpful.

MR. VEGH: Yes, sir.

MS. GRICE: Thank you. And then in terms of the investment summary documents that are filed in this application, would you be able to tell me which ones have their origin in the auditor general recommendations, specifically numbers 5 and 11?

[Witness panel confers]

MR. LOPEZ: I think panel 5 can answer that question.

MS. GRICE: Okay, thank you. I'm moving on to a different area now, and I just have a couple of questions left.

I have a question regarding -- there is just a reference made to reliability risk, and some of the memos that went to your board of directors. And I'm sorry this is not in the compendium, but I'll give you the reference and I've provided it to Hydro One. It is 3.SEC.4, attachment number 2.

Down at the bottom of page 2, in the second last paragraph after the comments -- I guess, sorry, I should give you more of a reference. It says:

> "For example, we may choose to reduce investments in 2018."

Sorry, that's...

Oh, you know what, page 1 is the second page of a memo. So sorry, it's page q, the bottom of the second paragraph:

> "For example, we may choose to reduce investments in 2018 to reduce rates in a year where customers may be experiencing high bill impacts of up to 72 percent total bill due to continued increases in the price of electricity. But these decisions may have a negative effect on reliability risk and system condition."

And if you scroll down, please, to page 8.

MR. VEGH: I'm sorry, Ms. Grice, I'm just having a bit of a challenge following where you were. Could you please go back to the previous reference, the one you just read from, please?

MS. GRICE: So it is 3 SEC.4, attachment number 2, and it is a memo to the Board and there's -- page 1 is actually the second page of attachment number 2.

MR. VEGH: I see that, because I thought I heard the number of customers experiencing bill impacts up to 72 percent.

MS. GRICE: Sorry, 7.2 percent.

MR. VEGH: Okay, thank you.

MS. GRICE: And then if we could go to page 8, please. Under figure 3, plan C, the first bullet, it says that there is a high risk of missing business objectives due to a large increase in reliability risk.

So I just wanted to provide those references, but then go back to the evidence in this proceeding, and this is at page 30 and 31 of the compendium, and the two lines that are at the bottom of the table there for SAIDI, the estimated input to SAIDI and then the forecasted SAIDI hours.

Is that -- I just want to confirm. Is that a reliability calculation or a reliability risk calculation?

MR. D'ANDREA: It is a reliability risk measure and it ties to the numbers on page 8 where you were previously showing us the tables.

MS. GRICE: So is this a similar concept to what Hydro One put forward in the transmission rate application?

MR. D'ANDREA: I was not involved with the transmission rate application. I can't answer that.

MS. GRICE: Is there anything in the evidence that speaks to reliability risk and what Hydro One means by that term?

MR. D'ANDREA: I would refer you to panel 5 to talk about the reliability risk.

MS. GRICE: Okay. A final question: For these two tables I've tried to recreate them myself from the evidence and the interrogatories and the undertakings, and I'm having a little difficulty.

Is there an underlying spreadsheet that supports table 4 and table 5? Is that something that Hydro One could provide before panel 5?

[Witness panel confers]

MR. VEGH: Mr. Chair, while the panel is seeing if they can provide that, I would just point out this is the type of question that is typically asked for in an interrogatory or an undertaking at the technical conference, and this material has been around for a while. I'll allow the panel to answer the question, but I'm just making that observation.

MR. QUESNELLE: Noted. Ms. Grice did say she tried to recreate themselves and was unable to, so I don't know when that effort took place, but understood.

MR. D'ANDREA: So we can't answer whether there is a spreadsheet or not behind this or what supports that, but we're willing to take an undertaking on it.

MS. GRICE: That would be great, thank you.

MR. SIDLOFSKY: That will be J1.8.

UNDERTAKING NO. J1.8: TO PROVIDE A VERSION OF THE DATA TO SUPPORT TABLES 4 AND 5, ESTIMATED INPUT TO SAIDI AND FORECASTED SAIDI HOURS.

MS. GRICE: If we could -- if there is any way at all to get that, please, before panel 5, that would be very helpful.

Thank you, I'm finished with my questions. Thank you.

MR. QUESNELLE: Thank you, Ms. Grice.

We'll take our afternoon break. Just looking at the estimated times going forward, it is unlikely we will get everyone in today, but we'll see what we can do, and then maybe at the end of the day, Mr. Vegh, we'll have a conversation about what we anticipate for tomorrow and how we'd like to manage that.

--- Recess taken at 3:23 p.m.

--- On resuming at 3:45 p.m.

MR. QUESNELLE: Mr. Vegh, I understand there was some discussion about tomorrow and the availability of Mr. McDonald, and we've come to a proposal.

MR. VEGH: Thank you, sir. I've discussed with counsel for the intervenors and so the person who's not available tomorrow is Keith McDonald and, an internal Hydro One witness who will be addressing compensation.

And the intervenor counsel have tried to determine can they carve up the cross-examinations in such a way as to be able to efficiently ask questions for the remainder of the panel tomorrow afternoon, and I'm advised that that probably just wouldn't work and that it would be -- we would end up with a lot of duplication and going back around.

So it seems that the most efficient solution to this would be to just stand down until we can have the full panel on Thursday.

MR. QUESNELLE: Okay, thanks. And I understand that moving panel 3 up isn't an option.

MR. VEGH: No, we've investigated that, and that's not...

MR. QUESNELLE: Well, we'll try to make up for it in the coming days and get back on schedule if we can, recognizing that we already have some slippage today. But obviously we will be able to work what in tomorrow; that's not going to cause a problem. We will finish with panel 1 tomorrow, I'm quite sure.

Thank you. I am just looking at my list here. Mr. Segel-Brown?

MR. SEGEL-BROWN: Hello, my name is Ben Segel-Brown. I'm appearing for the Vulnerable Energy Consumers Coalition. We distributed a updated compendium at noon today, and I believe printed copies have been distributed to the panel.

So my first set of questions relates to the...

MR. SIDLOFSKY: Sorry to interrupt. If we could just mark that as an exhibit before you go ahead, that would be great, K1.8.

EXHIBIT NO. K1.8: VECC CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1

MR. QUESNELLE: I take it we have the updated one up here. It will become apparent probably.

MR. SEGEL-BROWN: There is only one page, so...

MR. QUESNELLE: Let's move on then. We'll note it if we get to it and we don't have the right page.

MR. SIDLOFSKY: The updated version is tab 14, so if you could check at the end of that.

MR. QUESNELLE: We do have tab 14. Thank you.

CROSS-EXAMINATION BY MR. SEGEL-BROWN:

MR. SEGEL-BROWN: So my first set of questions relates to the allocation of costs associated with the three acquired local distribution companies.

So if you turn to tab 1, it's stated in this information response that Hydro One distribution has not allocated any increase in corporate common costs to the acquired customers.

MR. ANDRE: Yes, with -- this interrogatory response is in reference to 2016. So in all years up to 2021, there are no allocation of common costs to the acquireds per the agreement on deferred rebasing. Until such time as the acquired utilities are integrated into Hydro One's rate structure, the costs are kept completely separate.

MR. SEGEL-BROWN: Okay. So it's my understanding that if there were an increase in common costs attributable to the acquired utilities, that increase in cost would have to be allocated to them, correct?

MR. ANDRE: If there was an increase in common costs, yes. So common costs -- our position is that Hydro One's common costs do not change as a result of the integration of -- or the acquisition of the utilities. So Hydro One's common costs would not change as a result of acquiring the utilities.

MR. SEGEL-BROWN: So it's your view that you don't, but if they did increase, they would have to be allocated to those classes of customer?

MR. ANDRE: I'm not sure I agree with they would have to be allocated. They certainly wouldn't be -- we wouldn't certainly wouldn't be permitted to collect that from Hydro One's existing customers.

MR. SEGEL-BROWN: Okay. So if you could turn to tab 6, tab 6 sets out a number of cost drivers that are used for the purposes of cost allocation.

So looking at those cost drivers, a financial cost driver is the total capital?

[Witness panel confers]

MR. ANDRE: Yes, I do see that, Mr. Segel-Brown. Of course you understand that here the reference is with respect to allocating common corporate costs between our transmission and distribution lines of business and I'm -- the -- I -- certainly when I refer to cost allocation, I'm referring to the cost allocation for the purpose of setting rates so...

MR. SEGEL-BROWN: Right. I'm not referring to allocation between class -- well, between like business residential customers, but the allocation between business units.

MR. ANDRE: Right. No, I understand that. So we are on the same page.

MR. SEGEL-BROWN: Okay.

MR. ANDRE: This is with respect to common corporate cost allocation.

MR. SEGEL-BROWN: So for the purposes of common cost allocation between business units, you consider total capital to be one of your financial cost drivers?

MR. ANDRE: I don't know if somebody on the panel can answer that. I'm not in the business planning part of Hydro One, so I wouldn't -- I'm not familiar with the allocation of common corporate cost between our D and T businesses. I know that the very next panel, Mr....

MR. LOPEZ: Joel Jodoin is the expert on corporate cost allocation. This is some of the exhibits that you've got before this on Black and Veatch, he is the expert.

MR. SEGEL-BROWN: Okay. Well, the point that I'm trying to get at here is that several of the factors that are identified as cost drivers for the purposes of cost allocation will increase as a result of the acquisition of the three local distribution companies, correct?

And one example of that would be total capital. Another example would be invoices to vendors.

MR. ANDRE: You're correct if some these common corporate costs were being allocated to the acquireds. But as I said, you know, during this deferred rebasing period, the cost to serve the acquireds and Hydro One's legacy customers are kept completely separate. The acquired costs are simply not part of the revenue requirement that we're asking for in this application up to 2021.

MR. SEGEL-BROWN: Am I to take from that -- for example, under the treasury function, you have insurance costs. So for the purposes of Hydro One's insurance, all of the capital assets associated with the acquired utilities, those insurance costs are being kept separate?

MR. ANDRE: I think you need to that I can being take that up with Mr. Jodoin in the next panel.

MR. SEGEL-BROWN: So you are not able to speak to these cost drivers that would arise from the purposes of the acquisition of the local distribution companies?

MR. ANDRE: The cost drivers with respect to the allocation of common corporate costs? No, I'm not able to speak to that.

MR. LOPEZ: I think Joel is the appropriate witness; otherwise, we'll go through this twice.

At a high level, the costs are, for the most part, kept separate. So they are not included in the bucket of costs, they are kept separate and the -- so if we acquired an LDC, they run separately for the period of time and then they're fully integrated after that time period.

And that's when we would bring them into the rate case, and we allocate costs and shared costs. But for the time being, they're run fairly separate.

So they come with admin costs, they come with management costs that were already part of the LDC when we acquired them and they remained separate. They are not included in here, so they don't attract a share of corporate common costs at the Hydro One level.

MR. SEGEL-BROWN: So when we look at cost allocation between business units, there are costs which are specifically associated with the business unit, like you have a set of costs that are clearly associated with distribution, and then you are trying to allocate the common corporate costs over top of that, which aren't clearly associated.

So are you saying that none of the activities, the governance and the support activities which would be captured in corporate common costs are being undertaken by Hydro One for these local distribution companies?

MR. LOPEZ: So right at the top of the structure, there would be an amount that is not allocated to distribution or transmission shareholders under these rate cases.

Any costs associated, or that portion of costs associated with an LDC, for example, that is not included in the rate base for these purposes would be excluded.

So their share, there would be a part at the top of Hydro One that is retained by the shareholder and that part that belongs to -- that we believe belongs to the LDCs would also be retained by the shareholder because it cannot be recovered from the LDC customer and it cannot be recovered from the transmission or distribution customer. But Joel will be able to take you through, like, the actual -- the way that mechanically occurs, and he can demonstrate exactly how that's done in practice.

MR. SEGEL-BROWN: I will have to defer those questions, then.

The next set of questions I should also defer to Joel. They relate to whether or not the cost drivers associated with the acquired utilities were included for the purposes of allocating corporate common costs between distribution and transmission?

MR. LOPEZ: Yes.

MR. SEGEL-BROWN: Okay, so if you could turn to tab 7. So under tab 7 you have identified incremental OM&A activities associated with the three acquired utilities. We can see the portion of those costs related to customer care.

Can you tell me whether the activities captured in the incremental customer care costs are the same as those described in tab 8, which is described in the same for Hydro One?

MR. ANDRE: I don't -- I don't know if all of the items in table 1 that's shown in your tab 8 apply, but certainly call centre operations to the extent that the acquired utilities drive incremental costs from our call centre provider energy, so to the extent that there are additional costs they would be classified as incremental and would be contributing to that customer care line.

Similarly, meter reading; to the extent that there is additional meter reading, incremental meter reading, that would be included, and third-party support. I know postage, so I know increased postage costs are another incremental cost as associated with serving the acquired. So any incremental costs that are under the customer care budget would be included in the line on -- in VECC 55, the table shown in part C.

MR. SEGEL-BROWN: So going down two more lines from where you got to, how is the low-income energy assistance program funding being accounted for in the OM&A figures in Exhibit 7 for the acquired utilities?

MR. ANDRE: So actually, just to be clear, I don't know if I was, I was talking about the table in your tab 8.

MR. SEGEL-BROWN: Um-hmm.

MR. ANDRE: Like, all of those costs are associated with Hydro One.

MR. SEGEL-BROWN: Yeah.

MR. ANDRE: I was referring to the categories. I know that there are incremental costs of that same nature that are associated with serving the acquireds, but they wouldn't be in table 1. Table 1 are just the costs associated with serving Hydro One. I'm not sure if I made that clear. Sorry, your follow-up question was...

MR. SEGEL-BROWN: When we look at the customer care costs in the previous exhibit under C, we were wondering whether the low-income energy assistance program costs are being included there.

MR. ANDRE: Umm... I'm afraid I can't -- I can't say definitively if that's the line where the low-income cost would be or whether it's under "other", because I notice the next line is common corporate cost and "other", so I'm not exactly sure where -- which line they would be associated with.

MR. SEGEL-BROWN: Could you undertake to clarify how the low-income energy assistance program is being accounted for in those figures?

MR. ANDRE: Yes, I could do that.

MR. SIDLOFSKY: That will be J1.9.

UNDERTAKING NO. J1.9: TO CLARIFY HOW THE LOW-INCOME ENERGY ASSISTANCE PROGRAM IS BEING ACCOUNTED FOR IN TABLE 1 OF TAB 7 OF THE VECC COMPENDIUM.

MR. SEGEL-BROWN: So for the purposes of this table that we're looking at here under C, it does include corporate common costs associated with the OM&A. So the cost drivers that we talked about earlier, those were the cost drivers used to allocate those corporate common costs?

MR. ANDRE: No, I don't believe so. These would be the incremental costs associated with serving these utilities, so it would not be an allocation of Hydro One's common corporate cost; it would be to the extent that there are any incremental costs associated with the acquireds, that's what would be identified here. So it's not an allocation of Hydro One's broader corporate common costs.

MR. SEGEL-BROWN: So they are only paying the incremental common corporate costs. They are not being allocated a share of common corporate costs in accordance with Hydro One's usual methodology between business units?

MR. ANDRE: Yes, that would my understanding of what's shown on this table.

MR. SEGEL-BROWN: And for the purposes of allocating between business units were the cost drivers associated with the acquired utilities included?

MR. ANDRE: Again, so if it's allocation between business units it would be Joel on the next panel.

MR. SEGEL-BROWN: Okay, all right. So turning to tab 9. So tab 9 compiles together various places where you've discussed the advantages associated with your revenue cap proposal of the more common price cap proposal, but in listening to you this morning, it sounded like the main difference from our perspective is, between an annual IR and between your custom IR, where your custom IR is allowing an exceptional level of capital expenditures over the next five years, so that's the main reason for pursuing the -- what is the primary reason for pursuing the custom IR over the regular annual IR?

MR. D'ANDREA: So we'll go back to compliance with the rate handbook. First of all, the custom IR is a methodology that is allowed. There are no eligibility requirements, so it is allowed, and it is assessed in terms of our capital requirements, so again, it is the large and varying capital requirements. Because we've gone down the path of the custom IR, we therefore are ineligible for sort of an ECM type model which, as we discussed this morning, is limited to discrete capital projects, and so the custom IR allows us to meet our operational requirements and it helps us admit and integrate the acquired utilities.

MR. SEGEL-BROWN: So when you were talking about this this morning, turning to tab 14, you made references to the precedent of Toronto Hydro. And when we look at the capital expenditures which Toronto Hydro was facing, it was a substantial increase over the recent history and a substantially higher level of planned capital expenditures.

Looking at the same figures for Hydro One, that is not the case. The level of planned expenditures over the next five years is basically an inflationary increase from the last five years of capital expenditures; is that right? That's at the end -- there's two pages later. This isn't quite the most recent figures, but...

MR. D'ANDREA: So again, I go back to the criteria where we're looking at the revenue cap model. The amounts are not large, and they're not consistent -- they are what I refer to as lumpy as we did this morning.

And so if we were follow an ACM type model we wouldn't get enough capital investment needed to fund the distribution plan and the objectives we are trying to achieve there.

MR. SEGEL-BROWN: One of the differences which seems to arise is that all of your capital expenditures for the custom IR period will be recoverable rather than you having to demonstrate that they are exceptional capital expenditures as you would for an incremental capital module; right?

MR. D'ANDREA: They would be recoverable to the extent that we meet our in-service targets and the productivity.

So if we meet our -- so for sure on our in-service as demonstrated through our capital and service variance accounts, our proposal is to have verifiable productivity savings. But essentially, if we're meeting our in-service targets, then we would recover our capital.

MR. SEGEL-BROWN: So the main difference between the custom IR and the standard 7.5 percent would be that you are being allowed to -- you are being allowed to recover a high level of capital expenditures over the five-year period, and you're not having to demonstrate that those expenditures are exceptional.

MR. D'ANDREA: Sorry, what is the 7.5 percent?

MR. SEGEL-BROWN: Oh, that's the -- the total cash working capital allowance, which is 75 percent of total operating expenses plus the cost of power, which is the amount which would be allocated to capital expenditures under a regular IR.

MR. D'ANDREA: I think your question is whether or not we demonstrate that these are exceptional. I think that the investment plan, through our distribution system plan, will demonstrate that these are large non-recurring expenditures. And again, that is why we went with the revenue cap index.

MR. SEGEL-BROWN: So your position is that this level of capital expenditures is large and nonrecurring, and that's why you are entitled to the custom IR?

MR. D'ANDREA: Well, we're entitled to the custom IR as a matter of choice. We have to demonstrate that we are -- the outcomes of a revenue cap model. And as I expressed at the end of today just before the lunch break, we've met all those requirements under the revenue cap model.

MR. ANDRE: And if I could add -- I mean, the Board's handbook on distribution rate applications, in the glossary of terms were where it defines what a custom incentive rate-setting mechanism is, it says:

"While the price cap IR option, along with options such as ICM and ACM, should be adequate for most utilities, some utilities may find that their circumstances, such high growth or significant capital investments, may not be accommodated adequately through the standard approach. Utilities with the significant operating and capital expenditure needs may apply for a multi—year, minimum five years custom IR plan."

So it was contemplated by the Board's regulatory -- renewed regulatory framework that some utilities may have significant capital expenditures that aren't adequately addressed by the price cap plus ACM. And that is our situation, which is why we've applied for a custom IR.

MR. SEGEL-BROWN: Okay. Turning to the price cap versus revenue cap, from your responses this morning, it seemed like the main reason for preferring the revenue cap is that simply it will make it easier to integrate the acquired utilities and the resulting increase in capital and number of customers.

MR. ANDRE: Yes. I think I -- as I said this morning, it goes beyond making it easier to integrate the acquired utilities. I don't know that a price cap approach could accommodate the integration of the acquired utilities in 2021.

In '19 and '20, there really isn't a material difference between price cap and revenue cap, as long as the growth in your -- in your customer base and sales volume is accommodated, they're virtually identical. But the integration of the acquireds in 2021 makes a price cap unusable, as far as I'm concerned.

MR. SEGEL-BROWN: Okay. So at tab 10 -- at tab 10, we included a version of your table 2. That's page 31. Sorry.

MR. ANDRE: We're there.

MR. SEGEL-BROWN: Sorry, it's actually page 33 where we've tried to break out the year-to-year difference in rate base and the capital expenditures.

You've provided updated figures this morning. We were wondering if you could undertake to provide a version of table 2 using your updated figures, which shows the year-to-year difference in rate base and the capital expenditures.

[Witness panel confers]

MR. ANDRE: I'm advised that what we presented this morning changed the categorization of some of the capital between since the renewal in the other categories, but it didn't actually change the total capital investment.

So I don't think that there is -- I think this table would continue to be accurate.

MR. SEGEL-BROWN: So our table is based on the December 2017 update, but I have a note from my analyst that in the May 2018 updates, there were more recent updates to the rate base numbers which we haven't taken into account.

MR. ANDRE: Sorry, just give us a sec.

[Witness panel confers]

So our understanding of what was filed in December is the latest in terms of the forecast spending through the period 2018 to 2022. I know that he in May, we did a filing that updated the actual spend as of 2017 year-end. But I'm -- again, I'm not aware that it changed the forecast for '18 to '22, subject to check.

MR. SEGEL-BROWN: Subject to you verifying our numbers, we have a contrast here between the year-to-year difference in rate base, which for 2019 is 360 million, and the capital spend -- claimed capital expenditures, which are 736 million.

So you agree that there is a difference there? we'll get into it.

MR. ANDRE: Yes, you're -- I mean, given that the first line is rate base, if we change the actuals I would expect it would have changed rate base. So I think the best is to -- is for us to check and verify that if the '18 through '22 information has changed and, as you've requested, if it has changed then to update this modified table 2. So I think it would be best to undertake to do that.

MR. QUESNELLE: You'll take an undertaking taking on that?

MR. SIDLOFSKY: And that will be J1.10.

UNDERTAKING NO. J1.10: TO VERIFY THE '18 TO '22 INFORMATION AND MODIFY TABLE 2 IF REQUIRED

MR. SEGEL-BROWN: So at a theoretical level, the reason why there is a difference between the year-to-year difference in the rate base and the capital expenditure would be attributable to depreciation and the capital spending that is on work in progress?

MR. ANDRE: Yes.

MR. SEGEL-BROWN: Okay. So, Mr. D'Andrea, in I9.CME.6 -- I'm sorry, I don't know the -- Exhibit I, tab 9, CME 6, you indicate that the rate base includes working capital; is that correct?

MR. ANDRE: Yes.

MR. SEGEL-BROWN: So one of the main differences between your proposal and a standard price cap adopted by the Board is that under your plan, you'd make an upward adjustment for all additions to the rate base and not just exceptional capital spending?

MR. D'ANDREA: Well, you keep calling it exceptional. It is whatever we've proposed in terms of our investment plan, that's what we would put in.

MR. SEGEL-BROWN: Right. But you wouldn't have to separately justify that to an incremental capital module like would normally be the process.

MR. D'ANDREA: But following the rate handbook, we are justified in terms of our five-year projection of costs, and those are tested through the distribution system in terms of the investments we want to make, so it is consistent with the custom IR application.

MR. VEGH: Sorry, I hate to interrupt, but I think --

I am getting a bit confused by the line of questions. I think my friend starts -- uses indiscriminately, I think, the concept of a price cap IRM and then an exceptional requirement as it relates to an ICM model or ACM model, and I think that's causing a bit of confusion, at least for me.

The criteria of exceptional does not apply, I believe, to -- to any IRM with a price cap or revenue cap, and so I think that's causing some confusion by adding that qualifier into some of the questions and not the other questions.

If I'm wrong and you want to demonstrate that the criteria of exceptional is relevant to a price cap IRM, then perhaps you could identify that, and I think that will clarify the questions for the witnesses.

MR. SEGEL-BROWN: I'll come back to that.

So the effect of the capital factor is basically to take into account net additions to the rate base rather than capital spending?

MR. D'ANDREA: Correct, with the productivity factor as well.

MR. SEGEL-BROWN: Okay, so how is customer growth factored into the revenue cap proposal?

MR. ANDRE: As I replied this morning, our forecast of capital spend through the '18 to '22 period includes forecast capital to accommodate any growth, and then as far as OM&A is concerned, Hydro One is committing to the rebased amount in '18 and then is committing to live with the OM&A, you know, adjusted with -- for productivity less inflation and stretch, we're committing to live with that and not require any additional OM&A as a result of sales volume growth.

MR. SEGEL-BROWN: Okay, so your rate growth adjustment is modified by a productivity factor, but I don't see how it's modified by the fact that your capital expenditures may be related to customer growth and therefore may require no additional funding in rates.

MR. ANDRE: Sorry, could you repeat your question?

MR. SEGEL-BROWN: So to the extent that you are making capital expenditures in order to meet a growth and demand from your customer base which may not require any additional funding in rates, how is that taken into account in the revenue-requirement model?

MR. ANDRE: That's not taken into -- so it's taken into account in terms of determining the revenue that's to be collected, and then the rates that fall out of that revenue would take into account any change in load, sales volume in those years, so to the extent that sales volume is going up or in the case of '19 going down, that change in sales volume would be factored into the calculation of the rates so that the revenue requirement exactly as identified by the custom IR index, revenue cap index, would be collected, so the rates portion is taken into account at the time that you calculate the rates, taking into account the billing determinants.

MR. SEGEL-BROWN: So the capital expenditure to meet new demand would increase your revenue requirement, but that would be offset by the splitting it up of more people?

MR. ANDRE: Correct.

MR. SEGEL-BROWN: So in addition to your proposal for the recovery of all your rate base additions net of a productivity adjustment, you are proposing a capital in-service variance account. Basically it protects ratepayers from increase in revenue requirement that would relate to any excess of your capital expenditures forecast; is that correct?

MR. D'ANDREA: That's correct.

MR. SEGEL-BROWN: But it is a short-term protection, right? I mean, if you overspend your budget in a particular year, that would be recorded in the rate base and presumably adjusted for at the next rebasing?

MR. D'ANDREA: We're not compensated for any overages.

MR. SEGEL-BROWN: During the custom IR, but it would be included in the next -- potentially included in the next rebasing?

[Witness panel confers]

MR. D'ANDREA: It would show up in our next rebasing.

MR. SEGEL-BROWN: Okay, turning to tab 9. So from the calculations here it appears that you are using a forecast of capital expenditures to adjust your revenue requirement. So the adjustment would occur irrespective of any changes to the actual expenditures or an updated forecast?

[Witness panel confers]

MR. D'ANDREA: Consistent with the handbook, it is based on a forecast.

MR. SEGEL-BROWN: Okay, so looking at tab 10, page 30, table 2, so we have the factors here, the growth factors of 2.84, 2.73, 3.69, and 2.31, so we know in -- why would we not smooth those numbers in order to create a single capital factor adjustment which occurs every year?

[Witness panel confers]

MR. D'ANDREA: Just give us a minute.

[Witness panel confers]

MR. ANDRE: Certainly one of -- we thought there was a response that an -- an interrogatory that asked about that, but certainly one of the factors would be that in 2021, what you see there as a capital-related revenue requirement is really the introduction of the rate base associated with the acquired utilities. And that happens only in 2021, so attempting to smooth the capital spend really would mean that you're dealing with the integration of the acquireds in '19 and '20 to some extent, whereas it can only happen in '21 after the deferred rebasing -- five-year deferred rebasing period happens, so the acquireds is certainly one element of -- that happened in 2021, would be one element in terms of not being able to smooth that.

MR. SEGEL-BROWN: Okay, so the problem with smoothing is that it would allocate costs associated with the acquired utilities in the later years, the legacy customer base?

MR. ANDRE: Yeah, exactly. There is really no way to accommodate the inclusion of the rate base until 2021 -- I'm sorry, the inclusion of the rate base associated with the acquired utilities until 2021.

MR. SEGEL-BROWN: Okay. Could you turn to tab 13. So this is an interrogatory from the Consumers Council of Canada with respect to how you intend to report variances in the capital and service variance account.

My analysts want to know what variances you are over-putting.

Let's say you undertake none of the projects outlined in your application as an extreme, but a whole set of different projects, so if you did the same capital expenditure, that is not a variance that would be tracked, no?

MR. ANDRE: Could you just repeat your question for the benefit of Mr. D'Andrea?

MR. SEGEL-BROWN: The question is what variances are you reporting. It's variances in the level of aggregate capital expenditure, and not variances in the actual capital spend -- which capital expenditures are taking place?

MR. D'ANDREA: That would be correct.

MS. SIGURDSON: If so, how do ratepayers get assurance that the rates they are paying under this rebasing are going towards the projects that you are saying you would undertake on those other projects?

MR. D'ANDREA: Well, there are changes that happen annually in terms of our capital program. So we set up a forecast and we maintain a work envelope and those priorities change during the year. We may have a mandated project, or there may be a shift in priorities, or demand work may come up.

But at the end of the day, we are still targeting towards an in-service target and that's what holds us accountable.

MR. ANDRE: Then I would add that at the next rebasing, the details regarding the spending that occurred over that five-year period would be part of the evidence submitted as part of our next application. And then intervenors and the Board would have an opportunity to review exactly what the capital was spent on.

MR. SEGEL-BROWN: So the only control regarding what capital expenditures take place during the five-year period will be the threat of them not being included in the rate base upon rebasing?

MR. D'ANDREA: No, the control is that we have certain targets that we have to meet. So we've talked about the OEB scorecard, our internal scorecard, and the team scorecard, and those are all linked together. So to the extent that we have certain objectives to meet, they all tie in together in terms of the scorecard. So there is a control mechanism there.

MR. SEGEL-BROWN: So the scorecards relate to performance outcomes primarily, right?

MR. D'ANDREA: Correct.

MR. SEGEL-BROWN: So those would be tracking the extent to which capital expenditures impact on performance and not -- never mind.

So you're proposing a midterm adjustment to the cost of capital for the rate base. Can you explain the theory of this adjustment in a -- sorry. So why is there a cost-of-capital adjustment midterm when this wouldn't usually occur under a price cap formula?

MR. D'ANDREA: The reason -- excuse me -- the cost-of-capital update is coincident with the integration of the acquired utilities. So at that time, we would update the load forecast and the cost of capital to more equitably allocate the cost between legacy Hydro One customers and the acquired utility customers.

So it is not an annual update. It is a one-time update as an event. That event is the integration of the acquired utilities.

MR. SEGEL-BROWN: But during the update, the update is not limited to adding the capital associated with the acquired utilities. It's also reviewing all of your capital.

MR. D'ANDREA: No. What we're doing in 2021, we add the OM&A that is associated with those acquired utilities and we add the capital base, similar to if there were almost a cost of service. But you're adding that cost of service element of the acquireds into the midterm application. And again, that's why we went back with the revenue cap model; it's easier to integrate it that way.

MR. SEGEL-BROWN: So -- sorry, I was hearing you talking about it this morning, and I got the impression that during the midterm review, it would be all of the capital cost that would be reviewed and not just those associated with the newly acquired utilities.

MR. D'ANDREA: No, we are setting the capital element for our legacy customers today on a five-year forecast. What we do in 2021 is we add the rate base associated with those acquired utilities.

So if you were to go to table 2, you will see -- it is not specifically highlighted there, but in one of the interrogatories it is. It's that you are adding the rate base, basically those acquired utilities in 2021.

MR. ANDRE: And proposal is perhaps -- maybe I'm misunderstanding you. But the proposal is to update the cost of capital, so the rate of return associated with the addition of that rate base, not to change the level of capital spend.

MR. SEGEL-BROWN: Oh?

MR. ANDRE: We're not changing the capital spend. We are updating the cost of capital to whatever the Board's proscribed rate is in that year.

MR. SEGEL-BROWN: So is the only factor that is changing the addition of the amount associated with the acquired utilities? Or it sounds like you are also updating to use the current Board rate at that time?

MR. ANDRE: Yes. So for 2021, Hydro One has a forecast of its capital spend on -- for its, you know, Hydro One legacy customer classes, and then it has -- in 2021 also, it adds the rate base associated with the integration of the acquireds.

And then for both of those components, we'll be calculating the cost of that rate base at the new cost of capital that the Board has proscribed at that point in time.

MR. SEGEL-BROWN: So an incidental effect of your proposal is that it's protecting Hydro One against a potential change to the cost of capital that -- between what is forecasted for 2021 and what actually occurs?

MR. ANDRE: I think you've correctly characterized that as incidental. Yes, that would happen. The reason for doing so is to ensure that the cost -- because those acquired utilities haven't been rebased in some cases since 2011.

So we want to ensure at that time in 2021 when we take Hydro One's total costs and allocate a portion of those costs to serving the acquired utilities, we want to make sure that the inputs that go into that cost allocation model that's going to divvy up the costs and assign a certain portion to the acquireds, we want to make sure that that is the best reflection we can of what it costs to serve those acquired utilities.

That's why cost of capital and the load forecast is what we propose to be updated, because the load forecast is another key contributor in the cost allocation model in terms of how much a particular rate class attracts of the total costs.

So the two components are both tied to the integration of the acquired utilities.

MR. D'ANDREA: And if I could add on that, you mentioned that it would protect Hydro One. We're agnostic on the cost of capital because we don't set the cost of capital. So whichever way it goes, we will update at that time in 2021. It's an exogenous factor.

MR. SEGEL-BROWN: So it's only effect is to ensure you -- well, you'll have to bear the change either way. Okay.

Those are all my questions. Thank you.

MR. QUESNELLE: Thank you. Thank you very much, Mr. Segel-Brown. Ms. DeMarco?

CROSS-EXAMINATION BY MS. DEMARCO:

MS. DeMARCO: Thank you, Mr. Chair, and thank you, panel. I have just a few questions of clarification, largely in and around how customer consultation informed HONI's choice of revenue cap and the appropriateness of the capital factor. And specifically, I believe this follows on a few questions that Mr. D'Andrea responded to in relation to questions posed by Mr. Ladanyi.

So if I could take you -- we do have a compendium that we passed along just recently -- to tab number 1, and very specifically at page 003.

Unfortunately, we have the numbering configuration where you have zeros in front of all the page numbers.

MR. SIDLOFSKY: Sorry, Ms. DeMarco, if I could just stop you for a moment. That will be Exhibit K1.9.

EXHIBIT NO. K1.9: ANWAATIN CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 1

MS. DeMARCO: Thank you. I should have asked to have that marked. My apologies, Mr. Sidlofsky.

So at page 003, which is an excerpt from Exhibit A, tab 3, schedule 1, at pages 2 and 3, you speak very directly at the bottom of that page indicating that the planning process followed by Hydro One also resulted in significant reductions in investments in 2018, to mitigate customer rate impacts in that year.

And you conclude that as a result, the entire application is responsive to Hydro One's customer needs and preferences.

Do I have that right?

MR. D'ANDREA: Sorry, I'm reading the same statement, yes.

MS. DeMARCO: So quite specifically, it's your view that rate mitigation through the decreased investment is in fact responsive to your customer needs an preferences?

MR. D'ANDREA: Yes, based on our customer input, price was more important than reliability for the residential customers.

MS. DeMARCO: But fair to say that price isn't the only customer need and preference that you heard about; is that right?

MR. D'ANDREA: No, we heard about reliability as well.

MS. DeMARCO: Could we look at some of those specific instances where you heard about reliability. And very specifically, can I ask you to turn to tab 2, which is at page 9 of the brief, which is a response of Anwaatin in relation to IRs posed by Hydro One --

MR. ANDRE: Sorry, I don't believe we have -- are you referring to a brief? Is this a compendium that you have?

MS. DeMARCO: A compendium, I'm sorry.

MR. ANDRE: Yeah, none of the panel members have --

MS. DeMARCO: It is up on the screen.

MR. ANDRE: Ah.

MS. DeMARCO: And very specifically, HONI asked about community engagements in which Anwaatin participated and raised issues of reliability. Have I read that correctly on the page?

MR. D'ANDREA: Yes.

MS. DeMARCO: And the response, if I can just take you up to page 7 of the compendium, is outlined very specifically, where Anwaatin stated that:

> "Poor system reliability and the disproportionate negative impact on First Nations was a concern."

Do you see that?

MR. D'ANDREA: I do.

MS. DeMARCO: And then secondly at number 2 it indicated that First Nations communities raised concerns about the high frequency and duration of power outages. Do I have that right?

MR. D'ANDREA: Yes.

MS. DeMARCO: And then thirdly, we have issues of First Nations raising considerations about how distributed energy resources might be used to solve some of these concerns; do I have that right?

MR. D'ANDREA: Yes.

MS. DeMARCO: And can I ask you now to turn to -- so fair to say based on those considerations you heard about reliability specific to First Nations communities?

MR. D'ANDREA: We did.

MS. DeMARCO: And you heard about distributed energy resources specific to First Nation communities?

MR. D'ANDREA: Yes.

MS. DeMARCO: Great. At tab 3 of the compendium, which is Exhibit B1.1.1, section 1.3, attachment 4, that's the report on your specific First Nations engagement session. It starts at page 15, 015 of our compendium. The introductory page outlines some of the summaries, and then I'm going to ask you to move on to page 7 of that report, which is at page 18 of the compendium. And we have Chief Melvin Hardy, and I'm going to try this as a source of comic relief, at Biinjitiwaabik Zaaging Anishinaabek First Nation. And if you want to read through that, he specifically describes his concerns about reliability and outages, extreme outages in the First Nation community. You would agree with that?

MR. D'ANDREA: I see the statements, yes.

MS. DeMARCO: And you agree that he raises reliability concerns there?

MR. D'ANDREA: Yes.

MS. DeMARCO: And then if I can ask you to just move a page further down where we speak -- we see Chief Jim Leonard speaking of Rainy River First Nation. That one is a little easier to pronounce. He describes how his community is looking for solutions and attempted to develop, going on to the next page, solar resources; do I have that right, that reference? Yes, a solar farm in relation to addressing some of those concerns; do I have that right?

MR. D'ANDREA: I see that.

MS. DeMARCO: And you'd agree that that's certainly a possibility to use distributed energy resources to address --

MR. D'ANDREA: That's one possibility, yes.

MS. DeMARCO: Thank you. So fair to say that you heard about both reliability and distributed energy resource as part of the customer needs and preferences?

MR. D'ANDREA: Yes.

MS. DeMARCO: Could I ask you to turn back to the first page of that document, which is the notes on the First Nations engagement and specifically the note-taking summary of First Nations key messages. Do you see that paragraph?

MR. D'ANDREA: I'm reading it, yes.

MS. DeMARCO: Do you see any reference to reliability and distributed energy resources in that paragraph?

MR. D'ANDREA: I don't see any reference to reliability, no.

MS. DeMARCO: So despite the fact that these were raised, it is not necessarily reflected in the key messages, fair to say?

MR. D'ANDREA: Other than the top part of it, which, it says "note-taking summary of Hydro One key messages". It says:

"We are working with First Nations through honest and respectful engagement and we are working to improve service responsiveness and reliability of the power system and we are committed to finding solutions to address affordability."

MS. DeMARCO: So those are the Hydro One key messages, but in terms of the First Nations key messages, we don't see those two aspects reflected in the First Nation?

MR. D'ANDREA: Not in that paragraph, no.

MS. DeMARCO: Thank you.

So you would agree with me that those are, in fact, customer needs and preferences that you would want to address?

MR. D'ANDREA: Correct.

MS. DeMARCO: Let's move on to a few clarification questions if I can on your scorecard, which is our compendium at tab 3A and the specific targets reflected there at, I believe that's page 024 of our compendium. And at the bottom of that page.

You've got that up? I'm focused on the two lines related to SAIDI, the duration of interruptions, rural, and SAIFI, the frequency of outages in the rural communities, along the trend line from 2011 to 2016, reflecting 2017 actuals and 2017 target. Let's start with first SAIDI, the duration of interruptions in rural communities. We, in

2011, are at 8.2, 2012, 8.2, 2013, 8.1. We see an increase in 2014, so that's a longer duration of outages in 2014, to 8.6. We go to 9.1 in 2016 and -- 2015 and 2016; do I have that right?

MR. D'ANDREA: That's right.

MS. DeMARCO: And it's reflecting power being out for a longer period of time in those rural jurisdictions; is that fair?

MR. D'ANDREA: That's fair.

MS. DeMARCO: And fair to say that it got even worse in 2017, it went up to 9.4?

MR. D'ANDREA: It did.

MS. DeMARCO: Would you take, subject to check, that your target for 2017 and your target SAIDI for 2018 are worse than the average that your actual SAIDI was for 2011 to 2016?

MR. D'ANDREA: It is.

MS. DeMARCO: And I --

MR. ANDRE: Sorry, if I could just add, I mean, I think there needs to be an appreciation that those numbers would, of course, reflect the conditions in those years, particularly the frequency and type of storms, and I know wind storms can be particularly troublesome in terms of causing frequency of outages, and then depending on the type of storm, again, snow or conditions that create accessibility problems will impact the duration of outages.

So I think what you're seeing there is not so much, you know -- it is not necessarily the underlying system that is getting worse, as those numbers might suggest. It could have a lot to do with the frequency and nature of the storms that are experienced in those years, and you'd really have to look -- I think just looking at those high-level numbers is not sufficient or adequate. You really have to look at the underlying data that supports those numbers and the analysis that supports those numbers to better understand what is it that's driving that trend that you see.

MS. DeMARCO: So is it your view as you understand it, Mr. Andre, that the frequency and nature of the storms has gotten consistently worse in perfect correlation with the SAIDI numbers there?

MR. ANDRE: The storms and weather, I know in terms of how it impacts load, they act randomly, and so you can absolutely have two or three years of storm conditions that could make things worse, followed by two or three years of better conditions. All I'm suggesting is that, to look at the top-level numbers without looking at the underlying data and the underlying analysis that is driving that I think may paint an inappropriate or incorrect picture.

MS. DeMARCO: Could I ask you to undertake to provide that underlying data and analysis that you are referring to right now?

MR. ANDRE: I would expect and imagine that some of that is already in our evidence.

MS. DeMARCO: I must have missed it. I did search for the associated underlying weather-related data to try to find some explanation why the SAIDI is getting progressively worse over time. So I wonder if you could help my simple mind find that and undertake to provide the data and analysis.

MR. ANDRE: So I think my premise that the -- there are other factors that impact reliability at a high level; there are a number of factors that go towards that. I don't think that is an issue that can be disputed.

Clearly, there are a number of factors that drive those reliability performance numbers. That's the only point I'm trying to make.

MS. DeMARCO: I'm just a little...

MR. ANDRE: And I don't have access to that data, so I'm not aware of what data is available. But having been in the asset management group in my previous career, I do know from looking at that data in the past that there are a number of factors that can drive reliability.

MS. DeMARCO: So is it fair to say that the asset management group has access to that data?

MR. ANDRE: The asset management group would have additional detail, yes.

MS. DeMARCO: I wonder if you could undertake to have the asset management group support the submissions that you are giving in response here?

MR. VEGH: Sorry, just to clarify, Mr. Andre wasn't making submissions. He was saying that there are a number of factors can address the duration. And I agree with Ms. DeMarco that probably the panel that is best to specifically dive into what these factors might have been behind these numbers would be the asset management group, and particularly the evidence in the DSP.

I think Mr. Andre was giving a general observation and not trying to identify the reasons for these particular outage measures in that period.

So I think this is a matter that's probably best addressed through the asset management panel in terms of the details behind these numbers.

MR. QUESNELLE: I suppose, like other items that we've determined that we've got the best answered by a subsequent panel, Mr. Vegh, if any production of information could be provided in advance of them testifying, that a would be of assistance to Ms. DeMarco, I'm sure.

MR. VEGH: Thank you. We'll identify that evidence in advance.

MR. QUESNELLE: Great. Thank you.

MR. ELSAYED: Could I just clarify? With the asset management and talking about the DSP address trends associated with historical data?

MR. VEGH: They will address force majeure and be able to provide better information, in any event, than this panel on what may have been the factors in 2015, 2016, and 2017 with respect to interruptions longer than other periods.

I'm not sure what kind of information that they would have on that, but they would have better information than this panel would have on that.

MR. ELSAYED: Thank you.

MR. LOPEZ: I think they could also talk to not only the past, but the trend going forward because this stops at 2018. For example, vegetation-related management is designed to bring that SAIDI down, and that's the reason why we took that on. It is more cost-effective, but it is also more effective from a SAIDI perspective.

So a view on the past, but also what's happening going forward.

MR. QUESNELLE: Ms. DeMarco, is there anything in particular that you would like to have in advance? Or if they could just note what's on the transcript here and provide what information they have, would that be satisfactory?

MS. DeMARCO: Yes, I think there are two aspects that I'd love to see. The first is that based on what I'm hearing, I think there is a general agreement that we have no specific data as to what may have been the factors for those trends in SAIDI going down from this panel. Do I have that right?

MR. LOPEZ: I think we can't answer it whilst we're here today, but the data will be available. So we'll be able to get that data compiled.

MS. DeMARCO: So you will undertake to provide that data for me?

MR. VEGH: I'm sorry, could you repeat again what it is -- what's being undertaken is to advise where this data is available in the evidence, so that you can ask questions about the proper -- with the proper panel with respect to that data.

MR. QUESNELLE: I would take it if it's not in the evidence now, but if it exists, it will be produced?

MR. VEGH: Yes, sir, if you'd find that helpful.

MS. DeMARCO: That's perfect. Thank you. And I'm going to ask the same questions about...

MR. SIDLOFSKY: Sorry, Ms. DeMarco, that will be J1.11.

UNDERTAKING NO. J1.11: TO PROVIDE THE EVIDENCE AND PRODUCE THE DATA IF IT EXISTS TO SUPPORT THE SAIFI TREND AND THE SAIDI TREND

MS. DeMARCO: Thank you very much. Sorry about that.

Panel, with apologies, I'm going to ask the same questions about SAIFI in the rural context. And if I can just take you through there, we've got an average SAIFI in the rural context of 3.3 in 2011, 3.3 in 2012, 3.0 in 2013, 3.42014 -- 3.4 in 2015, 3.1 in 2016, and an actual of 3.0 in 2017. In the same context, is it fair to say that the target for 2017 is worse than the 2011 to 2016 average, subject to check?

MR. D'ANDREA: The target is worse than the historical numbers, yes.

MS. DeMARCO: And I wonder if we can expand the undertaking that was just given to include the SAIFI factors as well?

MR. D'ANDREA: I would have expected nothing less.

MS. DeMARCO: Thank you, Mr. D'Andrea. Safe to say as a matter of issue, reliability was a focus of the auditor general, as well. You would agree with that?

MR. D'ANDREA: Yes.

MS. DeMARCO: Thank you. I'm going to ask you a few questions now regarding productivity, and I'll ask you to turn to tab 4 of our compendium which starts at -- I believe it's page 026 of the compendium.

As I read it, and you will correct me if I've got this wrong, this is from A3, schedule 2, page 4, the productivity is actually decreasing over the 2002 to 2015 period as well; do I have that right? That's Hydro One's own productivity.

MR. FENRICK: Yes, that's correct.

MS. DeMARCO: And you propose a stretch factor of 0.45 percent, which is less than the 0.6 percent proposed by the Board; is that right?

MR. FENRICK: Proposed by the Board? What do you mean by that?

MS. DeMARCO: The average 0.6 percent of the category of the stretch factor that the Board originally put Hydro One in; is that correct?

MR. FENRICK: Through the fourth-generation IR at the time of this writing, it was 0.6 percent, as we discussed this morning. Then the 2017, an update came out and Hydro One was put in the group 4, the 0.45 percent which aligned with what our econometric benchmarking study, as well as PEG's report produced by OEB Staff.

MS. DeMARCO: I'm going to come to your econometric study. But let me just, at a very macro level -- humour me so I that understand what's going on -- the TSP is effectively a derivative measure, a change of outputs and change of inputs over time; is that fair?

MR. FENRICK: That's fair. It is measuring a trend, either through the industry or a specific company. It is measuring a trend in the ratio of outputs to inputs.

MS. DeMARCO: And that trend is retrospective in the first instance, in terms of your TSP study analysis, an excerpt of which is at tab 5 of our compendium; is that fair? It looks backward?

MR. FENRICK: Yes, it's looking at historic years, right.

MS. DeMARCO: And then to litmus test your conclusions, you looked at and conducted an econometric benchmarking study of total distribution cost; is that fair?

MR. FENRICK: I don't know about the litmus test part of that. But yes, we conducted a total cost econometric benchmarking study to design what the total stretch factor -- and so we could recommend the stretch factor for Hydro One.

MS. DeMARCO: So there are ways that you can do that. You can look at your peers, or you can go at it from an econometric basis. Is that fair?

MR. FENRICK: Through -- if you look at the fourth-generation IR and the Board's decision there, the preference was certainly for econometric total cost benchmarking.

If you go back to third-generation incentive regulation, there was both a peer group and econometric benchmarking study that played into the stretch factors.

But by the fourth generation, the Board decision focused solely on the econometric total cost benchmarking, and I'm also a proponent of that approach, as I believe it is a far more accurate measure of performance.

MS. DeMARCO: Okay. So can I ask you to turn to, thank you, page 29 of our compendium, which is, I believe, your assessment of the Hydro One annual TFP growth rate trends. Do you have that?

MR. FENRICK: I do, yes.

MS. DeMARCO: Now, for my very simple mind, I'm just trying to understand, where we have a negative productivity, it means that productivity is in fact getting worse?

MR. FENRICK: It -- from a high level it means that ratio for Hydro One, the ratio of the output index to the input index is going down, so the total factor productivity would be declining in that given year.

Now, there is a whole host of other aspects that do not play into that, the reliability and the safety measurements, as well as a whole host of other outputs that aren't encapsulated in that measure, but in a very simple level, the outputs produced by Hydro One divided by the input quantities of Hydro One are going down if there's a negative TFP --

MS. DeMARCO: So outputs over inputs equals productivity. Productivity is going down.

MR. FENRICK: In that -- in a given year, where there is negative productivity, yes.

MS. DeMARCO: So over the period of time that you've got here, 2003 to 2015, I believe it's your calculation that productivity has gone down by almost a full percent; is that right? 0.9 percent?

MR. FENRICK: Over that entire period as a negative 0.9 percent. If you look at the more recent period it's a positive .5 percent after we've looked at the reliability and safety adjustments, but over that entire period, yes, there is negative -- we are finding that there is negative productivity from Hydro One.

MS. DeMARCO: And to determine what the appropriate stretch is, you then did your econometric benchmarking study; is that fair?

MR. FENRICK: That's fair, right.

MS. DeMARCO: And you looked at not just backward-looking trends and costs but also projected forward-looking total distribution costs or estimates of total distribution costs; is that right?

MR. FENRICK: That's correct. We looked at both the historical actuals from Hydro One and then looked at the company's projected spending levels and put those into econometric benchmarking model to give the Board and stakeholders an idea of what the projected costs and what those would look like from a benchmark analysis.

MS. DeMARCO: So it's in that forward-looking aspect of your study that I want to ask just a few general contextual questions, almost in a macroeconomic context.

Is it fair to say that the industry is changing quite dramatically at this point in time?

MR. FENRICK: How so? When you say "dramatically", I mean, there is certainly a number of things going on as far as distributed energy resources and energy storage and those types of things. I don't know if the underlying cost structures are necessarily changing dramatically, but there certainly are changes ongoing in the industry.

MS. DeMARCO: You've heard the term "disruptive innovation"?

MR. FENRICK: I have.

MS. DeMARCO: And you've heard it applied to the current energy context?

MR. FENRICK: Yes.

MS. DeMARCO: And you would agree that there is some disruptive innovation going on in the current energy context?

MR. FENRICK: I think on some level, I mean, that remains to be seen, but there is certainly a potential that with new technologies, processes will be changing and things like that. There is certainly that possibility in the future.

MS. DeMARCO: And part of that might be due to the use of data, for example?

MR. FENRICK: That's one potential, using big data to find increased efficiencies and things like that. That is certainly a possibility.

MS. DeMARCO: And the other might be in relation to distributed energy resources, for example?

MR. FENRICK: That's likely too -- you know, if DR penetration increases that would have an impact on the industry, yes.

MS. DeMARCO: And as I understand your forward-looking econometric benchmarking study, there were no specific controls or deviations for big data or distributed energy resources; is that fair?

MR. FENRICK: As far as fashioning, like, the benchmark in those future years, no, there was no prediction, if you will, of what the industry would look like in future years. We're using the historical -- the historical data to fashion those benchmarks to look at all the variables and see how those are correlated with costs, and that is on a historical perspective, and then we apply that to the projections, but you're right, it is based on the history, because that's essentially all we have right now.

MS. DeMARCO: So history for the TFP and some forward stuff for the stretch factor of the X-factor. Fair to say that the X-factor doesn't include those assumptions?

MR. FENRICK: What assumptions are you referring to?

MS. DeMARCO: Assumptions around distributed energy resources and big data.

MR. FENRICK: Right, yeah, to the extent those will change in the next five years, there's no correction or adjustment for those types of things.

MS. DeMARCO: And they're not included in the estimates that you applied in the econometric study either?

MR. FENRICK: That would be accurate to say.

MS. DeMARCO: Thank you. I'm going to ask you one last series of hopefully very quick questions in relation to the Z factor that you proposed, and I'm at tab 6, the last tab of our compendium, at page 31. And you outlined there a number of events that you may, in fact, treat as a Z factor. Have I got that right?

MR. D'ANDREA: That's right.

MS. DeMARCO: And what I understand to be a Z factor is something that will be outside of your revenue cap; it will be a pass-through of costs to customers. Do I have that right as well?

MR. D'ANDREA: Right. It would be an application to the Board.

MS. DeMARCO: And what you are including as possible classifications of those Z factors would include extreme weather events, investments that are government-mandated or otherwise outside of management control? Is that fair?

MR. D'ANDREA: Fair.

MS. DeMARCO: You've got regional planning as one of those investments that are government-mandated and outside of Hydro One's control. Do I have that right?

MR. D'ANDREA: Correct.

MS. DeMARCO: Isn't regional planning something that you as Hydro One would do in the normal course of business?

MR. D'ANDREA: It would be, but if it were an investment, say, that the IESO thought was prudent in terms of regional planning that was beyond our control, we were mandated to do it, then that would be a candidate.

MS. DeMARCO: So if the IESO told you to do it, it's eligible to be outside of the revenue cap?

MR. D'ANDREA: It is eligible. We would have to see if it met the criterias, the criterias of causality, prudence and all that kind of -- but if it's beyond our control, if it's material, it meets the criteria, then it is eligible as a Z factor.

MS. DeMARCO: So do I read this right that conservation and demand management would fit in the same classification? It is not business as usual? This is something that's eligible as a Z factor?

MR. D'ANDREA: If you'll just give me a moment.

We had a response on one of our interrogatories, it is tab 15, BOMA.63, where we talk about CDM as an example for a Z factor.

MS. DeMARCO: So fair to say that it is in fact something you are considering outside the potential for --

MR. D'ANDREA: I would just say it is a candidate.

MR. ANDRE: Just to clarify, I think it is an example of a program that could be mandated by the government. CDM is -- there is an LRAM variance account, and so CDM is dealt with, you know, through other mechanisms. I think in the context of the Z factor it was simply being used as something that's being -- that was mandated by the government. I don't think CDM in and of itself...

MR. D'ANDREA: And that's what the response is, right? It says CDM is an example of it, given the LRAM methodology, we would not seek recovery. However, it says:

"Hydro One may seek said recovery in the future should a similarly impactful government-mandated investment arise."

MS. DeMARCO: So as I read this list, I was struck with the thought that anything that the OEB requires you to do as part of your rate application, anything that the government requires you to do as a matter of normal course could potentially be subject to a Z factor application outside of your proposed revenue cap. Have I read that wrong?

MR. D'ANDREA: Outside the rate case, yes. So you are in the middle of the IRM period, and a material non-controllable event happens, weather-mandated or a storm as the examples we've pointed out, those would be candidates for a Z factor, and we would make an application and would be subject to due prudence.

MS. DeMARCO: So just bear with me while I tease this out a little bit. The OEB in this decision requires you to do something. Is that a potential Z factor?

MR. D'ANDREA: No, the Z factor falls outside of your rate case. So once you've got your rate case and your decision, you are now into your IRM period. If the OEB were to decide for us to do something in this application and we were mandated, then of course it would be embedded in whatever rates are approved by this Board.

If, let's say, next year an event happened where we were mandated to do something, again meeting all the criteria outside of our control, then that is a scenario where we could apply for a Z factor or would be eligible for a Z factor, assuming we met the criteria.

MS. DeMARCO: And that would be in addition to your revenue cap? That would be outside of your revenue cap?

MR. D'ANDREA: If the OEB approved it, yes.

MS. DeMARCO: So can I just focus very specifically on storms. You've got all storms there. Are we talking very specifically the one-in-ten-year storm; would that potentially be a Z factor?

MR. D'ANDREA: Potentially. So it's events that -- and the way Z-factor is applied is it's applied on an event basis.

So if it was the ice storm, let's call it, one of the major ice storms, then that would be a candidate because it is beyond normal business circumstances and our budgets include planned costs for storms. But in an ice storm situation, as an example, it would be over and above; it would be material. We did all the right things, but we would ask for recovery through a Z factor, potentially.

MS. DeMARCO: So in this evidence, you haven't stipulated the threshold or the materiality level. But you are certainly willing to stipulate a materiality or a threshold level?

MR. D'ANDREA: In our response to 16.CCC.18, it is a million dollars, consistent with the Board's requirements.

MS. DeMARCO: And other materiality thresholds that you'd be willing to -- for example, the one-in-a-hundred-years storm, as our ice storm was, or is it strictly a financial threshold?

MR. D'ANDREA: Well, it is largely financial. I would -- I am hard-pressed to believe that we would go for a second Z factor for a million dollars, so it would have to be very significant.

MS. DeMARCO: Would you consider updating the threshold of the Z factors that you would in fact go for?

MR. D'ANDREA: Well, we're applying the Board's policy for the materiality threshold, so we are trying to be consistent with the handbook.

MS. DeMARCO: Would you be consider being more conservative than the Board's policy to give stakeholders ease?

MR. D'ANDREA: I don't think it's my place to say whether I would change the rules. We are trying to follow what the OEB set out.

MS. DeMARCO: So the bottom line is we could end up back here for anything above a million dollars in terms of these?

MR. D'ANDREA: I don't expect us to be here for a million dollars.

MS. DeMARCO: I'm going to ask you one tough set of questions around last week's outcomes. Very specifically, you've got as a Z factor changes to government policy, legislation, or regulation. Fair to say that we've had a fairly large change in government last week?

MR. VEGH: Mr. Chair, I'm not sure where Ms. DeMarco is going on this. The criteria is laid out in the Board's handbook, it is laid out in the evidence. You know, to speculate on what a government-elect may or may not have as a policy, I don't think is appropriate in this application.

MS. DeMARCO: I'm happy to let it go. Those are my questions.

MR. QUESNELLE: Thank you, Ms. DeMarco. I think we'll wrap up there as far as cross-examination goes today. Ms. Girvan, I'll have you up first tomorrow, followed by Mr. Brett. And as we discussed earlier, the scheduling won't allow us to do any more than panel 1 tomorrow and we'll see you in the morning.

And I'd like to -- just looking what we have estimated, it looks like we are on target to finish up before a lunch break. I'd like to not interrupt the short day with a lunch break. I'd like to go until lunch and if that takes us to one o'clock or whatever, let's plan on doing that and then we'll not sit again until Thursday morning with, starting with Panel 2 at that time.

One other item, and this is just a continuation of a conversation we had this morning regarding the treatment of the pension and post-employment benefits, Mr. Vegh, it would be the Board's preference to have this dealt with in conjunction with the elements that referred to -- or reflect the requirements in the transmission as well, so not deal with it here.

But that's what a caveat, and we'd like to get a better understanding. You don't have to respond it to it now. We can revisit this again tomorrow. The Board is not clear as to whether or not what's being requested now -- or, sorry, if it's not dealt with now, whether or not that places any kind of artificial limitations on the Board's discretion or range of possibilities, if dealt with later, the approach.

If Hydro One's approach now is setting up a situation where we can't revisit the full range that are available to us now, we'd like to know that and that's kind of a caveat to our preference. So if you could think about that and let us know tomorrow. Okay.

MR. VEGH: Thank you.

MR. QUESNELLE: Thank you. With that, we will adjourn until 9:30 tomorrow morning.

--- Whereupon the hearing adjourned at 5:12 p.m.